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Exhibit #: ACAA 1-4; TASC 1-2, 4-25

Part 4 of 8

For Part 5, see Barcode 0000169260

BEFORE THE ARIZONA CORPORATION COMMISSION

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2015 NOV 5 PM 4 46

COMMISSIONERS

SUSAN BITTER SMITH, Chairman
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO.E-04204A-15-0142 **TESTIMONY OF CYNTHIA ZWICK ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION**

Enclosed please find the testimony of Cynthia Zwick on behalf of the Arizona Community Action Association in the matter of Unisource Electric, Inc.'s rate case.

RESPECTFULLY submitted this 5th day of November, 2015

Cynthia Zwick
Executive Director
Arizona Community Action Association
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EXHIBIT
ACAA-1
ADMITTED

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, Chairman
BOB STUMP
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DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO.E-04204A-15-0142 **TESTIMONY OF CYNTHIA ZWICK ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION**

DIRECT TESTIMONY OF
CYNTHIA ZWICK ON BEHALF OF THE
ARIZONA COMMUNITY ACTION ASSOCIATION

November 5, 2015

Q. Please state your name and business address.

A. My name is Cynthia Zwick. My business address is 2700 N 3rd St., Ste. 3040, Phoenix, AZ 85004.

Q. What is your position at the Arizona Community Action Association?

A. I serve as the Executive Director of Arizona Community Action Association (ACAA). I've served in this position for over twelve years.

Q. Please describe your background and work experience.

A. ACAA is a non-profit organization that advocates on behalf of Community Action Agencies and the low-income community throughout Arizona. ACAA works with community partners throughout the State to: educate the community about issues related to poverty, improve public policy, and ensure low-income families have access to the tools needed to become and sustain self-sufficiency.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to request that the Arizona Corporation Commission consider the low-income customers of UNS Electric Inc. (UNSE) in this rate case. Specifically, with regard to this filing, I request that you:

- Hold harmless low-income CARES customers from the modifications in UNSE's deposit rules;
- Maintain the length of a deferred payment plan as six months; do not decrease it to three months;
- Set a goal of increased participation in the CARES rate schedule of 50%;
- Modify the Termination Notice Requirement to contain the contact information for local Bill Assistance and Weatherization agencies;
- Offer a current limiter as an alternative to disconnection for low-income customers; and

- Provide the agencies that distribute Warm Spirit Assistance with a 10% Program Delivery Fee.

Q. In what ways are low-income utility customers uniquely challenged?

Low-income customers face a number of challenges not present in the larger community. Specifically, low-income customers experience a higher energy burden than the average population. The energy burden, defined as a measure of energy costs divided by total income, measures the strain that utility bills put on a household budget. Typically, the energy burden is about 3% for the average population. For Arizonans in poverty, their energy burden is 14%. That's roughly one in every seven dollars coming in the home going out again to provide the basic heat and light the family needs to be safe and secure. For Arizonans in deep poverty, the numbers are even more dire. The energy burden for households with income less than 50% of the Federal Poverty Guideline is 19%. That's nearly one in every five dollars of income going right out the door to keep the lights on. The burden is slightly more severe in Mohave County, and even greater in Santa Cruz County.[1]

Many such customers seek assistance through programs such as the federal Low-Income Home Energy Assistance Program (LIHEAP). A survey of LIHEAP recipients found that nearly 90 percent of recipient households have at least one vulnerable member—defined as someone who is age 60 or older, age 18 or younger, or disabled— for whom a loss of heat in the winter or cooling in the summer could have serious health and safety implications. As many as 37 percent went without medical or dental care, and 34 percent did not fill a prescription or took less than their full dose of prescribed medication. Twenty-three percent of LIHEAP recipients kept their homes at temperatures they felt were unsafe or unhealthy, and 21% of the recipients left home for part of the day to save energy and avoid an unaffordable energy bill. Many LIHEAP recipients had difficulty paying for housing, in part because of their energy burden. Almost one-third did not

[1] Home Energy Affordability Gap, http://www.homeenergyaffordabilitygap.com/03a_affordabilityData.html

make their full mortgage or rent payment. Six percent were evicted from their homes or apartments, and four percent faced foreclosure on their mortgages.[2] In Arizona, less than 5% of the eligible households received assistance in 2014.[3] This is a result of Arizona receiving the least amount of LIHEAP assistance per eligible household in the nation, precipitating even greater strains on tight budgets.

Fifty-one percent of Arizona's families have gross annual incomes of $50,000 or less, with an average after-tax income of $23,540, less than $2,000 per month. Energy costs are consuming the after-tax household incomes of Arizona's low- and middle-income families at levels comparable to other necessities such as housing, food, and health care. Arizona households aged 65 or more, 25% of all households, have a median pre-tax income of $39,097, 25% below the U.S. median. Senior households in Mohave and Santa Cruz Counties fare even worse, with median pre-tax incomes of $34,285 and $26,186, respectively. These relatively low pre-tax median incomes indicate that low-income and senior households in UNSE's service territory are among those most vulnerable to energy price increases such as rising household utility bills.[4]

The U.S. Census Bureau reports that the average incomes of American households have declined across all five income quintiles since 2001, measured in constant 2013 dollars. The largest percentage losses of income are in the two lowest income quintiles. Households in the lowest quintile lost 13% of their real income between 2001 and 2013, while households in the second lowest quintile lost 9% of their real income. Declining real incomes increase the vulnerability of low- and middle-income households to energy price increases such as rising utility bills. The price of residential electricity in Arizona has increased by 36% since 2005, and is 18% above 2005 levels measured in real, inflation-adjusted terms.[5]

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[2] http://neada.org/wp-content/uploads/2013/05/NEA_Survey_Nov11.pdf

[3] http://neuac.org/AZ-LAD%202015%20State%20Sheet.pdf

[4] http://www.americaspower.org/sites/default/files/ARIZONA-Energy-Cost-Analysis-315R.pdf

[5] http://americaspower.org/sites/default/files/Trisko_2014_1.pdf

In the recently released poverty data for 2014, 21.2% of Arizonans were at or below the poverty line. Arizona now has the third highest poverty rate in the country. The state has the fourth-highest rate of residents in "deep poverty," at or below 50% of the Federal Poverty Guideline.[6] Childhood poverty is even worse, with Arizona at a staggering 25.2% of children below the poverty level. Families in Arizona have median income in the bottom 25% of states. Arizona ranks third-worst in children without health insurance, leaving one in every ten children uninsured. To put Arizona's children at a higher disadvantage, three quarters of Arizona households live without a broadband internet subscription, and 20% don't have internet subscriptions at all. This can severely hamper the ability of a child to do their homework, or an adult to pay their bills, or apply for work, or otherwise engage in society.[7]

The rates of poverty in Santa Cruz and Mohave Counties, although down from their peak values in 2011, have still not reached pre-recession levels. Indeed, the poverty rate in Santa Cruz is 28% above its pre-recession level, and the deep poverty rate is more than double its pre-recession total.[8] The poverty rate in Mohave County is 64% higher than it was in 2007, and the deep poverty rate is more than 40% above its pre-recession levels. This has happened in spite of the fact that increased percentages of Arizonans in poverty and deep poverty were working, either full time or part time, from 2007 to 2014.[9]

With budgets this tight, families are forced to make difficult choices to make ends meet. In the *Hunger In America 2014* study, a survey of food bank clients reported 65% of households being forced to choose between paying for food and paying for utilities in the past 12 months, with 25%

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6 http://www.azcentral.com/story/money/business/economy/2015/10/04/arizona-remains-among-worst-poverty/73234934/

7 Source: U.S. Census Bureau, 2014 American Community Survey 1-Year Estimates

8 Source: U.S. Census Bureau, 3-Year American Community Survey

9 Source: U.S. Census Bureau, 2014 American Community Survey 1-Year Estimates

facing this choice every month.[10] A survey of the cities whose mayors are members of the U.S. Conference of Mayor's Task Force found that utility costs ranked among the top three causes of hunger in 13% of cities, and that utility assistance programs are essential to combatting hunger.[11] A recent report from the Federal Reserve found that 47% of Americans could not cover an emergency expense of $400. Thirty-one percent of respondents reported going without medical care in the past year because they were unable to afford it.[12] Low-income households often report cutting back on food and clothing purchases in order to pay utility bills.[13] Indeed, utility costs were cited as a primary driver of homelessness among families with children.[14] No family should be forced into such a difficult position over family finances, and every effort should be made to prevent such crises in Arizona.

Low-income families are not immune from price increases in the housing market, either. The amount of cost-burdened renters, who pay more than 30% of their income for housing, is now up to 50%, increasing 12 percentage points in the past decade. The rise was even more substantial among renters facing severe cost burdens (paying more than half of their income for housing); their numbers increased 19%. According to a study published by the Joint Center for Housing Studies at Harvard University, "[t]hese levels were unimaginable just a decade ago, when the fact that the severely cost-burdened share was nearly 20 percent was already cause for serious concern."[15] In the report *Out Of Reach*, the National Low-Income Housing Coalition tallied the income required for vulnerable populations to make ends meet. In order to make enough to

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[10] http://help.feedingamerica.org/HungerInAmerica/FB164_AZ_Mesa_report.pdf?s_src=W15AREFER&s_referrer=www.stl.unitedway.org%2F2015%2F05%2F5-tough-choices-people-who-cant-afford-food-make%2F&s_subsrc=http%3A%2F%2Fwww.feedingamerica.org%2Fhunger-in-america%2Four-research%2Fhunger-in-america%2Fkey-findings.html&_ga=1.207809686.522753187.1445819108

[11] http://usmayors.org/pressreleases/documents/hungerhomelessnessreport_121208.pdf

[12] http://www.federalreserve.gov/econresdata/2014-report-economic-well-being-us-households-201505.pdf

[13] http://www.feedingamerica.org/hunger-in-america/our-research/in-short-supply/in-short-supply-executive.pdf

[14] COLORADO STATEWIDE HOMELESS COUNT Winter, 2007

[15] http://www.jchs.harvard.edu/sites/jchs.harvard.edu/files/jchs_americas_rental_housing_2013_1_0.pdf

afford a two bedroom apartment at fair market rent and not be cost-burdened, a minimum wage worker in Arizona would need to work 84 hours per week. Assuming a head of household is working full-time, they would need an hourly wage of $16.87, or an annual income of $35,090.[16] In the 2014 American Community Survey, 35% of Arizona households make less than this amount. This means that 857,000 households in Arizona are unable to find affordable housing based on their income. The 2009 Residential Energy Consumer Survey shows that low-income households excel at conserving energy; low-income families consume less energy per person and per household than households with incomes above 150% of the Federal Poverty Guideline. However, low-income households consume 15% more energy per square foot than higher income households. This is most likely due to low-income families living in older residences that are less energy efficient with older appliances. In light of their desire to manage their energy bills, combined with the difficulties not only with housing stock but also food insecurity, among other budgetary challenges, it is in the public interest to provide special consideration for low-income customers to ensure they have the ability to access the essential commodity that is electricity.

DEPOSIT RULES

Q. What are UNSE's current rules regarding deposits?

A. In Section 3.B.1.a of the Rules and Regulations, UNSE requires an additional deposit if a customer is delinquent in payment "more than twice in the last twelve (12) consecutive months or was… disconnected for nonpayment." Additionally, in Section 3.B.3.a, it states:

> "Residential Customers – Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account, after twelve (12) consecutive months of service during which time the Customer has not been delinquent more than two (2) times in a twelve (12) month period."[17]

and Section 3.B.4 says:

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[16] http://nlihc.org/sites/default/files/oor/OOR_2015_FULL.pdf

[17] https://www.uesaz.com/doc/customer/rates/electric/UES-903.pdf

> "The Company may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months, or the Company has a reasonable belief that the Customer is not credit worthy based on a rating from a credit agency utilized by the Company."

Q. What changes have been proposed?

A. In Section 3.B.1.a, UNSE has removed the phrase " more than," requiring additional deposits if a customer has been delinquent twice in the past twelve months. Section 3.B.3 has been changed to require a deposit from a residential customer if they become delinquent in two or more bills in a twelve month period. Additionally, deposits will not expire or be refunded if the customer has "been disconnected for non-payment , [or] ... the Customer has filed bankruptcy in the last twelve (12) months."

Q. What are the reasons given by UNSE for the rule change?

A. In the testimony of Denise Smith, it is stated that one of UNSE's largest customers filed for bankruptcy, leaving UNSE with a large unpaid bill.

Q. Do you support these changes?

A. No. I do not.

Q. Why not?

A. The problem being addressed is one with Commercial and Industrial customers, but the solution is being applied to Residential customers. The average low-income residential customer's deposit and arrearage pale in comparison to the bills and arrearages paid and owed by large commercial and industrial customers. This is solving a problem before it exists, with the potential to cause serious harm to low-income customers.

Q. How specifically will this affect low-income customers?

A. Requiring additional and more frequent deposits would present a substantial strain on the budgets of vulnerable community members. Recall from above that 47% of households surveyed by the

Federal Reserve were unable to pay a $400 emergency expense, which would certainly describe an additional deposit at a time when just paying the bills is tough enough. The response was even more severe for households making less than $40,000 per year; over two-thirds of them reported that they could not cover the expense, or would be forced to sell something or borrow the money to cover it. Of the people who were unable to pay a $400 emergency expense, they were asked how much of an emergency they could pay off; 39% said the largest expense they could cover with cash on hand is $100, while an additional 16% said they could cover an expense between $100 and $200. With the possibility of an additional deposit being over a thousand dollars, the Federal Reserve data shows that a significant portion of low-income households cannot cover the additional cost of a deposit. This would have the effect of shutting off these customers' electricity, which would be disastrous to low-income households in Arizona. Fifty-five percent of Arizona homes have electric water heating, 76% of Arizonans cook primarily with electricity, 86% of Arizonans use microwaves to prepare meals and snacks, 60% of Arizonans primarily use electricity for heating, and 95% of Arizona households use air conditioning.[18] UNSE customers assisted by WACOG, the Community Action Agency serving Mohave County, have reported being unable to replace spoiled food after disconnections; this happens most often with elderly clients and families with children. By causing these additional shutoffs, UNSE would be hampering every aspect of a low-income customer's life while providing barely any additional financial well-being for the Company. Furthermore, requiring an additional deposit when a customer files bankruptcy creates an additional stressor for a family going through an extremely difficult time financially.

Moreover, if low-income customers are delinquent on their payments, it is likely due to the fact they don't have the funds to pay the bill in the first place. Charging them additional fees is counterintuitive and will only create greater hardship.

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[18] 2009 RECS Survey, EIA DOE

Instituting harsher requirements for the refund of deposits likewise imposes an unfair burden on low-income customers. Thirty-two percent of Arizonans are in asset poverty, and 46% percent of Arizonans are one step away from falling into abject poverty.[19] In these circumstances, a refunded deposit could make the difference of whether a family can afford to put gas in the car to get to work or put food on the table, or be forced to go without. With one in four Americans not able to pay their bills on time,[20] it's likely that many of the low-income customers will fall victim to this enhanced criteria and not be able to receive a much-needed refund or worse, lose electricity.

Q. What solution do you propose?

A. Low-income customers should be exempted from these more stringent deposit and refund rules. This should be extended to customers who are on the CARES rate as well as customers who have received bill assistance in the past 12 months. These additional deposits would prove to be a substantial hardship for low-income customers, and as CARES customers make up 6% of all customers and just 3% of all kilowatt-hour sales in the test year, exempting low-income customers from additional deposit requirements does not represent a significant financial risk for the utility.

Q. Has this been implemented by any other Arizona utilities?

A. Yes. In Decision 71448, APS implemented the following deposit exemption for low-income customers:

> "APS will waive the collection of an additional security deposit from customers on low-income rate schedules (E-3 and E-4) under the following circumstances: (1) the customer has had more than two late payments in the previous 12 months, or (2) the customer has been disconnected for nonpayment."

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[19] http://scorecard.assetsandopportunity.org/latest/state/az, https://morrisoninstitute.asu.edu/news/who-are-arizonas-vulnerable-populations

[20] https://www.nfcc.org/wp-content/uploads/2015/04/NFCC_2015_Financial_Literacy_Survey_FINAL.pdf

In that ratecase, representatives from APS noted that, on occasion, "a customer can come up with the money to pay the delinquent bill, but because of this security deposit requirement, they cannot get reconnected or there is a delay in their reconnection."[21] I appreciate APS's consideration and desire to keep low-income customers connected, and I hope that we can create a similar exception for UNSE so that low-income customers don't get hit with the "double hammer" of requiring an additional deposit on top of any past due bills.[22] It is in the public interest to keep low-income customers connected to electricity, and waiving additional security deposits will further that interest.

DEFERRED PAYMENT PLAN

Q. What is UNSE's current deferred payment plan?

A. UNSE allows qualifying customers to participate in a deferred payment plan to "to retire unpaid bills for electric service." Currently, customers are able to pay their unpaid bills through the deferral plan over a period of six months.

Q. How has UNSE proposed to change it?

A. UNSE has proposed to decrease the time period for a deferred payment plan from six months to three months, halving the time customers have to pay off their debts.

Q. Is this likely to increase the amount of late payments collected from low-income customers?

A. No. A low-income customer who has engaged in a deferred payment plan is committed to paying off what they owe. Cutting their payment time in half makes it that much harder to pay their unpaid bills, likely contributing to UNSE's uncollectible "bad" debt.

Q. How would this affect low-income customers?

A. As I mentioned above, low-income customers are often in the position of choosing between paying for utilities or buying food, and several studies have shown that they put off medical care

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[21] Thomas Mumaw, E-01345-08-0172 Transcript, Volume I, 8/19/2009, pg 57.

[22] Jeff Guldner, E-01345-08-0172 Transcript, Volume V, 8/27/2009, pg 1216.

and clothing purchases to keep the lights on. Most of the clients seen by SEACAP and WACOG (the Community Action Agencies in UNSE's service territory) live paycheck to paycheck, so when a hot summer month pushes their bills up into the hundreds of dollars, they'll likely need more than three months to pay it off. This change would force their clients, along with thousands of other low-income households, to cut their budget to the bone or to allow their power to be disconnected. As these people depend on their electricity to heat and cool their home, provide hot water, and cook their food, this would put these clients in an impossible situation and cause undue hardship.

Q. How would you address this?

A. This proposal should be rejected outright. If, however, that does not happen, then low-income customers should be exempted from the stringent timeline and allowed six months to make a deferred payment. They are more likely to need the additional time to pay off any delinquent bills, and the small number of customers and kilowatt-hours consumed by low-income customers will not substantially affect UNSE's financial position.

CARES PARTICIPATION

Q. Can you describe the CARES program?

A. The Customer Assistance Residential Energy Support (CARES) Program offers monthly discounts for limited-income customers who need support in meeting their energy costs. It provides a discounted fixed charge, a discounted volumetric charge, an option to pay a decreased LFCR, and a percentage discount off the whole bill based on usage.

Q. Who is eligible for the CARES program?

A. Households with a combined income of 150% of the Federal Poverty Level or less are eligible to participate in the CARES rates. In 2015, for a family of four that amounts to $36,375 per year or $3,031.25 per month. After taxes, that comes to an annual salary of $29,305.82 or monthly income of $2,442.15.[23] According to the MIT Living Wage calculator, the living wage in Santa Cruz County is $46,108 and the living wage in Mohave County is $47,261. The households who qualify for CARES do not make a living wage.

Q. How many people are currently using the CARES rate?

A. In UNSE's rate case application, the Company said there are 6,112 actual customers on average in the test year on the CARES rate and 6,236 adjusted average number of customers.

Q. About how many people are eligible in the UNSE's service territory?

A. It's difficult to know exactly how many people are eligible in UNSE's territory. UNSE has 75,847 residential customers, and 29% of Arizona's population is at or below 150% of the federal poverty level, so a rough estimate would say that 21,671 of UNSE's customers are eligible.[24] In the rate case application, Terry Nay stated that the company has approximately 74,000 customers in Mohave County and 19,000 customers in Santa Cruz County; of those customers, 88% are residential. This implies that there are approximately 65,000 residential customers in Mohave County and 16,000 residential customers in Santa Cruz County. Mohave County has 35% of its population at 150% of poverty, and 43% of Santa Cruz County's population is at 150% of the poverty level or below.[25] Given these rates of poverty, the following calculations yield an estimate of CARES-eligible customers:

Area	Customers	Residents at 150% FPG	Customers Eligible for CARES (Column 2 * Column 3)
Mohave	65,000	35%	22,750
Santa Cruz	16,000	43%	6,880
Total			29,630

[23] http://www.taxformcalculator.com/state_tax/arizona.html
[24] U.S. Census Bureau, 2014 American Community Survey 1-Year Estimates
[25] Santa Cruz data is sourced from U.S. Census Bureau, 2011-2013 3-Year American Community Survey. It is the most recent data available from the county.

To take a more granular approach, I'll identify the major cities and census-designated places (CDPs) served by UNSE and count the number of people who live there at 150% of FPG or less. Factoring in the average household size yields the number of households at 150% of FPG:

Area[26]	Total Population	Population at 150% FPG	Number of HH	Average HH size	Number of HH at 150% FPG
Mohave County Cities/CDPs					
Kingman	27,370	9,465	11,057	2.48	3,824
Oatman	124	53	88	1.41	38
Lake Havasu City	52,459	13,402	22,727	2.31	5,806
Yucca	50	6	25	2.00	3
Golden Valley	7,983	2,337	3,576	2.23	1,047
Chloride	213	122	140	1.52	80
Dolan Springs	2,124	438	969	2.19	200
White Hills	311	100	149	2.09	48
Meadview	587	259	358	1.64	158
Fort Mohave	14,189	3,573	5,951	2.38	1,499
Bullhead City	39,302	14,177	16,679	2.36	6,016
Peach Springs	756	352	182	4.15	85
Mohave Valley	2,939	743	1,096	2.68	277
Temple Bar Marina	(not included in 2013 ACS)				
Santa Cruz County Cities/CDPs					
Nogales	20,490	10,540	6,314	3.25	3,248
Patagonia	639	239	327	1.95	122
Tubac	1,248	195	710	1.76	111
Tumacacori-Carmen	407	171	208	1.96	87
Amado	165	7	106	1.56	4
Rio Rico	(not included in 2013 ACS)				
Total HH in UNSE territory at 150% FPG					22,653

Q. Given these calculations, how many more people are eligible for the CARES rate in UNSE's territory?

[26] The data for the Cities listed is from the U.S. Census Bureau, 2011-2013 3-Year American Community Survey, while the data from the CDPs is from the U.S. Census Bureau, 2009-2013 5-Year American Community Survey

A. The range of households derived through these calculations was 21,671, 22,653, and 29,630. By these calculations, there are at least 3.5 times as many customers, and possibly 4.9 times as many customers who are eligible for CARES but are not currently enrolled.

Q. Why is it so important for low-income customers to obtain the CARES rate?

A. Low-income Arizonans are in a tough spot financially. Arizona hasn't seen a true recovery from the Great Recession, and almost half of our households are one misstep away from abject poverty. Electricity is essential for any household, even more so for a struggling household – the need to store and prepare healthy food, keep one's home at a safe temperature, provide light and information for work and homework – without these necessities, provided by electricity, a struggling household could seriously fall behind. The discount offered by the CARES rate takes significant pressure off the budgets of the households that use it, helping them maintain self-sufficiency and helping them to thrive.

Q. What would be a reasonable target for an increase?

A. Given that the likely amount of CARES-eligible customers is 355%-485% higher than the current number of customers on CARES, I believe a 50% increase in enrollment is feasible. This should be planned for in the next few years, with an outreach plan published shortly after the conclusion of this rate case.

Q. Are there any outreach methods the company should use for such an aggressive increase in CARES customers?

A. One possible solution is automatically enrolling customers who receive bill assistance, either from Warm Spirits, LIHEAP, or any other organization that may provide assistance. Also, concentrating the bill inserts in the summer months when bills are highest and customers are having the greatest difficulty paying their bills could attract more participants. Additionally, I believe the emphasis on community outreach events is an excellent way to increase participation, and our Community Action Agencies and SNAP partners are excellent allies to provide this outreach. VITA Sites, affordable housing locations, job fairs, community events, working with local DES offices, and presenting information at association and alliance meetings are all proven outreach methods. Door to door canvassing, engaging customers on social media, automated voice messaging, engaging Community-Based Organizations and Faith-Based Organizations, direct mail campaigns and postcard mailers to potentially eligible customers, outreach by field employees, sharing data about customers enrolled in discount rates for the gas companies in the service territory, a digital newsletter to customers with energy savings tips and discount rate information, coordinating with other low-income programs, and targeted online advertising were all methods reported by California utilities to the Low-Income Oversight Board as effective outreach.[27]

Q. Is the any other information you would like to add regarding the CARES rate?

A. Yes. I want to say that I'm very concerned about the Company's proposal to abolish the current CARES rate plan and replace it with a much smaller monthly discount. Low-income families on CARES wouldn't be able to make ends meet without this rate, and taking it away could cause significant hardship among a great number of UNSE customers. I'll elaborate on this point further in the testimony pertaining to rate design that will be filed at a later date.

TERMINATION NOTICE REQUIREMENT

Q. What is currently required on the termination notice requirement?

A. Currently the termination notice is required to list the name of the person whose service is to be terminated, the Company's Rate(s) that was violated, the date after which service may be terminated, a statement advising the customer to contact the Company to work out a solution in the matter, and information on how to dispute the termination of services.

Q. What should be added?

[27] http://www.liob.org/resultsqv.cfm?doctypes=10

A. Information notifying the customer of agencies providing bill assistance opportunities in their area, as well as information about weatherization agencies and the CARES discount.

Q. Why should it be added?

A. The financial strains of living in poverty put real stress on the people experiencing it. People in poverty were twice as likely to report chronic pain and mental distress as those earning $75,000 or more, and three to five times more likely to have extreme pain or extreme distress.[28] When faced with a difficult financial problem, poor people's IQ actually fell 13 points, equivalent to losing a full night's sleep.[29] Given these results, the researchers in the "Poverty Impedes Cognitive Function" study recommend that policymakers avoid cognitively taxing people in poverty. Providing a list of resources, in one location, to assist someone who's had trouble paying their bills greatly reduces the cognitive load of a possible utility disconnection and all of the negative consequences that accompany it. This would make it easier for the people who need them to access these valuable resources.

Q. What benefit would it have for UNSE customers?

A. This would likely decrease the number of customers who are ultimately disconnected, decrease the stress experienced by low-income customers who are able to avoid disconnection, and increase the utilization of the valuable bill assistance, weatherization, and discount rates that are offered by the Company.

CURRENT LIMITER AS AN ALTERNATIVE TO DISCONNECTION

Q. What has UNSE proposed in Section 12.H of the Rules & Regulations?

A. Section 12.H of the Rules and Regulations states that, if a customer has a medical alert designation and has accrued debt equivalent to a three month bill, the company may install a load limiter in lieu of disconnecting the customer's service for nonpayment.

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[28] http://www.brookings.edu/blogs/social-mobility-memos/posts/2015/02/19-cost-poverty-stress-graham

[29] http://www.sciencemag.org/content/341/6149/976.full "Poverty Impedes Cognitive Function", Anandi Mani1, Sendhil Mullainathan, Eldar Shafir3, Jiaying Zhao

Q. How would this affect a customer facing disconnection?

A. This could be a lifesaver. In addition to whatever medical equipment the customer may need that will now be able to continue to operate, this will take a significant amount of stress off of the customer's mind. Recall the study referenced above that demonstrated how stress regarding finances can reduce someone's IQ; removing the threat of disconnection is giving the customer mental bandwidth that they can use for work or their family or to improve their life in some way.

Q. Should this be made available to all CARES customers?

A. Yes.

Q. Why?

A. Like it or not, everyone depends on electricity to survive. As was cited above, most people in UNSE's service territory rely on electricity for food storage, cooking, cleaning, heating, cooling, and many other things. For Arizonans, that dependence on cooling can be critical; in the last thirty years, more Americans have died from heat than any other weather-related cause, and heat has killed twice as many people as cold and winter weather.[30] By ensuring that low-income customers have enough electricity to store and prepare food, and keep their homes at a safe temperature, you could be saving their lives.

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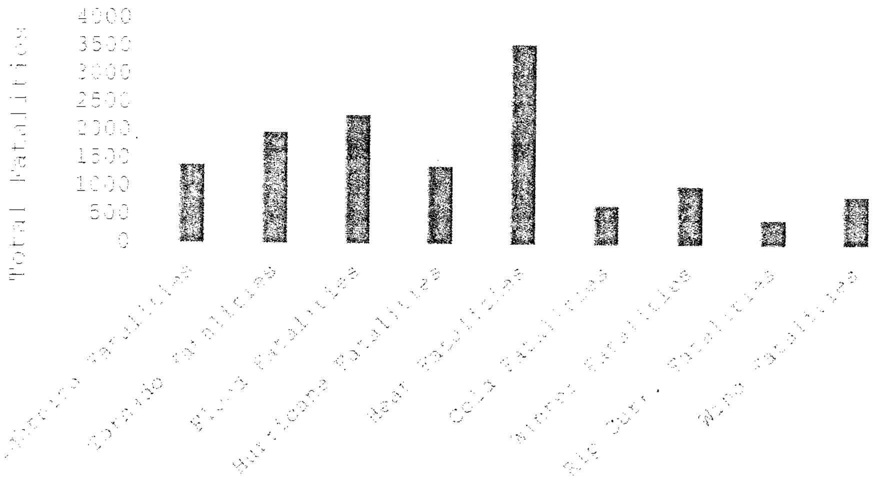
[30] http://www.nws.noaa.gov/os/hazstats/images/weather_fatalities.pdf

American Fatalities by Weather Type Since 1985



WARM SPIRITS

Q. What is the Warm Spirits Program?

A. The Warm Spirit program is a customer donation program, with a Company match, to provide bill assistance to Unisource Electric and Gas customers.

Q. What is the impact that this program has had?

A. The program has had substantial success. Already in FY16 (beginning in July) the utility has distributed over $6,000 in assistance. In FY15, the agencies distributed over $13,000, resulting in a 93% expenditure of their annual allocation. In FY14, over $14,000 was distributed in assistance, resulting in a full expenditure of their funds. Over $11,000 was spent in energy assistance in FY13, completely spending the allocation, in FY12 they similarly spent their entire allocation of over $7,000, and in FY11 the agencies distributed over $9,000.

Q. What if anything could be done to improve the program?

A. Currently the Warm Spirit program does not have any program delivery associated with it; the funds can only be used to assist customers with paying their bills. Most of the bill assistance programs ACAA administers have a program delivery amount associated with their program. This allows the agency to do outreach about the program and helps to defray some of the costs of providing assistance. If this program had a 10% program delivery amount, the agencies distributing the funds could allocate more resources to the program, increasing the number of customers assisted.

Q. Won't the program delivery fee mean that fewer customers will be served?

A. Not necessarily. The Warm Spirit program has two fund sources: customer contributions and up to a $25,000 match from UNSE. With the program delivery allocated to the agencies, they will be able to better promote the program to the community, and it will better facilitate their ability to distribute funds. The increased awareness and greater customer experience will likely lead to more customer contributions, which will work to replenish the funds dedicated to program delivery.

Q. Would increased outreach have any other benefits?

A. Yes. By empowering the Agencies, who have built up substantial local knowledge after years of serving the community, to better provide Warm Spirit assistance to more customers, they will have the ability to educate them about other programs offered by the utility and wraparound services provided by the Agency. Moreover, if customers are automatically enrolled in the CARES discount rate when they receive assistance (as has been proposed above), this can help the company in its proposed target to increase enrollment in CARES.

NET METERING

Q. What has the company proposed regarding net metering?

A. UNSE has proposed to compensate new DG customers as of June 1, 2015 for any excess energy they produce on the grid at the Renewable Credit Rate, rather than crediting them at the retail rate. Customers on this new net metering plan will also be required to take on a new three-part rate plan, consisting of a basic service charge equal to the RES-01 service charge, a demand charge, and a volumetric charge less than what is charged for RES-01.

Q. What is your response to this?

A. Net metering customers are approximately 1% of UNSE's residential customer base, while low-income customers make up approximately 30% of UNSE's residential customers. As you deliberate on this issue, please consider the customers who aren't able to make ends meet, and ensure that no additional charges are assessed on a population unable to take advantage of a product in their community.

Q. Does this conclude your testimony?

A. Yes, it does. Thank you.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

SUSAN BITTER SMITH, Chairman
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO.E-04204A-15-0142 **TESTIMONY OF CYNTHIA ZWICK ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION REGARDING RATE DESIGN**

DIRECT TESTIMONY OF
CYNTHIA ZWICK ON BEHALF OF THE
ARIZONA COMMUNITY ACTION ASSOCIATION

December 9, 2015

EXHIBIT
ACAA2
ADMITTED

Q. Please state your name and business address.

A. My name is Cynthia Zwick. My business address is 2700 N 3rd St., Ste. 3040, Phoenix, AZ 85004.

Q. What is your position at the Arizona Community Action Association?

A. I serve as the Executive Director of Arizona Community Action Association (ACAA). I've served in this position since 2003.

Q. Please describe your background and work experience.

A. ACAA is a non-profit organization that advocates on behalf of Community Action Agencies and the low-income community throughout Arizona. ACAA works with community partners throughout the state to: educate the community about issues related to poverty, improve public policy, and ensure low-income families have access to the tools needed to become and sustain self-sufficiency.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony today is to ensure that the priorities of low-income customers are considered in the ratemaking aspects of this rate case. Specifically, my testimony today will address:

- Our request that the CARES rates be maintained and the current discount honored;
- The eligibility of the CARES rates is expanded to 200% of the Federal Poverty Guideline;
- The doubling of the mandatory "fixed" fees for low-income residential customers is rejected; and
- The exclusion of the DSM surcharge from CARES rates is maintained.

CARES RATE

Q. WHAT CHANGES HAVE BEEN PROPOSED FOR THE CARES RATES?

A. The company has proposed to freeze the current CARES customer rates and reduce the discount to a flat $10 per month discount.

Q. HOW WILL THIS IMPACT LOW-INCOME CUSTOMER'S BILLS?

A. The change in CARES discounts will substantially affect low-income customers, with the most egregious effects focused on low-use customers. This is demonstrated in Table 1:

Table 1: CARES Customer Bill Impact					
Usage (kWh)	Current CARES bill	New RES-01 bill with CARES Discount	Monthly Bill Increase	Percent Increase in Monthly Bill	Annual Increase in Energy Bill
300	$20.37	$34.02	$13.65	67.00%	$163.80
600	$45.27	$62.04	$16.77	37.04%	$201.25
900	$77.15	$92.06	$14.92	19.33%	$178.99
1200	$106.85	$122.08	$15.23	14.26%	$182.82
1500	$135.98	$152.11	$16.13	11.86%	$193.51

As is demonstrated in the table above, by moving from a percentage discount to a flat discount, low-use customers' bills are substantially increased. Low-income customers on average use less electricity than their more affluent counterparts in order to keep their utility bills affordable. To that end, the percentage discount has been useful to encourage conservation, offering more substantial savings for customers who keep their energy use low. By freezing the current CARES rate and making the new CARES discount a flat rate, this incentive to conserve has been removed, and the consequences are laid bare in Table 1. Customers using very little energy will see a 67% bill increase, while customers using several times that amount of energy will see a proportionately smaller increase.

Compared to the price increase seen by RES-01 customers, CARES customers will see a larger total increase at every usage level, and a much larger percentage increase at each level.

Table 2: Customer bill comparison on RES-01 rate					
kWh usage	Old Price	New Price	Monthly Increase	Annual Increase	Percent Increase
300	$35.14	$44.02	$8.88	$106.54	25.26%
600	$63.30	$72.04	$8.75	$104.95	13.82%
900	$92.95	$102.06	$9.11	$109.31	9.80%
1200	$123.44	$132.08	$8.64	$103.71	7.00%
1500	$154.34	$162.11	$7.76	$93.13	5.03%
1800	$185.25	$192.13	$6.88	$82.55	3.71%

As it stands, the new CARES discount is effectively taken away by the updated rate design. New CARES customers will receive a $10 monthly credit, but the mandatory "fixed" fee is being increased by $10, effectively setting the credit to $0. By having their discounts taken away, low-income are being forced into real financial hardship. As was discussed in my November 6, 2015 testimony, half of all renters are cost-burdened, and 65% of food bank clients report being forced to choose between paying for food and utilities in the past 12 months. Such an abrupt increase in fixed charges while taking away benefits will only further harm these vulnerable families, forcing them into even more difficult situations where they're forced to choose between paying for housing, or food, or keeping the lights on.

Taking a more granular look at customer usage, we can see that the most frequent bill for a CARES customer is in the 400 kWh range, while the most frequent RES-01 bill is in the 500 kWh range (Figures 1, 2). CARES customers also have lower total bills, and a much tighter concentration of bills below 1,000 kWh. The savings incentive of the current CARES rate has certainly contributed to this trend of conservation, and freezing the current CARES rate and eliminating the percentage discount would remove that incentive, likely increasing consumption and making bills less affordable and manageable.

Figure 1

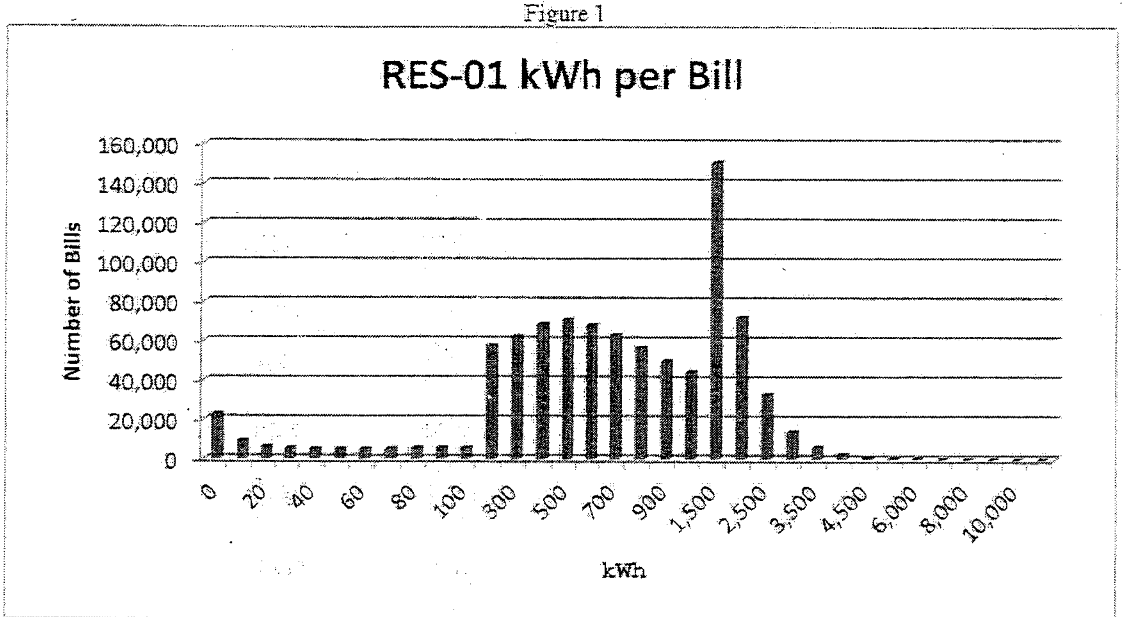
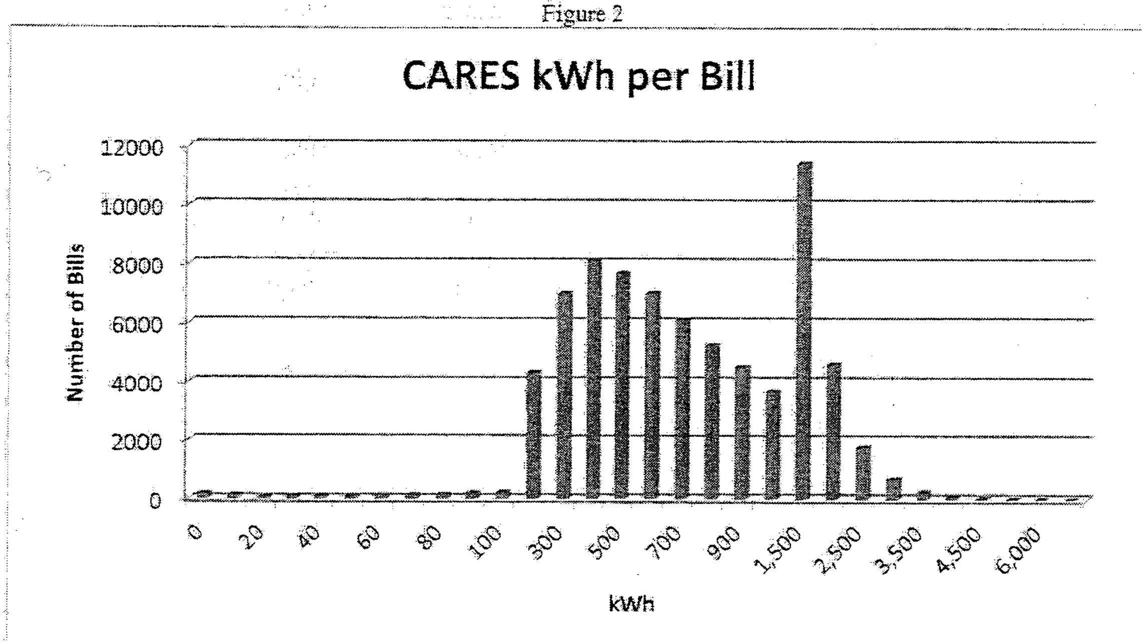


Figure 2



Q. How does a bill impact like this affect a low-income customer's quality of life?

A. One important factor in low-income energy consumption is their housing stock. Low-income households often live in substandard houses with poor insulation, drafty rooms, leaky roofs, and inefficient appliances. As such, a disproportionate amount of their energy is leaking out the walls or being used up by old and inefficient appliances. This can make conservation even more difficult, as the energy required to keep poor housing stock comfortable is greater than the energy required for a newer house in better condition. With that in mind, increasing a low-income customer's bill by as much as 67% could have disastrous consequences for those families. As you'll recall from the testimony submitted November 6, 2015, Arizona now has the third highest poverty rate in the country, and the fourth-highest rate of residents in deep poverty. Energy unaffordability can cause food insecurity and increased hospitalization rates, which utility assistance programs can ameliorate.[1] High utility bills are a primary driver of homelessness for families with children. In the survey performed by the Federal Reserve that demonstrated 47% of households were unable to pay a $400 emergency expense, 39% said the largest expense they could cover with cash on hand is $100, while an additional 16% said they could cover an expense between $100 and $200. These new rates constitute a several hundred dollar expense that low-income households are unable to avoid and must be able to pay immediately. This rate increase could easily be the crisis that pushes these families over the edge that was demonstrated by the Federal Reserve's research. Low-income discount rates, such as the CARES rate, can provide a bulwark against these negative consequences. Implementing such a rate shock on low-

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[1] http://www.ncbi.nlm.nih.gov/pubmed/17079530

income, low-use customers will certainly spawn untold crises, and it is irresponsible for UNSE to augment its revenue by taking so much from their customers with the very least.

Q. What do you recommend should be done for the CARES rate?

A. The CARES rate should remain unfrozen and the current discount rate should remain available for eligible customers. Low-income and senior customers depend on affordable electricity; effectively removing the CARES discount by setting it to the same value as the mandatory fixed fee increase will make electricity much less affordable for customers whose lives could be most damaged if they can't access it. As was described in greater detail in the November 6, 2015 filing, the CARES rate is currently under-enrolled considering the poverty of the areas served by UNSE; UNSE should work with the community it serves in order to increase the total number of CARES customers.

CARES ELIGIBILITY

Q. What is the current eligibility level for CARES customers?

A. Currently, CARES customers must be at or below 150% of the Federal Poverty Guideline to be eligible for CARES. That results in the following limits:[2]

Persons in Family/ Household	150% Federal Poverty Guideline - Annual Income	150% Federal Poverty Guideline - Monthly Income
1	$17,655.0	$1,471.25
2	$23,895.0	$1,991.25
3	$30,135.0	$2,511.25
4	$36,375.0	$3,031.25

For a family of three to make it on just over $2500 a month requires extremely difficult choices about which essential items can be skipped or decreased in the family budget. In this context, the CARES rate is an invaluable tool to help families stay afloat.

[2] https://aspe.hhs.gov/2015-poverty-guidelines

Q. Does the CARES discount rate reach all of the customers who need it?

A. No. According to the MIT Living Wage calculator, the following are the required incomes for a given household to support itself. I also included 200% of the Federal Poverty Guideline as a reference:

Persons in Family/ Household	Living Wage, Mohave County	Living Wage, Santa Cruz County	200% Federal Poverty Guideline
1	$20,284	$20,270	$23,540
2	$44,363	$43,210	$31,860
3	$56,101	$54,948	$40,180
4	$72,711	$70,295	$48,500

As is demonstrated in the table above, most households at 200% of the Federal Poverty Guideline do not make a living wage, and as a result have to go without essentials in their daily lives. Extending the CARES discount up to 200% of the Federal Poverty Guideline would ensure that these customers have another tool in their arsenal to make ends meet, to avoid hardship, and to avoid issues with missed payments and arrearages, which will ultimately benefit the company.

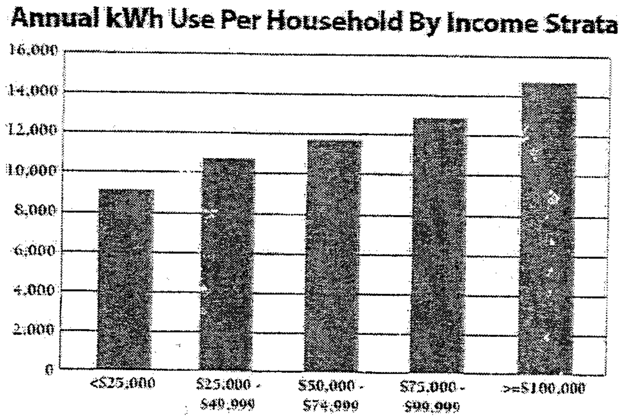
FIXED CHARGES

Q. What has UNSE proposed to do with regards to its residential fixed charges?

A. UNSE has proposed to increase the "fixed" mandatory fees on residential customers by 100%, from $10 per month to $20 per month.

Q. How does this affect low-income customers?

A. Significantly, disproportionately, and unfairly. Low-income customers, along with elderly customers, use less energy per household than the average population. These households do this in order to control monthly budgets, often in spite of structural impediments to energy conservation, such as inefficient living spaces or limited control over their home environment. When surveyed, low-income consumers reported more diverse and creative strategies for saving energy than other, more affluent households displayed.[3]



Source: John Howat, National Consumer Law Center, 2014

Nationally, low-income households who make less than 150% of the Federal Poverty Guideline use 14% less energy than the average of all households. In Arizona, the difference is even more staggering, with low-income customers using 25% less energy than the average household. In UNSE's territory, CARES customers use 8% less energy than residential customers on average. Low-income customers use less power because it's all they can afford, and because decreasing usage helps to control their bills and manage household budgets. Households headed by a senior – defined as a person 65 years of age or more – similarly use much less energy than the average population. Nationally, senior households use 14.2% less energy than non-senior households. In Arizona, senior households use on average 25.1% less energy than non-senior

[3] It's not all about "Green": Energy Use in Low-Income Communities

households.[4] Many seniors are on a fixed income budget, and as such they need to conserve energy to make ends meet. If their bill increases by $10 per month before they've even turned a light on, adding an annual expense of $120 per year, that could put a real strain on these vulnerable households' budgets. For reference, an individual at the poverty line makes $11,770 per year, or $981 per month. This additional $120 annual expense represents one percent of their total annual income, which is a significant charge to pay before they've used any electricity. Furthermore, home energy bills are at the "top of the stack" for low-income and elderly households because the potential consequence of not paying for household utilities is the risk of losing service. With this loss of service, there comes a very real possibility that one will lose their home. The only other expense that is similar is a household's rent or mortgage payment. Given the high priority of utility bills, low-income families face sacrificing other absolute necessities in order to pay for home energy. Household members skip meals or buy lower quality food; they don't take necessary medications or take a dose lower than prescribed, and don't see the doctor when they need to. Other needs such as transportation to and from work, clothing, and school supplies become a luxury. In this light, the energy burden of 14% for low-income households and 19% energy burden for households in extreme poverty represent a household crisis, as these bills are much steeper for low-income households than the average population, and not paying them could result in real hardship, including homelessness.

In listing his criteria for a sound rate structure, James Bonbright states an essential criterion as "fair-cost apportionment objective, which invokes the principle that the

[4] EIA, 2009. Prepared by NCLC.

burden of meeting the total revenue requirements must be distributed fairly and without arbitrariness, capriciousness, and inequities among the service and so as, if possible, to avoid undue discrimination."[5] The doubling of mandatory fees constitutes an unfair apportionment of costs on low-use customers, who overwhelmingly tend to be low-income and elderly, while high-use customers in larger houses avoid paying their fair share.

Q: What if any impact will increased fixed charges have on residential customers saving energy?

Doubling the fixed charges in low-income households will not only disincentivize saving, but it would lead to customers having less control over their energy bill and more wasteful electricity use.

Q. What is the typical load profile of a low-income customer?

As a result of minimal discretionary energy use, a majority of low-income customers have a relatively flat load profile and high load factor. This is explained by households below the poverty line being less likely to have air conditioning, primary home heating, and other appliances that contribute to peak load (Figures 3-6).[6]

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[5] Bonbright, James C. "Principles of Public Utility Rates," 2nd Edition.

[6] EIA RECS Survey, 2009 data

Figure 3

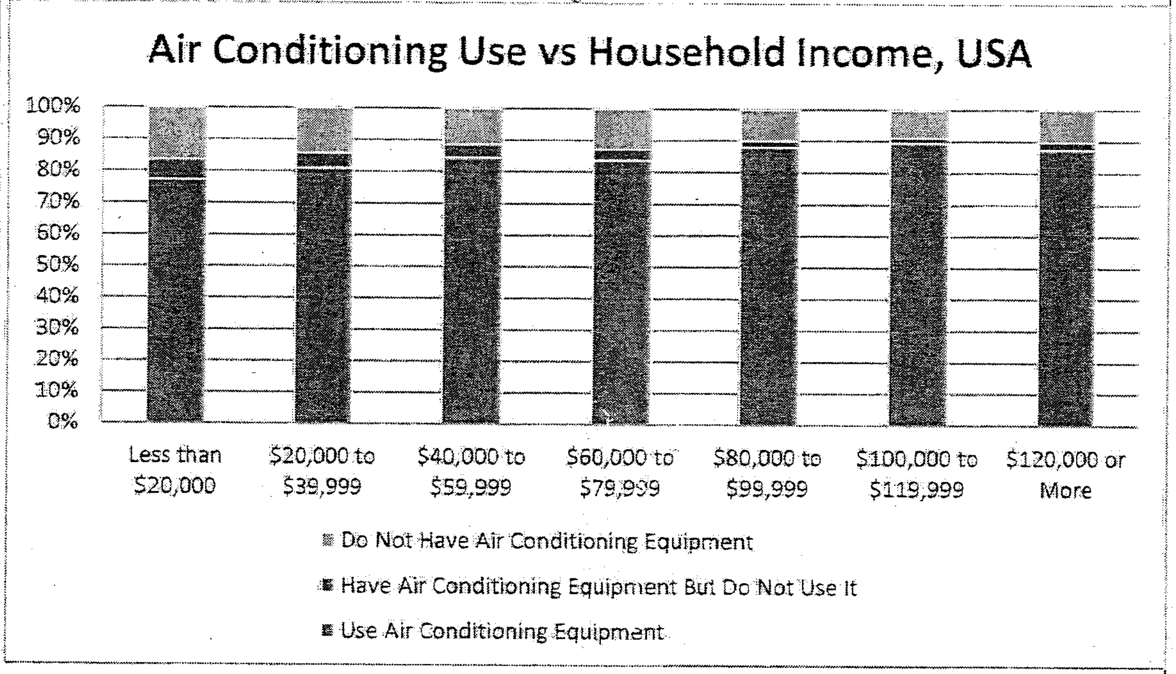


Figure 4

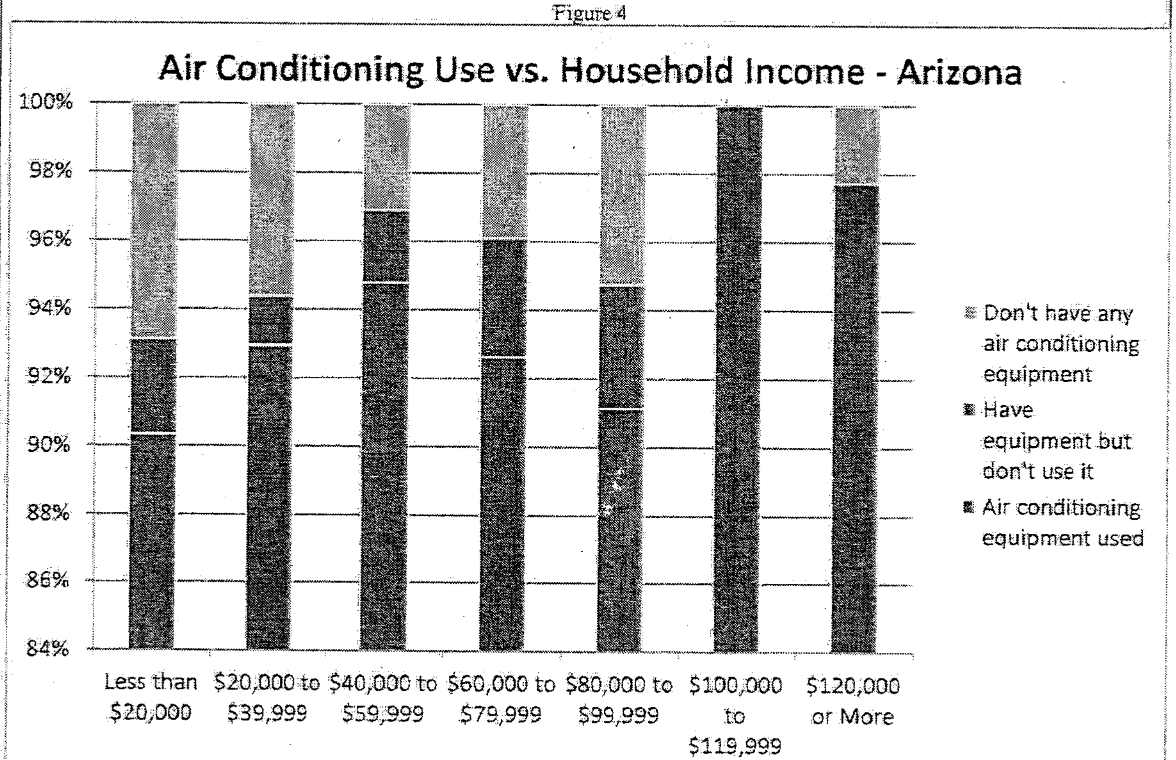


Figure 5.

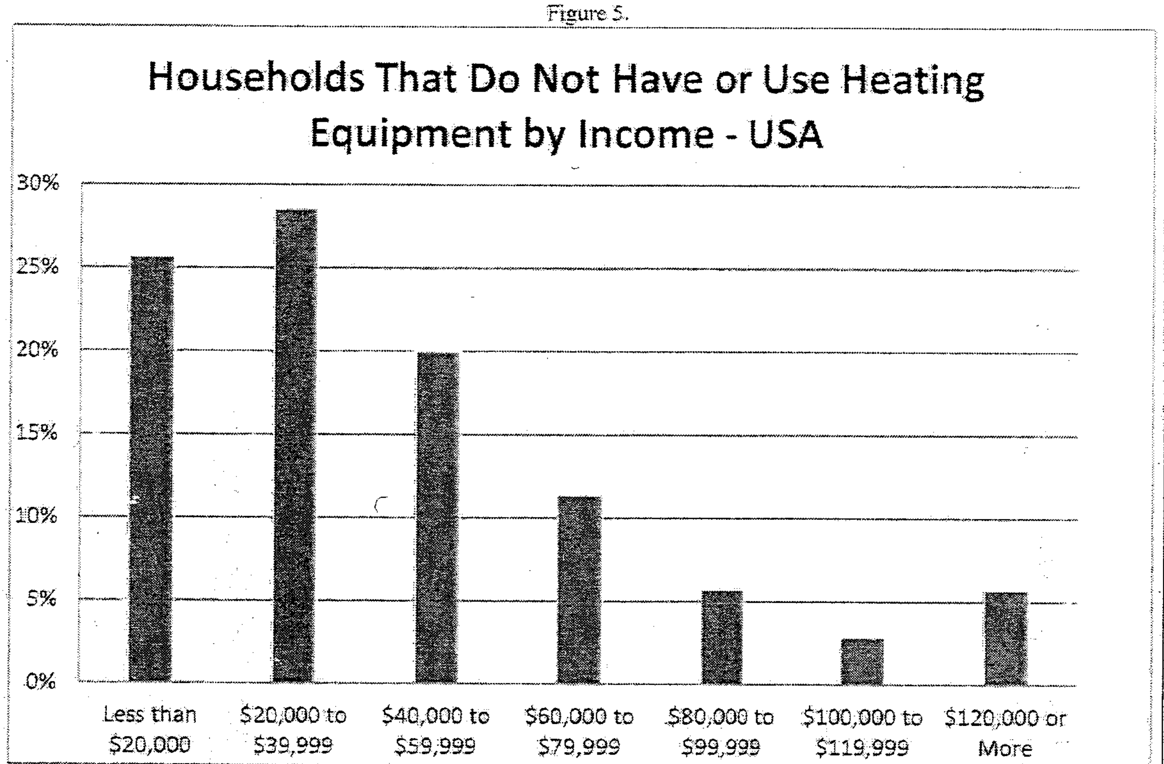
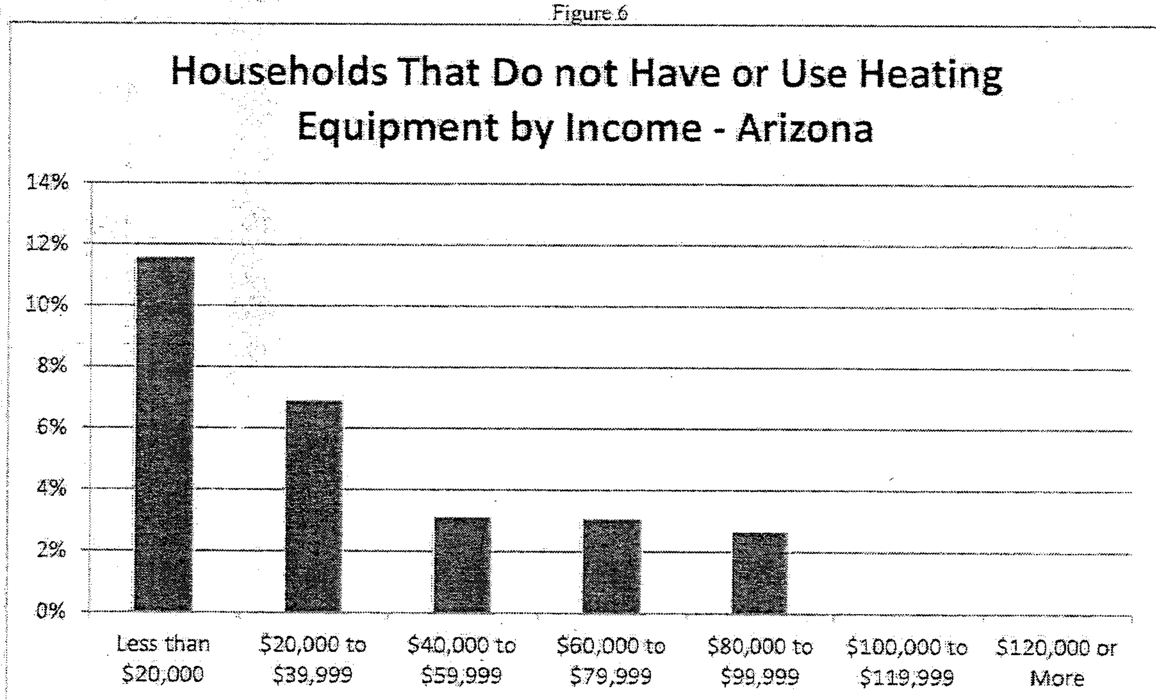


Figure 6



According to the testimony of Dallas J. Dukes, customers who exhibit a higher load factor use the electric system more efficiently and therefore more cost effectively. The updated rates were nominally designed to reward such customers with decreased rates. However, in these situations, low-use customers, who are overwhelmingly low-income and elderly, will see a larger overall price increase and a substantially larger percentage increase in their electric bills (Table 3).

Table 3: Customer bill comparison on RES-01 rate					
kWh usage	Old Price	New Price	Monthly Increase	Annual Increase	Percent Increase
300	$35.14	$44.02	$8.88	$106.54	25.26%
600	$63.30	$72.04	$8.75	$104.95	13.82%
900	$92.95	$102.06	$9.11	$109.31	9.80%
1200	$123.44	$132.08	$8.64	$103.71	7.00%
1500	$154.34	$162.11	$7.76	$93.13	5.03%
1800	$185.25	$192.13	$6.88	$82.55	3.71%

For customers who move from the current CARES rate to the proposed CARES rate, the impact is much starker (Table 4).

Table 4: CARES Customer Bill Impact					
Usage (kWh)	Current CARES bill	New RES-01 bill with CARES Discount	Monthly Bill Increase	Percent Increase in Monthly Bill	Annual Increase in Energy Bill
300	$20.37	$34.02	$13.65	67.00%	$163.80
600	$45.27	$62.04	$16.77	37.04%	$201.25
900	$77.15	$92.06	$14.92	19.33%	$178.99
1200	$106.85	$122.08	$15.23	14.26%	$182.82
1500	$135.98	$152.11	$16.13	11.86%	$193.51

Because low-income households generally reside in homes that are less energy efficient than average residences, in order to lower their energy bills, low-income households lower their usage by the unwelcome choice of doing without.

Q. How does the increase in fixed charges affect the public policy goals of energy efficiency?

A. Analysis by the Regulatory Assistance Project shows that the difference between a progressive and regressive design can have a large effect — 15 percent by one estimate, but it could be more — on customer usage. In this case, allocating an increased amount of revenue recovery to mandatory fees decreases the incentive for customers to conserve energy, as their usage has less of an effect over the total bill. High fixed charges directly reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances, insulation, or other residential or business improvements. They also reduce the ability of customers to control their own bills through their own consumption decisions.

As a result, customers are less likely to take on conservation efforts, which works against the public policy goals of the Energy Efficiency Resource Standard, going against the public interest.

Q. Has the National Association of State Utility Consumer Advocates taken a position on Mandatory "Fixed" Fees?

A. Yes.

Q. What is that position?

A. The National Association of State Utility Consumer Advocates (NASUCA) "opposes proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills," citing its "long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers." NASUCA "urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States."[7]

Q. Have other organizations publicly opposed increased mandatory "fixed" fees for residential customers?

A. Yes. The Christian Coalition of America[8] and the AARP[9] have both issued statements opposing increased mandatory fees, citing the need for customers to have control over their energy bills in order to maintain an affordable household budget.

Q. What recommendations do you have?

A. The Corporation Commission should maintain the mandatory "fixed" fees at $10 per month for CARES customers and it should not approve the company's proposed 100% increase.

DSM CHARGE

Q. WHAT HAS BEEN PROPOSED FOR THE DSM CHARGE FOR CARES CUSTOMERS?

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[7] THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1, "OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES"

[8] Americans Deserve Economic & Energy Security at Home http://americaspathtoprogress.com/op-eds/

[9] "A Higher Utility Bill Before You Even Turn On the Lights?" http://blog.aarp.org/2015/08/31/a-higher-utility-bill-before-you-even-turn-on-the-lights/

A. UNSE has proposed to eliminate the exclusion of the CARES rate from the DSM surcharge.

Q. DO YOU SUPPORT THIS PROPOSAL?

A. No.

Q. WHY NOT?

A. With the exception of the weatherization program, low-income customers are unable to access the benefits and opportunities presented by the Demand Side Management program. Low-income customers should not be forced to pay into a program from which they will receive almost no benefit. Furthermore, low-income customers often live in substandard housing stock, with drafty rooms and inefficient appliances. As such, low-income customers use more energy per square foot than households that are not low-income.[10] This makes conservation that much more difficult for vulnerable customers, as decreasing energy consumption to a typical amount, per square foot, could require sacrifice and deprivation that could amount to sacrificing a safe and healthy home to make ends meet.

Q. What is your recommendation for the DSM surcharge for CARES customers?

A. I recommend that the Corporation Commission maintain the exclusion of the CARES rate from the DSM surcharge. Many low-income communities haven't recovered from the financial crisis of 2008, and there is no reason to exact further charges from vulnerable communities to force them to pay for programs in which they won't be able to participate.

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[10] EIA 2009 RECS survey

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does. Thank you.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, Acting Chairman
BOB STUMP
BOB BURNS
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO.E-04204A-15-0142 **REBUTTAL TESTIMONY OF CYNTHIA ZWICK ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION**

EXHIBIT
ACAA-3
ADMITTED

REBUTTAL TESTIMONY OF
CYNTHIA ZWICK ON BEHALF OF THE
ARIZONA COMMUNITY ACTION ASSOCIATION

January 19th, 2016

Q. Please state your name and business address.

A. My name is Cynthia Zwick. My business address is 2700 N 3rd St., Ste. 3040, Phoenix, AZ 85004.

Q. What is your position at the Arizona Community Action Association?

A. I serve as the Executive Director of Arizona Community Action Association (ACAA). I've served in this position for over twelve years.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony today is to address issues brought up in Staff's testimony on rate design, specifically addressing Staff's recommendation on demand charges.

Q. What were Staff's recommendations regarding demand charges?

A. Staff recommended that all residential customers be migrated from two-part rates to three-part rates, made up of a fixed charge for customer services, a volumetric charge for energy use, and a demand charge calculated from the customer's peak demand in a given billing period.

Q. Did Staff suggest that an exemption be provided for vulnerable customers?

A. Yes.

Q. Are low-income customers vulnerable?

A. Yes.

Q. How so?

A. Low-income customers suffer myriad circumstances making their situations precarious and vulnerable. Over a recent three-year period, almost one-third of all Americans were poor at least once for two months or more.[1] Nearly one in five Arizonans is in poverty, and nearly thirty percent of Arizonans are within 150% of the Federal Poverty Line.[2] Of the Arizonans in poverty, 35% are children, 15% of those in poverty are disabled, and 8% are seniors. The people who find

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[1] http://www.census.gov/prod/2014pubs/p70-137.pdf

[2] POVERTY STATUS IN THE PAST 12 MONTHS 2010-2014 American Community Survey 5-Year Estimates

themselves struggling have stretched their budgets to the limit. According to a recent national survey, 56.3% of Americans have $1,000 or less combined in their checking and savings accounts. Most financial planners recommend having an emergency fund of at least $1,000, but a majority of Americans don't have that presently. What's more troublesome is that 24.8% don't even have a tenth of that; they have less than $100 combined in their checking and savings accounts.[3] Additionally, 38 percent of respondents said they would pay less than their full credit card balance this month, and 11 percent said they would make the minimum payment—meaning they would likely be mired in debt for years and pay more in interest than they originally borrowed.[4] Sixty percent of households experienced a financial shock in the previous year, causing half of them to struggle to make ends meet.[5] Low-income households are often unable to access basic financial services, with thirteen percent of Arizonans unbanked and eighteen percent underbanked. These households spend on average $3,029 in fees and interest per year as they are forced to work with alternative financial service providers.[6]

In addition to financial poverty, low-income people struggle with time poverty as well. Decreased commuting time is correlated with escaping poverty and intergenerational mobility at a time when the number of jobs within typical commuting distance for residents of major metropolitan areas is falling.[7] As poor residents shifted toward suburbs in the 2000s, their proximity to jobs fell more than for non-poor residents, and residents of high-poverty neighborhoods experienced particularly pronounced declines in job proximity.[8] Many low-income workers are required to take on multiple jobs, resulting in multiple commutes, exacting a

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[3] http://www.magnifymoney.com/blog/consumer-watchdog/store-credit-cards-deferred-interest-holiday-2015-study

[4] http://www.esquire.com/news-politics/news/a41147/half-of-americans-less-than-1000/

[5] http://www.pewtrusts.org/~/media/assets/2015/11/emergency-savings-report-2_artfinal.pdf?la=en

[6] https://www.fdic.gov/householdsurvey/, http://d3n8a8pro7vhmx.cloudfront.net/ufe/legacy_url/372/SOTD15.pdf?1448061430

[7] http://equality-of-opportunity.org/images/nbhds_paper.pdf

[8] http://www.brookings.edu/research/reports2/2015/03/24-people-jobs-distance-metropolitan-areas-kneebone-holmes

profound toll on their daily schedules.[9] Typically, these low-wage jobs are part-time with no guaranteed hours, making it difficult for individuals to manage time effectively across work and non-work areas of their lives. Many employers expect workers to be on-call and available if needed, even sometimes for 12-hour shifts without advanced notice.[10]

Q. In what ways could low-income customers be harmed by a demand charge?

A. Demand charges are difficult to understand, and can cause bills to vary wildly. Demand charges can lead to overcharging by failing to account for diversity of residential load. Moreover, the means by which low-income customers could decrease demand charges – upgrade to high-tech load control appliances or spreading their electric usage out over a larger period of time – are much less accessible to them than the residential customer base at large, putting them at a further disadvantage.

Q. How is a demand charge difficult to understand?

A. A demand charge, fining a customer for their maximum rate of energy use for a given hour in a billing period, is a wholly new billing mechanism for most residential customers. A low-income customer doesn't have the means or the time to study their electric bill or to monitor the electricity consumption of every appliance in their home every hour of the day.

When customers in California were asked if they had a demand charge on their bill, 60% said they weren't sure.[11] Given that so many customers don't even know whether they have demand charges on their bill, the notion that customers will be able to optimize their kilowatt demand rate in order to control their bills seems awfully far-fetched. Low-income customers are in the worst position on this, having much tighter time constraints, as was discussed above, they would be especially vulnerable to increased bill volatility from demand charges.

Q. How does a demand charge cause bill volatility?

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[9] http://scholarworks.wmich.edu/cgi/viewcontent.cgi?article=2763&context=jssw

[10] http://poverty.ucdavis.edu/sites/main/files/file-attachments/smith_cpr_policy_brief_employability.pdf

[11] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K932/65932012.PDF

A. A demand charge, as proposed here, would be measured as the customer's maximum one-hour demand in the billing month. A customer has limited control over when appliances run – refrigerators, air conditioning, furnace, and water heaters all cycle automatically. If these are running the same time as a customer needs to do laundry to have clean clothes for work the next day, or needs to prepare dinner for their family, they could see a severe price spike from this single electricity use event. Even adding a single kilowatt of demand, by running the microwave at the wrong time, could add $10 to a customer's bill under the current proposal. This could happen regardless of how much capacity is available on UNSE's grid when the customer is using electricity.

Q. How might demand charges overcharge customers?

A. Demand charges can overcharge customers by failing to account for diversity of load. On a given distribution system, hundreds of customers may share a distribution feeder. The combined demand of all of the customers affects the size of the distribution system, not the individual non-coincident peak demands of single residential households. Some customers are early risers, using significant amounts of hot water and electricity for cooking breakfast. Other customers may be heavier evening users, skipping breakfast, instead making a large family dinner and showering after work. In this case, these customers would be able to share capacity. However, if they were charged for their non-coincident peak demand, they would each be charged separately for the same capacity. Demand charges such as these ignore the diversity in residential customer load, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.[12] This is most dramatically displayed in apartments, where the utility only sees the combined load of an apartment building; in this case, charging customers for their maximum one-hour demand would result in a significant cost shift

[12] Lazar, Jim. "Use Great Caution in Design of Residential Demand Charges," **NATURAL GAS & ELECTRICITY,** February 2016. DOI 10.1002/gas.21884

onto multifamily homes. Low-income families are more likely to live in apartments, meaning that such a demand charge would result in a regressive cross-subsidy from low-income households to more affluent families. More generally, low-income customers may be cross-subsidizing more affluent customers with more efficient appliances. Low-income customers already use much less energy than average residential consumers, minimizing the number of electronic appliances they use. The best way for them to decrease their total demand would be to buy newer, more efficient appliances with lower power demand. Many low-income customers are forced to choose between buying food, prescriptions, or paying their utility bill; they can't buy the latest model air conditioner to shave off a kilowatt or two. As a result, they're punished for their lack of affluence through increased utility bills, paying higher charges to support larger use customers. This would appear to violate the guiding principle of equity in ratemaking.

Q. Can low-income customers shift their load to decrease demand?

A. Not practically, no. As was discussed above, many low-income people work multiple jobs with erratic schedules and long commutes. These people don't have the luxury of stretching out their energy use to match some complicated rate scheme. They need to feed their families, launder their clothes, shower, clean their homes, and they need to do it in the brief time they have between obligations. A worker at a shift job can't show up late because they needed to wait for their peak demand time to pass to use cheaper power. The urgency of life at the poverty line means that low-income households lack the time to take advantage of such a rate plan as this.

Q. Could low-income customers implement load management technology to decrease demand?

A. Not feasibly, no. Upgrading to smart appliances such as smart thermostats, water heaters, or other devices to automatically adjust load could cost hundreds, if not thousands of dollars. A single person at the poverty line has an income of $11,770; such a person couldn't possibly allocate a significant share of their income to smart appliances when it is so difficult to simply keep food on the table and a roof over their head.

Q. Are low-income customers vulnerable to demand charges?

A. Yes, they're in a position where they can't afford to upgrade to smart appliance to perform automated load control and they lack the flexibility in time to spread out their demand to avoid high fees. They are historically low-use customers, keen on conservation and the ability to save money, but lacking the time and bandwidth to adjust to this new rate scheme.

Q. How would low-income customers identify as vulnerable to demand charges?

A. Enrollment in the CARES rate would demonstrate vulnerability, as would the receipt of bill assistance on their accounts. With the income qualification documented, their vulnerability is unambiguous and easily tracked as the CARES customers and bill assistance payments are already tracked in the current system.

Q. What sort of alternative pricing system would be appropriate?

A. I believe this is the wrong question to ask about low-income ratepayers. Many are often unable to fully pay off their bills, or must make impossible choices between food and clothes and prescriptions every month. To seek "revenue stability" from low-income customers, either through demand charges or increased fixed charges, is not only deeply regressive but also unlikely to work. Increasing charges on customers who can barely afford to pay their bills now will only precipitate greater problems with payments, forcing the company to pay more in collections costs and ultimately writing off even more in bad debt. In order to maintain the balance between low-income energy affordability and revenue collection, low-income customers must be held harmless in this current pursuit to "modernize" rates.

Q. What sort of protections should be in place?

A. If any changes are implemented, low-income customers should be offered shadow billing services, to show them how much they would have spent on their previous plan. Customers who would have saved money on their previous plan should receive a credit for the difference. Any change in rates should also be accompanied by a greater investment in energy efficiency and demand response in low-income communities to allow them to better adapt to any changes being implemented.

Q. **Does this conclude your testimony today?**

A. Yes, it does. Thank you.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO.E-04204A-15-0142 **SURREBUTTAL TESTIMONY OF CYNTHIA ZWICK ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION**

SURREBUTTAL TESTIMONY OF
CYNTHIA ZWICK ON BEHALF OF THE
ARIZONA COMMUNITY ACTION ASSOCIATION

February 23rd, 2016

EXHIBIT
ACAA-4
ADMITTED

Q. Please state your name and business address.

A. My name is Cynthia Zwick. My business address is 2700 N 3rd St., Ste. 3040, Phoenix, AZ 85004.

Q. What is your position at the Arizona Community Action Association?

A. I serve as the Executive Director of Arizona Community Action Association (ACAA). I've served in this position for over twelve years.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to address the following items brought up in the Company's rebuttal testimony:

- CARES eligibility;
- Rules changes regarding residential deposits and CARES customers;
- The appropriateness of demand rates for low-income customers;
- CARES customers being on their own rate;
- The need to avoid fixed charge increases for low-income customers; and
- CARES outreach.

CARES ELIGIBILITY

Q. Was the issue of the CARES eligibility rate addressed in UNSE's rebuttal testimony?

A. Yes, it was addressed in the testimony of Craig Jones.

Q. What is the Company's position?

A. Mr. Jones said that the Company proposes to keep the eligibility level at 150% of the Federal Poverty Guideline. He went on to discuss the potential additional costs to increasing CARES eligibility.

Q. Are there also additional benefits the company would see by enrolling additional CARES customers by increasing eligibility to 200% of the Federal Poverty Guideline?

A. Yes. The company will be able to see reduced collections costs, decreased costs obtaining and paying interest on deposits, less company costs from payment plans, decreased bad debt write-off costs, and improved working capital allowances.[1]

Q. How will collections costs be reduced?

A. By providing the CARES discount to a low-income customer not on CARES, their bill will decrease significantly. By decreasing their bill, the company increases their ability to pay. The proposed cost to disconnect a customer is $47, with an additional $47 to reconnect, to say nothing of the costs to collect any payments the customer wasn't able to make. Avoiding these costs can have a real impact for the company and the customer.

Q. How are deposit maintenance costs reduced?

A. When the customer is enrolled in CARES and has a more affordable bill, they are less likely to have trouble paying. This means they would be less likely to need to provide an additional deposit, avoiding further economic distress as well as avoiding costs for the company by obviating the need to collect additional deposits and pay interest on those newly collected deposits. Using the company's EIA-861 data, the average bill is $85.24, meaning the average deposit would be twice that, $170.48. Paying an interest rate of 0.13% yields an average interest of $0.22 per deposit; not a significant amount, but a cost nonetheless. Additionally, the hourly rate of a UNS Customer Service Representative is $17.23-$23.94; assuming they spend 15 minutes collecting a deposit from a customer, the cost would be an average of $5.15 per deposit collected.

Q. How can the Company save on payment plans?

A. By making customers' bills more manageable, fewer customers will need to use payment plans to pay off their accounts. Enrolling customers in CARES will decrease the company time spent establishing and managing payment plans. This can have the additional effect of receiving

[1] Colton, Roger D. "Identifying Savings Arising from Low-Income Programs"

revenue sooner, decreasing lost time value in arrears. Again, the hourly rate of a customer service representative for UNS Electric is $17.23- $23.94/hr. Assuming it takes 15 minutes to negotiate and establish a payment plan, the cost to the company could be between $4.31 and $5.99 per payment plan, giving an average cost of $5.15.

Q. How are bad debt write-off expenses decreased?

A. By ensuring that low-income customers are signed up for CARES and have more reasonable bills, less debt is incurred which would ultimately be written off as a cost to the company.

Q. What is the current discount cost per CARES customer?

A. According to the testimony of Craig Jones, in the test year the company spent $581,326.00 on discounts for 6,236 CARES customers, resulting in a discount per customer of $93.22.

Q. What are the per-customer costs that can be avoided by enrolling a low-income customer in CARES?

A. If a low-income customer, by enrolling in CARES, is able to avoid one disconnection, one reconnection, one additional deposit, and one payment plan, they are able to avoid $105.00 of additional costs. Even if they are able to simply avoid one shutoff and reconnection, they can avoid $94.49 in costs. There will also be additional costs avoided by reducing bad debt expenses and improving working capital allowance which aren't captured in this number. Avoiding these costs benefits the company by allowing it to focus on the provision of electricity to customers who need it, forgoing the time and labor associated with these collection activities. As is demonstrated in this example, if the CARES rate makes the customer's electricity more affordable, the discount can often pay for itself in reduced collections and overhead costs.

DEPOSITS

Q. Did the Company respond to ACAA's request to hold harmless CARES customers from the deposit rule changes?

A. Yes, UNSE witness Denise Smith responded to this request.

Q. What was her response?

A. Ms. Smith disagreed with the recommendation to hold CARES customers harmless; she also clarified that "UNS Electric is not proposing to assess 'additional' deposit amounts."

Q. Do you agree with her assessment?

A. No. Under the current rules, the Company "may require a Customer to establish or reestablish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period."[2] Under the proposed rules, "[t]he Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) or more bills…"[3] Perhaps there's some confusion over the use of the word "additional," but let me be clear: this proposed rule change will allow the company to collect more dollars in deposits from more customers than they are able to under the current rules.

Q. Should this rule be applied to low-income CARES customers?

A. No, it should not. Assessing a deposit on a payment-troubled CARES customer will only make their financial situation worse and make it harder for them to pay off their original debt. The same protection afforded low-income APS customers, "waiving additional security deposits for low-income ratepayers,"[4] must be similarly provided to low-income UNS Electric customers.

DEMAND RATES

Q. Have you provided testimony regarding low-income customers and demand charges?

A. Yes, I filed testimony on January 19th stating that demand charges are not in the best interest of low-income customers.[5]

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2 https://www.uesaz.com/doc/customer/rates/electric/UES-903.pdf
3 Direct Testimony of Denise Smith, Exhibit DAS-1
4 ACC Decision 71448
5 http://images.edocket.azcc.gov/docketpdf/0000167848.pdf

Q. Have you reviewed the rebuttal testimony provided by the company regarding demand charges?

A. Yes, I have.

Q. Are there any issues the company raised that you would like to address?

A. Yes. I would like to address Dr. Overcast's recommendations for a demand charge.

Q. Can you briefly describe Dr. Overcast's recommendations?

A. Yes. Dr. Overcast recommended a demand charge with a 100% ratchet on the distribution demand charge, as well as a charge for coincident peak and noncoincident peak. He also recommended that the time frame for measuring a demand charge be 15 minutes.

Q. What effect would instituting a 100% ratchet on the distribution demand charge have on low-income customers?

A. A 100% ratchet would turn the demand charge into a fixed charge. After the peak demand for the year is set, most likely in the summer, staving off life-threatening heat,[6] the customer has no incentive to conserve demand below the peak usage. Moreover, the customer will continue to be charged for that peak usage, as if their demand is the same in the summer as it is during the shoulder months. With this increased charge implemented on the bill, low-income customers would be less able to control how much they pay for power, stretching their budgets ever-tighter.

Q. What justification was given for setting the demand charge range of 15 minutes?

A. The rationale given was that "15 minute intervals are more stable over time so customers do not see large swings in their demand measurements."

Q. Are there situations where customers may see increased bill volatility due to the 15 minute interval?

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[6] http://www.azdhs.gov/documents/preparedness/epidemiology-disease-control/extreme-weather/pubs/heat-related-illness-update-april-2015.pdf

A. Yes, an example would be a moderate-use apartment, using approximately 500 kWh per month. A customer with that monthly load would have an average demand of 0.7 kW. However, in a 15 minute span in the morning, that customer may take a shower, get dressed for work, and cook breakfast. This would use the hot water heater (approximately 4.5 kW), the hair dryer (1.5 kW), and the microwave (1.1 kW). With a 15-minute demand charge calculation, the customer would be charged for ten times their average monthly demand. A low-income customer would not be able to bear such a steep charge, and unless they stopped going to work, there's very little that could be done to shift the demand, making this an unavoidable fixed charge.

Q. Does Dr. Overcast cite any utilities that have instituted mandatory demand charges for residential customers?

A. Yes, Butler Rural Electric Cooperative in Kansas implemented a mandatory demand charge for peak use times.

Q. Does this cooperative's use of demand charges allay your concerns about demand charges?

A. No.

Q. Why not?

A. Very little evidence is provided to show customer adaptation to demand rates. All that is provided in the rebuttal testimony is a Manager's Report from the cooperative saying that "many… conserved." The report does not say how many or by how much. Additionally, it does not mention if any customers had difficulty with the demand charges, didn't understand how they were implemented, or saw their bills increase as a result. More to the point, there's no mention of how low-income customers were able to negotiate the demand charge, and how their experience compared to the residential customer base.

Q. Were any special considerations offered for "vulnerable customers"?

A. Yes, Craig Jones discussed the possibility of keeping "vulnerable customers" on transition rates until the next rate case. I believe that the most appropriate transition rate for low-income customers would be to hold them harmless in these proceedings and to continue the CARES discount as is.

Q. Are low-income customers vulnerable?

A. Yes, as I discussed in my testimony on January 19th, low-income customers are absolutely a vulnerable group, and I believe holding them harmless in these proceedings is the right move.

Q. Why so?

A. First and foremost, low-income customers struggle to pay their bills, experiencing a much higher energy burden than the average residential customer. An average family in Mohave or Santa Cruz County, earning the county median income, has an energy burden of 2.75%. Households earning the mean income of the bottom income quintile in Mohave County have an energy burden of 8.3%, nearly three times the burden of the median household. Families in Santa Cruz earning the mean of the lowest income quintile have an energy burden of 10.4%, more than three and a half times the energy burden of a household earning the median income for the county. The poverty rate for Mohave county is 19.9%, and the poverty rate for Santa Cruz county is 24.4%, so the mean income for the bottom quintile represents the average income of households in poverty in these areas. In order for the bill described in the bill impact section of CAJ-R-2 to be affordable (to have a comparable energy burden to a household with median income), the low-income household would need a discount of 63% or 70% for Mohave County or Santa Cruz County, respectively, in addition to the discount already provided in the CARES demand rate. Holding low-income customers harmless – maintaining the current CARES rates and leaving it unfrozen – would keep their energy burdens at 7.5% and 9.3% for Mohave and Santa Cruz counties, respectively. The Commission should pursue truly affordable rates; failing that, low-income customers must be held harmless from increasingly unaffordable bills.

MOVING THE CARES CUSTOMERS TO THE STANDARD DEMAND RATE

Q. Do you support the CARES customers being moved to the three part rate along with the standard residential customers?

A. No.

Q. Why not?

A. It all comes back to affordability. With the three part rate and flat percentage discount after the fact, CARES customers see an 11% increase in annual rates. Increases in energy costs are associated with tradeoffs between families paying for utilities or food, with an increased risk for nutritional risk for children in homes with higher energy burdens.[7] Given the substantial effects on health and wellness that increased energy bills have on the most vulnerable, I believe low-income customers should be held harmless from these proposed changes.

FIXED CHARGE INCREASE FOR LOW INCOME CUSTOMERS

Q. Was the issue of increased fixed charges for low-income customers brought up in the rebuttal testimony?

A. Yes, Dr. Overcast discussed the benefits of a higher fixed charge, specifically how it benefits higher-use low-income customers.

Q. Do you agree that a higher fixed charge is beneficial for low-income ratepayers?

A. No. Dr. Overcast is right that higher-use customers see a smaller percentage increase with larger fixed charges than lower-use customers did, as demonstrated in the Bill Impact Analysis in Craig Jones' rebuttal testimony. However, low-usage bills are much more frequent than high-usage bills among CARES customers. There were 20,000 more bills in the test year below the average kWh per bill than there were above the average kWh per bill. Even when bills less than 300 kWh are excluded from the total, the bills less than average outnumber the bills above the average by

[7] Heat or Eat: The Low Income Home Energy Assistance Program and Nutritional and Health Risks Among Children Less Than 3 Years of Age http://pediatrics.aappublications.org/content/118/5/e1293

7,000. Maintaining a low fixed charge provides more relief for more customers' bills, which puts it squarely in the public interest. Moreover, customer usage rates aren't static; a lower fixed charge and a higher kWh charge incentivizes customers to conserve energy and decrease their bills. If the policy of increased fixed charges were pursued, there's no incentive to conserve or take any specific action, as there's no way to reduce the impact of a fixed charge.

Q. **For low-income high-usage customers who are unable to significantly conserve energy, is there a policy action that may benefit them more than increased fixed charges?**

A. Many low-income households who live in poor housing stock with old and inefficient appliances may not be able to achieve savings due to the inefficiencies in their home. For these customers weatherization would provide much more relief than increased fixed charges. A study conducted by Oak Ridge National Laboratory found that weatherization saves clients $437 per year, providing savings in energy as well as health, safety, and comfort.[8]

CARES OUTREACH

Q. **Have you read Denise Smith's rebuttal testimony regarding CARES outreach?**

A. Yes, I have.

Q. **Do you have any additional comments to respond to what she said?**

A. The primary interest in bringing up the outreach that the Company has done on CARES is to say that it appears that CARES is significantly under-enrolled. After analyzing census data, it appears that approximately 24,000 UNSE customers are eligible for CARES, while only 6,200 customers are enrolled. It appears that this gap should be closed with increased outreach.

Q. **Does this conclude your testimony?**

A. Yes, it does. Thank you.

[8] http://weatherization.ornl.gov/pdfs/ORNL_TM-2010-66.pdf

FORTIS INC.

2014

Profitable.

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BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Regulated utility assets comprised approximately 93% of total assets of Fortis as at December 31, 2014 (December 31, 2013 – 90%). Approximately 95% of the Corporation's operating revenue [(1)] was derived from regulated utility operations in 2014 (2013 – 93%), while approximately 91% of the Corporation's operating earnings[(1)] were derived from regulated utility operations in 2014 (2013 – 87%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting processes. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE.

Electricity and gas infrastructure investments require the approval of the regulatory authorities, either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

Regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth. Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Significant regulatory uncertainty remains at FortisAlberta associated with the capital tracker mechanism under the PBR formula, which became effective January 1, 2013. The final decision on FortisAlberta's combined 2013, 2014 and 2015 Capital Tracker Application is expected in the first quarter of 2015. In December 2014 the regulator approved, on an interim basis, customer distribution rates for 2015 based on 90% of the applied for capital tracker amounts, as compared to 60% approved on an interim basis for 2013 and 2014. Any adjustment to interim capital tracker amounts will result in an adjustment to revenue. During its PBR term, FortisAlberta is exposed to risks related to the PBR formula, specifically that: (i) the Company will experience inflationary increases in excess of the inflationary factor set by the AUC; (ii) the Company will be unable to achieve the productivity improvements expected over the PBR term; (iii) the costs related to FortisAlberta's capital expenditures will be in excess of those provided for in the base formula and excess capital expenditures will not qualify, or be approved, as a capital tracker where necessary; and (iv) material unforeseen costs will be incurred that will not qualify or be approved. FortisAlberta's final allowed ROE and capital structure for 2013 through 2015 are also to be determined, subject to the outcome of the GCOC Proceeding, which is also expected in the first quarter of 2015.

As an owner of an electricity distribution network under the Electric Utilities Act (Alberta), FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers

[(1)] Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

At the regulated utilities, the above-noted risks are mitigated as any increase or decrease in future plan funding requirements and/or net benefit cost is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. Additionally, at the FortisBC Energy companies, UNS Energy, Central Hudson, FortisBC Electric and Newfoundland Power, actual net benefit cost above or below forecast net benefit cost approved for recovery in customer rates for the year is also subject to deferral account treatment, subject to regulatory approval. There can be no assurance that the current regulator-approved deferral mechanisms will continue to exist in the future. An inability to flow through net benefit cost in customer rates could have a material adverse effect on the results of operations and financial position of the regulated utilities. The defined benefit pension plans at Central Hudson, FortisAlberta, Newfoundland Power and certain plans at FortisOntario are closed to all new employees. Central Hudson's OPEB plan is also closed to all new employees.

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion on managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third party owners with respect to the existing facility support agreement for Springerville Unit 1. This dispute could result in the refusal of third party owners to pay some or all of their pro rata share of such Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments in Distributed Generation and Energy Efficiency: New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact UNS Energy's results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. UNS Energy is promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity or make the existing facilities of UNS Energy less economical. In addition, advances in such technologies could reduce electrical demand, which could negatively impact the results of operations, net earnings and cash flows of TEP and UNS Electric.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity, mainly at the Corporation's regulated utilities in the Caribbean. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

The management of GHG emissions is a specific environmental concern of the Corporation's regulated gas utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state GHG laws, regulations and guidelines. In British Columbia, the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric. The Energy Plan contains a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature passing the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act*, which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2011 the FortisBC Energy companies

http://www.nogalesinternational.com/opinion/guest_opinion/mandatory-surcharges-make-reducing-electric-costs-difficult/article_4b7d941a-d43b-11e5-b9eb-c7a680a73d25.html

Mandatory surcharges make reducing electric costs difficult

By Dana Marie Kennedy Feb 16, 2016

For many older Arizonans, managing monthly household expenses is not easy. And if Arizona utilities get their way, it may get even harder.

UNS Energy, parent company of Tucson Electric Power and UniSource Energy Services, is currently asking the Arizona Corporation Commission (ACC) to impose a mandatory surcharge on residential consumers that will make it even harder to guess what your power bill will be.

Seniors on limited or fixed incomes already know they did not get a Social Security COLA increase this year. Seniors also spend a higher percentage of their household income on utilities than younger age groups and also have much higher medical expenses.

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When a monthly budget is tight, often seniors try to keep power bills down by turning up the thermostat in the summer or turning down the heat in the winter, however dangerous, sometimes folks feel that there is no other choice.

But these energy conservation efforts would be less effective in saving money if utilities like UNS are allowed to raise the fixed charges of peoples' monthly bill. Fixed charges are owed even before you turn on a light switch!

UNS has asked the ACC to double the "basic service charge" on ratepayers' electric bills from $10 to $20 per month. That's a $120 annual increase.

Still more, UNS is also asking the ACC to allow it to add a brand new mandatory charge called a "demand charge" on residential customers' monthly bills. This "demand charge" would be based on a customer's maximum peak demand in a given month.

Utilities may want more revenue stability, but imposing mandatory fees comes at the expense of consumer control. Neither of these UNS proposed rate changes can be avoided by using less power.

And if approved by the ACC, demand charges would be difficult for most consumers to understand. Consumers often don't know when their household is experiencing its maximum electricity usage. This makes it nearly impossible for ratepayers to keep their electric bill as low as possible.

A current option available in Arizona is called a "time-of-use plan. It is voluntary and much easier for consumers to understand. In other words, we know that if we do laundry early on Saturday morning, it saves us money.

Time-of-use plans have worked well for years and we already know how they work. But demand charges are untested.

Why should an untested "demand charge" proposal be tested here in the heat of the Arizona summer? Even more so, no other state utility commission has ever imposed mandatory demand charges on residential customers.

The Arizona Corporation Commission should follow this national trend and say "no" to these surcharges as well.

(Kennedy is state director in Arizona for AARP, formerly the American Association of Retired Persons.)

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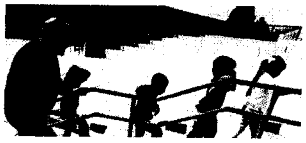

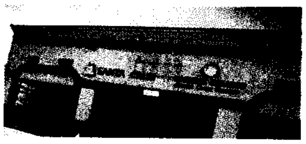

FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2015

February 17, 2016

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2015

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this 2015 Annual Information Form are defined below:

"2015 Annual Information Form" means this annual information form of the Corporation in respect of the year ended December 31, 2015;

"2015 Audited Consolidated Financial Statements" means the audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2015 and 2014 and related notes thereto;

"ACC" means the Arizona Corporation Commission;

"Algoma Power" means Algoma Power Inc.;

"APS" means the Arizona Public Service Company;

"AUC" means the Alberta Utilities Commission;

"BC Hydro" means the BC Hydro and Power Authority;

"BCUC" means the British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means the Board of Directors of the Corporation;

"BPC" means Brilliant Power Corporation;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CEA" means the Canadian Electricity Association;

"Central Hudson" means Central Hudson Gas & Electric Corporation;

"CEPSA" means the Capacity and Energy Purchase and Sale Agreement;

"CH Energy Group" means CH Energy Group, Inc.;

"COPE" means the Canadian Office and Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means the Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CPP" means the Clean Power Plan;

"CUPE" means the Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"Eastern Canadian Electric Utilities" means, collectively, the operations of Newfoundland Power, Maritime Electric and FortisOntario;

"EMS" means environmental management system;

"Entergy Nuclear Power" means Entergy Nuclear Power Marketing, LLC;

"EPA" means the United States Environmental Protection Agency;

"ERA" means the Electricity Regulatory Authority of the Cayman Islands;

"Ethos Energy" means EthosEnergy Power Plant Services, LLC;

"External Auditor" means the firm of Chartered Professional Accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FERC" means the United States Federal Energy Regulatory Commission;

"FHI" means FortisBC Holdings Inc., the parent company of FortisBC Energy;

"Fitch" means Fitch Ratings Inc.;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisBC Electric" means, collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc., but excludes its wholly owned partnership, Walden Power Partnership;

"FortisBC Energy" means FortisBC Energy Inc.;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Properties" means Fortis Properties Corporation;

"FortisTCI" means FortisTCI Limited;

"Fortis Turks and Caicos" means, collectively, FortisTCI and Turks and Caicos Utilities Limited;

"FortisUS" means FortisUS Inc.;

"FortisUS Holdings" means FortisUS Holdings Nova Scotia Limited;

"FortisWest" means FortisWest Inc.;

"**Four Corners"** means Four Corners Generating Station;

"GHG" means greenhouse gas;

"GOB" means the Government of Belize;

"GSMIP" means Gas Supply Mitigation Incentive Plan;

"GWh" means gigawatt hour(s);

"IBEW" means the International Brotherhood of Electrical Workers;

"IESO" means the Independent Electricity System Operator of Ontario;

"ISO" means International Organization for Standardization;

"ITC" means ITC Holdings Corp.;

"LNG" means liquefied natural gas;

"Management" means, collectively, the senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MATS" means Mercury and Air Toxics Standards;

"MD&A" means the Corporation's Management Discussion and Analysis prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual consolidated financial statements for the year ended December 31, 2015;

"MGP" means manufactured gas plant;

"Moody's" means Moody's Investors Service, Inc.;

"MW" means megawatt(s);

"MWh" means megawatt hour(s);

"NB Power" means New Brunswick Power Corporation;

"NEB" means the National Energy Board;

"NEPA" means the United States National Environmental Policy Act;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NL PUB" means the Newfoundland and Labrador Board of Commissioners of Public Utilities;

"NYISO" means the New York Independent System Operator;

"OEB" means the Ontario Energy Board;

"OSM" means the United States Office of Surface Mining;

"PBR" means performance-based rate-setting;

"PCB" means polychlorinated biphenyl;

"PEI" means Prince Edward Island;

"PJ" means petajoule(s);

"PNM" means Public Service Company of New Mexico;

"PPA" means power purchase agreement;

"PPFAC" means purchased power and fuel adjustment clause;

"PRMP" means Price-Risk Management Plan;

"ROE" means rate of return on common shareholders' equity;

"S&P" means Standard & Poor's Financial Services LLC;

"SEC" means the United States Securities and Exchange Commission;

"SEDAR" means the System for Electronic Document Analysis and Retrieval;

"SJCC" means the San Juan Coal Company;

"Spectra Energy" means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

"SRP" means Salt River Project Agricultural Improvement and Power District;

"T&D" means transmission and distribution;

"TEP" means Tucson Electric Power Company;

"TJ" means terajoule(s);

"TransCanada" means TransCanada Pipelines Limited;

"TSX" means the Toronto Stock Exchange;

"UNS Electric" and **"UNSE"** mean UNS Electric, Inc.;

"UNS Energy" means collectively, the operations of TEP, UNS Electric and UNS Gas;

"UNS Gas" means UNS Gas, Inc.;

"US GAAP" means accounting principles generally accepted in the United States;

"UUWA" means the United Utility Workers' Association of Canada;

"Walden" means the Walden Power Partnership;

"Waneta Expansion" means the 335-MW hydroelectric generating facility adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia;

"Waneta Partnership" means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

"WECA" means the Waneta Expansion Capacity Agreement;

"WEG" means WildEarth Guardians; and

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2015 Annual Information Form has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2015 Annual Information Form is given as of December 31, 2015.

Fortis includes forward-looking information in the 2015 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects Management's current beliefs and is based on information currently available to the Corporation's Management. The forward-looking information in the 2015 Annual Information Form, including the 2015 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the acquisition of ITC, the expected timing and conditions precedent to the closing of the acquisition of ITC, including shareholder approvals of both ITC and Fortis, regulatory approvals, governmental approvals and other customary closing conditions; the expectation that Fortis will borrow funds to satisfy its obligation to pay the cash portion of the purchase price and will issue securities to pay the balance of the purchase price; the impact of the acquisition on the Corporation's earnings, mid-year rate base, credit rating, estimated enterprise value and compound annual growth rate; the expectation that the acquisition of ITC will be accretive in the first full year following closing and that the acquisition will support the average annual dividend growth target of Fortis; the expectation that the Corporation will become an SEC registrant and have its common shares listed on the New York Stock Exchange in connection with the acquisition; the expectation that Fortis will identify one or more minority investors to invest in ITC; forecast 2016 to 2020 midyear rate bases for the Corporation and its largest regulated utilities; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the Corporations consolidated forecast gross capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the breakdown of total capital spending over the five-year period from 2016 through 2020; various natural gas investment opportunities that may be available to the Corporation; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas facility expansions, the Residential Solar Program, the Lower Mainland System Upgrade Project, FortisAlberta's pole replacement program, the Gas Main Replacement Program at Central Hudson, Woodfibre pipeline expansion, New York Transco, LLC at Central Hudson, renewable energy alternatives at UNS Energy, Wataynikaneyap transmission line, the consolidations of Rural Electrification Associations and the construction of a diesel power plant at Caribbean Utilities; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the expectation that the Corporation's subsidiaries will have reasonable access to long-term capital to fund their 2016 capital expenditure programs, operating and interest costs, and dividend payments; that TEP and UNS Electric expect to invest in renewable projects in 2016 to meet future renewable energy requirements; the impact of advances in technology and new energy efficiency standards on the Corporation's results of operations; the impact of new or revised environmental laws and regulations on the Corporation's results of operations; the expectation of the Corporation and its subsidiaries to remain compliant with existing, new or revised environmental laws and regulations; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; and the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed ROE under performance-based rate-setting, which commenced for a five-year term effective January 1, 2013; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices, electricity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably accurately assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in the MD&A for the year ended December 31, 2015 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2016 include, but are not limited to: uncertainty regarding the completion of the acquisition of ITC including but not limited to the receipt of shareholder approvals of ITC and Fortis, the receipt of regulatory and other governmental approvals, the availability of financing sources at the desired time or at all, on cost-efficient or commercially reasonable terms and the satisfaction or waiver of certain other conditions to closing; uncertainty related to the realization of some or all of the expected benefits of the acquisition of ITC; uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities, uncertainty of the impact *that a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; and risk associated with the impact of less favorable economic conditions on the Corporation's results of operations.*

All forward-looking information in the 2015 Annual Information Form is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012; (xiii) designate 12,000,000 First Preference Shares, Series K and 12,000,000 First Preference Shares, Series L on July 11, 2013; and; (xiv) designate 24,000,000 First Preference Shares, Series M and 24,000,000 First Preference Shares, Series N on September 16, 2014.

Fortis redeemed all of its outstanding First Preference Shares, Series A, First Preference Shares, Series B and First Preference Shares, Series C on September 30, 1997, December 2, 2002, and July 10, 2013, respectively. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H. On November 13, 2012, Fortis issued 8,000,000 First Preference Shares, Series J. On July 18, 2013, Fortis issued 10,000,000 First Preference Shares, Series K. On September 19, 2014, Fortis issued 24,000,000 First Preference Shares, Series M. On June 1, 2015, 2,975,154 First Preference Shares, Series H were converted into First Preference Shares, Series I, and 7,024,846 First Preference Shares, Series H remained outstanding.

The corporate head office and registered office of Fortis are located at Fortis Place, Suite 1100, 5 Springdale Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is a leader in the North American electric and gas utility business, with total assets of approximately $29 billion and fiscal 2015 revenue of $6.7 billion. The Corporation's asset mix is approximately 96% regulated utilities (70% electric, 26% gas), with the remaining 4% comprised of long-term contracted hydroelectric operations. The Corporation's regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. In 2015 the Corporation's electricity distribution systems met a combined peak demand of 9,705 MW and its gas distribution systems met a peak day demand of 1,323 TJ.

The Corporation's regulated holdings include electric distribution utilities in five Canadian provinces, two U.S. states and three Caribbean countries and natural gas utilities in the province of British Columbia and the states of Arizona and New York. As at December 31, 2015, approximately 47% of the Corporation's assets were located outside of Canada and approximately 49% of the Corporation's revenue was derived from foreign operations.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at February 17, 2016. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2015, or the total revenue of which individually constituted less than 10% of the Corporation's 2015 consolidated revenue. The principal subsidiaries together comprise approximately 76% of the Corporation's consolidated assets as at December 31, 2015 and approximately 71% of the Corporation's 2015 consolidated revenue. FortisBC Electric and Newfoundland Power comprise approximately 7% and 5%, respectively, of the Corporation's consolidated assets as at December 31, 2015 and approximately 5% and 10%, respectively, of the Corporation's 2015 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
UNS Energy (1)	Arizona State, United States	100
Central Hudson (2)	New York State, United States	100
FortisBC Energy (3)	British Columbia, Canada	100
FortisAlberta (4)	Alberta, Canada	100

(1) *UNS Energy, an Arizona State corporation, owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS, a Delaware State corporation, owns all of the shares of UNS Energy. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(2) *CH Energy Group, a New York State corporation, owns all of the shares of Central Hudson. FortisUS, a Delaware State corporation, owns all of the shares of CH Energy Group. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(3) *FHI, a British Columbia corporation, owns all of the shares of FortisBC Energy. Fortis owns all of the shares of FHI.*

(4) *FortisAlberta Holdings Inc., an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings Inc. Fortis owns all of the shares of FortisWest.*

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have grown approximately 92% from $15.0 billion as at December 31, 2012 to $28.8 billion as at December 31, 2015. The Corporation's shareholders' equity has also grown approximately 93% from $5.4 billion as at December 31, 2012 to $10.4 billion as at December 31, 2015. Net earnings attributable to common equity shareholders have increased from $315 million in 2012 to $728 million in 2015.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal regulated electric and gas utilities. This strategy includes a combination of growth from acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

Over the past three years, Fortis has significantly increased its regulated utility investments through acquisitions. In June 2013 Fortis acquired CH Energy Group for a purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated T&D utility serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. In August 2014 Fortis acquired UNS Energy for a purchase price of approximately US$4.5 billion, including the assumption of approximately US$2.0 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 663,000 electricity and gas customers.

On April 1, 2015, the Corporation completed construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility ahead of schedule and on budget while maintaining an excellent safety and environmental protection record. Construction of the Waneta Expansion commenced late in 2010. Fortis has a 51% controlling ownership interest in the Waneta Expansion and operates and maintains the non-regulated investment. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. In 2015, the Waneta Expansion contributed $22 million in earnings to the Corporation.

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million to a subsidiary of Slate Office REIT. As part of the transaction, Fortis subscribed to trust units of Slate Office REIT for total consideration of approximately $35 million. In October 2015, the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million to a private investor group.

In June and July of 2015, the Corporation completed the sale of its non-regulated generation assets in Upstate New York and Ontario, respectively, for gross proceeds of approximately $93 million.

In August 2015 the Corporation announced that it had reached terms of settlement with the GOB regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity.

In December 2015 the Corporation, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its share of the Aitken Creek Gas Storage Facility, the largest gas storage facility in British Columbia, with a total working gas capacity of 77 billion cubic feet for approximately US$266 million. The acquisition is subject to regulatory approval, and is expected to close in the first half of 2016.

The Corporation's gross consolidated capital expenditures for 2015 were approximately $2.2 billion, up approximately 30% from 2014. Over the past three years, including 2015, gross consolidated capital expenditures totalled $5.1 billion. Organic asset growth at the regulated utilities has been driven by the capital expenditure programs in western Canada. Total assets at FortisAlberta and the FortisBC gas and electric utilities have grown by approximately 27% and 9%, respectively, over the past three years. Organic growth at non-regulated operations has been driven by the construction of the Waneta Expansion.

2.2 Pending Acquisition of ITC

On February 9, 2016, Fortis and ITC entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin.

ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott Rodino Antitrust Improvement Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition.

The financing of the acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance, although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the acquisition, Fortis will become a registrant with the SEC and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

2.3 Outlook

Fortis is focused on closing the acquisition of ITC by the end of 2016. The acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix.

Substantially all of Fortis' assets are low-risk, regulated utilities and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one third of total assets. Over the five-year period through 2020, excluding the acquisition of ITC, the Corporation's highly executable capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%.

On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition of ITC. Following the acquisition, Fortis will be one of the top 15 North American public utilities ranked by enterprise value, with an estimated enterprise value of $42 billion. Additionally, ITC's midyear rate base, including construction work in progress, is expected to increase at a compound annual growth rate of approximately 7.5% through 2018, based on ITC's planned capital expenditure program.

Fortis continues to target 6% average annual dividend growth through 2020. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

Fortis expects long-term sustainable growth in rate base, assets and earnings resulting from strategic acquisitions and investment in its existing utility operations. The Corporation is also committed to identifying and executing on opportunities for incremental rate base and earnings growth through additional investments in existing service territories and in new franchise areas.

The approximate breakdown of the capital spending expected to be incurred over the five-year period from 2016 to 2020, excluding the acquisition of ITC, is as follows: 40% at Regulated Gas & Electric Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utilities; 5% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 35% to meet customer growth; 50% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e. sustaining capital expenditures); and 15% for facilities, equipment, vehicles, information technology and other assets.

Gross consolidated capital expenditures for 2016 are expected to be approximately $1.9 billion, as summarized in the following table. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast.

Forecast Gross Consolidated Capital Expenditures *(1)*
Year Ending December 31, 2016

	($ millions)
UNS Energy *(2)*	485
Central Hudson *(2)*	228
FortisBC Energy	349
FortisAlberta	441
FortisBC Electric	79
Eastern Canadian Electric Utilities	174
Regulated Electric Utilities – Caribbean *(2)*	127
Non-Regulated - Fortis Generation	15
Non-Regulated - Non-Utility *(3)*	3
Total	**1,901**

(1) Relates to forecast cash payments to acquire or construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of allowance for funds used during construction.
(2) Forecast capital expenditures are based on a forecast exchange rate of US$1.00 = CAD$1.38.
(3) Includes forecast capital expenditures of approximately $3 million at FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment of the Corporation's 2015 Audited Consolidated Financial Statements.

The most significant capital projects forecast for 2016 include:

- the Residential Solar Program at UNS Energy, consisting of the installation of rooftop solar systems for residential customers, for US$82 million, with forecast expenditures of US$16 million expected in 2016;
- the Gas Main Replacement Program at Central Hudson, a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system with forecast expenditures of US$21 million expected in 2016 and US$98 million from 2017 through 2020 with the majority of spending expected post-2020;
- the ongoing Tilbury LNG facility expansion by FortisBC Energy, which includes the construction of a second LNG tank and a new liquefier, both to be in service by the end of 2016 at a total project cost of approximately $440 million with $326 million of project costs incurred to the end of 2015 and forecast expenditures of $105 million in 2016;
- the Lower Mainland System Upgrade project at FortisBC Energy, which is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia, to be completed in 2018 for an estimated project cost of $427 million with forecast expenditures of $50 million expected in 2016;
- the replacement of vintage poles under FortisAlberta's Pole-Management Program is expected to cost $336 million through 2020 with forecast expenditures of $42 million expected in 2016; and

- the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment at Caribbean Utilities. The project cost is estimated to be US$85 million, with approximately US$48 million spent in 2015 and US$25 million forecast to be spent in 2016. The plant is expected to be commissioned in mid-2016.

FortisBC Energy is also pursuing additional LNG investment opportunities including a $600 million pipeline expansion for the proposed Woodfibre LNG site in British Columbia and further expansion of the Tilbury site that would include additional liquefaction, which investment opportunities are not included in the current capital expenditures forecast set forth in the table above.

Other potential projects that have not yet been included in the Corporation's capital expenditure forecast include, but are not limited to, the New York Transco, LLC at Central Hudson to address transmission constraints in New York; renewable energy alternatives at UNS Energy; Wataynikaneyap transmission line to connect remote First Nations communities at FortisOntario; further gas infrastructure opportunities at FortisBC Energy; and consolidation of Rural Electrification Associations at FortisAlberta.

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2016 to fund their capital expenditure programs.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's reporting utility segments, as well as the Waneta Expansion, is provided in the following table.

Midyear Rate Base *($billions)*		
	Actual 2015	**Forecast 2016**
UNS Energy [(1)]	4.1	4.8
Central Hudson [(1)]	1.4	1.6
FortisBC Energy	3.7	3.7
FortisAlberta	2.7	3.0
FortisBC Electric	1.3	1.3
Eastern Canadian Electric Utilities	1.6	1.7
Regulated Electric Utilities – Caribbean [(1)]	0.8	0.9
Waneta Expansion	0.8	0.8
Total	**16.4**	**17.8**

(1) *Actual midyear rate base for 2015 is based on the actual average exchange rate of US$1.00=CAD$1.28 and forecast midyear rate base for 2016 is based on a forecast exchange rate of US$1.00=CAD$1.38.*

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, which is treated as a separate segment. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The business segments of the Corporation are: (i) Regulated Electric & Gas Utilities – United States; (ii) Regulated Gas Utility – Canadian; (iii) Regulated Electric Utilities – Canadian; (iv) Regulated Electric Utilities – Caribbean; (v) Non-Regulated – Fortis Generation; (vi) Non-regulated – Non-Utility; and (vii) Corporate and Other.

The following sections describe the operations included in each of the Corporation's reportable segments.

3.1 Regulated Electric & Gas Utilities - United States

3.1.1 *UNS Energy*

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 663,000 electricity and gas customers. UNS Energy was acquired by Fortis in August 2014.

UNS Energy is primarily comprised of three wholly owned regulated utilities: TEP, UNS Electric and UNS Gas.

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP serves approximately 417,000 retail customers in a territory comprising approximately 2,991 square kilometres in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP's service area covers a population of approximately 1,000,000 people. TEP also sells wholesale electricity to other entities in the western United States.

UNS Electric is a vertically integrated regulated electric utility that generates, transmits and distributes electricity to approximately 94,000 retail customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 250,000.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. TEP has sufficient generating capacity that, together with existing PPAs and expected generation plant additions, should satisfy the requirements of its customer base and meet future peak demand requirements. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility that serves approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 700,000.

Market and Sales

UNS Energy's electricity sales were 15,366 GWh for 2015, compared to 14,560 GWh for the full year in 2014. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment. Gas volumes were 13 PJ for 2015, comparable with the full year in 2014. Revenue was US$1,588 million for 2015, compared to US$1,560 million for the full year in 2014.

The following table provides the composition of UNS Energy's 2015 and 2014 revenue, electricity sales, and gas volumes by customer class.

UNS Energy [(1)]
Revenue and Electricity & Gas Sales by Customer Class

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2015	2014	**2015**	2014	**2015**	2014
Residential	**37.3**	36.2	**29.8**	31.2	**55.1**	53.8
Commercial	**22.5**	22.5	**17.7**	19.1	**23.7**	24.1
Industrial	**17.0**	16.9	**21.8**	23.9	**2.0**	2.1
Other [(2)]	**23.2**	24.4	**30.7**	25.8	**19.2**	20.0
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

[(1)] *The 2014 information presented is for the year ended December 31, 2014. UNS Energy was acquired by Fortis in August 2014; therefore, only financial results from the date of acquisition, August 15, 2014, are reflected in the comparatives of the Corporation's 2014 Audited Consolidated Financial Statements.*

[(2)] *Includes electricity sales and gas volumes to other entities for resale and revenue from sources other than from the sale of electricity and gas.*

Power Supply

TEP meets the electricity supply requirements of its retail and wholesale customers with its owned electrical generating capacity of 2,501 MW and its transmission and distribution system consisting of approximately 15,654 kilometres of line. In 2015, TEP met a peak demand of 2,860 MW which includes firm sales to wholesale customers. TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities.

At December 31, 2015, TEP owned 2,501 MW of generating capacity, as set forth in the following table:

Generating Source	Unit No.	Location	Date in Service	Resource Type	Total Capacity (MW)	Operating Agent	TEP's Share (%)	TEP's Share (MW)
Springerville Station	1	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	2	Springerville, AZ	1990	Coal	406	TEP	100.0	406
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station (1)	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station (2)	4	Tucson, AZ	1967	Gas	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100.0	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	13	TEP	100.0	13
Ft. Huachuca Project		Ft. Huachuca, AZ	2014	Solar	17	TEP	100.0	17
Total Capacity (3)								**2,501**

(1) *In December 2014, TEP and UNS Electric together completed the acquisition of Unit 3 of the Gila River Power Station, a 550 MW gas-fired combined-cycle unit for US$219 million. Both TEP and UNS Electric rely on a portfolio of long-term, medium-term and short-term PPAs to meet customer load requirements.*

(2) *In August 2015, TEP exhausted its existing coal supply at Sundt Station and has been operating Sundt Station with natural gas as a primary fuel source. TEP expects to retire the Sundt Station earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 rate case.*

(3) *Excludes 913 MW of additional generation resources, which consist of certain capacity purchases and interruptible retail load.*

UNS Electric meets the electricity supply requirements of its retail customers through a mix of its own generation and power purchase contracts. UNS Electric owns and operates several gas and diesel-fuelled generating plants, with a collective electrical generating capacity of 298 MW, which provided approximately 73% of its 407 MW 2015 peak capacity needs.

UNS Electric's generating capacity as of December 31, 2015 is set forth in the following table:

Generating Source	Unit No.	Location	Date In Service	Resource Type	Total Capacity (MW)	Operating Agent	UNSE's Share (%)	UNSE's Share (MW)
Black Mountain	1	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Black Mountain	2	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Valencia	1	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	2	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	3	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	4	Nogales, AZ	Purchased 2003	Gas/Oil	21	UNSE	100.0	21
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	25.0	137
La Senita		Kingman, AZ	2011	Solar	1	UNSE	100.0	1
Rio Rico		Rio Rico, AZ	2014	Solar	7	UNSE	100.0	7
Total Capacity								**298**

Each of TEP and UNS Electric are subject to government-mandated renewable energy requirements. TEP satisfies these requirements through its 46 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (175 MW), wind resources (80 MW) and a landfill gas generation plant (4 MW). UNS Electric satisfies its respective requirements through its 8 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (10 MW) and wind resources (10 MW). TEP and UNS Electric expect to spend US$64 million on renewable projects in 2016 to meet future renewable energy requirements which are recoverable through rates.

Gas Purchases

UNS Gas directly manages its gas supply and transportation contracts. The price for gas varies based on market conditions, which include weather, supply balance, economic growth rates, and other factors. UNS Gas hedges its gas supply prices by entering into fixed-price forward contracts, collars, and financial swaps from time to time, up to three years in advance, with a view to hedging at least 70% of expected monthly gas consumption with fixed prices prior to the beginning of each month.

UNS Gas purchases the majority of its gas supply from the San Juan Basin. The gas is delivered on the El Paso Natural Gas, L.L.C. and Transwestern Pipeline Company interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet the demands of UNS Gas' customers.

Legal Proceedings

Springerville Generating Station, Unit 1
In November 2014 the Springerville Unit 1 third-party owners filed a complaint against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third party-owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York action and in the arbitration proceeding described below. As amended, the New York action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the American Arbitration Association alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the third-party trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming the owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As of December 31, 2015 TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the 2015 Audited Consolidated Financial Statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Navajo Generating Station Lease Extension

Navajo Generating Station is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in Navajo Generating Station, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo Generating Station. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the U.S. Department of the Interior, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo Generating Station. In 2015, TEP recorded additional estimated lease expense of approximately US$1 million with the expectation that the lease amendment will become effective. As at December 31, 2015 a total liability of US$3 million (December 31, 2014 – US$2 million) was recognized.

Environmental Contingencies

San Juan Generating Station
In August 2013, the U.S. Bureau of Land Management proposed regulations that, among other things, redefine the term "underground mine" to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately US$5 million of which TEP's proportionate share would approximate US$1 million. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot predict the final outcome of the Bureau of Land Management's proposed regulations.

In February 2013 WEG filed a Petition for Review in the U.S. District Court of Colorado against the OSM challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by OSM. Of the fifteen claims for relief in the WEG Petition, two concern SJCC's San Juan mine. WEG's allegations concerning the San Juan mine arise from OSM administrative actions in 2008. WEG alleges various NEPA violations against OSM, including, but not limited to, OSM's alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG's petition seeks various forms of relief, including a finding that the federal defendants violated NEPA by approving the mine plans; voiding, reversing, and remanding the various mining modification approvals; enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with NEPA has been demonstrated; and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. The parties have requested the court to stay this matter until April 2016 in furtherance of settlement negotiations. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Four Corners Generating Station
In October 2011 EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the U.S. District Court for the District of New Mexico against APS and the other Four Corners Generating Station participants alleging violations of the prevention of significant deterioration provisions of the Clean Air Act at Four Corners Generating Station. In January 2012 EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners Generating Station. Among other things, the plaintiffs sought to have the court issue an order to cease operations at Four Corners Generating Station until any required prevention of significant deterioration permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint.

TEP owns 7% of Four Corners Generating Station Units 4 and 5 and is liable for its share of any resulting liabilities. In June 2015 APS, the operator of Four Corners Generating Station, announced a settlement with the EPA for outstanding environmental issues related to New Source Review provisions under the Clean Air Act. The settlement calls for environmental upgrades including selective catalytic reduction upgrades already planned for under the Regional Haze regulation, environmental mitigation projects, and civil penalties. A consent decree reflecting terms of the settlement was entered by the court in August 2015, effectively closing the case. TEP's share of the additional capital, excluding the selective catalytic reduction upgrades, is approximately US$2 million over the three year period it will take to construct the upgrades. TEP's share of the annual operations and maintenance expenses is approximately US$1 million. In addition, TEP recorded less than US$1 million for its share of the one-time charges for environmental mitigation projects and civil penalties.

In May 2013 the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance tax, penalties, and interest totaling US$30 million to the coal supplier at Four Corners. TEP's share of the assessment is US$1 million based on its ownership percentage. In December 2013, the coal supplier and Four Corners Generating Station's operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners Generating Station, who will be liable for their share of any resulting liabilities. In June 2015 the U.S. District Court ruled in favor of the Four Corners Generating Station's participants. The New Mexico Taxation and Revenue Department filed an appeal of the decision in August 2015. TEP cannot predict the final outcome or timing of resolution of these claims.

Mine Reclamation Costs
TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements. TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Human Resources

As at December 31, 2015: (i) TEP employed approximately 1,478 employees, of whom 688 are represented by IBEW under a collective agreement expiring in January 2019; (ii) UNS Electric employed 145 approximately employees, of whom 111 are represented by IBEW under collective agreements expiring in June 2016 and February 2017; and (iii) UNS Gas employed approximately 184 employees, of whom 111 are represented by IBEW under collective agreements expiring February 2017 and June 2018. UniSource Energy Services Inc., another wholly owned subsidiary of UNS Energy, employed approximately 208 employees, of whom 199 are represented by IBEW under collective agreements expiring in May 2016, July 2016 and December 2016.

3.1.2 *Central Hudson*

Central Hudson is a regulated T&D utility serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson was acquired by Fortis as part of the acquisition of CH Energy Group in June 2013.

Central Hudson serves a territory comprising approximately 6,734 square kilometres in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and about the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric transmission system consists of approximately 1,000 kilometres of line. Central Hudson's electric distribution system consists of approximately 11,600 kilometres of overhead lines and 2,400 trench kilometres of underground lines, as well as customer service lines and meters. Central Hudson's electricity system met a peak demand of 1,059 MW in 2015.

Central Hudson's natural gas system consists of approximately 300 kilometres of transmission pipelines and 2,000 kilometres of distribution pipelines, as well as customer service lines and meters. In 2015 Central Hudson's natural gas system met a peak day demand of 140 TJ.

Market and Sales

Central Hudson's electricity sales were 5,132 GWh for 2015, compared to 5,075 GWh for 2014. Natural gas sales volumes for 2015 were 24 PJ, compared to 23 PJ for 2014. Revenue was US$691 million for 2015, compared to US$743 million in 2014.

The following tables compare the composition of Central Hudson's 2015 and 2014 revenue, electricity sales and gas volumes by customer class.

Central Hudson Revenue and Electricity Sales by Customer Class				
	Revenue (%)		GWh Sales (%)	
	2015	2014	**2015**	2014
Residential	**61.0**	60.9	**40.6**	40.3
Commercial	**26.4**	28.0	**38.0**	37.8
Industrial	**4.0**	4.1	**19.7**	20.1
Other	**7.9**	6.2	**0.7**	0.7
Sales for Resale	**0.7**	0.8	**1.0**	1.1
Total	**100.0**	100.0	**100.0**	100.0

Central Hudson Revenue and Gas Volumes by Customer Class				
	Revenue (%)		PJ Volumes (%)	
	2015	2014	**2015**	2014
Residential	**52.9**	53.5	**26.1**	27.1
Commercial	**26.5**	29.0	**33.1**	33.9
Industrial	**8.3**	4.8	**20.2**	17.2
Other	**3.1**	1.1	**7.7**	7.8
Sales for Resale	**9.2**	11.6	**12.9**	14.0
Total	**100.0**	100.0	**100.0**	100.0

Power Supply

Central Hudson relies on purchased capacity and energy from third-party providers, together with its own minimal generating capacity, to meet the demands of its full-service customers.

Central Hudson is obligated to supply electricity to its retail electric customers. Central Hudson, the staff of the New York State Public Service Commission and others entered into a settlement agreement in 1998 with respect to the auction of fossil-fuel generation plants owned by Central Hudson. Under the settlement agreement, Central Hudson's retail customers may elect to procure electricity from third-party suppliers or may continue to rely on Central Hudson. As part of its requirement to supply customers who continue to rely on Central Hudson for their energy supply, Central Hudson entered into a 10-year revenue sharing agreement with Constellation Energy Group, Inc. in 2011, pursuant to which Central Hudson shares in a portion of the power sales revenue attributable to Unit No. 2 of the Nine Mile Point Nuclear Generating Station.

During 2015 Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

In June 2014 Central Hudson entered into a PPA to purchase capacity from the Danskammer Generating Facility from October 2014 through August 2018, with approximately US$76 million in purchase commitments remaining as at December 31, 2015.

In November 2013 Central Hudson entered into a PPA to purchase 200 MW of installed capacity from the Roseton Generating Facility from May 2014 through April 2017, with approximately US$14 million in purchase commitments remaining as at December 31, 2015.

Costs of electric and natural gas commodity purchases are recovered from customers, without earning a profit on these costs. Rates are reset monthly based on Central Hudson's actual costs to purchase the electricity and natural gas needed to serve its full-service customers.

Other Contractual Obligations

CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of, and return on, five high-voltage transmission projects totaling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of its maximum commitment. As at December 31, 2015, no payment obligation was expected under this guarantee.

Litigation

Asbestos Litigation
Prior to and after its acquisition by Fortis, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by Central Hudson, and it has settled the remaining 156 cases. The company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in 2015 Audited Consolidated Financial Statements.

Environmental Contingencies

Former MGP Facilities
Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The New York State Department of Environmental Conservation has further requested that the company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the New York State Public Service Commission, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Human Resources

As at December 31, 2015, Central Hudson employed approximately 966 employees, of whom 566 are represented by IBEW under a collective agreement expiring April 30, 2017.

3.2 Regulated Gas Utility - Canadian

3.2.1 FortisBC Energy

FortisBC Energy is the largest distributor of natural gas in British Columbia, serving approximately 982,000 residential, commercial and industrial and transportation customers in more than 135 communities. Major areas served by FortisBC Energy include the Lower Mainland, Vancouver Island and Whistler regions of British Columbia.

In addition to providing T&D services to customers, FortisBC Energy also obtains natural gas supplies on behalf of most residential, commercial and industrial customers.

FortisBC Energy owns and operates approximately 48,000 kilometres of natural gas pipelines and met a peak day demand of 1,074 TJ in 2015.

Market and Sales

FortisBC Energy's natural gas sales volumes were 186 PJ in 2015, compared to 195 PJ in 2014. Revenue decreased from $1,435 million in 2014 to $1,295 million in 2015.

The following table compares the composition of FortisBC Energy's 2015 and 2014 revenue and natural gas volumes by customer class.

FortisBC Energy
Revenue and Gas Volumes by Customer Class

	Revenue (%)		**PJ Volumes (%)**	
	2015	2014	**2015**	2014
Residential	**56.8**	56.2	**36.0**	36.9
Commercial	**29.1**	30.2	**23.1**	23.1
Industrial	**1.7**	2.7	**1.6**	2.1
Transportation	**7.8**	6.8	**33.9**	31.8
Other (1)	**4.6**	4.1	**5.4**	6.1
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes amounts under fixed-revenue contracts and revenue from sources other than from the sale of natural gas.*

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, FortisBC Energy purchases natural gas supply from counterparties, including producers, aggregators and marketers. These counterparties adhere to standards of counterparty creditworthiness and contract execution and/or management policies. FortisBC Energy contracts for approximately 136 PJ of baseload and seasonal supply, of which the majority is sourced in north east British Columbia and transported on Spectra Energy's Westcoast Pipeline Transmission-South pipeline system. The remainder is sourced in Alberta and transported on TransCanada's pipeline transportation system.

FortisBC Energy procures and delivers natural gas directly to core market customers. Transportation only customers are responsible to procure and deliver their own natural gas to the FortisBC Energy system and FortisBC Energy then delivers the gas to the operating premises of these customers. FortisBC Energy contracts for transportation capacity on third party pipelines, such as Spectra and TransCanada, to transport gas supply from various market hubs to FortisBC Energy's system. These third-party pipelines are regulated by the NEB. FortisBC Energy pays both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by FortisBC Energy's core market customers. FortisBC Energy contracts for firm transportation capacity in order to ensure it is able to meet its obligation to supply customers within its broad operating region under all reasonable demand scenarios.

Gas Storage and Peak-Shaving Arrangements

FortisBC Energy incorporates peak shaving and gas storage facilities into its portfolio to:

(i) supplement contracted baseload and seasonal gas supply in the winter months while injecting excess baseload supply to refill storage in the summer months;
(ii) mitigate the risk of supply shortages during cooler weather and a peak day;
(iii) manage the cost of gas during the winter months; and
(iv) balance daily supply and demand on the distribution system during periods of peak use that occur over the course of the winter months.

FortisBC Energy holds approximately 35.3 PJs of total storage capacity. FortisBC Energy owns Tilbury and Mount Hayes LNG peak shaving facilities, which provide on-system storage capacity and deliverability. FortisBC Energy also contracts for underground storage capacity and deliverability from third parties in north east British Columbia, Alberta and the Pacific Northwest of the United States. On a combined basis, FortisBC Energy's Tilbury and Mount Hayes facilities, the contracted storage facilities, and other peaking arrangements can deliver up to 0.74 PJs per day of supply to FortisBC Energy on the coldest days of the heating season. The heating season typically occurs during the December through February period.

Off-System Sales

FortisBC Energy engages in off-system sales activities that allow for the recovery or mitigation of costs of any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met.

Under the GSMIP revenue sharing model, which is approved by the BCUC, FortisBC Energy can earn an incentive payment for mitigation activities. Historically, FortisBC Energy has earned approximately $1.0 million annually through GSMIP, while the remaining savings are credited back to customers through reduced rates. Subject to the BCUC's approval, FortisBC Energy earned an incentive payment of approximately $2.0 million in respect of the gas contract year ended October 31, 2015.

The current GSMIP program was approved by the BCUC following a comprehensive review in 2011. In 2013, the BCUC approved an extension of the program until October 31, 2016.

Price-Risk Management Plan

FortisBC Energy engages in price-risk management activities to mitigate the impact to customer rates of fluctuations in natural gas prices. These activities include physical gas purchasing and storage strategies as well as FortisBC Energy's current quarterly commodity rate-setting and deferral account mechanism. Prior to 2010, FEI also typically included the use of derivative instruments which were implemented pursuant to an annual price risk management plan reviewed and approved by the BCUC. Following a comprehensive review process, in July 2011 the BCUC directed FEI to suspend the majority of its natural gas commodity hedging activities. All hedges that had been in place from previously approved PRMPs prior to the suspension of the hedging strategy, expired in 2014.

During 2015, FortisBC Energy conducted a series of workshops with stakeholders to provide background and education and obtain feedback regarding FortisBC Energy's current price-risk management activities and possible strategies and options it could pursue in the future. Subsequently, FortisBC Energy filed the 2015 Price-Risk Management Application on December 23, 2015 with the BCUC which included FortisBC Energy's request to implement a medium-term hedging program and commodity rate-setting enhancements. FortisBC Energy is currently awaiting the BCUC's determination regarding the review process for this application.

Unbundling

A Customer Choice program at FortisBC Energy allows eligible commercial and residential customers a choice to buy their natural gas commodity supply from FortisBC Energy or directly from third-party marketers. FortisBC Energy continues to provide the delivery service of the natural gas to all its customers.

The program has been in place since November 2004 for commercial customers and November 2007 for residential customers. For the year ended December 31, 2015, approximately 4% of eligible commercial customers and 3% of eligible residential customers participated in the program by purchasing their commodity supply from alternate providers.

Legal Proceedings

In April 2013 FHI, the parent of FortisBC Energy, and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band. The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Coldwater Indian Band seeks orders cancelling the right of way and claims damages for wrongful interference with its use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Human Resources

As at December 31, 2015, FortisBC Energy had approximately 1,620 full-time equivalent employees. Approximately 70% of the employees are represented by IBEW and COPE under collective agreements. The IBEW collective agreement came into effect on April 1, 2015 and expires on March 31, 2019. There are two collective agreements between COPE and FortisBC Energy which expire March 31, 2017 and March 31, 2018, respectively.

3.3 Regulated Electric Utilities - Canadian

3.3.1 *FortisAlberta*

FortisAlberta is a regulated electricity distribution utility operating in Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 121,000 kilometres of distribution lines. Many of FortisAlberta's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 539,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers, and met a peak demand of 2,733 MW in 2015.

Market and Sales

FortisAlberta's annual energy deliveries decreased from 17,372 GWh in 2014 to 17,132 GWh in 2015. Revenue was $563 million in 2015 compared to $518 million in 2014.

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The following table compares the composition of FortisAlberta's 2015 and 2014 revenue and energy deliveries by customer class.

FortisAlberta Revenue and Energy Deliveries by Customer Class				
	Revenue (%)		**GWh Deliveries** [(1)] **(%)**	
	2015	2014	**2015**	2014
Residential	**29.4**	30.5	**17.5**	17.1
Large commercial, industrial and oil field	**21.9**	21.5	**60.7**	61.3
Farms	**13.5**	11.8	**7.9**	7.5
Small commercial	**12.0**	10.8	**8.0**	8.0
Small oil field	**9.6**	8.1	**5.5**	5.7
Other [(2)]	**13.6**	17.3	**0.4**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 6,663 GWh in 2015 and 7,076 GWh in 2014, based on interim settlement that is expected to be finalized in May 2016, and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

(2) *Includes revenue from sources other than the delivery of energy, including that related to street-lighting services, rate riders, deferrals and adjustments.*

Franchise Agreements

FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence, of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be as agreed by FortisAlberta and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to FortisAlberta for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

FortisAlberta holds franchise agreements with 156 municipalities within its service area. The franchise agreement template includes a 10-year term with an option that will permit the agreement to automatically renew for a further five years. To date, FortisAlberta has converted over 90% of the municipalities within its service area to the new franchise agreement. The current 10-year terms will not expire until 2023 and beyond.

Human Resources

As at December 31, 2015, FortisAlberta had approximately 1,162 full-time equivalent employees. Approximately 80% of the employees of FortisAlberta are members of the UUWA and represented by a collective agreement that expires on December 31, 2017.

3.3.2 *FortisBC Electric*

FortisBC Electric is an integrated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of British Columbia. FortisBC Electric serves a diverse mix of approximately 168,000 customers, of whom approximately 132,000 are served directly by FortisBC Electric in Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland, while the remainder are served through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro. In 2015, FortisBC Electric met a peak demand of 624 MW. Residential customers represent the largest customer class of the company. FortisBC Electric's T&D assets include approximately 7,200 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion, owned by Fortis and CPC/CBT; the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

Market and Sales

FortisBC Electric has a diverse customer base composed of residential, commercial, industrial and municipal wholesale, and other industrial customers. Electricity sales were 3,116 GWh in 2015, compared to 3,179 GWh in 2014. Revenue increased to $360 million in 2015 from $334 million in 2014.

The following table compares the composition of FortisBC Electric's 2015 and 2014 revenue and electricity sales by customer class.

FortisBC Electric Revenue and Electricity Sales by Customer Class				
	Revenue (%)		GWh Sales (%)	
	2015	2014	**2015**	2014
Residential	**45.3**	48.4	**40.2**	41.2
Commercial	**24.0**	24.7	**29.1**	28.9
Wholesale	**12.2**	13.0	**18.6**	18.1
Industrial	**8.3**	9.0	**12.1**	11.8
Other (1)	**10.2**	4.9	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity, including revenue of FortisBC Pacific Holdings Inc. associated with non-regulated operating, maintenance and management services.*

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. The company owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW, which provide approximately 45% of the company's energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the multi-party CPA that enables the six separate owners of nine major hydroelectric generating plants, with a combined capacity of approximately 1,900 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	256	BC Hydro
Waneta Dam	237	Teck Metals Ltd.
Waneta Expansion	335	Waneta Partnership
Kootenay River System	225	FortisBC Electric
Brilliant Dam	149	BPC
Brilliant Expansion	120	BEPC
Total	**1,902**	

BPC, BEPC, Teck Metals Ltd. and FortisBC Electric are collectively defined in the CPA as the entitlement parties. The CPA enables BC Hydro and the entitlement parties to generate more power from their respective generating plants than they could if they operated independently through coordinated use of water flows, subject to the 1961 Columbia River Treaty between Canada and the United States, and coordinated operation of storage reservoirs and generating plants. Under the CPA, BC Hydro takes into its system all power actually generated by the plants listed in the table above. In exchange for permitting BC Hydro to determine the output of these facilities, each of the entitlement parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is based on 50-year historical water flows. The entitlement parties receive their defined entitlements irrespective of actual water flows to the entitlement parties' generating plants. BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The entitlement parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and therefore do not face hydrology variability in generation supply planning. However, FortisBC Electric retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of FortisBC Electric's Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Electric receives under the CPA. The CPA does not affect FortisBC Electric's ownership of its physical generation assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

FortisBC Electric's remaining electricity supply is acquired through the following power purchase contracts:

i. a 149-MW long-term PPA with BPC terminating in 2056 (Brilliant PPA);
ii. a 200-MW PPA with BC Hydro terminating in 2033 (BC Hydro PPA);
iii. a capacity and energy purchase agreement with CPC, for a total of 78,500 MWh from 2013 through 2017 (Brilliant Expansion Capacity and Energy Purchase Agreement);
iv. a number of small power purchase contracts with independent power producers;
v. spot market and contracted capacity purchases; and
vi. a 40-year agreement to purchase 234 MW of capacity from the WECA.

These purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates.

Brilliant PPA
Under the Brilliant PPA, FortisBC Electric has agreed to purchase from BPC, on a long-term basis: (i) the entitlement allocated to the Brilliant hydroelectric plant; and (ii) after the expiration of the CPA, the actual electrical output generated by the Brilliant hydroelectric plant. While the total entitlement is 985,000 MWh, FortisBC Electric does not purchase the approximate 60,000 MWh of regulated flow upgrade entitlement under the Brilliant PPA. However, FortisBC Electric has entered into another agreement with CPC for this energy over a five-year period, as discussed below. The Brilliant PPA uses a take-or-pay contract structure, which requires that FortisBC Electric pay for the Brilliant hydroelectric plant's entitlement, irrespective of whether FortisBC Electric actually takes it. FortisBC Electric does not foresee any circumstances under which FortisBC Electric would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FortisBC Electric pays to BPC an amount that covers the operation and maintenance costs of the Brilliant hydroelectric plant and provides a return on capital, including original purchase costs, sustaining capital costs and any life-extension investments. During the second 30 years of the Brilliant PPA term, commencing in 2026, an adjustment using a market-price mechanism based on the depreciated value of the Brilliant hydroelectric plant and then-prevailing operating costs will be made to the amounts payable by FortisBC Electric. The Brilliant PPA provided FortisBC Electric with approximately 27% of its energy requirements in 2015.

BC Hydro PPA
FortisBC Electric is a party to the BC Hydro PPA, which provides FortisBC Electric with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. Energy bought pursuant to the BC Hydro PPA provided approximately 15% of FortisBC Electric's energy requirements in 2015. The current BC Hydro PPA was approved by the BCUC in May 2014 and expires in September 2033.

Brilliant Expansion Capacity and Energy Purchase Agreement
In November 2012, FortisBC Electric entered into an agreement to purchase CPC's unused capacity and energy entitlements from 2013 to 2017. The entitlements are from the Brilliant hydroelectric plant and the Brilliant hydroelectric expansion plant, including the 60,000 MWh from the Brilliant hydroelectric plant that is not included in the Brilliant PPA. The agreement is for a total of 78,500 MWh and provided approximately 2% of FortisBC Electric's energy requirements in 2015.

Small Power Purchase Contracts
FortisBC Electric has a number of small power purchase contracts with independent power producers, which collectively provided less than 1% of FortisBC Electric's energy supply requirements in 2015. The majority of these contracts have been accepted by the BCUC.

Spot Market and Contracted Capacity Purchases
During 2014, FortisBC Electric purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. To facilitate market transactions going forward, FortisBC Electric entered into the CEPSA with Powerex Corp. which was approved by the BCUC in April 2015. The CEPSA is a master agreement that sets the terms and conditions for future market transactions entered into by FortisBC Electric with Powerex Corp. The CEPSA became effective May 1, 2015 and expires on September 30, 2018, unless extended by a mutual agreement. Spot market and contracted purchases provided approximately 8% of FortisBC Electric's energy supply requirements in 2015.

WECA
The Corporation entered into the WECA to purchase capacity from the Waneta Expansion. The Waneta Expansion is owned and operated by a limited partnership, the limited partners of which are Fortis, which owns a 51% interest, and a wholly owned subsidiary of each of CPC/CBT. The WECA, which was approved by the BCUC in May 2012, allows FortisBC Electric to purchase capacity over a 40 year period as of April 2, 2015.

Legal Proceedings

The Government of British Columbia filed a claim in the B.C. Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2015 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2015, FortisBC Electric had approximately 507 full-time equivalent employees. Approximately 70% of the employees are represented by IBEW and COPE. The IBEW collective agreement expires January 31, 2018. FortisBC Electric's two COPE collective agreements expire March 31, 2017 and December 31, 2018.

3.3.3 *Eastern Canadian Electric Utilities*

Eastern Canadian Electric Utilities are comprised of the operations of Newfoundland Power, Maritime Electric and FortisOntario.

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 262,000 customers in approximately 600 communities. Newfoundland Power has installed generating capacity of 139 MW and met a peak demand of 1,359 MW in 2015. Newfoundland Power owns and operates approximately 12,000 kilometres of T&D lines.

The Corporation, through FortisWest, holds all of the common shares of Maritime Electric, an integrated electric utility and the principal distributor of electricity on PEI, serving approximately 78,000 customers, constituting approximately 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a New Brunswick Crown corporation, through various energy purchase agreements. Maritime Electric owns and operates on-Island generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 264 MW in 2015. Maritime Electric owns and operates approximately 5,800 kilometres of T&D lines.

FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power, Cornwall Electric and Algoma Power. FortisOntario also owns a 10% interest in certain regional electric distribution companies serving approximately 40,000 customers. FortisOntario met a combined peak demand of 260 MW in 2015. FortisOntario owns and operates approximately 3,600 kilometres of T&D lines.

Market and Sales

Electricity sales attributable to the Eastern Canadian Electric Utilities were 8,403 GWh in 2015 compared to 8,376 GWh in 2014. Revenue was $1,033 million in 2015 compared to $1,008 million in 2014.

The following table compares the composition of revenue and electricity sales by customer class at Eastern Canadian Electric Utilities in 2015 and 2014.

Eastern Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2015	2014	**2015**	2014
Residential	**56.6**	56.1	**56.9**	56.4
Commercial and Industrial	**40.1**	41.1	**43.0**	43.5
Other (1)	**3.3**	2.8	**0.1**	0.1
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Newfoundland Power
Approximately 93% of Newfoundland Power's energy requirements are purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the NL PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

The purchased power rate structure is the basis upon which Newfoundland Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect Newfoundland Hydro's marginal cost of generating electricity.

Newfoundland Hydro has a general rate application before the NL PUB which will establish a new wholesale rate for Newfoundland Power. The outcome of this application, and future changes in supply costs, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales. The recovery of Muskrat Falls development costs are expected to materially increase customer electricity rates.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled Newfoundland Power from meeting all of its customers' requirements. The NL PUB is conducting an inquiry and hearing into these system supply issues and power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. The NL PUB's final report on the adequacy and reliability of the Island Interconnected system until interconnection with Muskrat Falls is currently outstanding. A consideration of longer term issues associated with adequacy and reliability on the Island Interconnected system after interconnection with Muskrat Falls is ongoing. The Government of Newfoundland and Labrador has engaged consultants to complete an independent review of the electricity system in Newfoundland and Labrador. The consultant's report, released on October 30, 2015, indicated that Newfoundland Power's operations were substantially in compliance with industry best practice and that the NL PUB's oversight of the company appears to provide regulatory predictability and certainty.

Newfoundland Power operates 28 small generating facilities, which generate approximately 7% of the electricity sold by the company. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 5 MW and 37 MW, respectively.

Maritime Electric

Maritime Electric purchased 75% of the electricity required to meet its customers' needs from NB Power in 2015. The balance was met through the purchase of wind energy produced on PEI by facilities owned by the PEI Energy Corporation and from company-owned on-Island generation. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity: (i) a fixed pricing contract with NB Power expiring February 28, 2019; and (ii) a transmission capacity contract allowing Maritime Electric to reserve 30 MW of capacity to PEI expiring November 2032. As well, Maritime Electric has an Energy Purchase Agreement with NB Power expiring in February 2019.

Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau Nuclear Generating Station for the life of the unit and as part of its entitlement is required to pay its share of the capital and operating costs of the unit.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO. Canadian Niagara Power purchases approximately 80% of energy requirements for Gananoque through monthly energy purchases from Hydro One Networks Inc. and the remaining 20% is purchased, through the Hydroelectric Contract Initiative, from the five hydroelectric generating plants of the EO Generation LP. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the OEB, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per year. Both contracts expire in December 2019.

Human Resources

Newfoundland Power

As at December 31, 2015, Newfoundland Power had approximately 653 full-time equivalent employees, and approximately 49% of its employees were represented by IBEW under two collective agreements expiring September 30, 2017. One bargaining unit is composed predominately of clerical employees and the other predominately of skilled trade workers.

Maritime Electric

As at December 31, 2015, Maritime Electric had approximately 182 full-time equivalent employees, of whom approximately 70% were represented by IBEW under a collective agreement expiring December 31, 2018.

FortisOntario

As at December 31, 2015, FortisOntario had approximately 198 full-time equivalent employees, of whom approximately 58% were represented by CUPE, in Cornwall; IBEW in the Niagara region and Gananoque; and Power Workers Union, a CUPE affiliate, in the Algoma region. The expiry dates of the collective agreements are April 30, 2016; February 29, 2016 and July 31, 2016; and December 31, 2016, respectively.

3.4 Regulated Electric Utilities - Caribbean

The Regulated Electric Utilities - Caribbean segment includes Caribbean Utilities, Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity.

Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The company met a peak demand of 101 MW in 2015. Caribbean Utilities owns and operates more than 700 kilometres of T&D lines, including 24 kilometres of submarine cable. Fortis holds an approximate 60% (December 31, 2014 – 60%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U).

Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 14,000 customers on certain islands in Turks and Caicos. The utilities met a combined peak demand of approximately 38 MW in 2015. Fortis Turks and Caicos owns and operates approximately 600 kilometres of T&D lines.

Market and Sales

Electricity sales of Regulated Electric Utilities – Caribbean were 802 GWh in 2015, compared to 771 GWh in 2014. Revenue was $321 million in both 2015 and 2014.

The following table compares the composition of revenue and electricity sales by customer class at the Regulated Electric Utilities – Caribbean for 2015 and 2014.

Regulated Electric Utilities – Caribbean [(1)]
Revenue and Electricity Sales by Customer Class

	Revenue (%)		GWh Sales (%)	
	2015	2014	**2015**	2014
Residential	**42.9**	44.0	**43.0**	42.6
Commercial and Industrial	**56.2**	54.9	**57.0**	57.4
Other [(2)]	**0.9**	1.1	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Excludes Belize Electricity.*
(2) *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and it must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. Caribbean Utilities has an installed diesel-powered generating capacity of approximately 132 MW.

Caribbean Utilities is party to primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of Caribbean Utilities' diesel fuel requirements for the operation of its diesel-powered generating plant. Each contract was renewed for an additional 18-month term in September 2014 and is under negotiation for renewal in March 2016. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. These contracts enable Caribbean Utilities to purchase fuel from the suppliers on what it believes to be competitive terms and pricing. The fuel contracts include disaster recovery and business continuity plans in the event of foreseeable disruptions to fuel supplies to reduce the impact on Caribbean Utilities' operations.

In October 2014 the ERA announced that Caribbean Utilities was the successful bidder for new generation capacity. Caribbean Utilities will develop and operate a new 39.7 MW diesel power plant, including two 18.5 MW diesel-generating units and a 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. The project cost is estimated at US$85 million and the plant is expected to be commissioned mid-2016. Subsequently, in November 2014 the ERA issued a new non-exclusive Electricity Generation License to Caribbean Utilities for a term of 25 years, expiring in November 2039.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, with an installed generating capacity of 82 MW, to produce electricity for its customers. In September 2015 the third Wartsila generating unit was placed into commercial production.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Human Resources

As at December 31, 2015, Regulated Electric Utilities - Caribbean employed approximately 356 full-time equivalent employees. The 201 employees at Caribbean Utilities and 155 employees at Fortis Turks and Caicos are non-unionized.

3.5 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Non-Regulated - Fortis Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
British Columbia	2	hydro	351
Ontario	1	thermal	5
Total	**6**		**407**

The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. The non-regulated generation operations of BECOL consist of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia. All of the output of the facility is sold to BC Hydro under a long-term contract that cannot be terminated prior to 2024. As at December 31, 2015, the Walden hydroelectric generating facility has been classified as held for sale.

Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Construction of the $900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project also included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. FortisBC Electric operates and maintains the non-regulated investment.

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric.

In June 2015 and July 2015 the Corporation sold its non-regulated hydro generation assets in Upstate New York and Ontario, respectively.

Market and Sales

Energy sales from non-regulated generation assets were 844 GWh in 2015 compared to 407 GWh in 2014. Revenue was $107 million in 2015 compared to $38 million in 2014. Energy sales and revenue in 2015 were impacted by the completion of Waneta Expansion and the sale of the non-regulated hydro generation assets in Upstate New York and Ontario.

The following table compares the composition of Fortis Generation's 2015 and 2014 revenue and energy sales by location.

Non-Regulated - Fortis Generation
Revenue and Energy Sales by Location

	Revenue (%)		GWh Sales (%)	
	2015	2014	**2015**	2014
Belize	**28.1**	71.0	**26.8**	60.3
Ontario	**3.6**	13.2	**4.1**	13.2
British Columbia	**67.4**	5.5	**65.6**	8.3
Upstate New York	**0.9**	10.3	**3.5**	18.2
Total	**100.0**	100.0	**100.0**	100.0

Human Resources

As at December 31, 2015, BECOL employed approximately 34 full-time employees, none of whom participate in a collective agreement. Non-regulated generation operations in Ontario and British Columbia are staffed by employees of FortisOntario and FortisBC Inc., respectively.

3.6 Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties and Griffith Energy Services, Inc. The Corporation completed the sale of the commercial real estate assets of Fortis Properties in June 2015 and the hotel assets of Fortis Properties in October 2015. Griffith Energy Services, Inc. was sold in March 2014.

Fortis Properties' revenue was $171 million in 2015 compared to $249 million in 2014.

4.0 REGULATION

The Corporation's utilities primarily operate under a cost of service regulation and, in certain circumstances, performance-based rate-setting mechanisms, and are regulated by the regulatory body in their respective operating jurisdiction. With regulated utilities in nine different jurisdictions, Fortis has significant regulatory expertise.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's electric and gas utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 8 of the Corporation's 2015 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, federal, provincial and state governments have environmental assessment legislation, which is designed to foster better land-use planning and environmental protection through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after their commencement. The constant evolution of environmental legislation results in ongoing risks to the Corporation, as its subsidiaries must adjust their business operations to comply.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act, 2012;* (ii) *Canadian Environmental Protection Act, 1999*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Products Act*; (v) *Canada Wildlife Act*; (vi) *Navigation Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water Act;* (x) *National Fire Code of Canada;* (xi) *Pest Control Products Act and Regulations;* (xii) *PCB Regulations;* (xiii) *Species at Risk Act;* (xiv) *Ozone Depleting Substances Regulations;* (xv) *Indian Act* and the duty to consult and accommodate; (xvi) *International River Improvements Act;* and (xvii) *Migratory Birds Convention Act, 1994.*

Several key U.S. federal environmental laws and regulations affecting the operations of UNS Energy and Central Hudson include, but are not limited to, the: (i) *Clean Water Act*; (ii) *Safe Drinking Water Act*; (iii) *Clean Air Act*; (iv) *Endangered Species Act*; (v) *Resource Conservation & Recovery Act*; (vi) *Toxic Substances Control Act*; (vii) *Comprehensive Environmental Response, Compensation, and Liability Act*; (viii) *National Environmental Policy Act*; (ix) *Emergency Planning & Community Right to Know Act*; and (x) *Pollution Prevention Act of 1990*.

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leaching of the fuel and other operational by-products into the soil, groundwater, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk related to natural gas discharges; (iv) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (v) GHG and other fuel gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (vi) risk of fire; (vii) risk of disruption to vegetation; (viii) risk of contamination of soil and water near chemically treated poles; (ix) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (x) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

Air Emissions

In addition to changing air emission standards, the management of GHG emissions is a specific environmental concern of the Corporation's Regulated Utilities in Canada and the United States, primarily due to the uncertainties relating to new and emerging federal, provincial and state GHG laws, regulations and guidelines in Canada and the United States. Governmental policy direction is unfolding; however, it remains to be determined whether a GHG air emissions cap or limit may be imposed and to what extent it will impact the Corporation's utilities. Canada has committed to reduce GHG emissions to 30% below 2005 levels by 2030, and the United States has committed to reduce GHG emissions to 32% below 2005 levels by 2030. Both countries are in the process of imposing sectoral requirements, yet it is not certain how the Corporation's subsidiaries will be impacted.

Regulated Utilities – Canada
In British Columbia, the *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Industrial Reporting and Control Act* and *Greenhouse Gas Reduction Targets Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. To help mitigate uncertainty, FortisBC Energy participates in sector and industry groups in order to monitor the development of emerging regulation and policy.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to FortisBC Energy and, to a lesser degree, FortisBC Electric. These government initiatives continue to place pressure on natural gas consumption and its contribution to GHG emissions. The energy and emissions policy in British Columbia also presents opportunities for FortisBC Energy by creating support for incentives to expand the use of renewable energy (such as biogas), transportation related incentives (LNG/compressed natural gas refuelling) and to expand the Energy Efficiency and Conservation program. In addition, the Renewable and Low Carbon Fuel Requirements Regulation under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirement) Act* provides FortisBC Energy the opportunity to sell low carbon fuel credits generated from customer offerings. The *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

In 2011 FortisBC Energy began reporting its GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act.* The *Greenhouse Gas Reduction (Cap and Trade) Act* was repealed effective January 1, 2016 and was replaced by the *Greenhouse Gas Industrial Reporting and Control Act*. FortisBC Energy will continue to report its GHG emissions pursuant to the Greenhouse Gas Emission Reporting Regulation under the *Greenhouse Gas Industrial Reporting and Control Act*. In addition, FortisBC Energy continues to report its GHG emissions under Environment Canada's GHG Program. FortisBC Energy has developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves.

British Columbia continues to be a participant in the Western Climate Initiative, which expects to implement a cap-and-trade program to reduce GHG emissions. FortisBC Energy is expected to be covered under the program. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

The impact of GHG emissions is lower at the Corporation's Canadian regulated electric utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric, about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. The 335-MW Waneta Expansion is a clean renewable hydroelectric energy source and came into service in April 2015. Only a small portion of in-house generation at Canadian regulated electric utilities uses diesel fuel. The Corporation's Canadian regulated electric utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

Regulated Utilities – United States
UNS Energy and Central Hudson are subject to regulation by United States federal, state and local authorities related to the environmental effects of their operations. The impact of GHG emissions is lower at Central Hudson because it owns minimal generating capacity and relies on purchased capacity and energy from third-party providers.

UNS Energy owns significant generating assets. In August 2015, the EPA issued carbon emission regulations for existing power plants called the CPP. The CPP targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. TEP will continue to work with other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP has submitted comments on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. TEP cannot predict the ultimate outcome of these matters.

The Company's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016 the United States Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP. UNS Energy will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. UNS Energy anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

In 2012 the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. TEP's Navajo and Springerville plants must be compliant with these rules by April 2016. TEP is proceeding with its compliance activity at each of its facilities.

In June 2015, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision in *Michigan v. EPA* to uphold the MATS rules requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider "costs" before determining that the rules were "appropriate and necessary." At this time, the rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of its facilities, which ensures compliance with both the federal and state rule, as applicable.

The EPA's Regional Haze Rules impose emission controls on facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. Complying with the EPA's findings, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of TEP's coal-fired generating facilities or for individual joint owners to continue to participate in the units they own at these power plants.

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the *Resource Conservation and Recovery Act* for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP's share of the cost at Springerville is estimated to be US$2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be US$5 million at Four Corners, US$3 million at Navajo, and less than US$1 million at San Juan, the majority of which are expected to be capital expenditures.

Regulated Utilities – Caribbean

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada and the United States. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Under the Kyoto Protocol, the United Kingdom is legally bound to reduce its GHG emissions. As an overseas territory, the Cayman Islands are not required to set a target for emissions reduction but are required to give available national statistics on an annual basis to the United Kingdom which will be added to its inventory and reported to the United Nations Framework Convention on Climate Change Secretariat. Caribbean Utilities continues to supply the Cayman Islands Government with data for the national GHG inventory.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in house diesel-powered generation. The more recently installed generators at Caribbean Utilities and Fortis Turks and Caicos have also been designed to provide an increased output per gallon consumed over the older generators, which generate electricity in a more efficient and environmentally friendly manner. Further, exhaust stacks have been designed and installed so as to maximize sound attenuation and optimize exhaust plume dispersion, thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions.

Enterprise Risk Management

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has either an EMS or comprehensive environmental protocols. Through an EMS and environmental protocols, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMS and environmental protocols include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment and implementation of environmental protection measures; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, Newfoundland Power's EMS addresses water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat. FortisBC Electric's EMS addresses the environmental impacts associated with water flows including impacts on fisheries and critical habitats.

FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS is also expected to be ISO 14001 certified. External and/or internal audits of the EMSs and protocols are performed on a periodic basis. Based on audits last completed, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Environmental policies form the cornerstone of the EMSs and UNS Energy and Central Hudson's environmental protocols, and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regularly conduct environmental monitoring and audits of the EMSs and environmental protocols, and strive for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Non-Regulated Generation

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

Remediation and Asset Retirement Obligations

Central Hudson is exposed to environmental contingencies associated with MGPs that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid to late 1800s to the 1950s. The New York State Department of Environmental Conservation regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2015, Central Hudson has recognized approximately US$92 million in associated MGP environmental remediation liabilities. As approved by the New York State Public Service Commission, the company is currently permitted to recover MGP site investigation and remediation costs in customer rates. For additional information, refer to the "3.1.2 Central Hudson" section of this 2015 Annual Information Form.

The Corporation has asset retirement obligations as disclosed in the notes to its 2015 Audited Consolidated Financial Statements. As at December 31, 2015, a liability of $49 million in asset retirement obligations at UNS Energy, Central Hudson and FortisBC Electric has been recognized. With the exception of those asset retirement obligations recognized at UNS Energy, Central Hudson and FortisBC Electric, liabilities with respect to asset retirement obligations associated with the removal of PCB-contaminated oil from electrical equipment at Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric have not been recorded in the Corporation's 2015 Audited Consolidated Financial Statements, as they were determined to be immaterial to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs and Oversight

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs and protocols), compliance with environmental laws, regulations and guidelines, and environmental damage did not have a material impact on the Corporation's consolidated results of operations, cash flows or financial position during 2015 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2016. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with the environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

TEP has in place an Environmental Compliance Adjustor, as approved by the ACC, which allows for the recovery of certain capital carrying costs to comply with government-mandated environmental regulations between rate cases.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

Sustainability and Efficiency Initiatives

The Fortis utilities have various initiatives focused on clean energy to reduce GHG emissions, including hydroelectric, solar power, wind energy, natural gas and renewable natural gas. Each utility also has implemented energy efficiency programs directed at customers, which help in reducing air emissions and water usage. Further information on how Fortis is managing its impact on the environment will be contained in the Corporation's Environmental Report to be dated on or about March 31, 2016 and published on the Corporation's website at www.fortisinc.com.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 RISK FACTORS

For information with respect to the Corporation's business risks, refer to the "Business Risk Management" section of the Corporation's MD&A.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at February 17, 2016, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share (1)
Common Shares	281,854,344	One
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H (2)	7,024,846	None
First Preference Shares, Series I (2)	2,975,154	None
First Preference Shares, Series J	8,000,000	None
First Preference Shares, Series K	10,000,000	None
First Preference Shares, Series M	24,000,000	None

(1) *The First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive, and whether or not such dividends have been declared.*

(2) *On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.*

Dividend Policy
Fortis has targeted annual average dividend growth of 6% through 2020. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance. The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2015**	**2014**	**2013**
Common Shares	**$1.43**	$1.30	$1.25
First Preference Shares, Series C [(1)]	**-**	-	$0.4862
First Preference Shares, Series E	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series F	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series G [(2)]	**$0.9708**	$0.9708	$1.1416
First Preference Shares, Series H [(3)]	**$0.7344**	$1.0625	$1.0625
First Preference Shares, Series I [(3)]	**$0.3637**	-	-
First Preference Shares, Series J	**$1.1875**	$1.1875	$1.1875
First Preference Shares, Series K [(4)]	**$1.0000**	$1.0000	$0.6233
First Preference Shares, Series M [(5)]	**$1.0250**	$0.4613	-

(1) *In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C.*
(2) *The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.*
(3) *The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.*
(4) *The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.*
(5) *The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.*

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and Preferred Shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

In September 2015 Fortis increased its dividend per common share over 10% to $0.375 per share, or $1.50 on an annualized basis. In December 2015 the Board declared a fourth quarter 2015 dividend on the Common Shares and the First Preference Shares, Series E, F, G, H, I, J, K and M in accordance with the applicable annual prescribed rate to be paid on March 1, 2016 to holders of record as of February 17, 2016.

Common Shares
Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or ratably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series E
Holders of the 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. The Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F
Holders of the 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time at $25.00 per share if redeemed on or after December 1, 2015 plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G
Holders of the 9,200,000 First Preference Shares, Series G were entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. The annual fixed dividend rate per share for the First Preference Shares, Series G was reset to $0.9708 per share per annum for the five-year period from and including September 1, 2013 to but excluding September 1, 2018. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.13%. On September 1, 2018, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H
Holders of the 7,024,846 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $0.6250 per share per annum for each year up to but excluding June 1, 2020. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

On any First Preference Shares, Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I.

First Preference Shares, Series I
Holders of the 2,975,154 First Preference Shares, Series I are entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors of the Corporation, in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00, for the five-year period beginning after June 1, 2015. The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

On each First Preference Shares, Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a First Preference Shares, Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series I Conversion Date, the holders of First Preference Shares, Series I have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any First Preference Shares, Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series I or less than 1,000,000 First Preference Shares, Series H outstanding then no automatic conversion would take place.

First Preference Shares, Series J
Holders of the 8,000,000 First Preference Shares, Series J are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.1875 per share per annum. On or after December 1, 2017, the Corporation may, at its option, redeem for cash the First Preference Shares, Series J, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2018; at $25.75 per share if redeemed on or after December 1, 2018 but before December 1, 2019; at $25.50 per share if redeemed on or after December 1, 2019 but before December 1, 2020; at $25.25 per share if redeemed on or after December 1, 2020 but before December 1, 2021; and at $25.00 per share if redeemed on or after December 1, 2021 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series K
Holders of the 10,000,000 First Preference Shares, Series K are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0000 per share per annum for each year up to but excluding March 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series K are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.05%.

On each Series K Conversion Date, being March 1, 2019, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series K, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series K Conversion Date, the holders of First Preference Shares, Series K have the option to convert any or all of their First Preference Shares, Series K into an equal number of cumulative redeemable floating rate First Preference Shares, Series L.

Holders of the First Preference Shares, Series L will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.05%.

On each First Preference Shares, Series L Conversion Date, being March 1, 2024, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after March 1, 2019, that is not a First Preference Shares, Series L Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series L Conversion Date, the holders of First Preference Shares, Series L have the option to convert any or all of their First Preference Shares, Series L into an equal number of First Preference Shares, Series K.

On any First Preference Shares, Series K Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series K outstanding, such remaining First Preference Shares, Series K will automatically be converted into an equal number of First Preference Shares, Series L. On any First Preference Shares, Series L Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series L outstanding, such remaining First Preference Shares, Series L will automatically be converted into an equal number of First Preference Shares, Series K. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series L or less than 1,000,000 First Preference Shares, Series K outstanding then no automatic conversion would take place.

First Preference Shares, Series M
Holders of the 24,000,000 First Preference Shares, Series M are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0250 per share per annum for each year up to but excluding December 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series M are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.48%.

On each Series M Conversion Date, being December 1, 2019, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series M, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series M Conversion Date, the holders of First Preference Shares, Series M have the option to convert any or all of their First Preference Shares, Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series N.

Holders of the First Preference Shares, Series N will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.48%.

On each First Preference Shares, Series N Conversion Date, being December 1, 2024, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after December 1, 2019, that is not a First Preference Shares, Series N Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series N Conversion Date, the holders of First Preference Shares, Series N have the option to convert any or all of their First Preference Shares, Series N into an equal number of First Preference Shares, Series M.

On any First Preference Shares, Series M Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series M outstanding, such remaining First Preference Shares, Series M will automatically be converted into an equal number of First Preference Shares, Series N. On any First Preference Shares, Series N Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series N outstanding, such remaining First Preference Shares, Series N will automatically be converted into an equal number of First Preference Shares, Series M. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series N or less than 1,000,000 First Preference Shares, Series M outstanding then no automatic conversion would take place.

Debt Covenant Restrictions on Dividend Distributions
The Trust Indenture pertaining to the Corporation's $200 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has a $1 billion unsecured committed revolving corporate credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As of December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 65% at any time.

As at December 31, 2015 and 2014, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 CREDIT RATINGS

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's debt credit ratings as at February 17, 2016.

Fortis Credit Ratings

Company	DBRS	S&P	Moody's
Fortis [1]	A (low), Under Review - Negative (unsecured debt)	BBB+, Negative (unsecured debt)	N/A
Caribbean Utilities [2]	A (low), Stable (senior unsecured debt)	A-, Negative (senior unsecured debt)	N/A
Central Hudson [2] [3]	N/A	A, Negative (unsecured debt)	A2, Stable (unsecured debt)
FortisBC Energy	A, Stable (secured & unsecured debt)	N/A	A1/A3, Stable (secured/unsecured debt)
FortisAlberta [2]	A (low), Stable (senior unsecured debt)	A-, Negative (senior unsecured debt)	N/A
FortisBC Electric	A (low), Stable (secured & unsecured debt)	N/A	Baa1, Stable (unsecured debt)
Fortis Turks and Caicos	N/A	BBB, Stable (senior unsecured debt)	N/A
Maritime Electric [2]	N/A	A, Negative (senior secured debt)	N/A
Newfoundland Power	A, Stable (first mortgage bonds)	N/A	A2, Stable (first mortgage bonds)
TEP [2]	N/A	BBB+, Negative (unsecured debt)	A3, Stable (senior unsecured debt)
UNS Energy	N/A	N/A	Baa1, Stable (senior secured debt)

(1) *In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's corporate credit rating of A-, revised its unsecured debt credit rating to BBB+ from A-, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's corporate credit rating under review with negative implications.*

(2) *In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P revised its outlook on TEP, Central Hudson, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable.*

(3) *Central Hudson's senior unsecured debt is also rated by Fitch at 'A-, Stable'.*

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) its long-term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner with respect to both interest and principal commitments; (ii) its ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment decision; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities rated in the BBB category are considered to have long-term debt of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

Moody's long-term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. According to Moody's, a rating of Baa is the fourth highest of nine major categories and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

Fitch's long-term debt rating are on a rating scale that ranges from AAA to C, which represents the range from highest to lowest qualify of such securities. Fitch uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. Such modifiers are not added to the AAA rating or to ratings below B. Fitch states that its credit ratings provide an opinion on the relative ability of an entity to meet financial commitments, such as interest, preferred dividends, repayment of principal, insurance claims or counterparty obligations. Fitch's credit ratings do not directly address any risk other than credit risk. A rating of 'A' denotes expectation of low default risk, with strong capacity for payment of financial commitments. A rating of 'BBB' denotes current expectations of low default risk, with adequate capacity for the payment of financial commitments.

The Corporation pays each of DBRS, S&P and Moody's an annual monitoring fee and a one-time fee in connection with each rated issuance. In 2015, Fortis also paid fees to S&P and Moody's in respect of certain advisory services provided in connection with the pending acquisition of ITC. No such fees were paid in 2014.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K and First Preference Shares, Series M of Fortis are listed on the TSX under the symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively.

The following tables set forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M on a monthly basis for the year ended December 31, 2015.

Fortis
2015 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series E		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	42.23	38.77	14,559,158	26.08	25.75	20,889
February	42.23	38.32	15,673,004	26.04	25.58	25,379
March	40.29	38.36	18,477,567	25.86	25.63	54,230
April	39.90	38.05	9,767,559	25.80	25.60	54,105
May	39.49	37.12	11,546,629	25.90	25.59	24,900
June	38.49	34.45	15,119,531	25.80	25.55	16,200
July	38.46	35.08	11,661,513	25.75	25.45	18,387
August	38.75	34.16	14,095,079	25.69	25.20	16,415
September	38.17	34.20	17,476,551	25.47	25.18	95,148
October	40.14	37.18	15,692,958	25.47	25.30	128,932
November	38.60	36.35	12,504,209	25.49	25.06	32,705
December	38.26	35.51	15,464,056	25.35	25.16	360,105

Fortis
2015 Trading Prices and Volumes

	First Preference Shares, Series F			First Preference Shares, Series G		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	25.22	24.51	38,138	25.46	23.26	70,820
February	25.68	24.86	30,672	24.18	23.06	81,535
March	25.24	24.84	48,096	24.47	23.53	248,758
April	25.10	24.36	71,811	23.71	20.84	192,548
May	25.00	24.11	63,091	22.50	21.36	170,316
June	24.51	23.20	55,565	22.17	21.35	94,522
July	24.30	23.52	64,713	21.94	19.95	83,440
August	23.97	21.64	54,337	20.36	16.62	137,163
September	23.07	21.60	210,994	19.26	16.37	280,932
October	22.74	21.20	92,747	19.19	15.90	282,181
November	23.55	21.95	128,647	19.96	17.78	280,941
December	23.71	21.65	87,471	18.49	15.57	374,203

	First Preference Shares, Series H [(1)]			First Preference Shares, Series I [(1)]		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	19.59	16.84	405,862	-	-	-
February	17.29	16.50	219,928	-	-	-
March	16.97	16.05	402,886	-	-	-
April	16.80	15.20	892,668	-	-	-
May	17.10	15.90	233,282	-	-	-
June	17.00	16.05	204,409	17.16	15.61	31,999
July	17.23	16.09	343,502	17.00	15.50	18,950
August	16.55	14.01	293,047	16.10	13.00	20,650
September	15.64	13.00	76,007	14.26	12.10	35,030
October	14.70	13.60	138,311	13.35	12.00	49,072
November	15.70	13.95	110,962	13.75	12.00	75,755
December	14.81	12.75	145,156	13.00	10.92	101,208

	First Preference Shares, Series J			First Preference Shares, Series K		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	25.13	24.16	117,712	25.53	23.30	89,307
February	25.50	24.80	130,658	24.49	23.15	153,649
March	25.37	24.75	123,776	24.20	23.54	175,640
April	25.12	24.25	168,938	23.90	20.19	219,961
May	25.05	24.00	113,793	22.98	21.48	113,621
June	24.55	23.29	74,548	22.00	20.81	155,165
July	24.40	23.29	58,285	21.90	20.84	158,790
August	23.23	21.20	64,228	21.65	17.90	142,852
September	22.49	21.00	67,129	19.98	15.92	368,777
October	22.45	20.58	78,940	20.04	16.01	340,911
November	22.85	21.23	112,115	20.49	18.52	404,180
December	23.00	20.80	76,388	19.39	16.56	314,369

	First Preference Shares, Series M		
Month	High ($)	Low ($)	Volume
January	25.75	24.26	435,010
February	25.30	24.50	245,579
March	25.34	24.60	331,494
April	25.05	23.26	1,095,659
May	25.46	24.51	550,788
June	24.80	23.48	375,183
July	24.06	22.38	297,623
August	23.77	19.63	178,882
September	22.40	19.40	310,304
October	21.72	17.18	401,744
November	22.83	19.85	311,587
December	21.19	17.90	792,543

[(1)] *2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I on June 1, 2015. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.*

10.0 DIRECTORS AND OFFICERS

The Board has governance guidelines which cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the annual meeting of shareholders next following the date on which they achieve age 72 or the 12th anniversary of their initial election to the Board.

The following chart sets out the name and municipality of residence of each of the Directors of Fortis as of February 17, 2016, and indicates their principal occupations within the five preceding years. Each Director's current term expires at the close of the May 5, 2016 annual meeting of shareholders. Paul J. Bonavia, who was elected to the Board of the Corporation in May 2015, resigned from the Board effective February 8, 2016 in order to remain in compliance with the rules of another entity of which he is a director. These rules would not permit Mr. Bonavia to serve as a director of Fortis following the announcement by the Corporation that it has entered into an agreement to acquire ITC.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
TRACEY C. BALL *(1)* Edmonton, Alberta	Ms. Ball, 58, joined the Fortis Board in May 2014. She retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Prior to joining a predecessor bank to Canadian Western Bank in 1987, she worked in public accounting and consulting. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She currently serves on the City of Edmonton LRT Governance Board. Ms. Ball graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Chartered Professionals Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. Ms. Ball holds an ICD.D designation from the Institute of Corporate Directors. She serves as a director of FortisAlberta and is Chair of that company's Audit Committee. She does not serve as a director of any other reporting issuer.
PIERRE J. BLOUIN *(3)* Ile Bizard, Quebec	Mr. Blouin, 58, joined the Fortis Board in May 2015. He was Chief Executive Officer of Manitoba Telecom Services, Inc. until his retirement in December 2014. Prior to joining Manitoba Telecom Services, Inc. as its Chief Executive Officer in 2005, Mr. Blouin held various executive positions in the Bell Canada group of companies, including Group President, Consumer Markets for Bell Canada, Chief Executive Officer of BCE Emergis, Inc. and CEO of Bell Mobility. Mr. Blouin graduated from Hautes Etudes Commerciales with a Bachelor of Commerce in Business Administration. He is a Fellow of Purchasing Management Association of Canada and a Fellow of the Institute of Bankers (Canada). Mr. Blouin was appointed to the Human Resources Committee on May 7, 2015. He does not serve as a director of any other reporting issuer.
PETER E. CASE *(1) (2)* Kingston, Ontario	Mr. Case, 61, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. Mr. Case was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. He was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 through 2010 and served as Chair of the FortisOntario Board from 2009 through 2010. He does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
MAURA J. CLARK (1) New York, New York	Ms. Clark, 57, joined the Fortis Board in May 2015. She retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business, a leading energy retailer in Canada and the United States, from 2007. Previously Ms. Clark was Executive Vice President of North American Strategy and Mergers and Acquisitions for Direct Energy. Ms. Clark's prior experience includes investment banking and serving as Chief Financial Officer of an independent oil refining and marketing company. Ms. Clark graduated from Queen's University with a Bachelor of Arts in Economics. She is a member of the Association of Chartered Professional Accountants of Ontario. Ms. Clark was appointed to the Audit Committee in May 2015 upon her election to the Board. Ms. Clark also serves as a director of Elizabeth Arden, Inc.
IDA J. GOODREAU (2) (3) Bowen Island, British Columbia	Ms. Goodreau, 64, is a past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she served as President and Chief Executive Officer of Vancouver Coastal Health Authority from 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies. She was awarded an MBA and a Bachelor of Commerce, Honours, degree from the University of Windsor and a Bachelor of Arts (English and Economics) from the University of Western Ontario. She has served on numerous private and public sector boards and has been a director of FortisBC Energy and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau serves as Chair of the Governance Committee of FortisBC Energy and FortisBC Inc. She was first elected to the Board in May 2009. Ms. Goodreau does not serve as a director of any other reporting issuer.
DOUGLAS J. HAUGHEY (1) (3) Calgary, Alberta	Mr. Haughey, 59, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation, a commercial construction and industrial services company focused on the western Canadian market. From 2010 through its successful sale to Pembina Pipeline in April 2012, he served as President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream facilities. From 1999 through 2008, he held several executive roles with Spectra Energy and predecessor companies. Mr. Haughey had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010, and serves as Chair of that Board. Mr. Haughey was appointed Chair of the Human Resources Committee in March 2015. Mr. Haughey is also lead director of Keyera Corporation.
R. HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 70, is President of Vintage Consulting Group Inc., Harry McWatters Inc., and TIME Estate Winery, all of which are engaged in various aspects of the British Columbia wine industry. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters was first elected to the Board in May 2007. He was a Director of FHI and FortisBC Inc., where he served as Chair from 2006 through 2010. Mr. McWatters does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY *(2) (3)* Mississauga, Ontario	Mr. Munkley, 70, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. While there he acted as lead advisor on over 175 capital markets and strategic and advisory assignments for North American utility clients. Prior to that he was COO at Enbridge Inc. and Chairman of Enbridge Consumer Gas. Previously he was President and CEO of Consumer Gas where he led the company through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science (Engineering), Honours. Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.
DAVID G. NORRIS *(1) (2) (3)* St. John's, Newfoundland and Labrador	Mr. Norris, 68, a Corporate Director, was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board of the Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. Mr. Norris served as Chair of the Audit Committee of the Board from May 2006 through March 2011. He was a director of Newfoundland Power from 2003 through 2010 and served as Chair of that Board from 2006 through 2010. Mr. Norris served as a director of Fortis Properties from 2006 through 2010. He does not serve as a director of any other reporting issuer.
BARRY V. PERRY St. John's, Newfoundland and Labrador	Mr. Perry, 51, is President and Chief Executive Officer of the Corporation. Prior to his current position at Fortis, he served as President from June 30, 2014 to December 31, 2014 and prior to that served as Vice President, Finance and Chief Financial Officer of the Corporation. Mr. Perry joined the Fortis organization in 2000 as Vice President, Finance and Chief Financial Officer of Newfoundland Power. He earned a Bachelor of Commerce from Memorial University of Newfoundland and is a member of the Association of Chartered Professional Accountants of Newfoundland and Labrador. Mr. Perry serves on the Boards of Fortis utilities in British Columbia, Alberta, Arizona and New York. Mr. Perry was appointed to the Board on January 1, 2015, concurrent with his appointment as President and Chief Executive Officer of the Corporation.

(1) *Serves on the Audit Committee.*
(2) *Serves on the Governance and Nominating Committee.*
(3) *Serves on the Human Resources Committee.*

The following table sets out the name and municipality of residence of each of the officers of Fortis as of December 31, 2015, and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
Barry V. Perry St. John's, Newfoundland and Labrador	President and Chief Executive Officer [(1)]
Karl W. Smith St. John's, Newfoundland and Labrador	Executive Vice President, Chief Financial Officer [(2)]
Nora M. Duke St. John's, Newfoundland and Labrador	Executive Vice President, Corporate Services and Chief Human Resource Officer [(3)]
Earl A. Ludlow Paradise, Newfoundland and Labrador	Executive Vice President, Eastern Canadian and Caribbean Operations [(4)]
David C. Bennett St. John's, Newfoundland and Labrador	Vice President, Chief Legal Officer and Corporate Secretary [(5)]
James D. Spinney Mount Pearl, Newfoundland and Labrador	Vice President, Treasurer [(6)]
Jamie D. Roberts Mount Pearl, Newfoundland and Labrador	Vice President, Controller [(7)]
Regan P. O'Dea St. John's, Newfoundland and Labrador	Assistant Corporate Secretary [(8)]

(1) *Mr. Perry was appointed President and Chief Executive Officer, effective January 1, 2015, upon the retirement of Mr. H. Stanley Marshall. Mr. Perry became President of Fortis effective June 30, 2014. Prior to that time, Mr. Perry served as Vice President, Finance and Chief Financial Officer of Fortis since 2004.*

(2) *Mr. Smith was appointed Executive Vice President, Chief Financial Officer, effective June 30, 2014. Prior to that time, Mr. Smith served as President and Chief Executive Officer of FortisAlberta since 2007.*

(3) *Ms. Duke was appointed Executive Vice President, Corporate Services and Chief Human Resource Officer, effective August 1, 2015. Prior to that time, Ms. Duke served as President and Chief Executive Officer of Fortis Properties since 2008.*

(4) *Mr. Ludlow was appointed Executive Vice President, Eastern Canadian and Caribbean Operations, effective August 1, 2014. Prior to that time, Mr. Ludlow served as President and Chief Executive Officer at Newfoundland Power since 2007.*

(5) *Mr. Bennett was appointed Vice President, Chief Legal Officer and Corporate Secretary, effective September 19, 2014. Prior to that time, Mr. Bennett served as Vice President, Operations Support, General Counsel and Corporate Secretary since 2013 and Vice President, General Counsel and Corporate Secretary since 2010 for FortisBC Inc., FortisBC Energy and FHI.*

(6) *Mr. Spinney was appointed Vice President, Treasurer, effective March 20, 2013. Prior to that time, Mr. Spinney served as Manager, Treasury at Fortis since October 2002.*

(7) *Mr. Roberts was appointed Vice President, Controller, effective March 20, 2013. Prior to that time, Mr. Roberts served as Vice President, Finance and Chief Financial Officer of Fortis Properties since July 2008.*

(8) *Mr. O'Dea was appointed Assistant Corporate Secretary effective May 7, 2015, and holds the position of Associate General Counsel since January 2014. Prior to that time, Mr. O'Dea served as Director, Legal and Corporate Services and Corporate Secretary of Johnson Inc. since 2011.*

As at December 31, 2015, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 603,991 Common Shares, representing 0.2% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2015, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
TRACEY C. BALL Edmonton, Alberta	Ms. Ball retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She currently serves on the City of Edmonton LRT Governance Board. She graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Canadian Chartered Professional Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. She holds an ICD.D designation from the Institute of Corporate Directors.
MAURA J. CLARK New York, New York	Ms. Clark retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business, a leading energy retailer in Canada and the United States. Previously Ms. Clark was Executive Vice President of North American Strategy and Mergers and Acquisitions for Direct Energy. Ms. Clark's prior experience includes investment banking and serving as Chief Financial Officer of an independent oil refining and marketing company. Ms. Clark graduated from Queen's University with a Bachelor of Arts in Economics. She is a member of the Association of Chartered Professional Accountants of Ontario.
DOUGLAS J. HAUGHEY Calgary, Alberta	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
DAVID G. NORRIS St. John's, Newfoundland and Labrador	Mr. Norris was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. He graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees*. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's 2015 Audited Consolidated Financial Statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"**AIF**" means the Annual Information Form filed by the Corporation;

"**Committee**" means the Audit Committee appointed by the Board pursuant to this mandate;

"**Board**" means the board of directors of the Corporation;

"**Corporation**" means Fortis Inc.;

"**Director**" means a member of the Board;

"**Financially Literate**" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"**External Auditor**" means the firm of chartered professional accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"**Independent**" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in National Instrument 52-110;

"**Internal Auditor**" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"**Management**" means the senior officers of the Corporation;

"**MD&A**" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"**Member**" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. The President and Chief Executive Officer, the Executive Vice President, Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor, including any non-audit services provided by the External Auditor.

1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing and tax structures.

2.7. The Committee shall be responsible for the oversight of the Internal Auditor.

2.8. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing;

3.2. Derivative Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring from Independent Auditing Firms Policy;

3.5. Policy on the Role of the Internal Audit Function;

3.6. Disclosure Policy; and

3.7. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

4. Retaining and Compensating Advisors

The Committee shall have the sole authority to engage independent counsel and any other advisors as the Committee may deem appropriate in its sole discretion and to set the compensation for any advisors employed by the Committee. The Committee shall not be required to obtain the approval of the Board in order to retain or compensate such consultants or advisors.

E. Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax, and non-audit services were as follows.

Fortis External Auditor Service Fees ($ thousands)		
Ernst & Young LLP	**2015**	**2014**
Audit Fees	5,223	4,601
Audit-Related Fees	870	748
Tax Fees	475	119
Non-Audit Fees	-	48
Total	**6,568**	**5,516**

Audit fees were higher in 2015 than in 2014, mainly due to general increases in fees and the impact of foreign exchange on US dollar-denominated audit fees. The increase in tax fees was largely due to additional work completed on the sale of non-core assets. Ernst & Young LLP did not provide any non-audit services in 2015.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Professional Accountants, Fortis Place, Suite 800, 5 Springdale Street, St. John's, NL, A1E 0E4. The consolidated financial statements of the Corporation for the fiscal year ended December 31, 2015 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Association of Chartered Professional Accountants of Newfoundland and Labrador.

14.0 ADDITIONAL INFORMATION

Additional financial information is provided in the Corporation's MD&A and 2015 Audited Consolidated Financial Statements, which are incorporated herein by reference. These documents and additional information relating to the Corporation can be found on the Corporation's website at www.fortisinc.com and on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, will be contained in the management information circular of Fortis to be dated on or about March 18, 2016 for the May 5, 2016 annual meeting of shareholders.

Requests for additional copies of the above-mentioned documents, as well as the 2015 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

EXHIBIT
TASC 5
admitted

HARVARD Kennedy School
MOSSAVAR-RAHMANI CENTER
for Business and Government

Harvard Electricity Policy Group

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PARTICIPANTS

Funding for the Harvard Electricity Policy Group over the course of its activities has been provided by the Mossavar-Rahmani Center for Business and Government of Harvard's Kennedy School of Government, and by the generous support of the following organizations:

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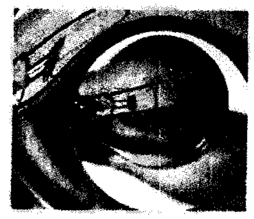
British Columbia Transmission Corporation
California Independent System Operator
Calpine Corporation
Carolina Power and Light
Central and Southwest
Central Maine Power
Cinergy
Citizens Power
Constellation Energy Group, Inc.
DC Energy
Duke Energy
Duquesne
Dynegy
EBSCO Industries
Edison Electric Institute
Edison Mission Energy
EGA
ELCON
Electric Reliability Council of Texas
Energy East
Enron
Entergy Services, Inc.
EPSA (Electric Power Supply Association)
Exelon/ComEd
FirstEnergy Corporation
Fortis
GDF Suez
GE Energy
GenOn Energy
Georgia Transmission
Goldman Sachs
GPU
Intercontinental
Independent System Operator New England
ITC Holdings
Kaiser Aluminum & Chemical
Macquarie Energy
Merrill Lynch
Midcontinent Independent System Operator
Mirant Corporation
Morgan Stanley
National Gas Clearinghouse
National Grid USA



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Search

Google™ search engine

National Independent Energy Producers
National Rural Electric Cooperative Association
New York Independent System Operator
New York State Electric and Gas
Niagara Mohawk
Northeast Utilities
Orange and Rockland Utilities
Oxbow Power
PacifiCorp
Pacific Gas and Electric
PJM Interconnection
PSE&G
Public Service Enterprise Group
Sempra Energy/San Diego Gas & Electric
Sithe Energies
Southern California Edison
Southern Company
Tennessee Valley Authority
Trans-Elect/Michigan Electric Transmission Company
TransEnergie US, Ltd.
Tucson Electric Power
TXU Corporation
UNS Energy Corporation
US Department of Energy
Viridity Energy
Wisconsin Electric
Wisconsin Public Power
Wisconsin Energy Corporation
Xcel Energy

Other participants have come from:
Acre International
Alabama Public Service Committee
Alberta Utilities Commission
Ameren
American Antitrust Institute
American Enterprise Institute
American Public Power Association
American Superconductor
American Wind Energy Association
Analysis Group
ANEEL, Brazil
Apache Corporation
APX
Arizona Corporation Commission
Arkansas Electric Cooperative Corporation
Arkansas Public Service Commission
Armour, Goodin, Schlotz & MacBride
Asia-Pacific Energy Forum
Atlantic Energy Partners
Austin Energy
Australian Competition and Consumer Commission
Baker & Miller
Barker, Dunn & Rossi
Bates White
Borlick Associates
Boston Edison
Boston University
Brandeis University
The Brattle Group
Brown Rudnick
Bruder, Gentile & Marcoux
Burson Marsteller
California Energy Commission
California Public Utilities Commission

California State Senate
Calpine Corporation
Cambridge Energy Research Associates
Cambridge University
Cameron & McKenna
Catholic University of Louvin
CATO Institute
CEERT
Center for the Advancement of Energy Markets
Central Hudson
Centrica PLC
Christensen Associates
Clarkson University
Citicorp
CME Group
Colorado Office of Consumer Counsel
Colorado Public Utilities Commission
Columbia University
ComEd
Comillas Pontifical University
Commodities Futures Trading Commission
Compass-Lexecon
Con Edison
Conectiv
Connecticut Department of Public Utility Control
Conservation Law Foundation
CNT Energy
CPS Energy
Cornell University Institute of Public Affairs
Couch, White, Brenner
CRA International
DCT Energia, Brazil
Delaware Public Service Commission
Deloitte Consulting
Dickstein, Shapiro & Morin
District of Columbia Public Service Commission
Dow Chemical
Duke Energy
Economics Resource Group
Electric Generating Association
Electricity Journal
Electric Power Research Institute
Electric Power Supply Association
Enel North America
Enel S.p.A.
Energy 5.0
Energy Resource Economics
Energy Probe
ENTE Nacional Regulador del Gas
Environmental Defense Fund
Environmental Law and Policy Center of the Midwest
Equitable Resources, Inc.
ERCOT (Texas)
ERG
Energy Security Analysis, Inc.
ESPY Energy Solutions
Executive Branch of Arizona
Federal Energy Regulatory Commission
Financial Accounting Standards Board
First Circuit Court of Appeals
Foley Hoag
GE Energy Financial Services
George Washington University School of Law
Georgia Public Service Commission
GridAmerica, LLC

Hale & Dorr
Hansen, McQuat, Hamrin & Rohde
Harvard University
Hogan & Hartson
House Committee on Energy and Commerce
Howrey & Simon
Hunton & Williams
ICF International
Idaho Power
Idaho Public Utilities Commission
IEC
Illinois Attorney General
Illinois Commerce Commission
IMO Ontario
Independent Energy Producers Association
Indiana Utility Regulatory Commission
Instituto de Investigacion Tecnologica
Intercontinental Energy Corporation
InterGen Services, Inc.
Iowa Utilities Board
Italian Energy Authority
J. Makowski Associates
Johns Hopkins University
Jones, Day, Reavis & Pogue
Kentucky Public Service Commission
Kidder Peabody
Landrum & Brown
Latham & Watkins
Law Offices of Scott Hempling
Lawrence Livermore National Laboratory
LeBoeuf, Lamb, Greene & MacRae, LLP
LECG
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Long Island Lighting Company
Louisville Gas & Electric
LS Power Development
Maine Public Utilities Commission
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Martorelli e GouveiaAdvogados
Massachusetts Department of Public Utilities
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McKinsey and Company
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Monitoring Analytics
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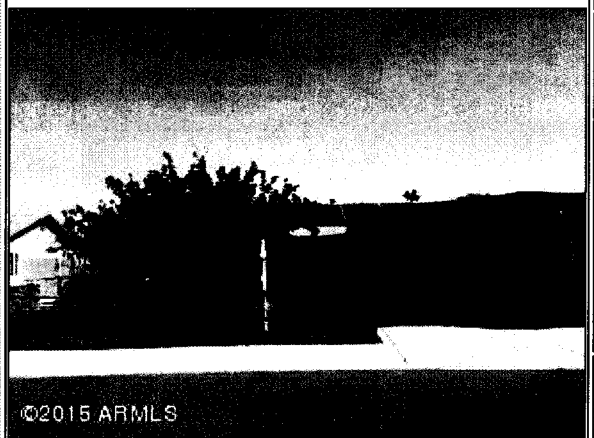
NARUC
Nashville Electric Service
National Commission of Energy Policy
National Conference of State Legislators
National Consumer Law Center
National Economic Research Associates
National Electric Power Authority
National Energy Board
National Governors Association
National Regulatory Research Institute

Natural Resources Defense Council
National Association of Regulatory Utility Commissioners
National Energy Board
National Independent Energy Producers
National Regulatory Research Institute
Natural Gas Clearinghouse
Natural Resources Defense Council
Neptune Energy
NERA Economic Consulting
New Energy Ventures
New England Power Generators Association
New Harbor, Inc.
New Hampshire Public Utilities Commission
New Jersey Board of Public Utilities
NGC Corporation
New York Power Authority
New York Public Service Commission
New York State Energy Office
New York State Public Service Commission
New Zealand Electricity Commission
NextEra Energy Resources
Ni Source
North American Electric Reliability Council
North Carolina Public Utilities Commission
The NorthBridge Group
Norwegian Water Resources and Energy Administration
The National Regulatory Research Institute
Nuclear Regulatory Commission
Oak Ridge National Laboratories
Oklahoma Gas and Electric
Office for Electricity Regulation (UK)
Oliver, Oliver & Waltz
Ontario IMO
Orange and Rockland
Oregon Public Utility Commission
Otter Tail Power Company
Pacific Gas & Electric
Pacific Telesis
Paul Dragoumis Associates
PECO Energy
Pennsylvania Commonwealth Court
ennsylvania House of Representatives
Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission
Pontificia Universidad Catolica de Chile
Potomac Economics
Potomac Electric Power Company
PowerGEM
Predicate
Progress and Freedom Foundation
PSEG Energy Resources & Trade
PSI Energy
Public Service Commission of New Mexico
Public Utility Commission of Texas
Public Utility Research Center, University of Florida
Public Utilities Commission of Ohio
Public Utility Commission of Texas
Putnam, Hayes & Bartlett
Quarles & Brady
Regulatory Assistance Project
Regulatory Entity for Electric Sector (Portugal)
Reid & Priest
Rensselaer Polytechnic Institute
Resources for the Future
Rhode Island Public Utilities Commission

Ridley & Associates
RTO West Project Team
Sacramento Municipal Utility District
Schwab Capital Markets LP
Senate Committee on Energy and Natural Resources
Seventh Circuit Court of Appeals
Skadden, Arps, Slate, Meagher & Flom, LLP
Solar Alliance
South Dakota Public Utilities Commission
Southern California Edison
Spiegel & McDiarmid
Stanford University
State of Oklahoma
Steptoe & Johnson
Stoel Rives
Strategic Performance Management
Strategy Integration
Suffolk University
Sullivan & Cromwell
SunPower Corporation
Svanda Consulting
Synapse Energy Economics
Texas Ratepayers' Organization to Save Energy
Texas State Senate
TransEnergie US Ltd
TransGrid Australia
TRANSLink Development Company
Transpower New Zealand, Ltd.
Troutman & Sanders
UNC Global Institute for Energy and Environmental Systems
Unicom
Union of Concerned Scientists
University of Arizona
University of California at Los Angeles
University of California Energy Institute
University of Florida Public Utility Research Center
University of Hull Business School (UK)
University of Manchester Institute of Science and Technology (UK)
University of Maryland
University of Sussex (UK)
University of Texas at Austin
University of Wisconsin
US Department of Energy
US Department of Justice Antitrust Division
US Environmental Protection Agency
US Power Generating Company LLC
Utah Public Service Commission
Utility Consumers' Action Network
The Utility Reform Network
Utilities Telecom Council
Van Ness Feldman
Vermont Public Service Board
Washington State Energy Facility Site Evaluation Council
Washington Utilities and Transportation Commission
WEPCO
Winston & Strawn
Wisconsin Public Service Commission
The World Bank
World Resources Institute

Please email comments and suggestions to our Web Administrator. This page was last updated January 31, 2007.

Client Report (1) **6814 W BERKELEY RD, Phoenix, AZ 85035** **$129,900**



5293833 Residential Single Family - Detached Closed

Beds/Baths: 3 / 2
Bedrooms Plus: 4
Approx SqFt: 1,040 / County Assessor
Price/SqFt: $124.9
Year Built: 1977
Pool: None
Encoded Features: 32FRO3S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 6,569 / County Assessor
Apx Lot Size Range: 1 - 7,500
Subdivision: MARYVALE TERRACE 41
Tax Municipality: Maricopa - COUNTY
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: unknown
Hun Block: 1850 N
Map Code/Grid: P31
Bldg Number:

EXHIBIT
TASC 6
admitted

Ele Sch Dist: 083 - Cartwright Elementary District
Elementary School: Peralta School
Jr. High School: Estrella Middle School

High School Dist #: 210 - Phoenix Union High School District
High School: Trevor Browne High School

Cross Streets: 67TH AV & MCDOWELL **Directions:** Go west on 1-10 to 67th Ave and go north to McDowell to Coronado and go west to 69th go north and turns into Berkeley. property is on the right hand side as soon as you turn on the curve.

Public Remarks: This is the perfect 3bd 2 bath home under $130k with separate office space, and optional 4th bedroom. This home is move in ready, the bedrooms are very spacious. Plus a converted garage to a room with full bath and large closet! Tile floors throughout the entire home.The backyard has a new fence for privacy, covered patio, and lots of space for kids and pets. It has an RV gate and driveway from the front to the back RV gate. The drive way is big enough for 3 cars side by side. Plus Solar Panels to keep bills low during the summer heat.

Features	Room Details	Construction & Utilities	County, Tax and Financing
Approx SqFt Range: 1,000 - 1,200 **Garage Spaces:** 0 **Carport Spaces:** 0 **Total Covered Spaces:** 0 **Slab Parking Spaces:** 3 **Parking Features:** RV Gate **Pool - Private:** No Pool **Spa:** None **Horses:** N **Fireplace:** No Fireplace **Property Description:** North/South Exposure **Landscaping:** Grass Front; Synthetic Grass Back **Exterior Features:** Covered Patio(s); Storage Shed(s) **Features:** Drink Wtr Filter Sys **Flooring:** Tile	**Kitchen Features:** Range/Oven Elec; Dishwasher **Master Bathroom:** Full Bth Master Bdrm **Master Bedroom:** Split **Laundry:** Inside Laundry **Dining Area:** Eat-in Kitchen **Basement Y/N:** N **Sep Den/Office Y/N:** Y **Other Rooms:** Family Room **Items Updated:** Floor Yr Updated: 2013; Bath(s) Yr Updated: 2013	**Architecture:** Spanish **Const - Finish:** Stucco; Siding **Construction:** Frame - Wood **Roofing:** Comp Shingle **Fencing:** Block; Wood; Chain Link **Cooling:** Refrigeration **Heating:** Electric Heat **Utilities:** SRP; SW Gas **Water:** City Water **Sewer:** Sewer - Public; Sewer in & Cnctd **Services:** City Services **Technology:** Cable TV Avail; HighSpd Intrnt Aval **Energy/Green Feature:** Solar Panels; Ceiling Fan(s) **Solar Panels:** Ownership: Owned	**County Code:** Maricopa **Legal Subdivision:** MARYVALE TERRACE NO 41 PER MCR 177-37 **AN:** 102-76-362 **Lot Number:** 942 **Town-Range-Section:** 2N-1E-36 **Cty Bk&Pg:** 17737 **Plat:** **Taxes/Yr:** $639/2014 **Ownership:** Fee Simple **New Financing:** Cash; VA; FHA; Conventional **Total Asum Mnth Pmts:** $30 **Down Payment:** $0 **Existing 1st Loan:** Treat as Free&Clear **Existing 1st Ln Trms:** **Disclosures:** Agency Discl Req **Possession:** Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

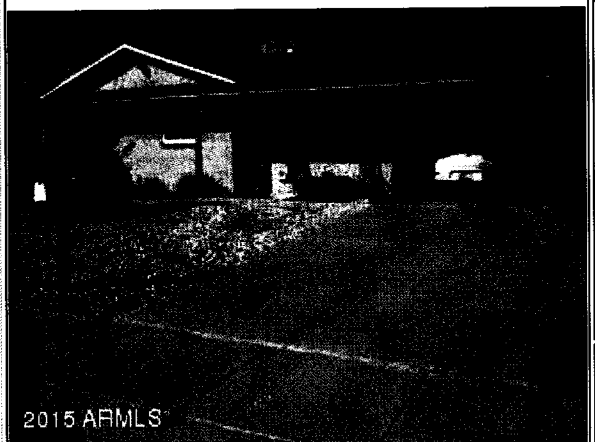
Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / $0 /
PAD Fee Y/N: N / $0 /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: $ 0 $
Cap Impv/Impt Fee 2:$0 $

Listing Dates		Pricing and Sale Info		Listing Contract Info
CDOM/ADOM:	16 / 19	**List Price:**	$129,900	**Special Listing Cond:** Owner/Agent
Status Change Date:	08/08/2015	**Sold Price:**	$129,900	
Close of Escrow Date:	08/07/2015	**Sold Price/SqFt:**	$124.9	
Off Market Date:	06/29/2015	**Loan Type:**	FHA	
		Loan Years:	30	
		Payment Type:	Fixed	
		Buyr Concess to Sell:	0 %	
		Sellr Concess to Buy:	0 %	

Client Report (1) **4516 W EVA ST, Glendale, AZ 85302** **$130,000**



5353359 Residential Single Family - Detached Closed

Beds/Baths: 3 / 2
Bedrooms Plus: 3
Approx SqFt: 1,008 / County Assessor
Price/SqFt: $128.96
Year Built: 1971
Pool: None
Encoded Features: 32RO1C2S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 4,190 / County Assessor
Apx Lot Size Range: 1 - 7,500
Subdivision: SKYVIEW NORTH 1
Tax Municipality: Glendale
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: Unknown
Hun Block:
Map Code/Grid: M32
Bldg Number:

Ele Sch Dist: 006 - Washington Elementary District
Elementary School: Sunset School - Glendale
Jr. High School: Abraham Lincoln Traditional School

High School Dist #: 205 - Glendale Union High School District
High School: Glendale High School

Cross Streets: 45th ave and Olive **Directions:** From Olive go north to Eva. West on Eva to house on North side of the street

Public Remarks: Fantastic opportunity. Beautiful 3 bedroom/ 2 bath gem. All appliances convey. Newer roof. Newer a/c. Newer water heater. Newer appliances.New lifetime warrantied Solar panels that make your electric bill super cheap. Upgraded Alarm system for added security. Tile throughout house. All new dual-pane windows throughout as well. Perfect house for a great price. SEE SPECIAL INSTRUCTIONS FOR SHOWING AND CLOSE OF ESCROW. WELCOME HOME FRIENDS!!!!!!!!!!

Master Bedroom	12	10	**Bedroom 2**	10	9	**Bedroom 3**	10	9
						Kitchen	9	14
						Great Room	15	14

Features

Approx SqFt Range: 1,000 - 1,200
Garage Spaces: 0
Carport Spaces: 1
Total Covered Spaces: 1
Slab Parking Spaces: 2
Parking Features: Separate Strge Area
Pool - Private: No Pool
Spa: None
Horses: N
Fireplace: No Fireplace
Property Description: North/South Exposure
Landscaping: Gravel/Stone Front; Natural Desert Back
Exterior Features: Covered Patio(s); Storage Shed(s)
Flooring: Tile
Windows: Sunscreen(s); Dual Pane

Room Details

Kitchen Features: Range/Oven Elec; Disposal; Refrigerator; Pantry; Non-laminate Counter
Master Bathroom: 3/4 Bath Master Bdrm
Master Bedroom: Not Split
Laundry: Washer Included; Dryer Included
Dining Area: Eat-in Kitchen
Basement Y/N: N
Sep Den/Office Y/N: N
Other Rooms: Great Room

Construction & Utilities

Unit Style: All on One Level
Const - Finish: Painted
Construction: Block
Roofing: Comp Shingle
Fencing: Wood
Cooling: Refrigeration
Heating: Electric Heat
Utilities: SRP
Water: City Water
Sewer: Sewer - Public
Services: City Services
Technology: Sat Dish TV Lsd; Cable TV Avail; Security Sys Leased
Energy/Green Feature: Solar Panels; Ceiling Fan(s)
Solar Panels: Ownership: Owned

County, Tax and Financing

County Code: Maricopa
Legal Subdivision: SKYVIEW NORTH UNIT ONE
AN: 148-07-391
Lot Number: 112
Town-Range-Section: 3N-2E-28
Cty Bk&Pg:
Plat:
Taxes/Yr: $565/2014
Ownership: Fee Simple
New Financing: Cash; VA; FHA; Conventional
Total Asum Mnth Pmts: $0
Down Payment: $0
Existing 1st Loan: Treat as Free&Clear
Existing 1st Ln Trms:
Disclosures: Seller Disc Avail; Agency Discl Req
Possession: By Agreement

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: $ 0 $
Cap Impv/Impt Fee 2:$0 $

Listing Dates	Pricing and Sale Info	Listing Contract Info

Client Report (1) **12219 N CHERRY HILLS DR W, Sun City, AZ 85351** **$140,000**

5242351 Residential Single Family - Detached Closed

Beds/Baths: 2 / 1.5
Bedrooms Plus: 2
Approx SqFt: 1,062 / County Assessor
Price/SqFt: $131.83
Year Built: 1960
Pool: Community Only
Encoded Features: 21.5RO1G1S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 1,062 / County Assessor
Apx Lot Size Range: 1 - 7,500
Subdivision: Newlife Unit One
Tax Municipality: Maricopa - COUNTY
Marketing Name: SUN CITY
Planned Cmty Name: SUN CITY
Model:
Builder Name: DELWEBB
Hun Block:
Map Code/Grid: L30
Bldg Number:

Ele Sch Dist: 000 - Out of Area
Elementary School: Adult
Jr. High School: Adult

High School Dist #: 000 - Out of Area
High School: Adult

Cross Streets: Alabama Ave. **Directions:** From Grand Ave., South on 111th Ave to Left on N. Cherry Hills Dr. W. to property on the Left. From Westbound W. Alabama Ave., Right on N. Cherry Hills Dr. W to property on the Right.

Public Remarks: UNIQUE FURNISHED SUN CITY 2 BEDROOM, 1 and ½ BATH, HOME ON SUN CITY NORTH GOLF COURSE, (HOME COMES WITH A FREE GOLF CART) AND WITH $30K OWNED SOLAR PANELS THAT ALLOW THE BUYER TO HAVE NO APS ELECTRIC BILL. THE AVERAGE APS CREDIT IS $750! OWNER HAS ADDED INSULATION AND A FOIL BARRIER TO THE ATTIC. ALL WINDOWS HAVE BEEN REPLACED WITH DOUBLE-PANE, LOW E. THERE IS A UP-DATED KITCHEN WITH A NEWER GAS STOVE AND OVEN, NON-LAMINATE COUNTER-TOPS WITH UNDER-MOUNT SINK, & POPLAR CABINETS. ALL APPLIANCES CONVEY WITH HOME. OUTSIDE, THERE ARE FRONT & BACK WATER FEATURES & DESERT LANDSCAPING ENCOMPASSED WITH A UNIQUE IRON FENCE. GATES ALLOW GOLF COURSE & SIDE PARKING ACCESS. THERE IS A SINGLE CAR GARAGE (WITH WORKBENCH, CART PARKING) & A SECOND VEHICLE PARKING SLAB. THIS HOME IS MOVE IN READY.

Features

Approx SqFt Range: 1,000 - 1,200
Garage Spaces: 1
Carport Spaces: 0
Total Covered Spaces: 1
Slab Parking Spaces: 1
Parking Features: Attch'd Gar Cabinets; Electric Door Opener
Pool - Private: No Pool
Spa: None
Horses: N
Fireplace: No Fireplace
Landscaping: Desert Front; Desert Back
Features: Furnished(See Rmrks)
Community Features: Biking/Walking Path; Comm Tennis Court(s); Community Pool; Community Pool Htd; Community Spa; Community Spa Htd; Golf Course; Handball/Raquetball; Workout Facility
Flooring: Tile
Windows: Dual Pane; Low-E

Room Details

Kitchen Features: Range/Oven Gas; Disposal; Dishwasher; Refrigerator; Pantry; Non-laminate Counter
Master Bathroom: Other (See Remarks)
Laundry: Washer Included; Dryer Included; Inside Laundry
Dining Area: Dining in LR/GR
Basement Y/N: N
Sep Den/Office Y/N: N
Other Rooms: Arizona Room/Lanai

Construction & Utilities

Const - Finish: Painted
Construction: Block; Spray Foam Insulatn
Roofing: Comp Shingle
Fencing: View/Wrought Iron
Cooling: Refrigeration
Heating: Gas Heat
Plumbing: Gas Hot Water Heater
Utilities: APS; SW Gas
Water: City Water
Sewer: Sewer - Public
Energy/Green Feature: Solar Panels; Ceiling Fan(s); Gray Water System
Solar Panels: Ownership: Owned; Grid: On

County, Tax and Financing

County Code: Maricopa
Legal Subdivision:
AN: 200-87-072
Lot Number: 72
Town-Range-Section: --
Cty Bk&Pg:
Plat:
Taxes/Yr: $561/2014
Ownership: Fee Simple
New Financing: Cash; Conventional
Total Asum Mnth Pmts: $0
Down Payment: $0
Existing 1st Loan: Treat as Free&Clear
Existing 1st Ln Trms:
Disclosures: Agency Discl Req
Possession: Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: Y / $462 / Annually
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $38.5
Cap Imprv/Impact Fee: $ 3000 $
Cap Impv/Impt Fee 2: $0 $

Listing Dates	Pricing and Sale Info	Listing Contract Info

Client Report (1) **200 W PALM CT, Coolidge, AZ 85128** **$97,000**

5188956 Residential Single Family - Detached Closed

Beds/Baths: 3 / 2
Bedrooms Plus: 3
Approx SqFt: 1,176 / County Assessor
Price/SqFt: $82.48
Year Built: 2005
Pool: None
Encoded Features: 32FR3G3C2S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 7,425 / County Assessor
Apx Lot Size Range: 1 - 7,500
Subdivision: Sundance
Tax Municipality: Coolidge
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: PCI Homes
Hun Block:
Map Code/Grid: W45
Bldg Number:

Ele Sch Dist: 0021 - Coolidge Unified District - Pinal
Elementary School: Coolidge High School
Jr. High School: Coolidge High School

High School Dist #: 0021 - Coolidge Unified District - Pinal
High School: Coolidge High School

Cross Streets: N. Arizona Blvd & Vah Ki Inn Rd **Directions:** East on Vah Ki Inn, North on Main St, West on Sundance Dr, North on 3rd St, East on Palm Ct to home

Public Remarks: This home is incredible! The owners have put in just about every upgrade possible. This 3 bedroom 2 bath home has a leased solar system that has been paid for. Termite protection for 2 more years,rain gutters,10 x 10 storage shed,wood pile and outdoor fireplace,outdoor fans,spotlights,sprinkler system,huge covered patio,16' electric patio sun shade,utility sink with hot and cold water,metal rear gate in block wall to access open space behind home,large side gate,doggie door,dog play area,

Features
Approx SqFt Range: 1,000 - 1,200
Garage Spaces: 3
Carport Spaces: 3
Total Covered Spaces: 6
Slab Parking Spaces: 2
Parking Features: Dir Entry frm Garage; Electric Door Opener
Pool - Private: No Pool
Spa: None
Horses: N
Fireplace: Exterior Fireplace
Property Description: Cul-De-Sac Lot
Landscaping: Desert Front; Desert Back; Auto Timer H2O Front; Auto Timer H2O Back
Exterior Features: Patio; Covered Patio(s); Storage Shed(s)
Features: Vaulted Ceiling(s); Water Softener Owned; Drink Wtr Filter Sys
Flooring: Laminate; Tile
Windows: Sunscreen(s); Dual Pane

Room Details
Kitchen Features: Range/Oven Elec; Built-in Microwave; Refrigerator
Master Bathroom: 3/4 Bath Master Bdrm
Laundry: Wshr/Dry HookUp Only
Dining Area: Dining in LR/GR
Basement Y/N: N
Sep Den/Office Y/N: N
Other Rooms: Family Room

Construction & Utilities
Architecture: Ranch
Unit Style: All on One Level
Const - Finish: Stucco
Construction: Frame - Wood
Roofing: Comp Shingle
Fencing: Block
Cooling: Refrigeration; HVAC SEER Rating: 20
Heating: Electric Heat
Plumbing: Electric Hot Wtr Htr
Utilities: APS
Water: Pvt Water Company
Sewer: Sewer - Public
Services: City Services
Technology: Cable TV Avail; HighSpd Intrnt Aval; Security Sys Owned
Energy/Green Feature: Solar Panels; Ceiling Fan(s)
Solar Panels: Ownership: Leased; Grid: On; kW: 5,520

County, Tax and Financing
County Code: Pinal
Legal Subdivision: SUNDANCE COOLIDGE
AN: 203-19-041
Lot Number: 33
Town-Range-Section: 05S-08E-15
Cty Bk&Pg:
Plat:
Taxes/Yr: $587/2014
Ownership: Fee Simple
New Financing: Cash; VA; FHA; Farm Home/ USDA
Total Asum Mnth Pmts: $0
Down Payment: $0
Existing 1st Loan: Treat as Free&Clear
Existing 1st Ln Trms:
Disclosures: Seller Disc Avail
Possession: Close of Escrow

Fees & Homeowner Association Information
HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: $ 0 $
Cap Impv/Impt Fee 2:$0 $

Listing Dates
CDOM/ADOM:	14 / 14
Status Change Date:	01/15/2015
Close of Escrow Date:	01/15/2015
Off Market Date:	11/04/2014

Pricing and Sale Info
List Price:	$110,000
Sold Price:	$97,000
Sold Price/SqFt:	$82.48
Loan Type:	Conventional
Loan Years:	30

Listing Contract Info
Special Listing Cond: N/A

Client Report (1) **1136 N KADOTA AVE, Casa Grande, AZ 85122** **$95,000**

5219794 Residential Single Family - Detached Closed

Beds/Baths: 3 / 2
Bedrooms Plus: 3
Approx SqFt: 1,200 / County Assessor
Price/SqFt: $79.16
Year Built: 1950
Pool: None
Encoded Features: 32RO1C
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 16,553 / County Assessor
Apx Lot Size Range: 15,001 - 18,000
Subdivision: Evergreen Addition
Tax Municipality: Casa Grande
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: Unknown
Hun Block: 1100 N
Map Code/Grid: X41
Bldg Number:

Ele Sch Dist: 0004 - Casa Grande Elementary District - Pinal
Elementary School: Evergreen Elementary School
Jr. High School: Casa Grande Middle School

High School Dist #: 0082 - Casa Grande Union HS District - Pinal
High School: Casa Grande Union High School

Cross Streets: Trekell and McMurray Blvd., **Directions:** Head West on McMurray Blvd., from Trekell Rd. Home is on the Southeast corner of McMurray and Kadota.

Public Remarks: Solar panels, block construction, help to keep energy costs low!!! Better than Rent! Huge 2 lot parcel with tons of potential in this 3BR 2BA home located in the Evergreen Historic Neighborhood. Built in 1950, updated in the late 90's, including new roof, stucco, paint, etc. Gas range and water heater, ceiling fans throughout. Come take a look! See if this is your new home. Home Warranty. Buyer to confirm all details.

Features	Room Details	Construction & Utilities	County, Tax and Financing
Approx SqFt Range: 1,000 - 1,200 **Garage Spaces:** 0 **Carport Spaces:** 1 **Total Covered Spaces:** 1 **Slab Parking Spaces:** 0 **Parking Features:** RV Gate; RV Parking; Unassigned Parking **Pool - Private:** No Pool **Spa:** None **Horses:** N **Fireplace:** No Fireplace **Landscaping:** Dirt Back; Desert Front **Flooring:** Carpet; Laminate; Tile	**Kitchen Features:** Range/Oven Gas; Dishwasher; Refrigerator **Master Bathroom:** 3/4 Bath Master Bdrm **Laundry:** Wshr/Dry HookUp Only **Dining Area:** Eat-in Kitchen; Dining in LR/GR **Basement Y/N:** N **Sep Den/Office Y/N: N** **Other Rooms:** Great Room **Items Updated:** Floor Yr Updated: 2013; Floor Partial/Full: Full; Wiring Yr Updated: 1996; Wiring Partial/Full: Full; Plmbg Yr Updated: 1996; Plmbg Partial/Full: Full; Ht/Cool Yr Updated: 1966; Ht/Cool Partial/Full: Full; Roof Yr Updated: 1996; Roof Partial/Full: Full; Kitchen Yr Updated: 1996; Kitchen Partial/Full: Partial; Bath(s) Yr Updated: 1996; Bath(s) Partial/Full: Partial	**Architecture:** Ranch **Const - Finish:** Painted; Stucco **Construction:** Block **Roofing:** Comp Shingle **Fencing:** Chain Link **Cooling:** Refrigeration **Heating:** Gas Heat **Plumbing:** Gas Hot Water Heater **Utilities:** APS; SW Gas **Water:** Pvt Water Company **Sewer:** Sewer - Public; Sewer in & Cnctd **Services:** City Services **Technology:** 3+ Exist Tele Lines; Pre-Wire Sat Dish; Cable TV Avail **Energy/Green Feature:** Solar Panels; Ceiling Fan(s) **Solar Panels:** Ownership: Owned	**County Code:** Pinal **Legal Subdivision:** EVERGREEN ADDITION **AN:** 506-09-013 **Lot Number:** 19 **Town-Range-Section:** 06S-06E-20 **Cty Bk&Pg:** **Plat:** **Taxes/Yr:** $479/2014 **Ownership:** Fee Simple **New Financing:** Cash; VA; FHA; Conventional; Farm Home/ USDA **Total Asum Mnth Pmts:** $0 **Down Payment:** $1,000 **Existing 1st Loan:** FHA **Existing 1st Ln Trms:** **Disclosures:** Seller Disc Avail; Agency Discl Req **Possession:** Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: $ 0 $
Cap Impv/Impt Fee 2:$0 $

Listing Dates		Pricing and Sale Info		Listing Contract Info
CDOM/ADOM:	34 / 34	**List Price:**	$90,000	**Special Listing Cond:** N/A
Status Change Date:	04/23/2015	**Sold Price:**	$95,000	
Close of Escrow Date:	04/22/2015	**Sold Price/SqFt:**	$79.17	
Off Market Date:	04/21/2015	**Loan Type:**	FHA	
		Loan Years:	30	
		Payment Type:	Fixed	

Client Report (1) **101 S CENTRAL AVE, Florence, AZ 85132** **$138,000**

5323401	Residential	Single Family - Detached	Closed

Beds/Baths: 3 / 3
Bedrooms Plus: 4
Approx SqFt: 2,315 / County Assessor
Price/SqFt: $59.61
Year Built: 1963
Pool: Private Only
Encoded Features: 33FRXPQO1C
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 11,325 / County Assessor
Apx Lot Size Range: 12,501 - 15,000
Subdivision: WILLOW MANOR
Tax Municipality: Florence
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: unknown
Hun Block: 100 S
Map Code/Grid: W47
Bldg Number:

Ele Sch Dist: 0001 - Florence Unified District - Pinal
Elementary School: Florence K-8
Jr. High School: Florence K-8

High School Dist #: 0001 - Florence Unified District - Pinal
High School: Florence High School

Cross Streets: BUTTE & CENTRAL **Directions:** Traveling west on Butte, from the intersection of Main and Butte to Central. Turn South on Central Ave to home on Left

Public Remarks: Wow!! You've got to see this one! Hard to find block home with open floor plan... House feels so open and inviting when your inside! Large kitchen, Large living room and Large Bedrooms! There are two bedrooms and two baths connected to the open concept living, and an additional bedroom, bath and living space with it's own entrance. This could be used for a mother-in-law suite or you could even rent it out for additional income! Lots of possibilities, ... Huge back yard with above ground pool to cool down on those long hot summer days. The home comes with a completely fenced in back yard. Are you looking for a home close to town with no HOA'S? With easy access to schools and work? Then look no further and schedule your appointment to preview this move in ready charmer today!

Features	Room Details	Construction & Utilities	County, Tax and Financing
Approx SqFt Range: 2,251 - 2,500 **Garage Spaces:** 0 **Carport Spaces:** 1 **Total Covered Spaces:** 1 **Slab Parking Spaces:** 0 **Parking Features:** RV Parking **Pool - Private:** Pool - Private; Above Ground Pool **Spa:** None **Horses:** N **Fireplace:** 1 Fireplace **Landscaping:** Desert Front; Desert Back **Exterior Features:** Patio; Storage Shed(s) **Add'l Property Use:** None **Flooring:** Tile	**Kitchen Features:** Range/Oven Gas; Disposal; Dishwasher; Pantry; Granite Countertops; Kitchen Island **Master Bathroom:** Full Bth Master Bdrm; Double Sinks **Additional Bedroom:** Mstr Bdr Walkin Clst **Laundry:** Washer Included; Dryer Included; Wshr/Dry HookUp Only; Inside Laundry **Dining Area:** Eat-in Kitchen **Basement Y/N:** N **Sep Den/Office Y/N:** Y **Other Rooms:** Family Room; Guest Qtrs-Sep Entrn	**Architecture:** Ranch **Const - Finish:** Painted **Construction:** Block **Roofing:** Comp Shingle **Fencing:** Chain Link **Cooling:** Refrigeration **Heating:** Electric Heat; Gas Heat **Utilities:** APS; SW Gas **Water:** City Water **Sewer:** Sewer - Public **Services:** City Services **Technology:** 3+ Exist Tele Lines **Energy/Green Feature:** Solar Panels; Ceiling Fan(s) **Solar Panels:** Ownership: Leased	**County Code:** Pinal **Legal Subdivision:** **AN:** 202-07-086-B **Lot Number:** 86 **Town-Range-Section:** -- **Cty Bk&Pg:** **Plat:** **Taxes/Yr:** $865.5/2014 **Ownership:** Fee Simple **New Financing:** Cash; VA; FHA; Conventional **Total Asum Mnth Pmts:** $0 **Down Payment:** $0 **Existing 1st Loan:** Treat as Free&Clear **Existing 1st Ln Trms:** **Disclosures:** Seller Disc Avail; Agency Discl Req **Possession:** Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /	
HOA 2 Y/N: / /	
HOA 3 Y/N: / /	

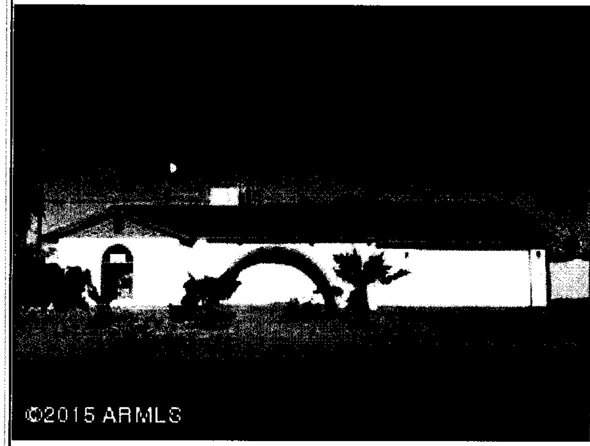
Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / $0 /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: % 0 %
Cap Impv/Impt Fee 2:%0 %

Listing Dates		Pricing and Sale Info		Listing Contract Info
CDOM/ADOM:	44 / 44	**List Price:**	$139,900	**Special Listing Cond:** N/A
Status Change Date:	10/23/2015	**Sold Price:**	$138,000	
Close of Escrow Date:	10/22/2015	**Sold Price/SqFt:**	$59.61	
Off Market Date:	10/03/2015	**Loan Type:**	Cash	
		Loan Years:	0	
		Payment Type:	Other	
		Buyr Concess to Sell:	0 $	
		Sellr Concess to Buy:	0 $	

Client Report (1) **818 W MERRITT PKWY, Gila Bend, AZ 85337** **$95,000**



5219435 Residential Single Family - Detached Closed

Beds/Baths: 4 / 2
Bedrooms Plus: 4
Approx SqFt: 1,736 / Appraiser
Price/SqFt: $54.72
Year Built: 1976
Pool: None
Encoded Features: 42FRX2G
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 10,724 / County Assessor
Apx Lot Size Range: 10,001 - 12,500
Subdivision: Gila Bend Estates
Tax Municipality: Gila Bend
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: Unknown
Hun Block:
Map Code/Grid: Y22
Bldg Number:

Ele Sch Dist: 024 - Gila Bend Unified District
Elementary School: Gila Bend Elementary
Jr. High School: Gila Bend Elementary

High School Dist #: 024 - Gila Bend Unified District
High School: Gila Bend High School

Cross Streets: Pima St. & Harrington Ave. **Directions:** Take Harrington Ave. North to Merritt Pkwy., West to Home.

Public Remarks: This 4 bedroom Ranch style home on a corner lot is the reason you waited. Walk inside to the comfortable living room with pass-through to the large kitchen with island, custom cabinets and tile countertops and tons of extra cabinet storage space. The family room with redbrick fireplace is a great cozy space for those cold nights. The large laundry room with additional storage will be a welcome place for those everyday chores. Four bedrooms, a living room, family room, large kitchen and large fenced backyard all mean that this home has plenty of room to spread out and create your wonderful space. Add to that the solar panels and you have yourself an incredible opportunity to call home.

Features

Approx SqFt Range: 1,601 - 1,800
Garage Spaces: 2
Carport Spaces: 0
Total Covered Spaces: 2
Slab Parking Spaces: 0
Parking Features: Electric Door Opener
Pool - Private: No Pool
Spa: None
Horses: N
Fireplace: 1 Fireplace; Fireplace Family Rm
Landscaping: Dirt Back; Desert Front
Exterior Features: Covered Patio(s)
Flooring: Carpet; Tile

Room Details

Kitchen Features: Range/Oven Elec; Disposal; Dishwasher; Built-in Microwave
Master Bathroom: 3/4 Bath Master Bdrm
Laundry: Inside Laundry
Dining Area: Eat-in Kitchen
Basement Y/N: N
Sep Den/Office Y/N: N
Other Rooms: Family Room

Construction & Utilities

Const - Finish: Painted
Construction: Frame - Wood
Roofing: Comp Shingle
Fencing: Block
Cooling: Refrigeration
Heating: Gas Heat
Plumbing: Gas Hot Water Heater
Utilities: APS
Water: City Water
Sewer: Sewer - Public
Services: City Services
Energy/Green Feature: Solar Panels
Solar Panels: Ownership: Leased

County, Tax and Financing

County Code: Maricopa
Legal Subdivision: GILA BEND ESTATES
AN: 403-61-101
Lot Number: 101
Town-Range-Section: 5S-5W-36
Cty Bk&Pg:
Plat:
Taxes/Yr: $249/2014
Ownership: Fee Simple
New Financing: Cash; FHA; Conventional
Total Asum Mnth Pmts: $0
Down Payment: $0
Existing 1st Loan: Treat as Free&Clear
Existing 1st Ln Trms:
Disclosures: Agency Discl Req
Possession: Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: $ 0 $
Cap Impv/Impt Fee 2:$0 $

Listing Dates

CDOM/ADOM:	11 / 11
Status Change Date:	04/14/2015
Close of Escrow Date:	04/09/2015
Off Market Date:	01/20/2015

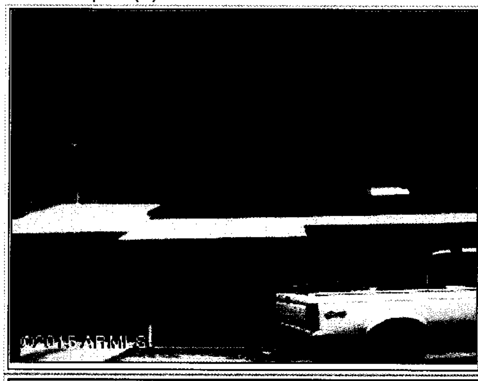
Pricing and Sale Info

List Price:	$60,000
Sold Price:	$95,000
Sold Price/SqFt:	$54.72
Loan Type:	FHA
Loan Years:	30
Payment Type:	Fixed
Buyr Concess to Sell:	0 $
Sellr Concess to Buy:	2,850 $

Listing Contract Info

Special Listing Cond: HUD Owned Property

Client Report (1) **836 E Ironwood DR, Phoenix, AZ 85020** **$100,000**



5290462	Residential	Single Family - Detached	Closed

Beds/Baths: 2 / 1
Bedrooms Plus: 3
Approx SqFt: 1,112 / County Assessor
Price/SqFt: $89.93
Year Built: 1963
Pool: None
Encoded Features: 21RO2S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached
Dwelling Styles: Detached

Approx Lot SqFt: 9,281 / County Assessor
Apx Lot Size Range: 7,501 - 10,000
Subdivision: GEBBY PLACE 2
Tax Municipality: Phoenix
Marketing Name:
Planned Cmty Name:
Model:
Builder Name: Unknown
Hun Block:
Map Code/Grid: M34
Bldg Number:

Ele Sch Dist: 006 - Washington Elementary District
Elementary School: Sunnyslope Elementary School
Jr. High School: Royal Palm Middle School

High School Dist #: 040 - Glendale Elementary District
High School: Sunnyslope High School

Cross Streets: 7th Street and Dunlap **Directions:** From Dunlap, go North on 7th Street, East on Mountain View, North on 9th Street, West on E Ironwood. Home on North side of street

Public Remarks: Home sold "as-is." Property needs work. Carport turned into 3rd bedroom. Lots of potential here! Large fenced yard. Needs work. Leased solar panels. Great potential for fixer-upper or investment property.

Features

Approx SqFt Range: 1,000 - 1,200
Garage Spaces: 0
Carport Spaces: 0
Total Covered Spaces: 0
Slab Parking Spaces: 2
Parking Features: RV Gate
Pool - Private: No Pool
Spa: None
Horses: N
Fireplace: No Fireplace
Property Description: Mountain View(s); North/South Exposure
Landscaping: Desert Front; Desert Back
Exterior Features: Covered Patio(s)
Features: Fix-Up Needs Repair; No Interior Steps
Community Features: Near Bus Stop
Flooring: Carpet; Concrete

Room Details

Kitchen Features: Range/Oven Elec; Refrigerator; Pantry
Master Bathroom: None
Laundry: Wshr/Dry HookUp Only
Dining Area: Eat-in Kitchen
Basement Y/N: N
Sep Den/Office Y/N: N
Other Rooms: Bonus/Game Room

Construction & Utilities

Architecture: Ranch
Unit Style: All on One Level
Const - Finish: Painted
Construction: Block
Roofing: Comp Shingle
Fencing: Chain Link
Cooling: Refrigeration
Heating: Electric Heat
Plumbing: Solar Hot Water Htr
Utilities: APS
Water: City Water
Sewer: Sewer - Public
Services: City Services
Energy/Green Feature: Solar Panels
Solar Panels: Ownership: Leased; Grid: On

County, Tax and Financing

County Code: Maricopa
Legal Subdivision:
AN: 159-40-027
Lot Number: 27
Town-Range-Section: 3N-3E-28
Cty Bk&Pg:
Plat:
Taxes/Yr: $607/2014
Ownership: Fee Simple
New Financing: Cash; FHA; Conventional
Total Asum Mnth Pmts: $0
Down Payment: $0
Existing 1st Loan: Conventional
Existing 1st Ln Trms: Non Assumable
Disclosures: None
Possession: Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /
HOA 2 Y/N: / /
HOA 3 Y/N: / /

Association Fee Incl: No Fees
Assoc Rules/Info: None

Rec Center Fee Y/N: N / /
Rec Center Fee 2 Y/N: N / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $0
Cap Imprv/Impact Fee: % 0 %
Cap Impv/Impt Fee 2:%0 %
Com Facilities Distr: N

Listing Dates

CDOM/ADOM:	131 / 131
Status Change Date:	11/03/2015
Close of Escrow Date:	11/02/2015
Off Market Date:	10/16/2015

Pricing and Sale Info

List Price:	$99,000
Sold Price:	$100,000
Sold Price/SqFt:	$89.93
Loan Type:	Conventional
Loan Years:	30
Payment Type:	Fixed
Buyr Concess to Sell:	0 $
Sellr Concess to Buy:	0 $
Closing Cost Split:	Normal - N

Listing Contract Info

Special Listing Cond: N/A

Listed by: Century 21 Arizona Foothills (cere03)

Prepared by Cameron C Carter

All information should be verified by the recipient and none is guaranteed as accurate by ARMLS. DND2 (D o N ot D isplay or D isclose) - the data in fields marked with DND2 is confidential, for agent use only, and may not be shared with customers or clients in any manner whatsoever.

03/07/2016 4:33 PM

Client Report (1) **13230 W SHADOW HILLS DR, Sun City West, AZ 85375** **$112,000**

4872629 Residential Single Family - Detached Closed

Beds/Baths: 2 / 2
Bedrooms Plus: 2
Approx SqFt: 1,160 / County Assessor
Price/SqFt: $96.55
Year Built: 1979
Pool: Community Only
Encoded Features: 22RD2G2S
Exterior Stories: 1
# of Interior Levels: 1
Dwelling Type: Single Family - Detached

Approx Lot SqFt: 10,048 / County Assessor
Apx Lot Size Range: 10,001 - 12,500
Subdivision: Sun City West
Tax Municipality: Maricopa - COUNTY
Marketing Name:
Planned Cmty Name: Sun City West
Model:
Builder Name: Del Webb
Hun Block:
Map Code/Grid: K29
Bldg Number:

Ele Sch Dist: 000 - Out of Area
Elementary School: Adult
Jr. High School: Adult

High School Dist #: 000 - Out of Area
High School: Adult

Cross Streets: Bell Rd. and RH Johnson **Directions:** West on Bell Rd. to RH Johnson Blvd., North to 133rd, East to Shadow Hills Dr., South to property on left.

Public Remarks: Sun City West gem. 2/bd rm 2/bath well cared for home away from noise and traffic. New countertops and backsplash in kitchen. Brand new dishwasher. Two master suites with walk-in closets. Large serene lot with low maintenance landscaping in the front and your beautiful serene, fenced back yard under your private Ramada for shade and entertaining w/Palms, Rosewood,Tangelo and Ruby Red Grapefruit trees. Orange tree in front. Garage has large separate laundry room with lots of storage.Enjoy the gorgeous, inexpensive winters here in AZ with the very economical stay green Solar City rooftop panels to ensure extremely low power bills both in winter and summer(high $14.00 month). Rec Center is just a few minutes away with endless golf, swimming, workout facility, tennis and more. Must see!!

Features	Room Details	Construction & Utilities	County, Tax and Financing
Approx SqFt Range: 1,000 - 1,200 **Garage Spaces:** 2 **Carport Spaces:** 0 **Total Covered Spaces:** 2 **Slab Parking Spaces:** 2 **Parking Features:** Electric Door Opener; Golf Cart Garage **Pool - Private:** No Pool **Spa:** None **Horses:** N **Fireplace:** No Fireplace **Property Description:** North/South Exposure **Landscaping:** Desert Front; Desert Back; Grass Back; Yrd Wtring Sys Front; Yrd Wtring Sys Back; Auto Timer H2O Front **Exterior Features:** Gazebo/Ramada **Features:** 9+ Flat Ceilings **Community Features:** Biking/Walking Path; Clubhouse/Rec Room; Comm Tennis Court(s); Community Pool; Community Pool Htd; Community Spa; Community Spa Htd; Golf Course **Flooring:** Carpet; Linoleum	**Kitchen Features:** Range/Oven Elec; Disposal; Dishwasher; Refrigerator; Pantry **Master Bathroom:** 3/4 Bath Master Bdrm **Additional Bedroom:** 2 Master Bdrms; Mstr Bdr Walkin Clst; Othr Bdr Walkin Clst **Laundry:** Wshr/Dry HookUp Only; Inside Laundry **Dining Area:** Formal; Eat-in Kitchen **Basement Y/N:** N **Basement Description:** None **Items Updated:** Plmbg Yr Updated: 2010; Plmbg Partial/Full: Partial; Roof Yr Updated: 2007; Roof Partial/Full: Full; Kitchen Yr Updated: 2012; Kitchen Partial/Full: Partial; Bath(s) Yr Updated: 2010; Bath(s) Partial/Full: Partial	**Architecture:** Ranch **Unit Style:** All on One Level **Const - Finish:** Painted **Construction:** Frame - Wood **Roofing:** Comp Shingle **Fencing:** Chain Link **Cooling:** Refrigeration; Window/Wall Unit **Heating:** Electric Heat **Utilities:** APS **Water:** Pvt Water Company **Sewer:** Sewer - Public **Technology:** 3+ Exist Tele Lines; Pre-Wire Sat Dish; Sat Dish TV Lsd **Energy/Green Feature:** Solar Panels; Ceiling Fan(s) **Solar Panels:** Ownership: Owned	**County Code:** Maricopa **Legal Subdivision:** SUN CITY WEST 3 LOT 1-728 & TR A-D **AN:** 232-02-533 **Lot Number:** 533 **Town-Range-Section:** 4N-1W-26 **Cty Bk&Pg:** **Plat:** **Taxes/Yr:** $689/2012 **Ownership:** Fee Simple **New Financing:** Cash; VA; FHA; Conventional **Total Asum Mnth Pmts:** $0 **Down Payment:** $0 **Existing 1st Loan:** Treat as Free&Clear **Existing 1st Ln Trms:** **Disclosures:** Seller Disc Avail **Possession:** Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /

HOA 2 Y/N: Y / $0 / Annually
HOA 2 Transfer Fee: $230
HOA 2 Name: Sun City West **HOA 2 Telephone:** 623-541-6100

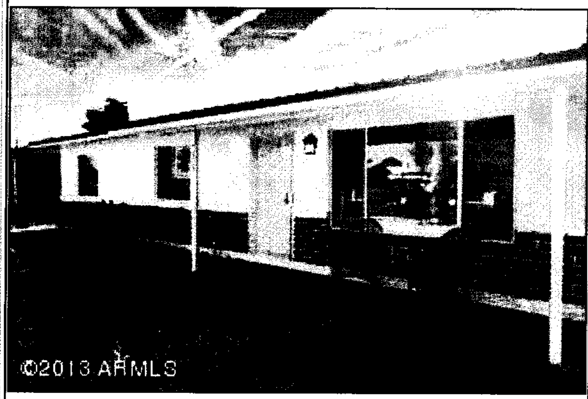
HOA 3 Y/N: / /

Association Fee Incl: Common Area Maint; Street Maint
Assoc Rules/Info: Pets OK (See Rmrks); Sep RV Prkng Avail; Rental OK (See Rmks)

Rec Center Fee Y/N: Y / $385 / Annually
Rec Center Fee 2 Y/N: / /
Land Lease Fee Y/N: N / /
PAD Fee Y/N: N / /

Ttl Mthly Fee Equiv: $32.08
Cap Imprv/Impact Fee: $ 2500 $
Cap Impv/Impt Fee 2:

Client Report (1) **7403 W BROWN ST, Peoria, AZ 85345** **$119,950**



5041777 Residential Single Family - Detached Closed

Beds/Baths: 3 / 2 **Bedrooms Plus:** 3 **Approx SqFt:** 1,080 / County Assessor **Price/SqFt:** $111.06 **Year Built:** 1969 **Pool:** Private Only **Encoded Features:** 32RP1G2S **Exterior Stories:** 1 **# of Interior Levels:** 1 **Dwelling Type:** Single Family - Detached **Dwelling Styles:** Detached	**Approx Lot SqFt:** 6,273 / County Assessor **Apx Lot Size Range:** 1 - 7,500 **Subdivision:** Sun Town **Tax Municipality:** Peoria **Marketing Name:** **Planned Cmty Name:** **Model:** **Builder Name:** Unknown **Hun Block:** 10100 N **Map Code/Grid:** M31 **Bldg Number:**
Ele Sch Dist: 011 - Peoria Unified District **Elementary School:** Peoria Elementary School **Jr. High School:** Peoria Elementary School	**High School Dist #:** 011 - Peoria Unified District **High School:** Peoria High School

Cross Streets: 75 Ave and Peoria **Directions:** Take 75 Ave to Brown then east to property

Public Remarks: NOT a Foreclosure or Short Sale. Seller can close quickly. Home remodeled and in great shape. Shows pride of ownership. New Roof, New Solar system, New Dual Pane Windows, New permitted garage and laundry room built in 2011. Covered and enclosed rear patio, Diving pool with new pump and filter in 2010, New electrical panel in 2011, Remodeled Bathrooms, hardwood and tile floors, Block construction, NO HOA, Home is in great shape!! Solar system means half of your electrical costs are paid for. Refrigerator, Washer and Dryer included. Home comes with a 2 year termite warranty.

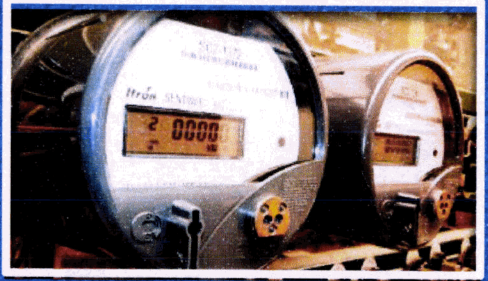
Features	Room Details	Construction & Utilities	County, Tax and Financing
Approx SqFt Range: 1,000 - 1,200 **Garage Spaces:** 1 **Carport Spaces:** 0 **Total Covered Spaces:** 1 **Slab Parking Spaces:** 2 **Parking Features:** Electric Door Opener **Pool - Private:** Pool - Private; Fenced Pool; Diving Pool **Spa:** None **Horses:** N **Fireplace:** No Fireplace **Landscaping:** Desert Front; Auto Timer H2O Front **Exterior Features:** Covered Patio(s); Built-in BBQ **Flooring:** Tile; Wood **Windows:** Dual Pane; Low-E; Vinyl Frame	**Kitchen Features:** Range/Oven Gas; Refrigerator; Kitchen Island **Master Bathroom:** 3/4 Bath Master Bdrm **Laundry:** Washer Included; Dryer Included **Dining Area:** Eat-in Kitchen **Basement Y/N:** N **Basement Description:** None **Sep Den/Office Y/N: N** **Items Updated:** Floor Yr Updated: 2013; Floor Partial/Full: Partial; Wiring Yr Updated: 2011; Wiring Partial/Full: Partial; Roof Yr Updated: 2011; Roof Partial/Full: Full; Kitchen Yr Updated: 2013; Kitchen Partial/Full: Partial; Bath(s) Yr Updated: 2011; Bath(s) Partial/Full: Full; Rm Adtn Yr Updated: 2011; Rm Adtn Partial/Full: Partial; Pool Yr Updated: 2010; Pool Partial/Full: Partial	**Const - Finish:** Painted **Construction:** Block **Roofing:** Metal **Fencing:** Wood **Cooling:** Refrigeration **Heating:** Electric Heat **Plumbing:** Gas Hot Water Heater **Utilities:** SRP; SW Gas **Water:** City Water **Sewer:** Sewer - Public **Energy/Green Feature:** Solar Panels; Ceiling Fan(s) **Solar Panels:** Ownership: Leased; Grid: On; kW: 495	**County Code:** Maricopa **Legal Subdivision:** SUN TOWN LOT 1-73 **AN:** 143-48-046-A **Lot Number:** 46 **Town-Range-Section:** 3N-1E-25 **Cty Bk&Pg:** **Plat:** **Taxes/Yr:** $329/2013 **Ownership:** Fee Simple **New Financing:** Cash; VA; FHA; Conventional **Total Asum Mnth Pmts:** $0 **Down Payment:** $0 **Existing 1st Loan:** FHA **Existing 1st Ln Trms:** **Disclosures:** Seller Disc Avail; Agency Discl Req **Possession:** Close of Escrow

Fees & Homeowner Association Information

HOA Y/N: N / /	
HOA 2 Y/N: / /	
HOA 3 Y/N: / /	

Association Fee Incl: No Fees **Assoc Rules/Info:** None	**Rec Center Fee Y/N:** N / / **Rec Center Fee 2 Y/N:** N / / **Land Lease Fee Y/N:** N / / **PAD Fee Y/N:** N / /	**Ttl Mthly Fee Equiv:** $0 **Cap Imprv/Impact Fee:** $ 0 $ **Cap Impv/Impt Fee 2:**$0 $

Listing Dates	Pricing and Sale Info	Listing Contract Info
CDOM/ADOM: 37 / 37 **Status Change Date:** 03/01/2014 **Close of Escrow Date:** 02/28/2014 **Off Market Date:** 01/18/2014	**List Price:** $119,950 **Sold Price:** $119,950 **Sold Price/SqFt:** $111.06 **Loan Type:** FHA **Loan Years:** 30	**Special Listing Cond:** N/A



Reducing Environmental Risk through Diversification

Erik Bakken

Sr Director, Transmission and Environmental Services

UNS Energy Corporation
A Fortis Company

February 2016

UNS Energy Overview

UNS Energy Corporation
A Fortis Company

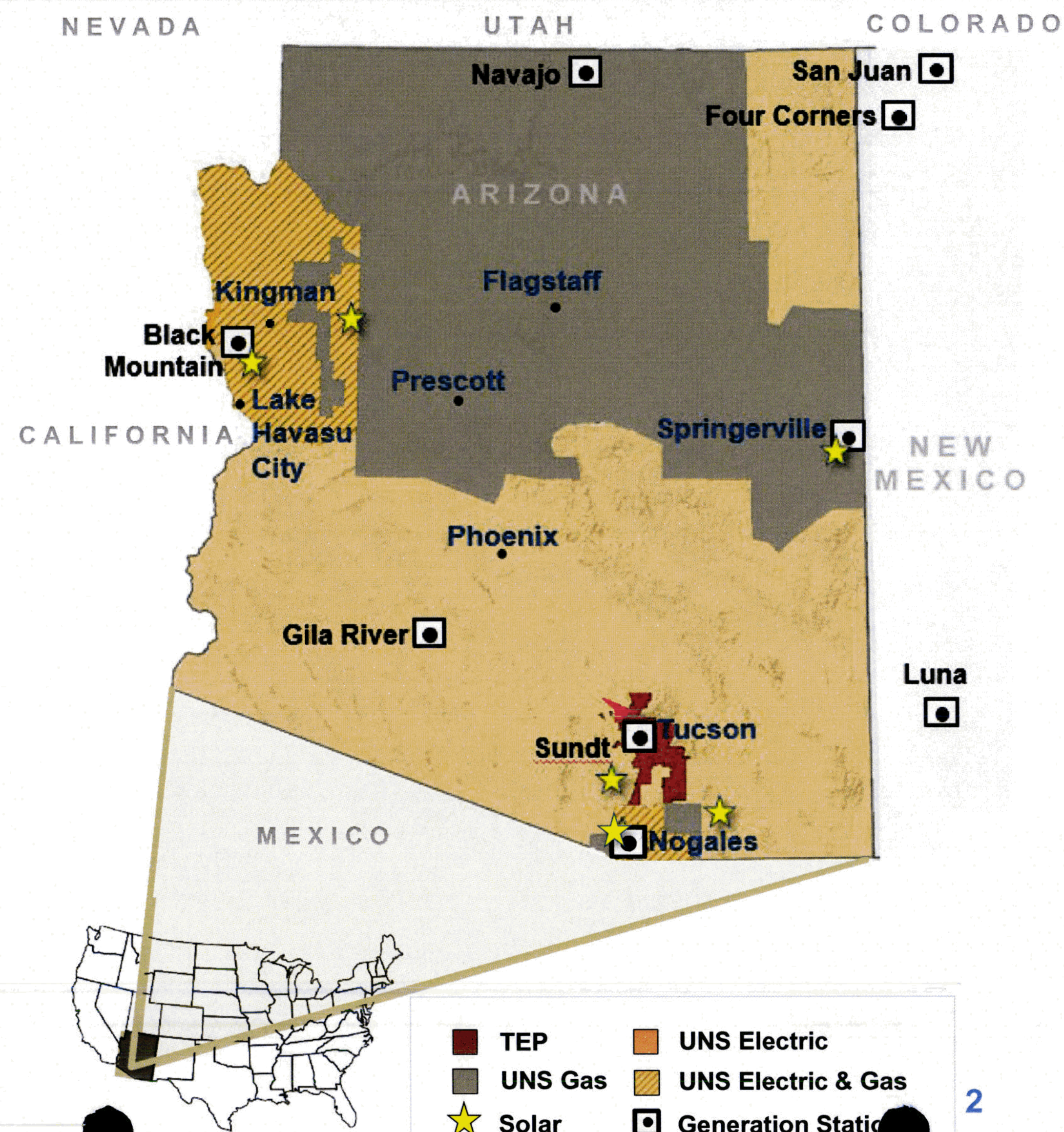
TEP
Tucson Electric Power

- Vertically integrated electric utility
- 415,000 retail customers

UniSourceEnergy SERVICES

- UNS Electric - 93,000 retail customers
- UNS Gas - 150,000 retail customers

2,000 employees

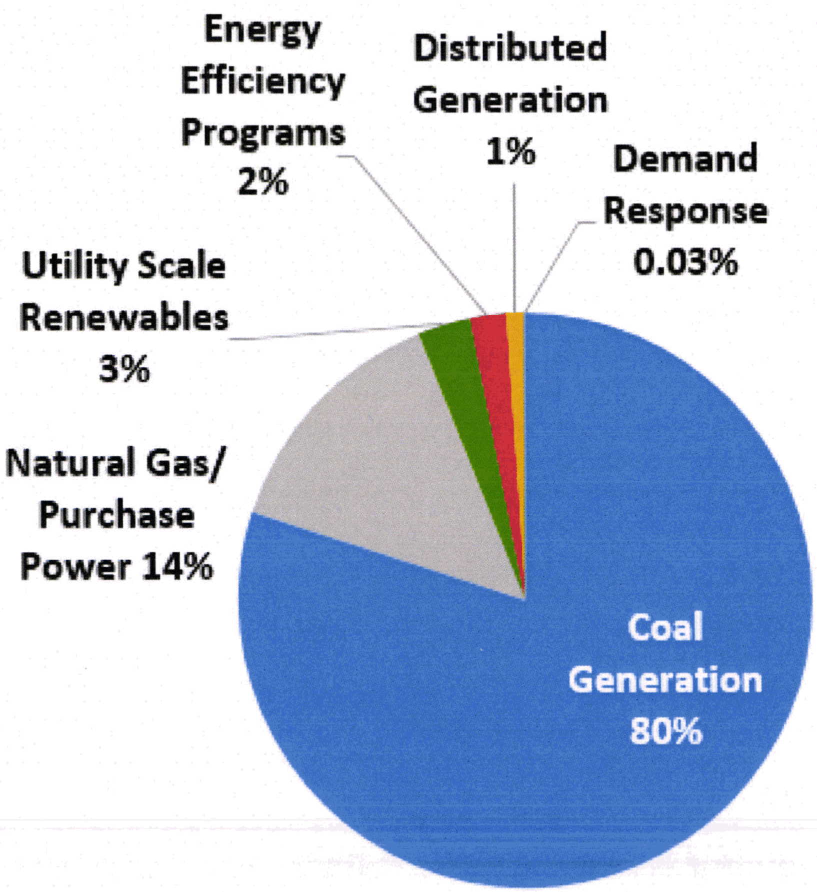


Environmental Regulatory Challenges for Utilities

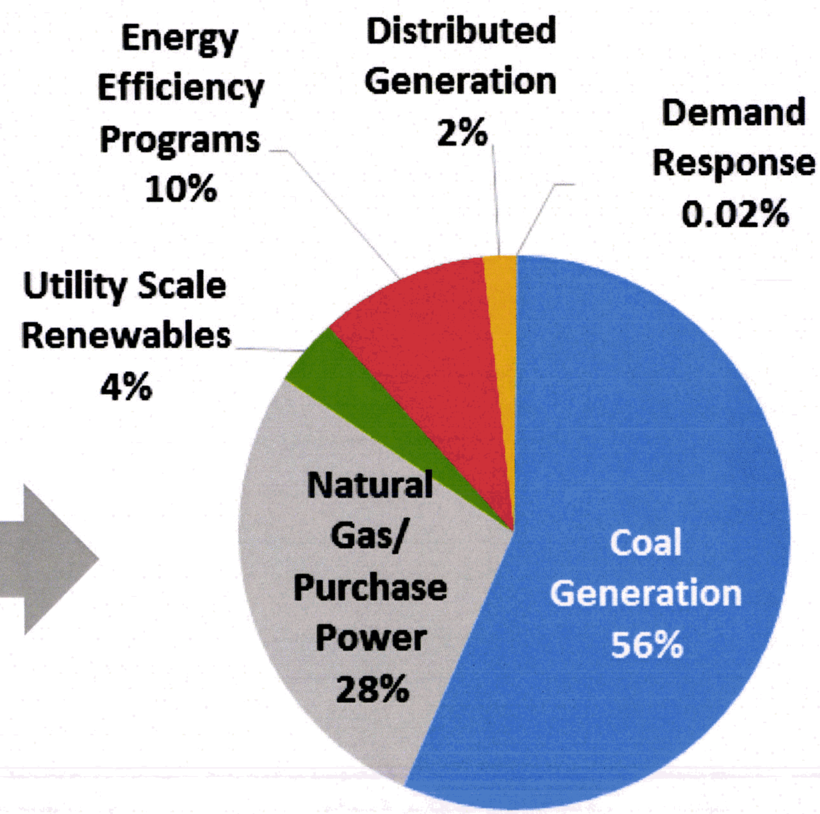
Air	Climate	Water	Land & Natural Resources	Waste & Chemical Management
MATS	NSPS- New & Modified Sources	316(b)	Transmission Siting and Permitting	Coal Ash
Interstate Transport (CAIR/CSAPR)	NSPS-Existing Sources	Effluent Guidelines Limitations	Avian Protection	PCBs in Electrical Equipment
Regional Haze/Visibility	BACT Permitting	Waters of the United States	Endangered Species	HazMat Transport
Multiple NAAQS	International Negotiations	NPDES Pesticide Permits	Vegetation Management	
New Source Review (NSR)		Waterbody-Specific Standards		

Resource Diversification Strategy
TEP 2014 Integrated Resource Plan

2013 Portfolio Energy Mix



Estimated 2020 Portfolio Energy Mix



Resource Diversification Strategy

~33% Reduction in Coal Capacity

San Juan Unit 2

Planned shutdown of 170MWs by 2018

Sundt Unit 4

Switch from coal to natural gas in 2017

Gila River Unit 3

550 MW Natural Gas Facility (2014)

~25% Reduction in CO_2 Emissions

Areva Concentrated Solar

5MW facility at Sundt

Macho Springs

50MW New Mexico wind resource

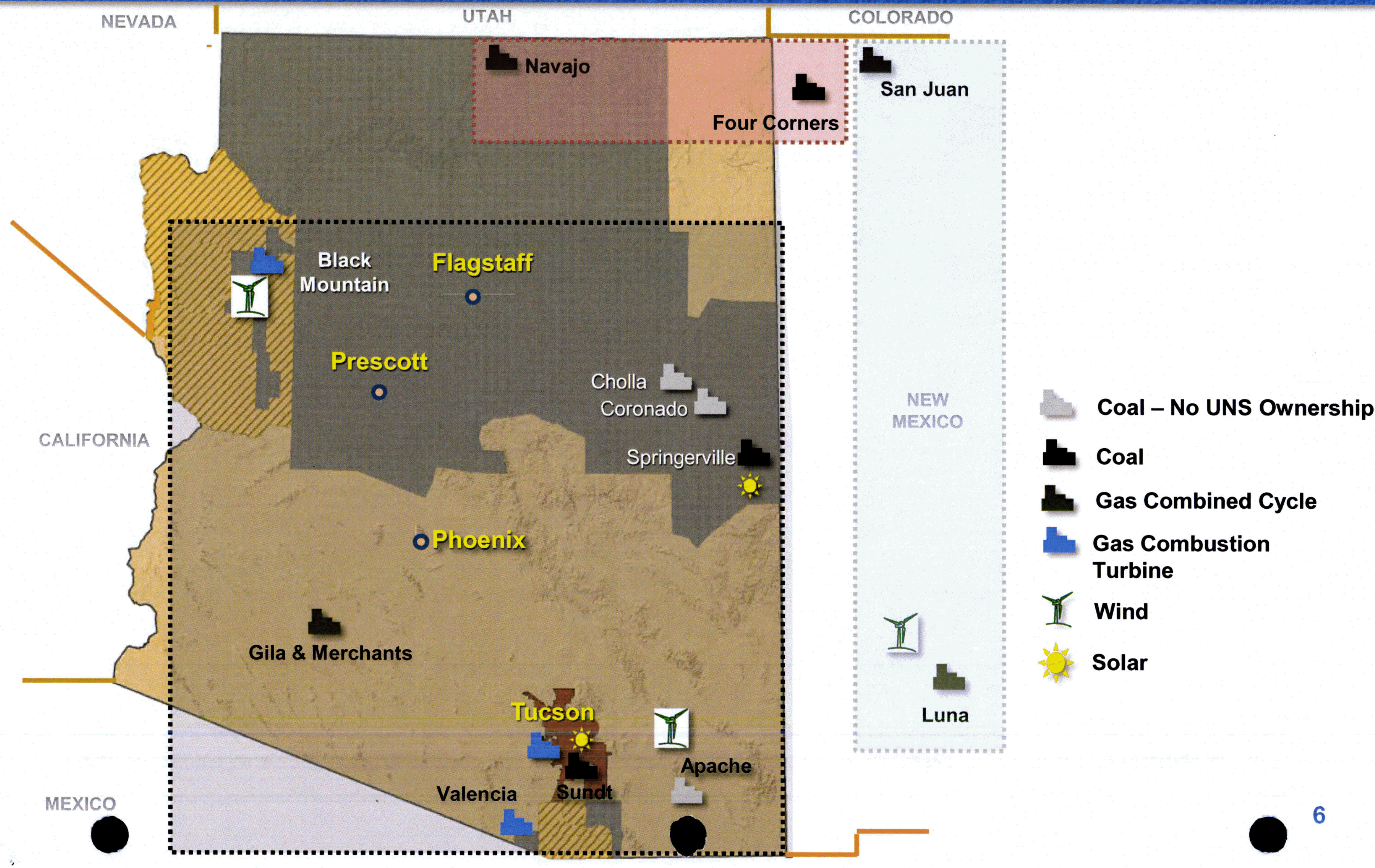
Fort Huachuca Solar Facility

17 MW photo voltaic (largest Army facility in the world)

Prairie Fire Solar

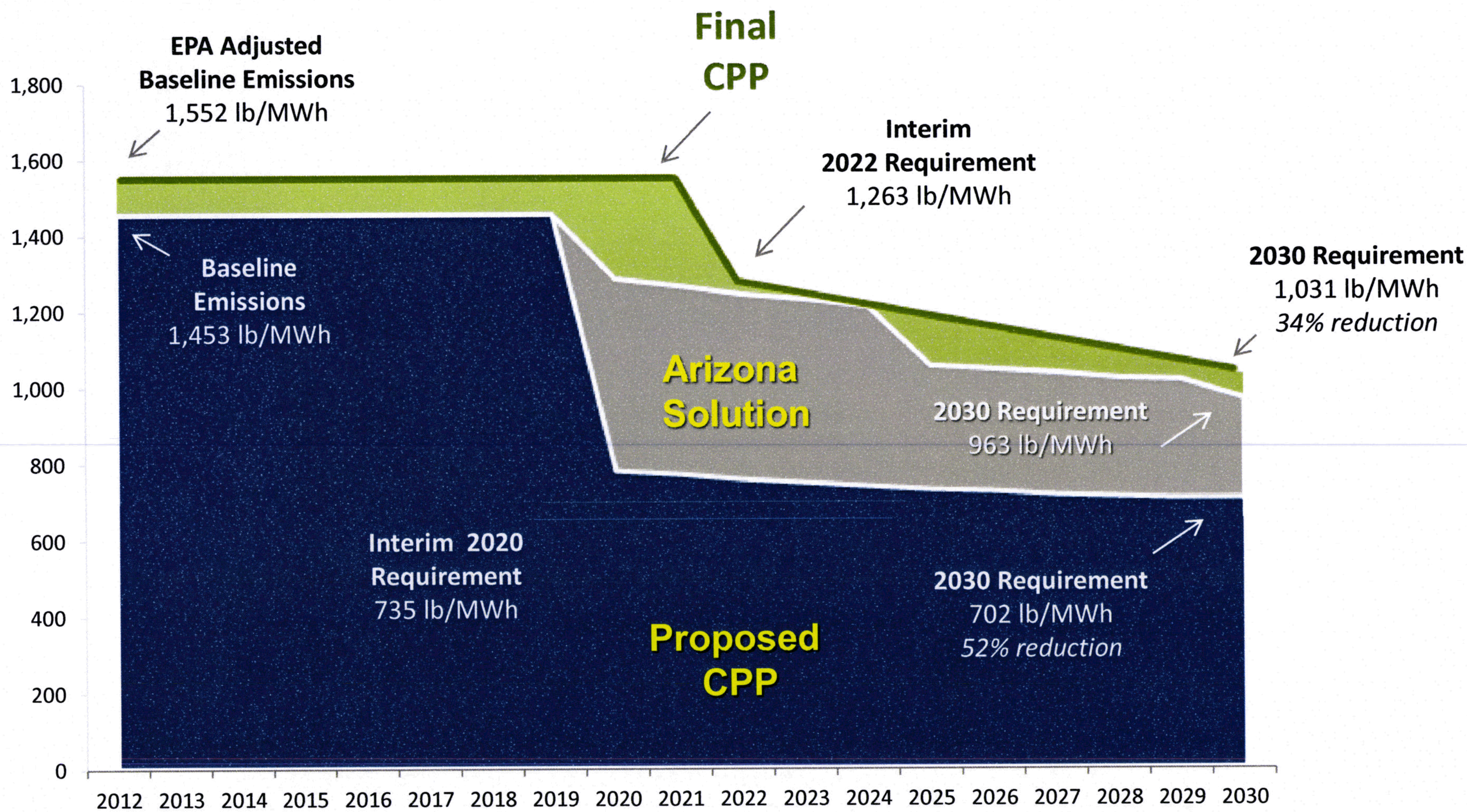
5 MW single axis solar facility

Clean Power Plan Regions



Clean Power Plan (CPP)

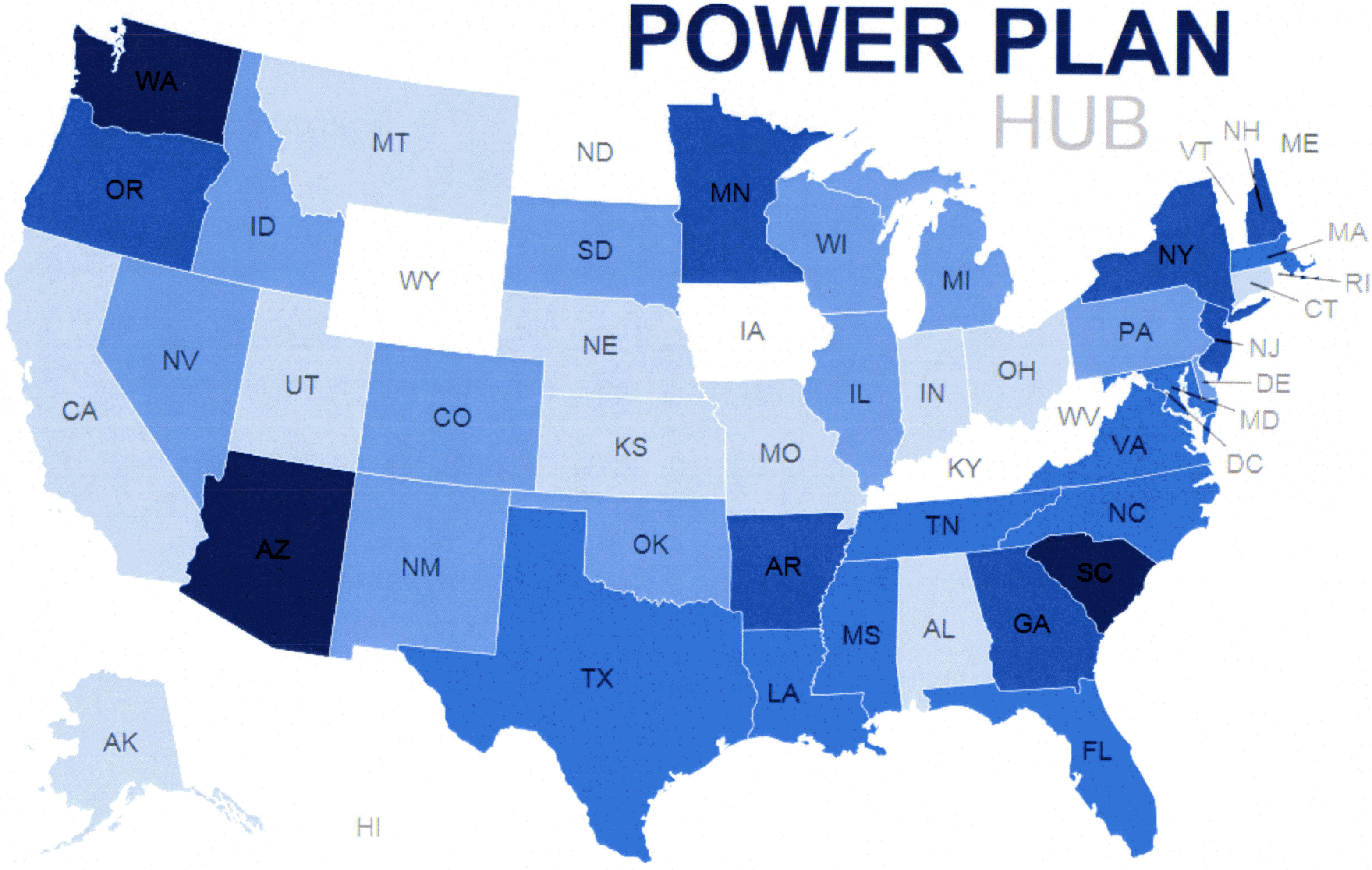
Final Arizona Reduction Requirements



"Arizona's step 1 interim goal of 1,263 pounds per megawatt-hour reflects changes EPA made to provide a smoother glide path and less of a "cliff" at the beginning of the program. The "cliff" had been particularly significant for Arizona." - EPA

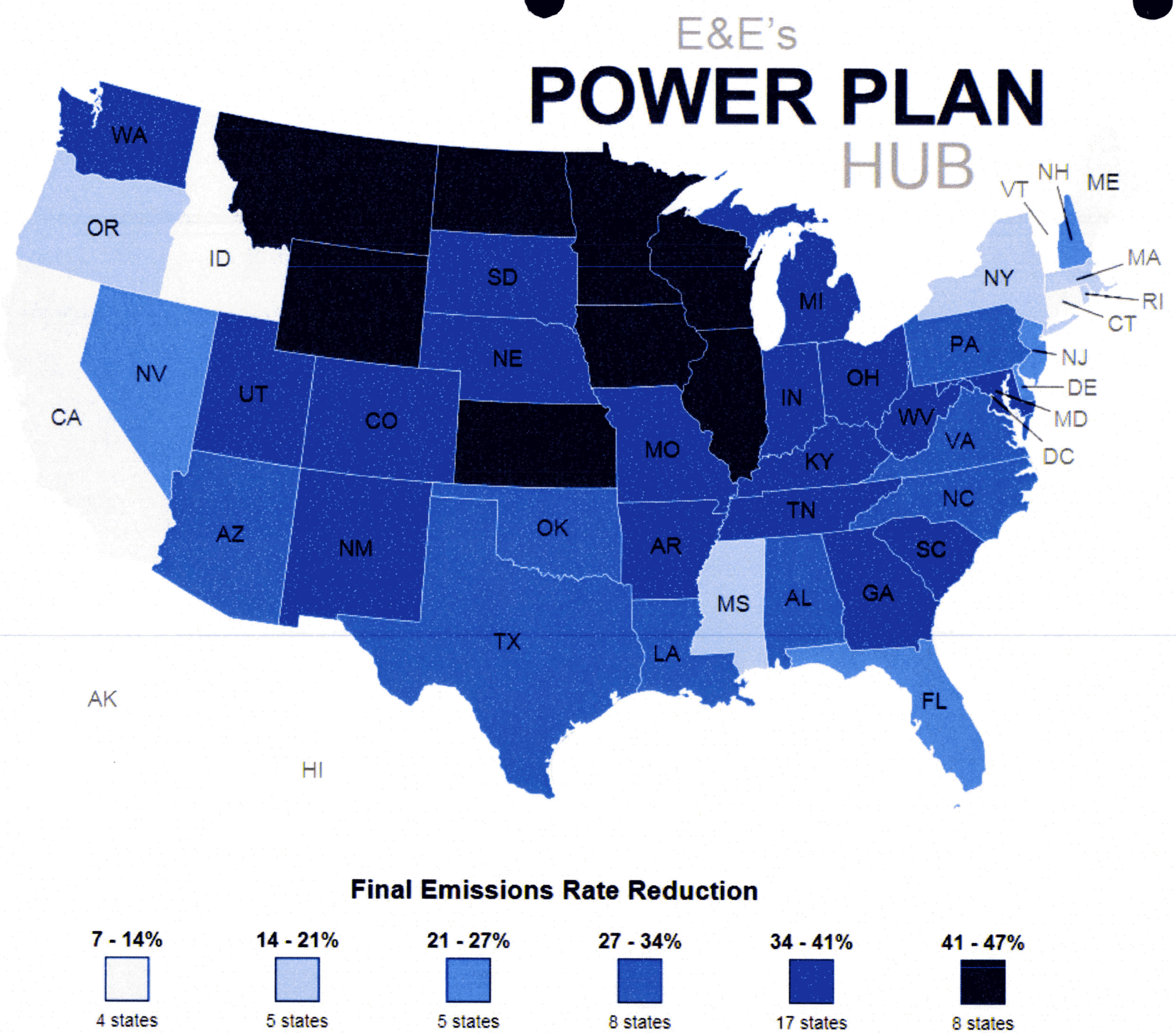
E&E's

POWER PLAN HUB



Proposed Emissions Rate Reduction

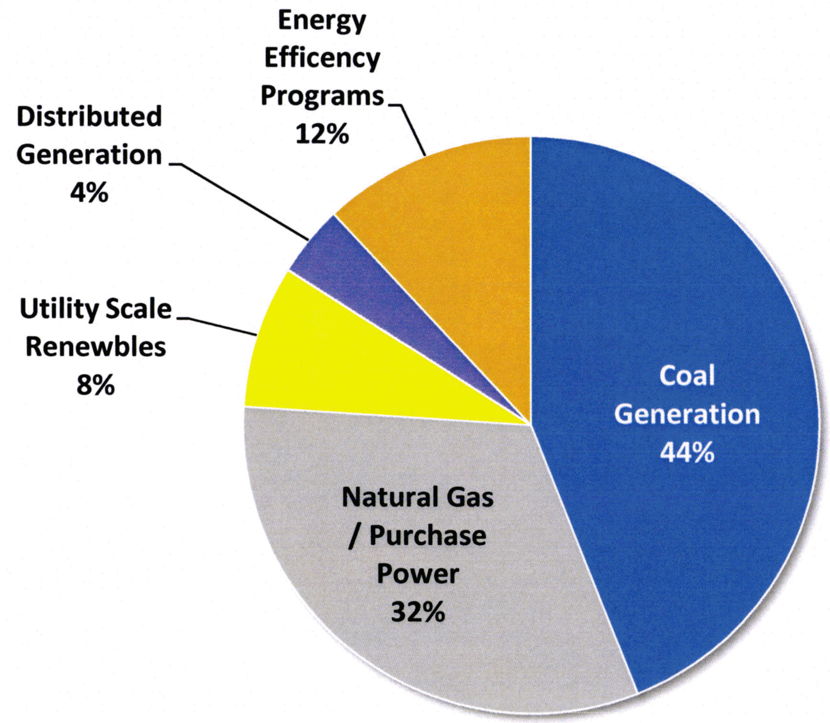
10 - 20%	20 - 30%	30 - 36%	36 - 40%	40 - 50%	50 - 72%
8 states	11 states	11 states	9 states	7 states	3 states


E&E's
POWER PLAN
HUB
WA
OR
ID
CA
NV
UT
AZ
CO
NM
SD
NE
TX
OK
MO
AR
LA
MS
AL
MI
IN
OH
KY
TN
WV
VA
NC
SC
GA
FL
PA
NY
VT
NH
ME
MA
RI
CT
NJ
DE
MD
DC
AK
HI
Final Emissions Rate Reduction
7 - 14%
4 states
14 - 21%
5 states
21 - 27%
5 states
27 - 34%
8 states
34 - 41%
17 states
41 - 47%
8 states

2016 Resource Diversification Strategy

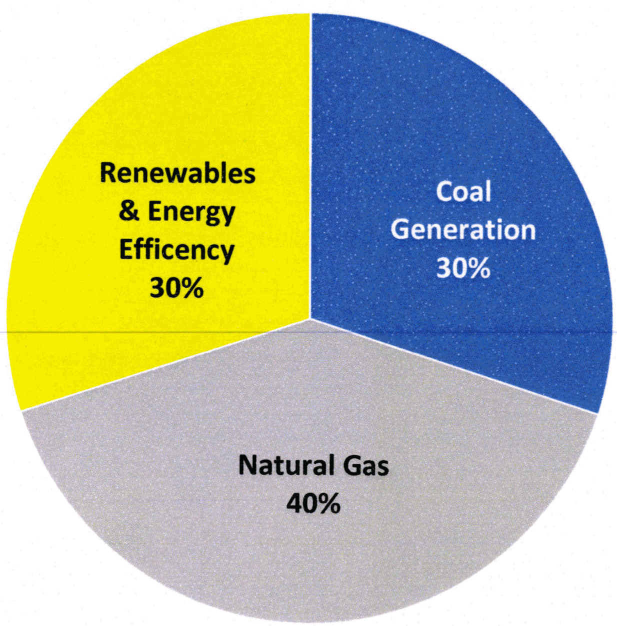
- **Switch Sundt Plant to natural gas**
- **San Juan Generating Station**
  - Potential to shutdown additional unit
- **Gila River Power Station**
  - Option to acquire additional resources
- **Energy Efficiency and Renewables**
  - Clean energy resources account for 24% of the future energy portfolio

Estimated 2023 Portfolio Energy Mix



TEP Diversification Strategy

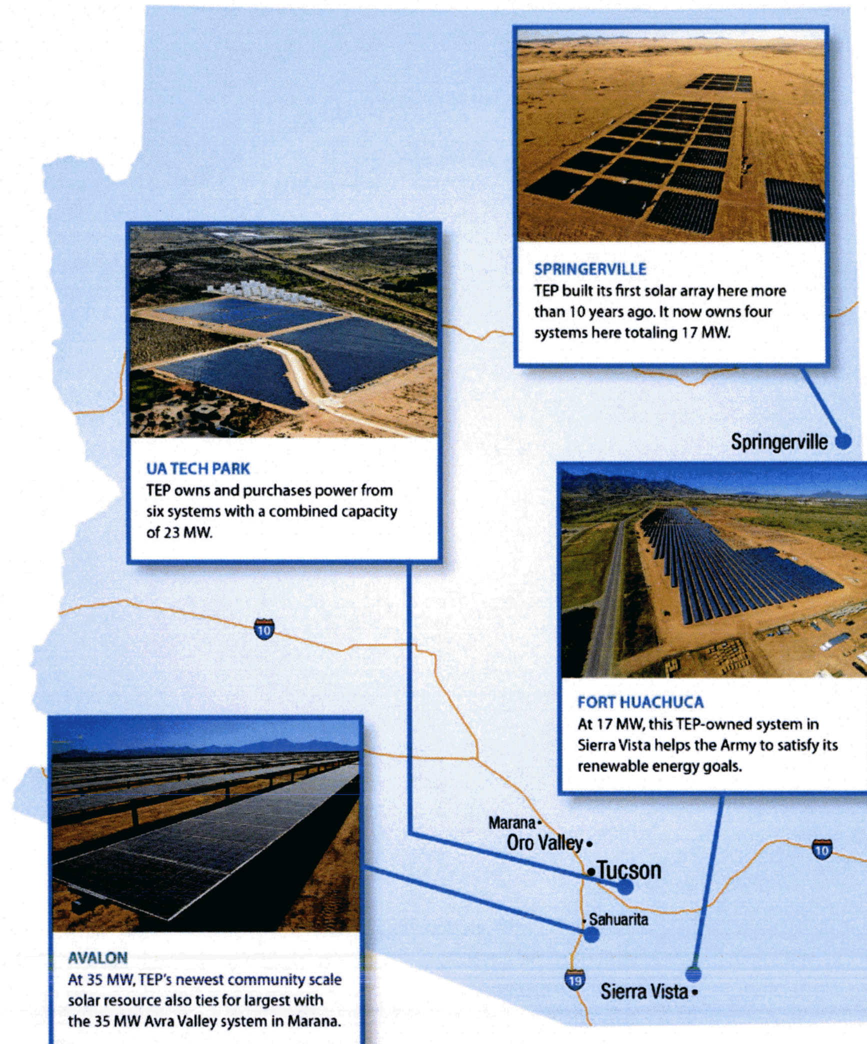
Estimated 2030 Portfolio Energy Mix



- **Increase Clean Energy Resources**
- **Pursue Additional Natural Gas Resources**
- **Potential to end participation in remote coal plants**
  - Potential to exist Navajo Generating Station in 2030
  - Potential to exist Four Corners Power Plant in 2031
- **Springerville Generating Station**
  - Long term optionality to comply with the CPP
- **Participate in Development of the final GHG Plans**
  - Maintain flexibility, one size doesn't fit all
  - Trading-ready plans critical to compliance

Solar Energy Leadership

- More than 290 megawatts (MW) of community-scale solar capacity, enough to serve 60,000+ homes
- History of solar energy innovation
  - Record-setting Springerville array
  - Community solar program pioneer
  - "Solar Zone" at UA Tech Park
  - TEP Residential Solar Program
- National recognition
  - Solar Electric Power Association (SEPA) 2012 Investor Owned Utility of the Year
  - SEPA's Top 10 Solar Utility in Nation



Getting More for Less

- Large community-scale solar power systems produce more valuable output than DG systems

- Large community-scale systems produce solar power at about half the cost of DG systems

TEP's Solar Strategy

- Increase investments in cost-effective community scale systems
- Reduce subsidies for less cost-effective DG systems
- Provide more cost-effective solar options for customers

Better Solar Energy Options

- **TEP Residential Solar Program**
  - Launched in 2015 for up to 600 customers
  - Proposed expansion to another 1000 customers in 2016
- **TEP Residential Community Solar Program (2016)**
  - Fixed rate service from local community-scale solar arrays
- **Bright Tucson Community Solar Program**
  - Flexible way to get power from local community-scale solar power systems
  - For any business or residential customer

Comparison Shopping

Community Scale Systems

By TEP ★★★★★ Prime

400,000+ Customer Reviews

- Built to serve community energy needs
- Robust, durable, high-performance systems
- Designed to maximize output during peak usage periods, complement local grid

TEP Price: 5.8 cents/kWh

Distributed Generation (DG)

By Local homes and businesses ★★★★★

5,000+ Customer Reviews

- Built to serve the personal needs of individual customers
- Excess output appears intermittently at various locations on the local grid
- Systems require support from local grid, higher rate and tax subsidies

TEP's Price (Net Metering): 11 cents/kWh

More Community Scale Solar

- New rates will allow TEP to secure 30 percent of energy from renewables by 2030 – double the state goal of 15 percent by 2025
- Plans for 2016
  - 31 MW of new community scale systems
  - Two 10-MW energy storage projects

EXHIBIT
TASC 8
admitted

Thursday, February 18, 2016 3:33 PM ET Extra

Fortis eyes Ontario acquisitions, even as it digests $11.3B ITC purchase

By Gene Laverty

An in-progress acquisition with an $11.3 billion price tag has not taken Fortis Inc. out of the hunt for companies to purchase.

A provincial government "tax holiday" for utility sales in Ontario has the Newfoundland and Labrador-based company eyeing purchases in that market, Fortis President and CEO Barry Perry said. Without naming a potential target, Perry said the company's team in the province is evaluating opportunities. Fortis announced Feb. 9 its plan to buy Novi, Mich.-headquartered electric transmission company ITC Holdings Corp.

Ontario, which recently sold a 15% stake in province-owned electricity utility Hydro One Ltd to the public, is encouraging the sale and amalgamation of smaller utilities owned by municipalities to improve service and reliability in its power grid.

"We have been there a long time trying to achieve this obviously, and with the tax holiday approach we are optimistic that we will find a few opportunities," Perry said on a Feb. 18 conference call to discuss fourth-quarter earnings. "We have a good business in Ontario. It's making money. We have a team on the ground there that continues to have a lot of dialogue with various municipal utilities. So I would expect we will make progress there."

Hydro One, the biggest utility in Canada's most-populous province, is a formidable competitor in the acquisition market, Perry said. Hydro One agreed Jan. 29 to acquire Great Lakes Power Transmission from Brookfield Infrastructure LP and is participating in a merger of municipal utilities that was started before the province sold shares of the company to the public.

"It's a competitive environment," Perry said. "We've got to compete with now especially Hydro One, who you saw just recently purchased the transmission from Brookfield. So that's a player that obviously we are competing with. But we're still there and we are focused on it, and our team is optimistic that we can have some success over the next few years."

Among Fortis' Canadian electric distribution companies is FortisOntario Inc., which is comprised of four local distribution companies serving a total of 64,000 customers. It also owns a 10% interest in three other distribution utilities that serve a total of 38,000 customers.

Fortis has a track record of buying companies that provide better-than-forecast returns, and it expects ITC to continue that streak, Perry said. The deal to buy the company should be closed by the end of 2016, pending approval by FERC and other federal and state regulators.

"Over the past decade, we have a proven track record of acquisitions that have delivered more than the projected accretion as well as added to our geographic, regulatory, and economic diversity," he said. "We expect the acquisition of ITC will be an extension of this track record. ITC not only further strengthens and diversifies our business, but it also accelerates our growth."

The company does not plan big changes to ITC's management. Perry said he joined other Fortis executives at ITC's headquarters recently to review the transaction.

"We spent every waking hour with the executive management team last week, as we met with over 160 investors, and I also had a chance to meet and address the full team," Perry said. "The team is really top notch, and the cultural fit is bang on. ITC has done a tremendous job in building this business over the years. Their earnings grew by approximately 16% annually on average over the last 10 years, their shareholder returns are more than double the S&P 500 Utilities Sector Index since their IPO in 2005, and they are recognized as being the best in class in the United States in terms of safety."

Fortis is also looking to grow its regulated businesses by capital investments in projects like solar farms. Perry issued a challenge to David Hutchens, CEO of the company's UNS Energy Corp. unit in Arizona to deliver those types of investments.

"I look at, for example, in Arizona I would love to do utility-scale solar with long-term PPAs [power purchase agreements]," he said. "I'm challenging Mr. Hutchens at UNS to find some of those opportunities. Those are the kind of things I'm looking for, very much consistent with the risk profile of the regulated business. I can tell you if we don't have two or three more of those over the five-year period, I'm going to be pretty disappointed. I really think that the pipeline there will provide us with some of those opportunities."

Rolling Out Residential Demand Charges

EXHIBIT
TASC 9
admitted

PRESENTED TO

EUCI Residential Demand Charges Summit

PRESENTED BY

Ryan Hledik

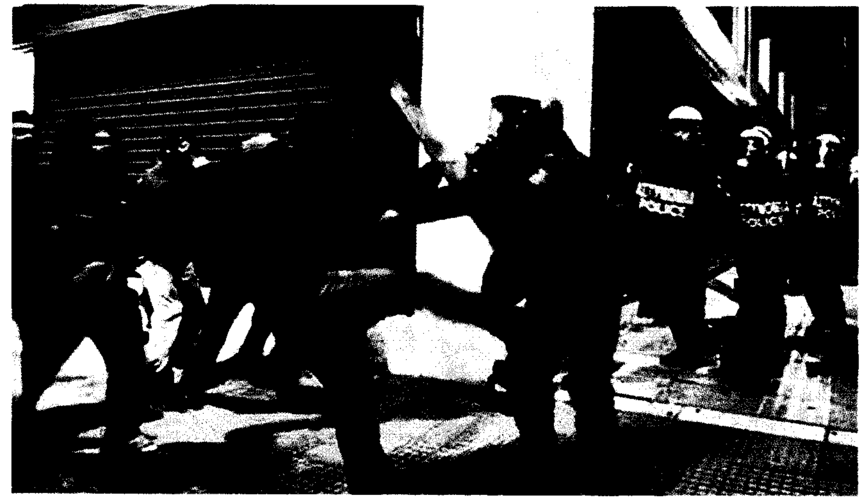
May 2015

THE Brattle GROUP

So you've decided to roll out a demand charge...

Transition option 1

- The tariff change is made overnight
- "Customers will figure it out"



Transition option 2

- The transition is carefully planned
- It is grounded in quantitative research
- It is gradual
- It includes pre-emptive outreach

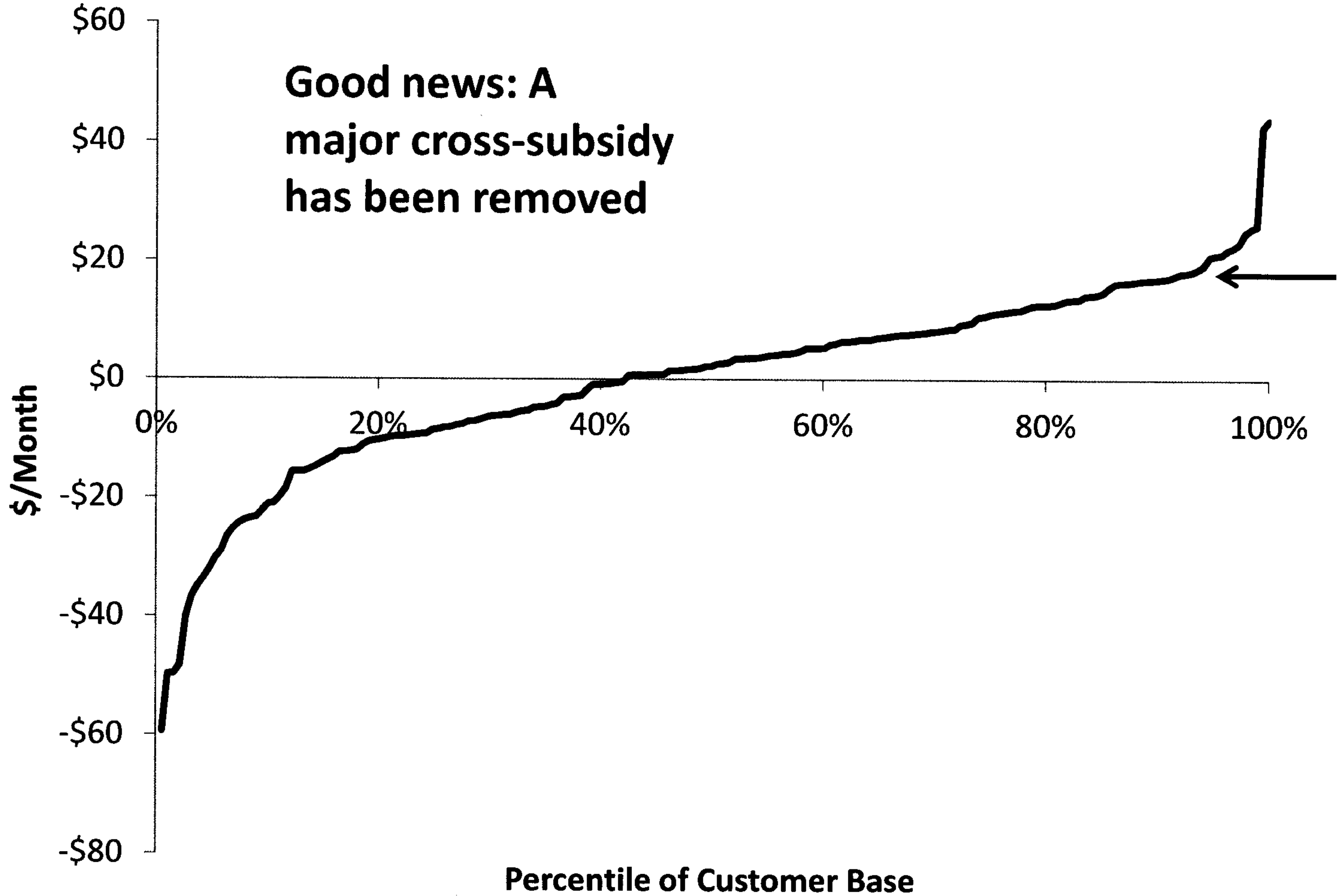
Throughout this presentation, I use a simple example to illustrate the rate transition

	Old Two-Part Rate	New Three-Part Rate
Fixed charge	$10/month	$10/month
Volumetric charge	11 cents/kWh	6 cents/kWh
Demand charge	$0	$9/kW-month

- The rates are revenue neutral
- Analysis is based on actual hourly utility load research data (~200 customers)
- Demand is measured as maximum (non-coincident) demand per month
- Demand is measured as average over a 60-minute interval

The rate change will affect each customer's bill differently

Distribution of Bill Changes



Bad news: Some customers will experience bill increases

More good news: Transition plans help facilitate the change for these customers

Several issues should be considered when transitioning customers to the new rate

- ✓ Customer price response
- ✓ The role of enabling technology
- ✓ Opt-in versus opt-out deployment
- ✓ Rate transition strategies

Customer price response

Most assessments of bill impacts ignore likely customer response to the new rate

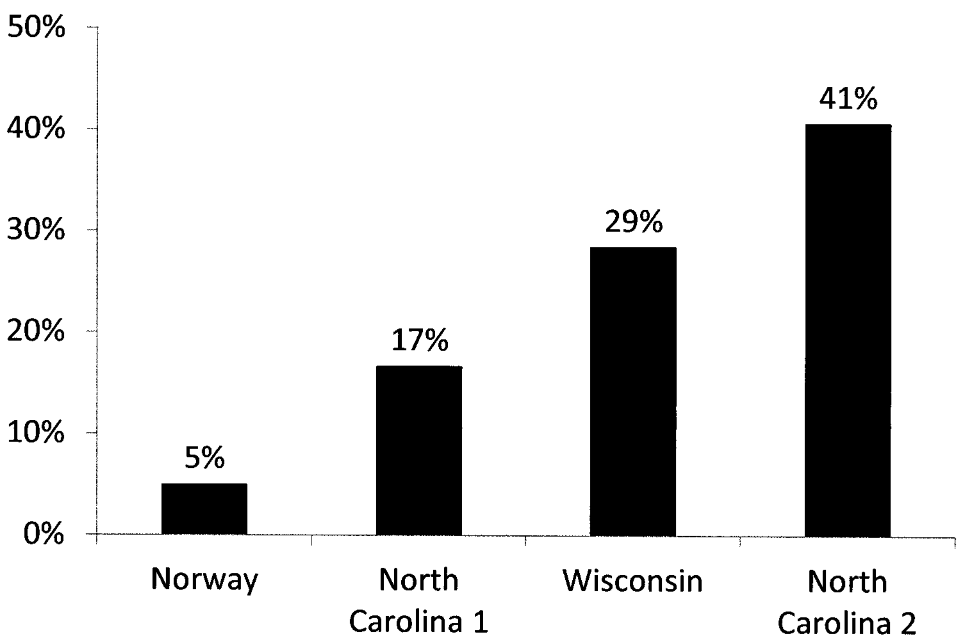
Under a three-part rate, customers can reduce peak demand to lower their bill

Price response has been observed in at least 40 different experimental studies of time-varying volumetric rates over the past decade

But will customers respond to a demand charge?

Three experimental pilots have detected significant response to demand charges

Average Reduction in Max Demand



Note: The North Carolina pilot was analyzed through two separate studies using different methodologies; both results are presented here

However…

- Two of the pilots are old and the third is from a unique climate
- The impact estimates vary widely
- Findings are based on small sample sizes
- New research is needed

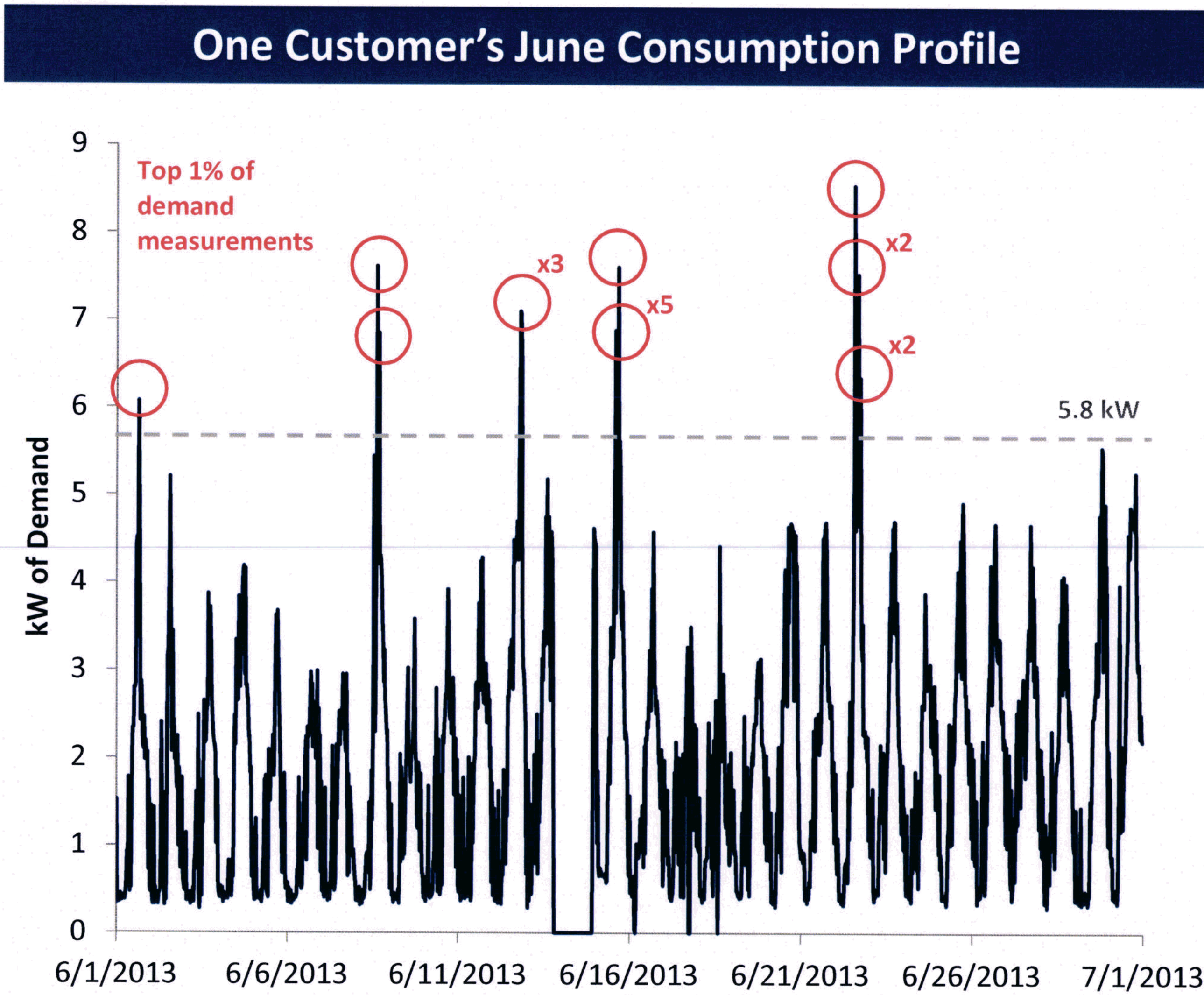
Customers will respond to a demand charge if three conditions are met

1) Customers must generally be sensitive to changes in price. If customers are not generally sensitive to changes in the price of electricity, then they will not respond to rate changes. A customer's degree of sensitivity to the price of electricity depends on a wide range of socio-economic variables and other factors that vary regionally.

2) The rate design change must provide the customer with a meaningful bill savings opportunity. Customers will only respond to a rate design change if it presents them with an opportunity to reduce their bill. Otherwise, there is no compelling reason to change behavior.

3) The rate design must be actionable. Even if customers are price responsive and the new rate provides a bill savings opportunity, customers will only respond if they know which actions will lead to those bill savings. If they do not know how or when to change their consumption pattern in order to reduce their bill, or do not understand the rate, they will not take action.

Is there a meaningful bill savings opportunity?



YES:
30% of max demand is concentrated in the top 1% of hours

Is the new rate actionable?

It can be, with the right customer education

Responding to a demand charge does <u>not</u> require that the customers know exactly when the interval of maximum demand will occur

If customers generally know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs

This simple message should be stressed in customer marketing and outreach initiatives associated with the demand rate

The following example is a hypothetical illustration of the composition of the typical customer's maximum demand (8.5 kW), and the benefits of staggering the use of a few key appliances

Staggering the use of a few key appliances could lead to significant demand reductions

Avg. Demand Over 30-min

Appliance	Avg. Demand (kW)	
Dryer	4.0	Flexible Load (7.5 kW)
Oven	2.0	
Stove	1.0	
Hand iron	0.5	
Misc. plug loads	0.2	Inflexible Load (1 kW)
Lighting	0.3	
Refrigerator	0.5	
Total	**8.5**	

Comments

- Use of some of the appliances is inflexible (1 kW)
- Use of other appliances could be easily staggered to reduce demand
- Simply delaying use of the dryer until after the oven, stove, and hand iron had been turned off would reduce the customer's maximum demand by 3.5 kW
- This would bring the customer's maximum demand down to 5 kW, **a roughly 40% reduction in demand**

We have developed a model to simulate customer response to demand charges

The model is based on a widely accepted methodological framework that captures two key effects

- **Load shifting** in response to a change in rate structure
- **Conservation (or the opposite)** in response to a change in average rate level

The model draws on an extensive library of customer price elasticity estimates found in pricing pilots over the past decade

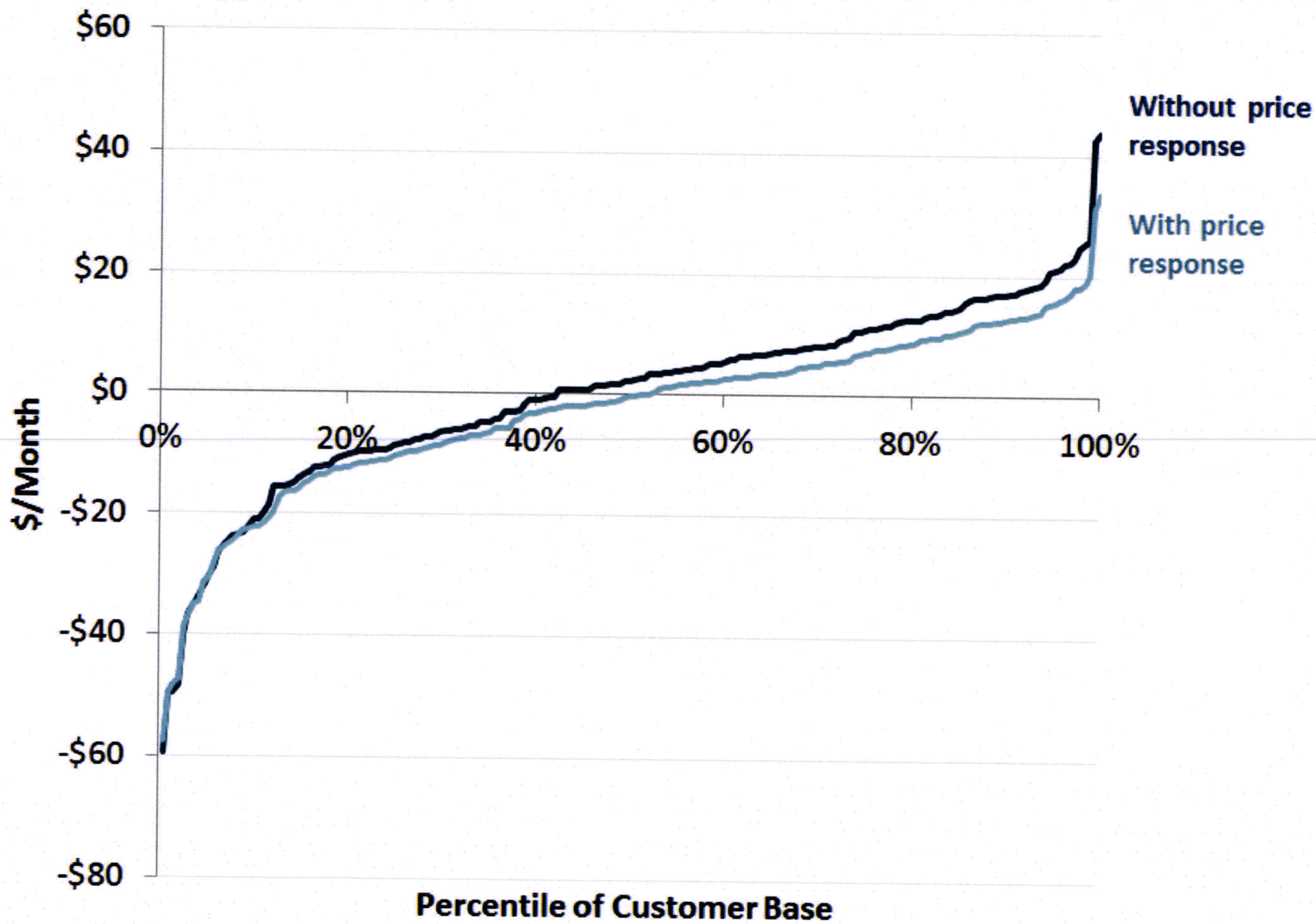
Customers could modify consumption patterns by a significant amount

Average Change in Residential Load Profile Due to Price Response

	Average change
Customer max demand	-5.3%
Class peak demand	-1.7%
System peak-coincident demand	-1.5%
Annual consumption	0.2%

The change in consumption leads to lower customer bills

Distribution of Bill Changes



The role of enabling technology

Technology will help customers manage demand

Smarter demand management will be enabled by new technologies

And third parties will compete to be the customer's energy advisor

comverge energy made better
OPOWER
ENERNOC
Google

Examples of enabling technologies & services

Demand limiters: Demand limiters are a technology that has been around for a long time. They prevent the simultaneous use of multiple appliances, as specified by the owner

Energy "orb": The energy orb has also been around for at least a decade. It glows different colors depending on trends in stock price, weather, or any other index that the owner ties it to. In the case of demand charges, it could provide an indication that the customer is approaching certain demand thresholds

In-home information displays: These devices display real-time information about the owner's usage. They would help not only in alerting the customer when his demand is high, but would help the customer understand the electricity consumption of various appliances

Smart appliances: The "connected home" is emerging as a fast growing consumer product industry segment. Companies like Nest are seeking to provide home smart automation services through networked appliances, such as the central air-conditioner. Other products are also available today that apply window air-conditioners. This network could be leveraged to manage energy consumption in many ways.

Curtailment service providers: In the C&I sector, curtailment service providers who provide demand response programs to their clients are also working with these clients to manage their demand and reduce their demand charge. Similar services could be offered by residential DR providers

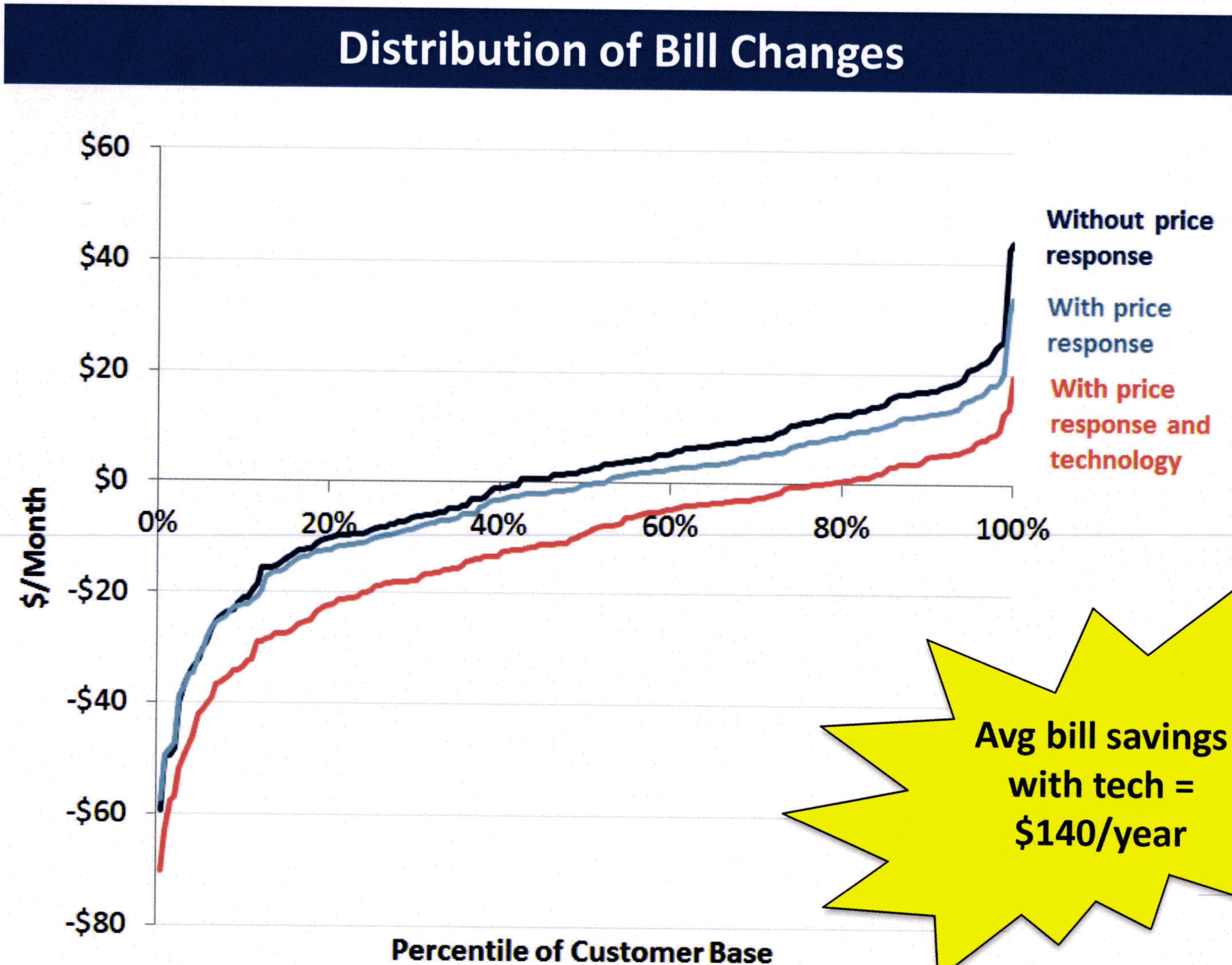
Technology will enable larger, more targeted demand reductions

Average Change in Residential Load Profile Due to Price Response

	Without Tech	With Tech
Customer max demand	-5.3%	**-22.0%**
Class peak demand	-1.7%	**-3.1%**
System peak-coincident demand	-1.5%	**-3.0%**
Annual consumption	0.2%	**0.2%**

- We assume that technology will allow customers to target the top 1% of demand intervals each month
- Response is similar to that observed in residential critical peak pricing rates

Bill savings could increase significantly with technology



Avg bill savings with tech = $140/year

Opt-in versus opt-out deployment

The new rate could be offered on an opt-in basis

With an opt-in offering, customers remain on the existing rate unless they proactively sign up for the new rate

This reduces the risk that customers will be surprised by a bill change

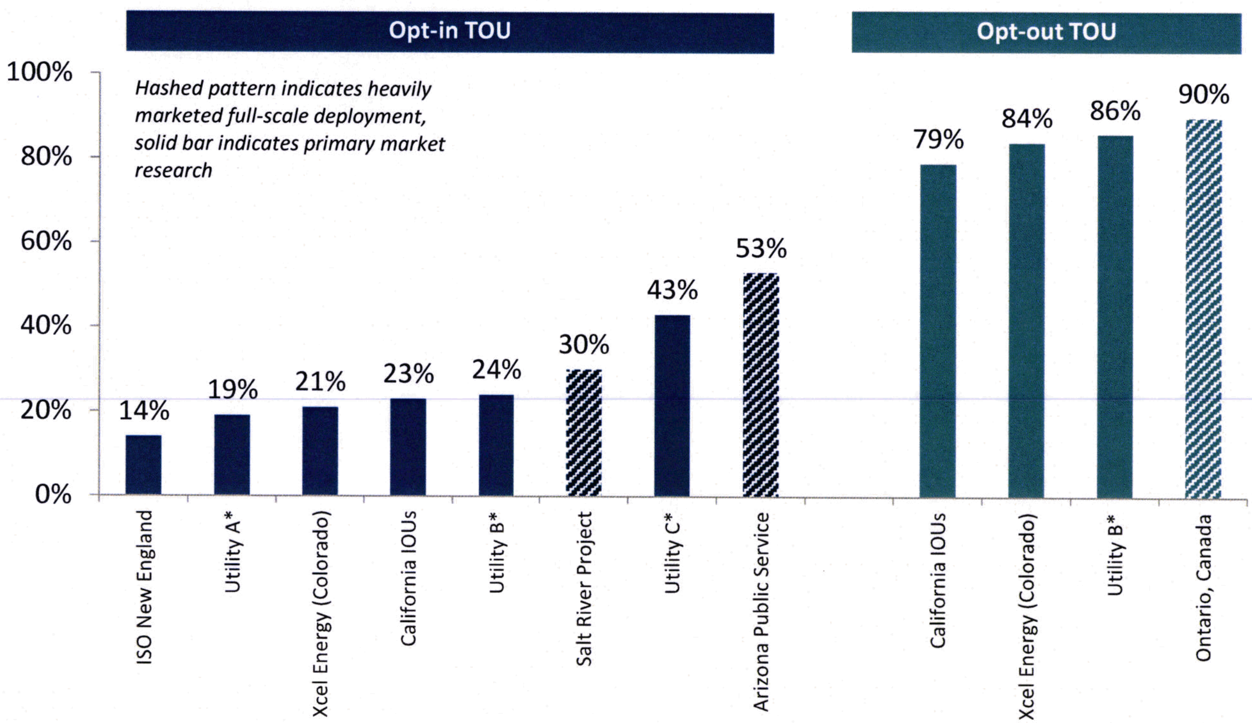
But…

Will customers enroll?

Will this enrollment lead to revenue loss for the utility?

Customer enrollment in TOU rates is shown to be lower with opt-in deployment than with opt-out

Residential TOU Enrollment Rates



* Utility identity is concealed because study results have not yet been made public

Comments

- With good marketing and outreach, opt-in rates of 20% to 30% are feasible
- APS has over half of its customers on opt-in TOU rates
- 10% of APS's residential customers have a demand charge

Opt-in enrollment will depend in part on the bill savings opportunity for customers

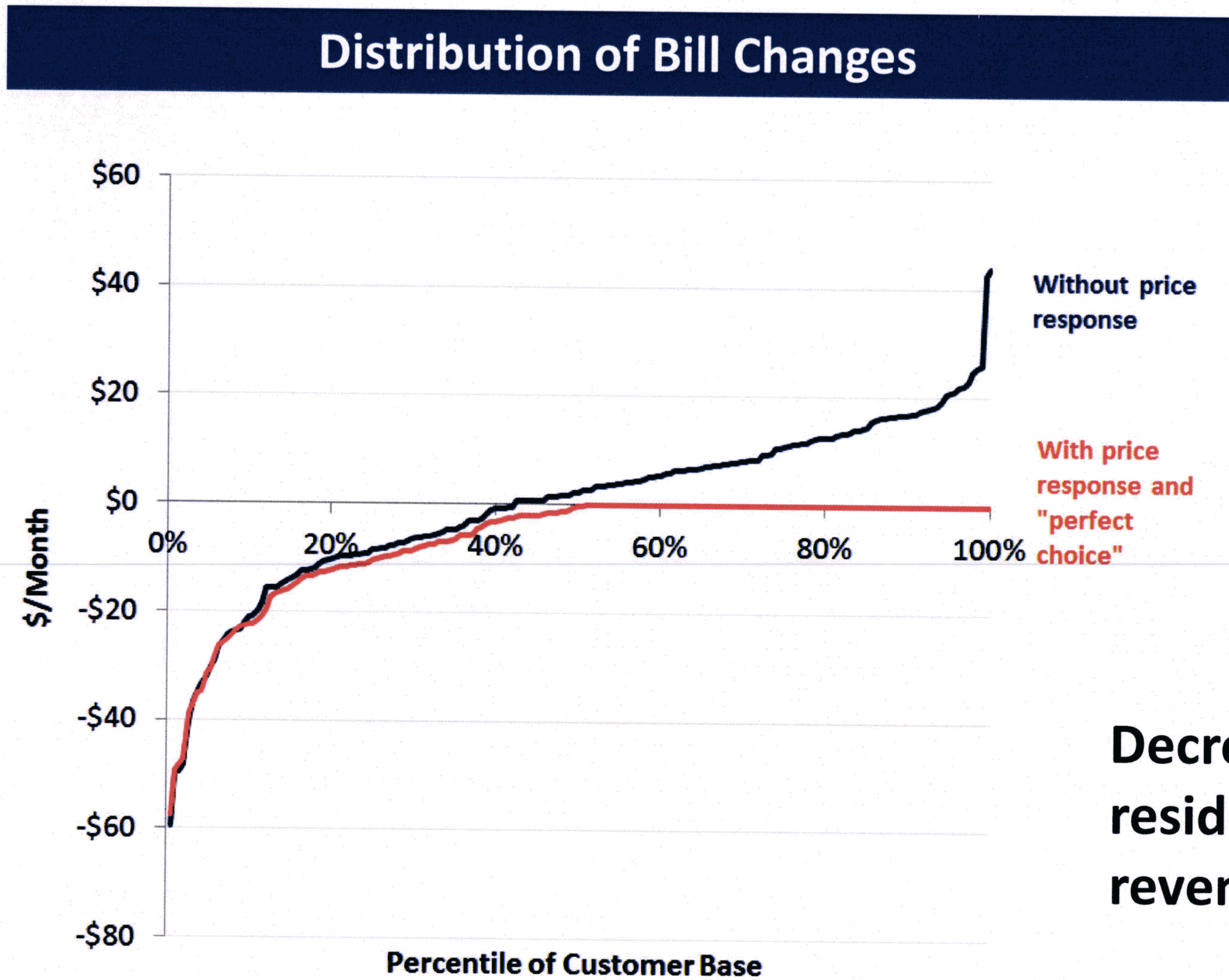
One extreme approach is to assume that customers are "human supercomputers" who always choose the rate that minimizes their bill

With this assumption, a customer will enroll in the new rate even if it saves him one penny

Bill savings are the only thing that matter in this scenario; there is no consideration for factors like awareness and risk aversion

We call this the "perfect choice" scenario

The "perfect choice" scenario is the worst case scenario from a utility revenue perspective



Decrease in residential revenue = 5%

A summary of the "perfect choice" scenario

Impact Due to "Perfect Choice" Rate Switching

	Change
Customers opting in to new rate	52%
Utility revenue loss (%)	-5%
Avg switcher's bill savings (%)	-8%
Avg switcher's bill savings ($/mo)	-$13

In reality, customers are not “human supercomputers”

Customers are more likely to opt-in to the new rate if it provides large bill savings, but they will not choose the bill-minimizing rate with complete certainty

Other factors will influence their enrollment decision, such as:

- Lack of awareness of the new rate
- Uncertainty about the impact of the new rate on their bill
- Limited time and resources at to conduct the research necessary to make the optimal decision
- Perception that features of the bill-minimizing rate are negative attributes (e.g. increased bill volatility)

Realistic switching rates can be estimated using a “discrete choice model”

Illustration of the rate choice model

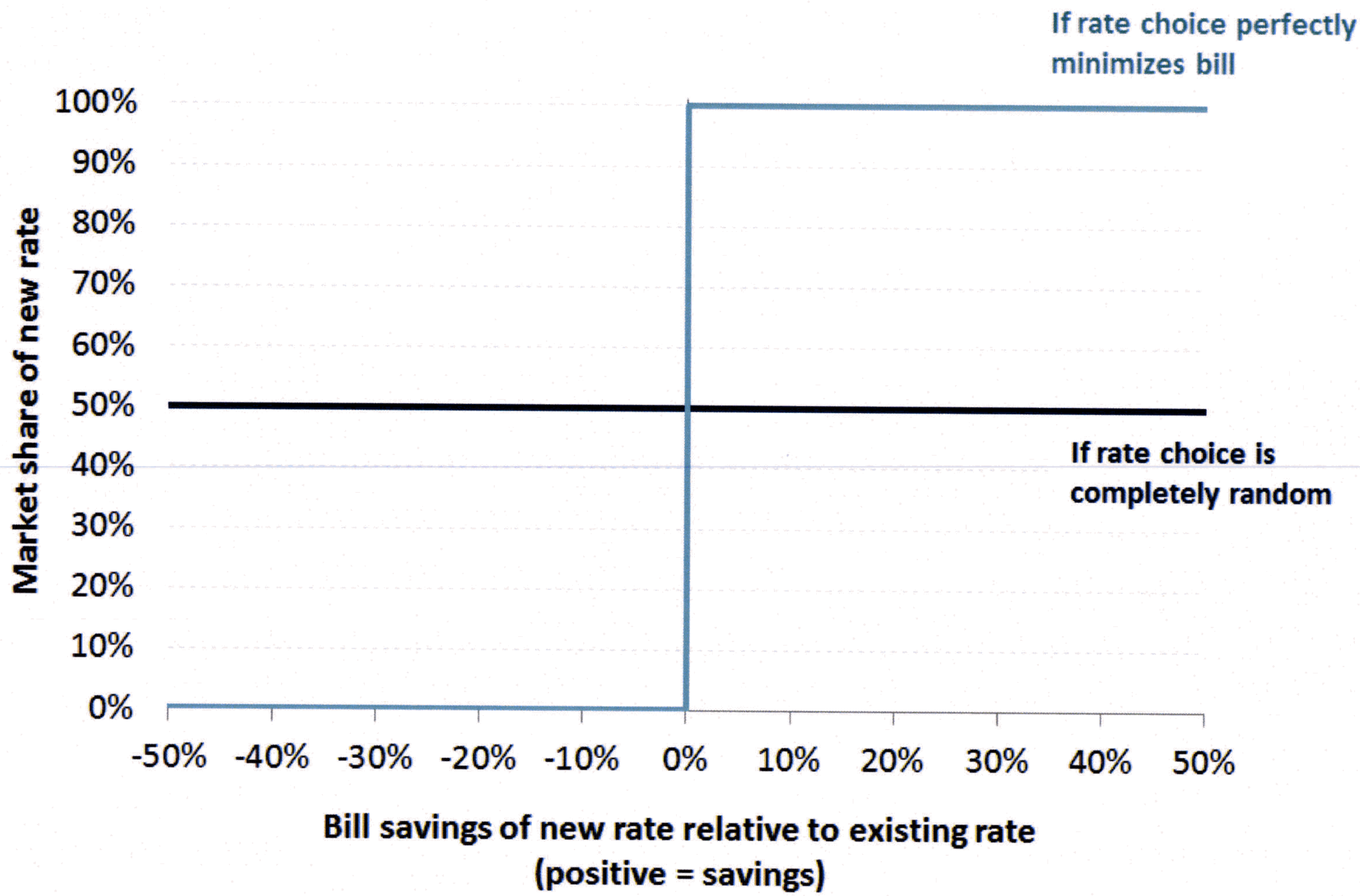
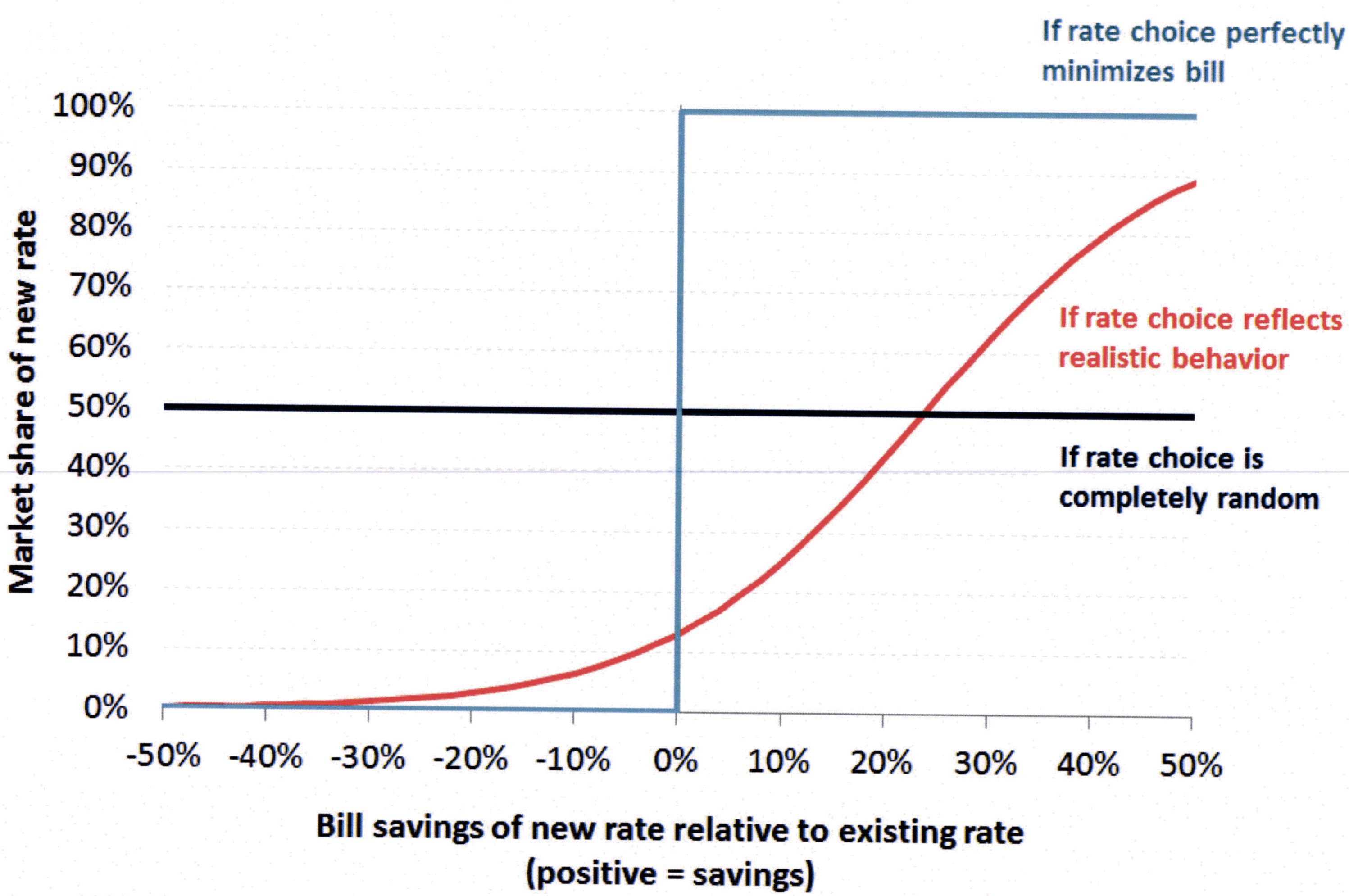


Illustration of the rate choice model



Realistic rate switching behavior can still lead to significant revenue impacts

Impact Due to Rate Switching

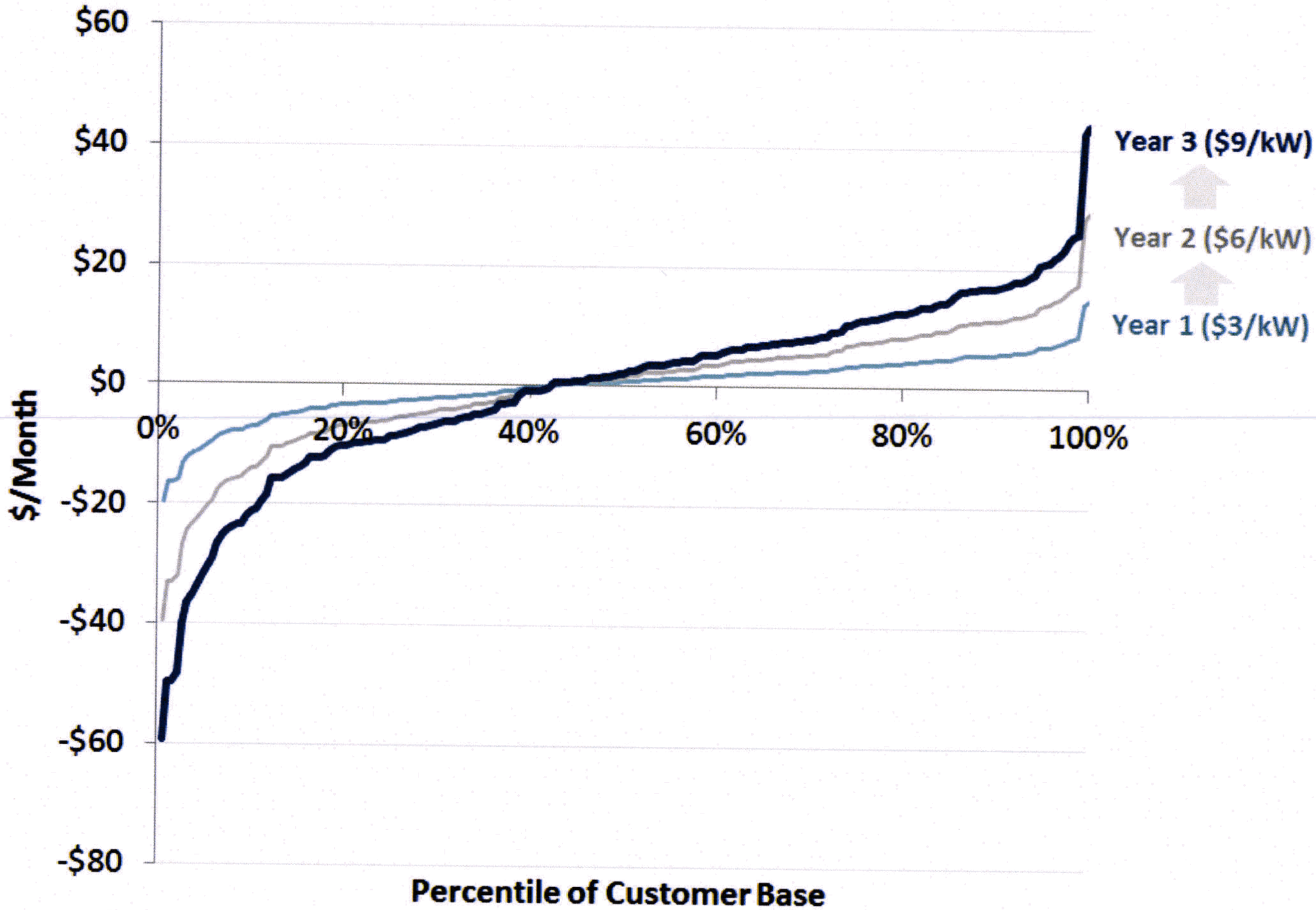
	Perfect Choice	Realistic Choice
Customers opting in to new rate	52%	**22%**
Utility revenue loss (%)	-5%	**-3%**
Avg switcher's bill savings (%)	-8%	**-9%**
Avg switcher's bill savings ($/mo)	-$13	**-$17**

- One approach to mitigating the revenue impact has been to build the anticipated revenue loss into the new rate design
- Another approach is to recover the lost revenue from the customers who are on the old flat rate

Rate transition strategies

With an opt-out rate offering, a gradual transition will minimize annual bill changes

Distribution of Bill Changes by Year



Other available tools for making the transition include the following

- Temporary bill protection
- Tiered demand charges or ceiling on applicable demand
- Shadow bills
- Enhanced customer outreach and education
- Rebates for enabling technologies
- Separate rate for vulnerable / low income customers

The transition to demand charges will take time

Rate Design	Pilots	Impact Analysis	Transition Plans	Regulatory Activity
Rate benchmarking	Pilot design	Load impacts	Multi-year rate rollout strategies	Rate case testimony
Cost structure review	Sample selection	Bill impacts	Protections for vulnerable customers	Stakeholder outreach and education
Formation of ratemaking objectives	Process evaluation	Revenue impacts	Customer education	Conferences, whitepapers, webinars, etc.
Rate development	Customer satisfaction surveys	Conservation impacts		
	Load impact analysis	Societal costs & benefits		

This is just the beginning!

- How should the new three-part rate be designed?
- How does the new rate design compare to that of other utilities?
- How will customer bills be impacted?
- Who will be the "winners" and "losers"?
- Can "vulnerable" customers be protected?
- How will owners of distributed generation be impacted?
- Will the "death spiral" be avoided or just delayed?
- Should the rate be opt-in, opt-out, or mandatory?
- Should customers be offered a menu of rate options?
- If there is rate choice, how will utility revenue be impacted?
- Should the rate be piloted before full-scale deployment?
- How should the pilot be designed?
- Will the new rate change consumption patterns?
- What are the financial implications of these changes in consumption?
- How should the consumption changes be measured?
- How should the rate be marketed to customers?
- How should the transition to the new rate be made?
- What tools can be offered to customers to facilitate the transition?
- What is the best way to present all of this to regulators?
- And the list goes on…

Presenter Information

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Ryan Hledik is a Principal in The Brattle Group's San Francisco office. Mr. Hledik specializes in the economics of policies and technologies that are focused on the energy consumer. He assists clients confronting complex issues related to the recent slowdown in electricity sales growth and the evolution of utility customers from passive consumers to active managers of their energy needs.

Mr. Hledik has supported utilities, policymakers, law firms, technology firms, research organizations, and wholesale market operators in matters related to retail rate design, energy efficiency, demand response, distributed generation, and smart grid investments. He has worked with more than 50 clients across 30 states and seven countries.

A frequent presenter on the benefits of smarter energy management, Mr. Hledik has spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam. He regularly publishes articles on complex retail electricity issues.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.

About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
- Cost of Capital
- Demand Forecasting Methodology
- Demand Response and Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation
- Energy Contract Litigation
- Environmental Compliance
- Fuel and Power Procurement
- Incentive Regulation
- Rate Design and Cost Allocation
- Regulatory Strategy and Litigation Support
- Renewables
- Resource Planning
- Retail Access and Restructuring
- Risk Management
- Market-Based Rates
- Market Design and Competitive Analysis
- Mergers and Acquisitions
- Transmission

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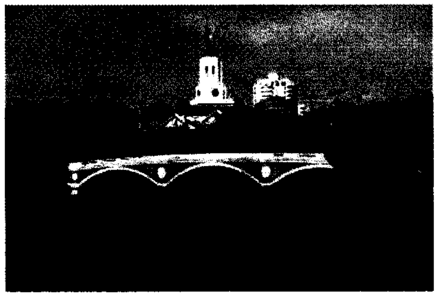
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Further reading

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Brown, Toby and Ahmad Faruqui, "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs," Australian Energy Market Commission, August 2014.

Caves, Douglas and Laurits Christensen, "Econometric Analysis of Residential Time-of-Use Electricity Pricing Experiments," *Journal of Econometrics*, 1980.

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Yakubovich, Valery, Mark Granovetter, and Patrick McGuire, "Electric Charges: The Social Construction of Rate Systems," *Theory and Society*, 2005.

EXHIBIT
TASC 10
admitted

UniSourceEnergy
SERVICES

SunShare Residential Solar Program
Grid-Tied
Up Front Incentive (UFI)
Renewable Energy Credit Purchase Agreement

This Grid-Tied Residential Up Front Incentive (UFI) Agreement (the "Agreement") is hereby made and entered into this _____ day of ____________, 20___, by and between UNS Electric, Inc., an Arizona corporation ("Company"), and _________________________, ("Customer"). Company and Customer may be referred to individually herein as a "Party" or collectively as the "Parties." Grid-Tied Residential Solar is hereby referred to as the "Program."

RECITALS

A. Company desires to increase the number of solar electricity generation facilities and the consumption of solar electricity within its service territory, while concurrently reducing the cost of solar electric generation systems for its customers. In support of these objectives and to further Company's continuing commitment to develop and encourage the use of renewable energy resources, Company has implemented the Program to provide financial incentives to its customers to install solar generating equipment; and

B. Company desires for Customer to participate in the Program and Customer desires to so participate under the terms and conditions contained in this Agreement, at the address of ______________________________________,___________, Arizona (the "Premises").

NOW, THEREFORE, in consideration of these premises and of the mutual promises herein contained, Company and Customer hereby agree as follows:

AGREEMENT

1. PROGRAM

Customer shall elect to participate in the Program by entering into this Agreement subject to the following conditions:

1.1 Renewable Energy System

1.1.1 System. Customer shall purchase a renewable energy generating system from any third party of Customer's choice ("Customer System"). To qualify under the Program, any such Customer System must comply with all renewable energy grid-tied residential solar technology specific requirements set forth in Attachment A "System Qualifications" and Attachment B "Off Angle and Shading Annual Derating Chart", which are attached hereto and incorporated herein.

1.1.2 Basis of Payment. The calculation of Customer environmental credits and Company payments hereunder shall be based on the system capacity or estimated energy kWh production rather than on measured system output. This represents a one time Up Front Incentive ("UFI") payment method.

2. SYSTEM INSTALLATION

To qualify for participation in the Program, all Customer Systems shall be installed by or on behalf of Customer in accordance with the requirements set forth in Attachment A and Attachment B including, without limitation, a proper interconnection with Company's existing power grid. Customer shall be solely responsible for the installation of the Customer System, including all costs and expenses associated therewith.

3. SYSTEM INSPECTION

Following installation of Customer's System, Company shall inspect the Customer System for compliance with the applicable requirements set forth in Attachment A and Attachment B. If the Customer System or installation is found to be not in compliance for any reason, Company will notify Customer of the deficiencies causing the noncompliance. Company will have no further obligations under this Agreement until all such deficiencies are remedied by Customer to Company's reasonable satisfaction.

4. SYSTEM ELECTRICAL OUTPUT

Customer hereby assigns to Company all of its rights to all electrical output of the Customer System and all associated environmental credits, specifically including those created under the

Arizona Corporation Commission's Renewable Energy Standard and Tariff Program (the "REST"), which may result from the installation and use of the Customer System. Company will thereafter return any and all value of such electric output to the Customer at no cost to Customer. Company's right to Customer's power output and Renewable Energy Credits assigned hereunder shall continue until December 31st of the 20th full calendar year after completion of the installation of the Customer System in compliance with this Agreement (the "Assignment Period") and shall survive any termination of this Agreement.

5. RENEWABLE ENERGY CREDIT PURCHASE

Subject to the Customer System passing the Company inspection set forth in Section 3 above and to Customer's compliance with the remaining terms and conditions of this Agreement, Company shall pay Customer $ _____ per DC Watt of installed grid-tied residential solar generating capacity of the Customer System for which completed Agreements are received and accepted by the Company and which system is operational within 180 days after application acceptance, as prorated by any de-rating for off-angle and shading that may apply by the percentages listed on the chart in Attachment B. The Customer System's DC Watts of installed grid-tied residential solar generating capacity shall be determined by Company following Company's receipt of a copy of the City or County building permit associated with the installation of the Customer System, successful Customer System inspection and determination of the level of compliance with Attachment B. Any amounts determined to be owed under this Section shall be paid by Company to Customer within 30 days following the Company's completion of AC kWh testing hereunder.

6. RIGHTS TO CREDITS

Company shall have the right to the Renewable Energy Credits from the Customer System until the end of the Assignment Period. Customer shall not offer to sell or trade Renewable Energy Credits from the Customer System to any other party during this time. Customer shall not remove the Customer System or any components thereof from the Premises during the Assignment Period without express agreement of Company. If Customer removes the Customer System in violation of this Section 6, Customer shall immediately reimburse Company all UFI amounts paid by Company to Customer hereunder.

7. METER READING

Once per year, typically in late December, during the term of this Agreement, Company shall read the Customer System solar production meter. Thus, Company reserves the right to read, at its option, the Customer System meter. Customer shall provide Company with reasonable access to its Customer System to conduct any such readings.

8. WARRANTY

COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND HEREUNDER, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO ITS PERFORMANCE OF ANY SERVICES OR PROVISION OF ANY GOODS HEREUNDER. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CUSTOMER SYSTEM, ITS OPERATION, SAFETY, INSTALLATION, OR COMPLIANCE WITH ANY BUILDING OR SAFETY CODES, RULES OR REGULATIONS, AND TO THE MAXIMUM EXTENT PERMITTED BY LAW, COMPANY HEREBY EXPRESSLY DISCLAIMS ANY AND ALL LIABILITY ASSOCIATED THEREWITH.

9. LIMITATION OF LIABILITY

COMPANY'S ENTIRE LIABILITY ARISING OUT OF ITS PERFORMANCE UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES STEMMING FROM CLAIMS DIRECTLY ATTRIBUTABLE TO COMPANY'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. IN NO EVENT SHALL COMPANY, ITS EMPLOYEES OR AGENTS BE LIABLE TO CUSTOMER FOR LOSS OF PROFITS OR ANY OTHER SPECIAL, INDIRECT, OR CONSEQUENTIAL DAMAGE, HOWEVER CAUSED, RESULTING FROM COMPANY'S PERFORMANCE HEREUNDER.

10. TERMINATION

If either Party shall at any time commit any material breach of any covenant or warranty under this Agreement and shall fail to cure the same within 30 days following written notice thereof, the non-breaching Party may terminate this Agreement, in whole or in part. This Agreement may also be terminated at any time by mutual written agreement of the Parties.

11. MISCELLANEOUS

11.1 Modification, Waiver and Severability. This Agreement may not be modified or supplemented except by written instrument signed by the Parties. No waiver of any default or breach hereof shall be deemed a waiver of any other default or breach thereof. If any part of this Agreement is declared void and/or unenforceable, such part shall be deemed severed from this Agreement which shall otherwise remain in full force and effect.

11.2 Assignment. This Agreement and the rights, duties, and obligations hereunder may not be assigned or delegated by any Party without the prior written consent of Company.

11.3 Governing Law and Venue. This Agreement shall be governed by the laws of the State of Arizona, without regard to the choice of law provisions thereof. Venue for any dispute arising hereunder shall be any court of competent jurisdiction located in Pima County, Arizona.

11.4 Entire Agreement. This Agreement is the final integration of the agreement between the Parties with respect to the matters covered by it and supersedes any prior understanding or agreements, oral or written, with respect thereto.

11.5 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same Agreement.

11.6 Titles and Captions. Titles or captions contained in this Agreement are inserted for convenience and for reference only and in no way define, limit, extend, or describe the scope of this Agreement or the intent of any provision hereof.

11.7 Expenses and Attorney's Fees. In the event of a breach or threatened breach of any term or provision of this Agreement, the non-breaching party shall be entitled to all of its remedies available at law or in equity, unless otherwise limited in this Agreement, and in addition shall be entitled to be reimbursed for all of its reasonable costs and expenses in enforcing this Agreement (if successful), including, but not limited to, reasonable attorney's fees. This section shall survive termination or expiration of this Agreement for any reason.

11.8 Force Majeure. Neither Party shall be liable to the other for failure to perform its obligations hereunder to the extent such failure results from causes beyond its reasonable control, including strikes, climatic conditions, acts of God, governmental laws, regulations, orders or requirements, interruptions of power or unavailability of equipment or supplies.

11.9 Customer Sale of Premises. In the event Customer sells the Premises where the Customer installed the Customer System, Customer's successor-in-interest shall expressly assume all of Customer's obligations hereunder in writing, and this Agreement shall not be affected, nor shall Company's rights hereunder be disturbed in any way, including, without limitation, Company's continued right to all Renewable Energy Credits assigned pursuant to Section 4 hereunder.

11.10 Notices. All notices under this Agreement shall be in writing and shall be given to the Parties thereto by personal service (including receipted confirmed facsimile), or by certified or registered mail, return receipt requested, or by recognized overnight courier service, to the Parties at the addresses set forth below. All notices shall be deemed given upon the actual receipt thereof.

Company: **UNS Electric, Inc.**
PO Box 3099
Kingman, Arizona 86402
Fax: (928) 681-8999
Attn: Energy Services Department

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of ____________, 20____.

UNS ELECTRIC, INC.

By:______________________________

Title:_____________________________

CUSTOMER

By:______________________________

Print Name:_______________________

Address:

____

____

____

Phone: ___________________________

BELOW TO BE FILLED IN BY UTILITY

Estimated Capacity Reserved:______________ kWh

Estimated Funding Reserved: $ ___________

Date Reserved: __________________________

Application Process

ATTACHMENT A

Grid-Tied Residential Solar System Qualifications

All grid-tied residential solar Customer Systems must meet the following system and installation requirements to qualify for UNS Electric, Inc., ("UNS Electric" or the "Company") Renewable Energy Credit Purchase Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the Renewable Energy Credit Purchase Program Agreement.

1. All systems shall be installed with a horizontal tilt angle between 10 degrees and 60 degrees, and an azimuth angle of +/- 100 degrees of due south. Installation configurations for some systems receiving a UFI will not be eligible for the full RECPP incentive. The reduction will be determined by the UNS Electric developed de-rating chart, Attachment B of this document, and as discussed further in this report under the section titled Conforming Project Incentives.

2. Qualifying systems using Building Integrated Photovoltaic (BIPV) modules of total array capacity of 5 kWDC or less shall receive 90% of the UFI incentive value for PV systems listed in Attachment A. Systems using BIPV module of total array capacity of greater than 5 kWDC shall only receive a PBI (see grid-tied residential PBI Agreement).

3. Photovoltaic modules must be covered by a manufacturer's warranty of at least 20 years.

4. Inverters must be covered by a manufacturer's warranty of at least ten years to receive a UFI and at least five years to receive a PBI (see grid-tied residential PBI Agreement).

5. The minimum PV array size shall be no less than 1,200 Wdc.

6. All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL Standard 1703.

7. All other electrical components must be UL listed.

8. The inverter must be certified as meeting the requirements of IEEE-1547 - Recommended Practice for Utility Interface of Photovoltaic Systems and it must be UL 1741 certified.

9. The Customer System design and installation must meet all requirements of the latest edition of the National Electrical Code, including Article 690 and all grounding, conductor, raceway, overcurrent protection, disconnect and labeling requirements.
10. The Customer System and installation must meet the requirements of all federal, state and local building codes and have been successfully inspected by the building official having

jurisdiction. Accordingly, the installation must be completed in accordance with the requirements of the latest edition of National Electrical Code in effect in the jurisdiction where the installation is being completed (NEC), including, without limitation, Sections 200-6, 210-6, 230-70, 240-3, 250-26, 250-50, 250-122, all of Article 690 pertaining to Solar Photovoltaic Systems, thereof, all as amended and superseded.

11. The Customer System must meet Company and Arizona Corporation Commission interconnection requirements for self-generation equipment.

12. The Customer System installation must meet the UNS Electric Service Requirements as follows:

    "AN AC DISCONNECT MEANS SHALL BE PROVIDED IN AN AREA ACCESSIBLE AT ALL TIMES TO THE COMPANY ON ALL UNGROUNDED AC CONDUCTORS AND SHALL CONSIST OF A LOCKABLE GANG OPERATED DISCONNECT CLEARLY INDICATING OPEN OR CLOSED. THE SWITCH SHALL BE VISUALLY INSPECTED TO DETERMINE THAT IT IS OPEN. THE SWITCH SHALL BE CLEARLY LABELED "DG SERVICE DISCONNECT."

13. For Residential Customer Systems, Company will provide a meter and meter socket that will be installed in a readily accessible outdoor location by the Customer between the Customer System and the connection to the overcurrent device in the Customer's electric service panel. For Non-Residential Customer Systems, Company shall provide the meter only, to be installed in a Customer supplied meter socket to be installed in a readily accessible outdoor location by the Customer between the Customer System and the connection to the overcurrent device in the Customer's electric service panel.

14. Energy storage devices are not allowed as part of the Customer System unless the energy storage charge controller is a separate component and Company can locate the meter at the Customer System's inverter output. Other types of qualified energy storage devices meet PBI requirements (see PBI Agreement).

15. Installation must have been made after January 1, 1997.

16. The Customer must be connected to the Company's electric grid.

17. All Customer System installations must be completed in a professional, workmanlike and safe manner.

ATTACHMENT B
SunShare PV Off-Angle & Shading Annual Energy Derating Chart

SunShare PV Off-Angle & Shading Annual Energy Derating Chart

Revised 04/14/2008

Array Azimuth Angle from Due South

Array Angle above Horizontal

Array Angle above Horizontal	EAST 100–80	80–60	60–40	40–20	SOUTH 20–20	20–40	40–60	60–80	80–100 WEST
0–10	80%	80%	80%	80%	80%	80%	80%	80%	80%
10–15	80%	80%	85%	85%	85%	85%	80%	80%	80%
15–20	90%	90%	95%	95%	95%	95%	90%	90%	85%
20–25	85%	90%	95%	95%	100%	95%	90%	90%	85%
25–30	85%	90%	95%	95%	100%	95%	90%	85%	80%
30–35	80%	85%	90%	95%	100%	95%	90%	80%	75%
35–40	75%	85%	90%	95%	95%	90%	85%	80%	70%
40–45	75%	85%	90%	95%	95%	90%	85%	75%	70%
45–50	70%	80%	85%	95%	95%	90%	80%	75%	65%
50–55	70%	80%	85%	90%	90%	85%	80%	70%	60%
55–60	65%	75%	80%	90%	90%	85%	75%	70%	60%

EAST SOUTH WEST

Array Azimuth Angle from Due South

Array Angle above Horizontal

If both off angle and shading conditions apply, multiply the off angle derating factor with the shading derating factor to obtain the array derating factor for the SunShare payment calculation.

Maximum Morning Shaded Hours	0	1	0	1	0	2	1	2	2	0	3	1	3	3	2
Maximum Evening Shaded Hours	0	0	1	1	2	0	2	1	2	3	0	3	1	2	3
Percentage of Annual Energy =	100%	100%	100%	95%	90%	90%	85%	85%	75%	75%	70%	70%	70%	60%	60%

UniSourceEnergy
SERVICES

SunShare Grid-Tied Non-Residential 100 kW AC or less Solar Program Up Front Incentive (UFI) Renewable Energy Credit Purchase Agreement

This Grid-Tied Non-Residential 100 kW AC or less Solar Up Front Incentive (UFI) Agreement (the "Agreement") is hereby made and entered into this _____ day of ____________, 20___, by and between UniSource Energy Services, an Arizona corporation ("Company"), and __________________________, ("Customer"). Company and Customer may be referred to individually herein as a "Party" or collectively as the "Parties." Grid-Tied Non-Residential 100 kW or less Solar is hereby referred to as the "Program."

RECITALS

A. Company desires to increase the number of solar electricity generation facilities and the consumption of solar electricity within its service territory, while concurrently reducing the cost of solar electric generation systems for its customers. In support of these objectives and to further Company's continuing commitment to develop and encourage the use of renewable energy resources, Company has implemented the Program to provide financial incentives to its customers to install solar generating equipment; and

B. Company desires for Customer to participate in the Program and Customer desires to so participate under the terms and conditions contained in this Agreement, at the address of ____,___________, Arizona (the "Premises").

NOW, THEREFORE, in consideration of these premises and of the mutual promises herein contained, Company and Customer hereby agree as follows:

AGREEMENT

1. PROGRAM

Customer shall elect to participate in the Program by entering into this Agreement subject to the following conditions:

1.1 Renewable Energy System

1.1.1 System. Customer shall purchase a renewable energy generating system from any third party of Customer's choice ("Customer System"). To qualify under the Program, any such Customer System must comply with all renewable energy on-grid non-residential solar technology specific requirements set forth in Attachment A "System Qualifications" and Attachment B "Off Angle & Shading Annual Derating Chart", which are attached hereto and incorporated herein.

1.1.2 Basis of Payment. The calculation Customer environmental credits and Company payments hereunder shall be based on the system capacity or estimated energy kWh production rather than on measured system output. This represents a one time Up Front Incentive ("UFI") payment method.

2. SYSTEM INSTALLATION

To qualify for participation in the Program, all Customer Systems shall be installed by or on behalf of Customer in accordance with the requirements set forth in Attachment A and Attachment B, including, without limitation, a proper interconnection with Company's existing power grid. Customer shall be solely responsible for the installation of the Customer System, including all costs and expenses associated therewith.

3. SYSTEM INSPECTION

Following installation of Customer's System, Company shall inspect the Customer System for compliance with the applicable requirements set forth in Attachment A and Attachment B. If the Customer System or installation is found to be not in compliance for any reason, Company will notify Customer of the deficiencies causing the noncompliance. Company will have no further obligations under this Agreement until all such deficiencies are remedied by Customer to Company's reasonable satisfaction.

4. SYSTEM ELECTRICAL OUTPUT

Customer hereby assigns to Company all of its rights to all electrical output of the Customer System and all associated environmental credits, specifically including those created under the Arizona Corporation Commission's Renewable Energy Standard and Tariff Program (the "REST"), which may result from the installation and use of the Customer System. Company will thereafter return any and all value of such electric output to the Customer at no cost to Customer. Company's right to Customer's power output and Renewable Energy Credits assigned hereunder shall continue until December 31st of the 20th full calendar year after completion of the installation of the Customer System in compliance with this Agreement (the "Assignment Period") and shall survive any termination of this Agreement.

5. RENEWABLE ENERGY CREDIT PURCHASE

Subject to the Customer System passing the Company inspection set forth in Section 3 above and to Customer's compliance with the remaining terms and conditions of this Agreement, Company shall pay Customer $_____ per DC Watt of installed On-Grid non-residential solar generating capacity of the Customer System for which completed Agreements are received and accepted by the Company and which system is operational within 180 days after application acceptance, as prorated by any de-rating for off-angle and shading that may apply by the percentages listed on the chart in Attachment B. The Customer System's DC Watts of installed on-grid non-residential solar generating capacity shall be determined by Company following Company's receipt of a copy of the City or County building permit associated with the installation of the Customer System, successful Customer System inspection and determination of the level of compliance with Attachment B. Any amounts determined to be owed under this Section shall be paid by Company to Customer within 30 days following the Company's completion of AC kWh testing hereunder.

6. RIGHTS TO CREDITS

Company shall have the right to the Renewable Energy Credits from the Customer System until the end of the Assignment Period. Customer shall not offer to sell or trade Renewable Energy Credits from the Customer System to any other party during this time. Customer shall not remove the Customer System or any components thereof from the Premises during the Assignment Period without express agreement of Company. If Customer removes the Customer System in violation of this Section 6, Customer shall immediately reimburse Company all UFI amounts paid by Company to Customer hereunder.

7. METER READING

Once per year, typically in late December, during the term of this Agreement, Company shall read the Customer System solar production meter. Thus, Company reserves the right to read, at its option, the Customer System meter. Customer shall provide Company with reasonable access to its Customer System to conduct any such readings.

8. WARRANTY

COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND HEREUNDER, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO ITS PERFORMANCE HEREUNDER. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CUSTOMER SYSTEM, ITS OPERATION, SAFETY, INSTALLATION, OR COMPLIANCE WITH ANY BUILDING OR SAFETY CODES, RULES OR

REGULATIONS, AND TO THE MAXIMUM EXTENT PERMITTED BY LAW, COMPANY HEREBY EXPRESSLY DISCLAIMS ANY AND ALL LIABILITY ASSOCIATED THEREWITH.

9. LIMITATION OF LIABILITY

COMPANY'S ENTIRE LIABILITY ARISING OUT OF ITS PERFORMANCE UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES STEMMING FROM CLAIMS DIRECTLY ATTRIBUTABLE TO COMPANY'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. IN NO EVENT SHALL COMPANY, ITS EMPLOYEES OR AGENTS BE LIABLE TO CUSTOMER FOR LOSS OF PROFITS OR ANY OTHER SPECIAL, INDIRECT, OR CONSEQUENTIAL DAMAGE, HOWEVER CAUSED, RESULTING FROM COMPANY'S PERFORMANCE HEREUNDER.

10. TERMINATION

If either Party shall at any time commit any material breach of any covenant or warranty under this Agreement and shall fail to cure the same within 30 days following written notice thereof, the non-breaching Party may terminate this Agreement, in whole or in part. This Agreement may also be terminated at any time by mutual written agreement of the Parties.

11. MISCELLANEOUS

11.1 Modification, Waiver and Severability. This Agreement may not be modified or supplemented except by written instrument signed by the Parties. No waiver of any default or breach hereof shall be deemed a waiver of any other default or breach thereof. If any part of this Agreement is declared void and/or unenforceable, such part shall be deemed severed from this Agreement which shall otherwise remain in full force and effect.

11.2 Assignment. This Agreement and the rights, duties, and obligations hereunder may not be assigned or delegated by any Party without the prior written consent of Company.

11.3 Governing Law and Venue. This Agreement shall be governed by the laws of the State of Arizona, without regard to the choice of law provisions thereof. Venue for any dispute arising hereunder shall be any court of competent jurisdiction located in Pima County, Arizona.

11.4 Entire Agreement. This Agreement is the final integration of the agreement between the Parties with respect to the matters covered by it and supersedes any prior understanding or agreements, oral or written, with respect thereto.

11.5 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same Agreement.

11.6 Titles and Captions. Titles or captions contained in this Agreement are inserted for convenience and for reference only and in no way define, limit, extend, or describe the scope of this Agreement or the intent of any provision hereof.

11.7 Expenses and Attorney's Fees. In the event of a breach or threatened breach of any term or provision of this Agreement, the non-breaching party shall be entitled to all of its remedies available at law or in equity, unless otherwise limited in this Agreement, and in addition shall be entitled to be reimbursed for all of its reasonable costs and expenses in enforcing this Agreement (if successful), including, but not limited to, reasonable attorney's fees. This section shall survive termination or expiration of this Agreement for any reason.

11.8 Force Majeure. Neither Party shall be liable to the other for failure to perform its obligations hereunder to the extent such failure results from causes beyond its reasonable control, including strikes, climatic conditions, acts of God, governmental laws, regulations, orders or requirements, interruptions of power or unavailability of equipment or supplies.

11.9 Customer Sale of Facility. In the event Customer sells the Premises where the Customer installed the Customer System, Customer's successor-in-interest shall expressly assume all of Customer's obligations hereunder in writing, and this Agreement shall not be affected, nor shall Company's rights hereunder be disturbed in any way, including, without limitation, Company's continued right to all Renewable Energy Credits assigned pursuant to Section 4 hereunder.

11.10 Notices. All notices under this Agreement shall be in writing and shall be given to the Parties thereto by personal service (including receipted confirmed facsimile), or by certified or registered mail, return receipt requested, or by recognized overnight courier service, to the Parties at the addresses set forth below. All notices shall be deemed given upon the actual receipt thereof.

Company: **UniSource Energy Services**
Attn: Energy Services Department
PO Box 3099
Kingman, Arizona 86402

Fax: (928) 681-8999

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of ________________________, 20____.

UNISOURCE ENERGY SERVICES

By:________________________________

Title:______________________________

CUSTOMER

By:________________________________

Print Name:_________________________

Address:

____

____

____

Phone: ____________________________

BELOW TO BE FILLED IN BY UTILITY

Estimated Capacity Reserved: __________ DC Watts

X $1.75

= Reservation __________

Date: ______________

Application Process

ATTACHMENT A

Grid-Tied Non-Residential Solar System Qualifications

All grid-tied non-residential solar Customer Systems must meet the following system and installation requirements to qualify for UniSource Energy Services ("UES" or the "Company") Renewable Energy Credit Purchase Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the Renewable Energy Credit Purchase Program Agreement.

1. All systems shall be installed with a horizontal tilt angle between 10 degrees and 60 degrees, and an azimuth angle of +/- 100 degrees of due south. Installation configurations for some systems receiving a UFI will not be eligible for the full RECPP incentive. The reduction will be determined by the UES developed de-rating chart, Attachment B of this document, and as discussed further in this report under the section titled Conforming Project Incentives.

2. Qualifying systems using Building Integrated Photovoltaic (BIPV) modules of total array capacity of 5 kWDC or less shall receive 90% of the UFI incentive value for PV systems listed in Attachment A. Systems using BIPV module of total array capacity of greater than 5 kWDC shall only receive a PBI (see PBI Agreement).

3. Photovoltaic modules must be covered by a manufacturer's warranty of at least 20 years.

4. Inverters must be covered by a manufacturer's warranty of at least ten years to receive a UFI and at least five years to receive a PBI (see PBI Agreement).

5. The minimum PV array size shall be no less than 1,200 Wdc

6. All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL Standard 1703.

7. All other electrical components must be UL listed.

8. The inverter must be certified as meeting the requirements of IEEE-1547 - Recommended Practice for Utility Interface of Photovoltaic Systems and it must be UL 1741 certified.

9. The Customer System design and installation must meet all requirements of the latest edition of the National Electrical Code, including Article 690 and all grounding, conductor, raceway, overcurrent protection, disconnect and labeling requirements.

10. The Customer System and installation must meet the requirements of all federal, state and local building codes and have been successfully inspected by the building official having jurisdiction. Accordingly, the installation must be completed in accordance with the requirements of the latest edition of National Electrical Code in effect in the jurisdiction where the installation is being completed (NEC), including, without limitation, Sections 200-

6, 210-6, 230-70, 240-3, 250-26, 250-50, 250-122, all of Article 690 pertaining to Solar Photovoltaic Systems, thereof, all as amended and superseded.

11. The Customer System must meet Company and Arizona Corporation Commission interconnection requirements for self-generation equipment.

12. The Customer System installation must meet the UES Service Requirements 2000 Edition, Page 1.20, as follows:

    "AN AC DISCONNECT MEANS SHALL BE PROVIDED ON ALL UNGROUNDED AC CONDUCTORS and SHALL CONSIST OF A LOCKABLE GANG OPERATED DISCONNECT CLEARLY INDICATING OPEN OR CLOSED. THE SWITCH SHALL BE VISUALLY INSPECTED TO DETERMINE THAT THE SWITCH IS OPEN. THE SWITCH SHALL BE CLEARLY LABELED STATING "DG SERVICE DISCONNECT."

13. For Non-Residential Customer Systems, Company shall provide the meter only, to be installed in a Customer supplied meter socket to be installed in a readily accessible outdoor location by the Customer between the Customer System and the connection to the overcurrent device in the Customer's electric service panel.

14. Energy storage devices are not allowed as part of the Customer System unless the energy storage charge controller is a separate component and Company can locate the meter at the Customer System's inverter output. Other types of qualified energy storage devices meet PBI requirements (see PBI Agreement).

15. Installation must have been made after January 1, 1997.

16. The Customer must be connected to the Company's electric grid.

17. All Customer System installations must be completed in a professional, workmanlike and safe manner.

ATTACHMENT B
SunShare PV Off-Angle & Shading Annual Energy Derating Chart

SunShare PV Off-Angle & Shading Annual Energy Derating Chart

Revised 04/14/2008

Array Azimuth Angle from Due South

EAST — SOUTH — WEST

Array Angle above Horizontal	EAST 100–80	80–60	60–40	40–20	20 SOUTH 20	20–40	40–60	60–80	80–100 WEST
0–10	80%	80%	80%	80%	80%	80%	80%	80%	80%
10–15	80%	80%	85%	85%	85%	85%	80%	80%	80%
15–20	90%	90%	95%	95%	95%	95%	90%	90%	85%
20–25	85%	90%	95%	95%	100%	95%	90%	90%	85%
25–30	85%	90%	95%	95%	100%	95%	90%	85%	80%
30–35	80%	85%	90%	95%	100%	95%	90%	80%	75%
35–40	75%	85%	90%	95%	95%	90%	85%	80%	70%
40–45	75%	85%	90%	95%	95%	90%	85%	75%	70%
45–50	70%	80%	85%	95%	95%	90%	80%	75%	65%
50–55	70%	80%	85%	90%	90%	85%	80%	70%	60%
55–60	65%	75%	80%	90%	90%	85%	75%	70%	60%

EAST — SOUTH — WEST

Array Azimuth Angle from Due South

If both off angle and shading conditions apply, multiply the off angle derating factor with the shading derating factor to obtain the array derating factor for the SunShare payment calculation.

Maximum Morning Shaded Hours	0	1	0	1	0	2	1	2	2	0	3	1	3	3	2
Maximum Evening Shaded Hours	0	0	1	1	2	0	2	1	2	3	0	3	1	2	3
Percentage of Annual Energy =	100%	100%	100%	95%	90%	90%	85%	85%	75%	75%	70%	70%	70%	60%	60%

UniSourceEnergy SERVICES

SunShare Residential Solar Program
Off-Grid
Up Front Incentive (UFI)
Renewable Energy Credit Purchase Agreement

This Off-Grid Residential Solar Up Front Incentive (UFI) Agreement (the "Agreement") is hereby made and entered into this _____ day of ____________, 20___, by and between UniSource Energy Services, an Arizona corporation ("Company"), and __________________________, ("Customer"). Company and Customer may be referred to individually herein as a "Party" or collectively as the "Parties." Off-Grid Residential Solar is hereby referred to as the "Program."

RECITALS

A. Company desires to increase the number of solar electricity generation facilities and the consumption of solar electricity within its service territory, while concurrently reducing the cost of solar electric generation systems for its customers. In support of these objectives and to further Company's continuing commitment to develop and encourage the use of renewable energy resources, Company has implemented the Program to provide financial incentives to its customers to install solar generating equipment; and

B. Company desires for Customer to participate in the Program and Customer desires to so participate under the terms and conditions contained in this Agreement, at the address of ______________________________________,___________, Arizona (the "Premises").

NOW, THEREFORE, in consideration of these premises and of the mutual promises herein contained, Company and Customer hereby agree as follows:

AGREEMENT

1. PROGRAM

Customer shall elect to participate in the Program by entering into this Agreement subject to the following conditions:

1.1 Renewable Energy System

1.1.1 System. Customer shall purchase a renewable energy generating system from any third party of Customer's choice ("Customer System"). To qualify under the Program, any such Customer System must comply with all renewable energy off-grid residential solar technology specific requirements set forth in Attachment A "System Qualifications" and Attachment B "Off Angle & Shading Annual Derating Chart", which are attached hereto and incorporated herein.

1.1.2 Basis of Payment. The calculation Customer environmental credits and Company payments hereunder shall be based on the system capacity or estimated energy kWh production rather than on measured system output. This represents a one time Up Front Incentive ("UFI") payment method.

2. SYSTEM INSTALLATION

To qualify for participation in the Program, all Customer Systems shall be installed by or on behalf of Customer in accordance with the requirements set forth in Attachment A and Attachment B, including, without limitation, a proper interconnection with Company's existing power grid. Customer shall be solely responsible for the installation of the Customer System, including all costs and expenses associated therewith.

3. SYSTEM INSPECTION

Following installation of Customer's System, Company shall inspect the Customer System for compliance with the applicable requirements set forth in Attachment A and Attachment B. If the Customer System or installation is found to be not in compliance for any reason, Company will notify Customer of the deficiencies causing the noncompliance. Company will have no further obligations under this Agreement until all such deficiencies are remedied by Customer to Company's reasonable satisfaction.

4. SYSTEM ELECTRICAL OUTPUT

Customer hereby assigns to Company all of its rights to all electrical output of the Customer System and all associated environmental credits, specifically including those created under the Arizona Corporation Commission's Renewable Energy Standard and Tariff Program (the "REST"), which may result from the installation and use of the Customer System. Company will thereafter return any and all value of such electric output to the Customer at no cost to Customer. Company's right to Customer's power output and Renewable Energy Credits assigned hereunder shall continue until December 31st of the 20th full calendar year after completion of the installation of the Customer System in compliance with this Agreement (the "Assignment Period") and shall survive any termination of this Agreement.

5. RENEWABLE ENERGY CREDIT PURCHASE

Subject to the Customer System passing the Company inspection set forth in Section 3 above and to Customer's compliance with the remaining terms and conditions of this Agreement, Company shall pay Customer $1.60 per DC Watt of installed off-grid residential solar generating capacity of the Customer System for which completed Agreements are received and accepted by the Company and which system is operational within 180 days after application acceptance, as prorated by any de-rating for off-angle and shading that may apply by the percentages listed on the chart in Attachment B. The Customer System's DC Watts of installed off-grid residential solar generating capacity shall be determined by Company following Company's receipt of a copy of the City or County building permit associated with the installation of the Customer System, successful Customer System inspection and determination of the level of compliance with Attachment B. Any amounts determined to be owed under this Section shall be paid by Company to Customer within 30 days following the Company's completion of AC kWh testing hereunder.

6. RIGHTS TO CREDITS

Company shall have the right to the Renewable Energy Credits from the Customer System until the end of the Assignment Period. Customer shall not offer to sell or trade Renewable Energy Credits from the Customer System to any other party during this time. Customer shall not remove the Customer System or any components thereof from the Premises during the Assignment Period without express agreement of Company. If Customer removes the Customer System in violation of this Section 6, Customer shall immediately reimburse Company all UFI amounts paid by Company to Customer hereunder.

7. WARRANTY

COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND HEREUNDER, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO ITS PERFORMANCE HEREUNDER. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CUSTOMER SYSTEM, ITS OPERATION, SAFETY, INSTALLATION, OR COMPLIANCE WITH ANY BUILDING OR SAFETY CODES, RULES OR REGULATIONS, AND TO THE MAXIMUM EXTENT PERMITTED BY LAW, COMPANY HEREBY EXPRESSLY DISCLAIMS ANY AND ALL LIABILITY ASSOCIATED THEREWITH.

8. LIMITATION OF LIABILITY

COMPANY'S ENTIRE LIABILITY ARISING OUT OF ITS PERFORMANCE UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES STEMMING FROM CLAIMS DIRECTLY ATTRIBUTABLE TO COMPANY'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. IN NO EVENT SHALL COMPANY, ITS EMPLOYEES OR AGENTS BE LIABLE TO CUSTOMER FOR LOSS OF PROFITS OR ANY OTHER SPECIAL, INDIRECT, OR CONSEQUENTIAL DAMAGE, HOWEVER CAUSED, RESULTING FROM COMPANY'S PERFORMANCE HEREUNDER.

9. TERMINATION

If either Party shall at any time commit any material breach of any covenant or warranty under this Agreement and shall fail to cure the same within 30 days following written notice thereof, the non-breaching Party may terminate this Agreement, in whole or in part. This Agreement may also be terminated at any time by mutual written agreement of the Parties.

10. MISCELLANEOUS

10.1 Modification, Waiver and Severability. This Agreement may not be modified or supplemented except by written instrument signed by the Parties. No waiver of any default or breach hereof shall be deemed a waiver of any other default or breach thereof. If any part of this Agreement is declared void and/or unenforceable, such part shall be deemed severed from this Agreement which shall otherwise remain in full force and effect.

10.2 Assignment. This Agreement and the rights, duties, and obligations hereunder may not be assigned or delegated by any Party without the prior written consent of Company.

10.3 Governing Law and Venue. This Agreement shall be governed by the laws of the State of Arizona, without regard to the choice of law provisions thereof. Venue for any dispute arising hereunder shall be any court of competent jurisdiction located in Pima County, Arizona.

10.4 Entire Agreement. This Agreement is the final integration of the agreement between the Parties with respect to the matters covered by it and supersedes any prior understanding or agreements, oral or written, with respect thereto.

10.5 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same Agreement.

10.6 Titles and Captions. Titles or captions contained in this Agreement are inserted for convenience and for reference only and in no way define, limit, extend, or describe the scope of this Agreement or the intent of any provision hereof.

10.7 Expenses and Attorney's Fees. In the event of a breach or threatened breach of any term or provision of this Agreement, the non-breaching party shall be entitled to all of its remedies available at law or in equity, unless otherwise limited in this Agreement, and in addition shall be entitled to be reimbursed for all of its reasonable costs and expenses in enforcing this Agreement (if successful), including, but not limited to, reasonable attorney's fees. This section shall survive termination or expiration of this Agreement for any reason.

10.8 Force Majeure. Neither Party shall be liable to the other for failure to perform its obligations hereunder to the extent such failure results from causes beyond its reasonable control, including srikes, climatic conditions, acts of God, governmental laws, regulations, orders or requirements, interruptions of power or unavailability of equipment or supplies.

10.9 Customer Sale of Facility. In the event Customer sells the Premises where the Customer installed the Customer System, Customer's successor-in-interest shall expressly assume all of Customer's obligations hereunder in writing, and this Agreement shall not be affected, nor shall Company's rights hereunder be disturbed in any way, including, without limitation, Company's continued right to all Renewable Energy Credits assigned pursuant to Section 4 hereunder.

10.10 Notices. All notices under this Agreement shall be in writing and shall be given to the Parties thereto by personal service (including receipted confirmed facsimile), or by certified or registered mail, return receipt requested, or by recognized overnight courier service, to the Parties at the addresses set forth below. All notices shall be deemed given upon the actual receipt thereof.

Company: **UniSource Energy Services**

Attn: Energy Services Department
PO Box 3099
Kingman, Arizona 86402

Fax: (928) 681-8999

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of ________________________, 20____.

UNISOURCE ENERGY SERVICES

By:________________________________

Title:______________________________

CUSTOMER

By:________________________________

Print Name:_________________________

Address:
____
____
____

Phone: ____________________________

BELOW TO BE FILLED IN BY UTILITY

Estimated Capacity Reserved: __________ DC Watts

X $1.60

= Reservation __________

Date: ______________

Application Process

ATTACHMENT A

Off-Grid Non-Residential Solar System Qualifications

All off-grid residential solar Customer Systems must meet the following system and installation requirements to qualify for UniSource Energy Services ("UES" or the "Company") Renewable Energy Credit Purchase Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the Renewable Energy Credit Purchase Program Agreement.

1. All systems shall be installed with a horizontal tilt angle between 10 degrees and 60 degrees, and an azimuth angle of +/- 100 degrees of due south. Installation configurations for some systems receiving a UFI will not be eligible for the full RECPP incentive. The reduction will be determined by the UES developed de-rating chart, Attachment B of this document, and as discussed further in this report under the section titled Conforming Project Incentives.

2. Qualifying systems using Building Integrated Photovoltaic (BIPV) modules of total array capacity of 5 kWDC or less shall receive 90% of the UFI incentive value for PV systems listed in Attachment A. Systems using BIPV module of total array capacity of greater than 5 kWDC shall only receive a PBI (see PBI Agreement).

3. Photovoltaic modules must be covered by a manufacturer's warranty of at least 20 years.

4. Inverters must be covered by a manufacturer's warranty of at least ten years to receive a UFI and at least five years to receive a PBI (see PBI Agreement).

5. The minimum PV array size shall be no less than 600 watts DC and the maximum PV array size shall not exceed 4,000 watts AC (5,680 watts DC). For customers currently not paying into the REST tariff, the maximum Solar Electric array size shall not exceed 2,000 watts AC (2,840 watts DC).

6. All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL Standard 1703.

7. Off-Grid systems will not be metered. Compliance reporting production will be based on an annual 20% capacity factor using nameplate DC rating for capacity.

8. All other electrical components must be UL listed.

9. The Customer System design and installation must meet all requirements of the latest edition of the National Electrical Code, including Article 690 and all grounding, conductor, raceway, overcurrent protection, disconnect and labeling requirements.

10. The Customer System and installation must meet the requirements of all federal, state and local building codes and have been successfully inspected by the building official having jurisdiction. Accordingly, the installation must be completed in accordance with the

requirements of the latest edition of National Electrical Code in effect in the jurisdiction where the installation is being completed (NEC), including, without limitation, Sections 200-6, 210-6, 230-70, 240-3, 250-26, 250-50, 250-122, all of Article 690 pertaining to Solar Photovoltaic Systems, thereof, all as amended and superseded.

11. The Customer System must meet Company and Arizona Corporation Commission interconnection requirements for self-generation equipment.

12. Installation must have been made after January 1, 1997.

13. All Customer System installations must be completed in a professional, workmanlike and safe manner.

ATTACHMENT B
SunShare PV Off-Angle & Shading Annual Energy Derating Chart

SunShare PV Off-Angle & Shading Annual Energy Derating Chart

Revised 04/14/2008

Array Azimuth Angle from Due South

EAST — SOUTH — WEST

Array Angle above Horizontal

Array Angle above Horizontal	100	80	60	40	20	20	40	60	80	100
0	80%	80%	80%	80%	80%	80%	80%	80%	80%	
10	80%	80%	85%	85%	85%	85%	80%	80%	80%	
15	90%	90%	95%	95%	95%	95%	90%	90%	85%	
20	85%	90%	95%	95%	100%	95%	90%	90%	85%	
25	85%	90%	95%	95%	100%	95%	90%	85%	80%	
30	80%	85%	90%	95%	100%	95%	90%	80%	75%	
35	75%	85%	90%	95%	95%	90%	85%	80%	70%	
40	75%	85%	90%	95%	95%	90%	85%	75%	70%	
45	70%	80%	85%	95%	95%	90%	80%	75%	65%	
50	70%	80%	85%	90%	90%	85%	80%	70%	60%	
55	65%	75%	80%	90%	90%	85%	75%	70%	60%	
60										

100 80 60 40 20 20 40 60 80 100

EAST — SOUTH — WEST

Array Azimuth Angle from Due South

Array Angle above Horizontal

If both off angle and shading conditions apply, multiply the off angle derating factor with the shading derating factor to obtain the array derating factor for the SunShare payment calculation.

Maximum Morning Shaded Hours	0	1	0	1	0	2	1	2	2	0	3	1	3	3	2
Maximum Evening Shaded Hours	0	0	1	1	2	0	2	1	2	3	0	3	1	2	3
Percentage of Annual Energy =	100%	100%	100%	95%	90%	90%	85%	85%	75%	75%	70%	70%	70%	60%	60%

UniSourceEnergy SERVICES

SunShare Grid-Tied Non-Residential 70 kW DC or less Solar Program Up Front Incentive (UFI) Renewable Energy Credit Purchase Agreement

This Grid-Tied Non-Residential 70 kW DC or less Solar Up Front Incentive (UFI) Agreement (the "Agreement") is hereby made and entered into this ______ day of ___________, 20___, by and between UniSource Energy Services, an Arizona corporation ("Company"), and __________________________, ("Customer"). Company and Customer may be referred to individually herein as a "Party" or collectively as the "Parties." Grid-Tied Non-Residential 70 kW or less Solar is hereby referred to as the "Program."

RECITALS

A. Company desires to increase the number of solar electricity generation facilities and the consumption of solar electricity within its service territory, while concurrently reducing the cost of solar electric generation systems for its customers. In support of these objectives and to further Company's continuing commitment to develop and encourage the use of renewable energy resources, Company has implemented the Program to provide financial incentives to its customers to install solar generating equipment; and

B. Company desires for Customer to participate in the Program and Customer desires to so participate under the terms and conditions contained in this Agreement, at the address of ____, Arizona (the "Premises").

NOW, THEREFORE, in consideration of these premises and of the mutual promises herein contained, Company and Customer hereby agree as follows:

AGREEMENT

1. PROGRAM

Customer shall elect to participate in the Program by entering into this Agreement subject to the following conditions:

1.1 Renewable Energy System

1.1.1 System. Customer shall purchase a renewable energy generating system from any third party of Customer's choice ("Customer System"). To qualify under the Program, any such Customer System must comply with all renewable energy on-grid non-residential solar technology specific requirements set forth in Attachment A "System Qualifications" and Attachment B "Off Angle & Shading Annual Derating Chart", which are attached hereto and incorporated herein.

1.1.2 Basis of Payment. The calculation Customer environmental credits and Company payments hereunder shall be based on the system capacity or estimated energy kWh production rather than on measured system output. This represents a one time Up Front Incentive ("UFI") payment method.

2. SYSTEM INSTALLATION

To qualify for participation in the Program, all Customer Systems shall be installed by or on behalf of Customer in accordance with the requirements set forth in Attachment A and Attachment B, including, without limitation, a proper interconnection with Company's existing power grid. Customer shall be solely responsible for the installation of the Customer System, including all costs and expenses associated therewith.

3. SYSTEM INSPECTION

Following installation of Customer's System, Company shall inspect the Customer System for compliance with the applicable requirements set forth in Attachment A and Attachment B. If the Customer System or installation is found to be not in compliance for any reason, Company will notify Customer of the deficiencies causing the noncompliance. Company will have no further obligations under this Agreement until all such deficiencies are remedied by Customer to Company's reasonable satisfaction.

4. SYSTEM ELECTRICAL OUTPUT

Customer hereby assigns to Company all of its rights to all electrical output of the Customer System and all associated environmental credits, specifically including those created under the Arizona Corporation Commission's Renewable Energy Standard and Tariff Program (the "REST"), which may result from the installation and use of the Customer System. Company will thereafter return any and all value of such electric output to the Customer at no cost to Customer. Company's right to Customer's power output and Renewable Energy Credits assigned hereunder shall continue until December 31st of the 20th full calendar year after completion of the installation of the Customer System in compliance with this Agreement (the "Assignment Period") and shall survive any termination of this Agreement.

5. RENEWABLE ENERGY CREDIT PURCHASE

Subject to the Customer System passing the Company inspection set forth in Section 3 above and to Customer's compliance with the remaining terms and conditions of this Agreement, Company shall pay Customer $_________ per DC Watt of installed on-Grid non-residential solar generating capacity of the Customer System for which completed Agreements are received and accepted by the Company and which system is operational within 180 days after application acceptance, as prorated by any de-rating for off-angle and shading that may apply by the percentages listed on the chart in Attachment B. The Customer System's DC Watts of installed on-grid non-residential solar generating capacity shall be determined by Company following Company's receipt of a copy of the City or County building permit associated with the installation of the Customer System, successful Customer System inspection and determination of the level of compliance with Attachment B. Any amounts determined to be owed under this Section shall be paid by Company to Customer within 30 days following the Company's completion of AC kWh testing hereunder.

6. RIGHTS TO CREDITS

Company shall have the right to the Renewable Energy Credits from the Customer System until the end of the Assignment Period. Customer shall not offer to sell or trade Renewable Energy Credits from the Customer System to any other party during this time. Customer shall not remove the Customer System or any components thereof from the Premises during the Assignment Period without express agreement of Company. If Customer removes the Customer System in violation of this Section 6, Customer shall immediately reimburse Company all UFI amounts paid by Company to Customer hereunder.

7. METER READING

Once per year, typically in late December, during the term of this Agreement, Company shall read the Customer System solar production meter. Thus, Company reserves the right to read, at its option, the Customer System meter. Customer shall provide Company with reasonable access to its Customer System to conduct any such readings.

8. WARRANTY

COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND HEREUNDER, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO ITS PERFORMANCE HEREUNDER. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, COMPANY MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CUSTOMER SYSTEM, ITS OPERATION, SAFETY, INSTALLATION, OR COMPLIANCE WITH ANY BUILDING OR SAFETY CODES,

RULES OR REGULATIONS, AND TO THE MAXIMUM EXTENT PERMITTED BY LAW, COMPANY HEREBY EXPRESSLY DISCLAIMS ANY AND ALL LIABILITY ASSOCIATED THEREWITH.

9. LIMITATION OF LIABILITY

COMPANY'S ENTIRE LIABILITY ARISING OUT OF ITS PERFORMANCE UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES STEMMING FROM CLAIMS DIRECTLY ATTRIBUTABLE TO COMPANY'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. IN NO EVENT SHALL COMPANY, ITS EMPLOYEES OR AGENTS BE LIABLE TO CUSTOMER FOR LOSS OF PROFITS OR ANY OTHER SPECIAL, INDIRECT, OR CONSEQUENTIAL DAMAGE, HOWEVER CAUSED, RESULTING FROM COMPANY'S PERFORMANCE HEREUNDER.

10. TERMINATION

If either Party shall at any time commit any material breach of any covenant or warranty under this Agreement and shall fail to cure the same within 30 days following written notice thereof, the non-breaching Party may terminate this Agreement, in whole or in part. This Agreement may also be terminated at any time by mutual written agreement of the Parties.

11. MISCELLANEOUS

11.1 Modification, Waiver and Severability. This Agreement may not be modified or supplemented except by written instrument signed by the Parties. No waiver of any default or breach hereof shall be deemed a waiver of any other default or breach thereof. If any part of this Agreement is declared void and/or unenforceable, such part shall be deemed severed from this Agreement which shall otherwise remain in full force and effect.

11.2 Assignment. This Agreement and the rights, duties, and obligations hereunder may not be assigned or delegated by any Party without the prior written consent of Company.

11.3 Governing Law and Venue. This Agreement shall be governed by the laws of the State of Arizona, without regard to the choice of law provisions thereof. Venue for any dispute arising hereunder shall be any court of competent jurisdiction located in Pima County, Arizona.

11.4 Entire Agreement. This Agreement is the final integration of the agreement between the Parties with respect to the matters covered by it and supersedes any prior understanding or agreements, oral or written, with respect thereto.

11.5 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same Agreement.

11.6 Titles and Captions. Titles or captions contained in this Agreement are inserted for convenience and for reference only and in no way define, limit, extend, or describe the scope of this Agreement or the intent of any provision hereof.

11.7 Expenses and Attorney's Fees. In the event of a breach or threatened breach of any term or provision of this Agreement, the non-breaching party shall be entitled to all of its remedies available at law or in equity, unless otherwise limited in this Agreement, and in addition shall be entitled to be reimbursed for all of its reasonable costs and expenses in enforcing this Agreement (if successful), including, but not limited to, reasonable attorney's fees. This section shall survive termination or expiration of this Agreement for any reason.

11.8 Force Majeure. Neither Party shall be liable to the other for failure to perform its obligations hereunder to the extent such failure results from causes beyond its reasonable control, including strikes, climatic conditions, acts of God, governmental laws, regulations, orders or requirements, interruptions of power or unavailability of equipment or supplies.

11.9 Customer Sale of Facility. In the event Customer sells the Premises where the Customer installed the Customer System, Customer's successor-in-interest shall expressly assume all of Customer's obligations hereunder in writing, and this Agreement shall not be affected, nor shall Company's rights hereunder be disturbed in any way, including, without limitation, Company's continued right to all Renewable Energy Credits assigned pursuant to Section 4 hereunder.

11.10 Notices. All notices under this Agreement shall be in writing and shall be given to the Parties thereto by personal service (including receipted confirmed facsimile), or by certified or registered mail, return receipt requested, or by recognized overnight courier service, to the Parties at the addresses set forth below. All notices shall be deemed given upon the actual receipt thereof.

Company: **UniSource Energy Services**
Attn: Energy Services Department
PO Box 3099
Kingman, Arizona 86402

Fax: (928) 681-8999

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of ______________________, 20____.

UNISOURCE ENERGY SERVICES

By:______________________________

Title:____________________________

CUSTOMER

By:______________________________

Print Name:_______________________

Address:

____

____

____

Phone: __________________________

BELOW TO BE FILLED IN BY UTILITY

Estimated Capacity Reserved: ___________ DC Watts

X ___________

= Reservation $___________

Date: __________________

Application Process
ATTACHMENT A
Grid-Tied Non-Residential Solar System Qualifications

All grid-tied non-residential solar Customer Systems must meet the following system and installation requirements to qualify for UniSource Energy Services ("UES" or the "Company") Renewable Energy Credit Purchase Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the Renewable Energy Credit Purchase Program Agreement.

1. All systems shall be installed with a horizontal tilt angle between 10 degrees and 60 degrees, and an azimuth angle of +/- 100 degrees of due south. Installation configurations for some systems receiving a UFI will not be eligible for the full RECPP incentive. The reduction will be determined by the UES developed de-rating chart, Attachment B of this document, and as discussed further in this report under the section titled Conforming Project Incentives.

2. Qualifying systems using Building Integrated Photovoltaic (BIPV) modules of total array capacity of 5 kWDC or less shall receive 90% of the UFI incentive value for PV systems listed in Attachment A. Systems using BIPV module of total array capacity of greater than 5 kWDC shall only receive a PBI (see PBI Agreement).

3. Photovoltaic modules must be covered by a manufacturer's warranty of at least 20 years.

4. Inverters must be covered by a manufacturer's warranty of at least ten years to receive a UFI and at least five years to receive a PBI (see PBI Agreement).

5. The minimum PV array size shall be no less than 1,200 Wdc

6. All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL Standard 1703.

7. All other electrical components must be UL listed.

8. The inverter must be certified as meeting the requirements of IEEE-1547 - Recommended Practice for Utility Interface of Photovoltaic Systems and it must be UL 1741 certified.

9. The Customer System design and installation must meet all requirements of the latest edition of the National Electrical Code, including Article 690 and all grounding, conductor, raceway, overcurrent protection, disconnect and labeling requirements.

10. The Customer System and installation must meet the requirements of all federal, state and local building codes and have been successfully inspected by the building official having jurisdiction. Accordingly, the installation must be completed in accordance with the

requirements of the latest edition of National Electrical Code in effect in the jurisdiction where the installation is being completed (NEC), including, without limitation, Sections 200-6, 210-6, 230-70, 240-3, 250-26, 250-50, 250-122, all of Article 690 pertaining to Solar Photovoltaic Systems, thereof, all as amended and superseded.

11. The Customer System must meet Company and Arizona Corporation Commission interconnection requirements for self-generation equipment.

12. The Customer System installation must meet the UES Service Requirements 2000 Edition, Page 1.20, as follows:

    "AN AC DISCONNECT MEANS SHALL BE PROVIDED ON ALL UNGROUNDED AC CONDUCTORS and SHALL CONSIST OF A LOCKABLE GANG OPERATED DISCONNECT CLEARLY INDICATING OPEN OR CLOSED. THE SWITCH SHALL BE VISUALLY INSPECTED TO DETERMINE THAT THE SWITCH IS OPEN. THE SWITCH SHALL BE CLEARLY LABELED STATING "DG SERVICE DISCONNECT."

13. For Non-Residential Customer Systems, Company shall provide the meter only, to be installed in a Customer supplied meter socket to be installed in a readily accessible outdoor location by the Customer between the Customer System and the connection to the overcurrent device in the Customer's electric service panel.

14. Energy storage devices are not allowed as part of the Customer System unless the energy storage charge controller is a separate component and Company can locate the meter at the Customer System's inverter output. Other types of qualified energy storage devices meet PBI requirements (see PBI Agreement).

15. Installation must have been made after January 1, 1997.

16. The Customer must be connected to the Company's electric grid.

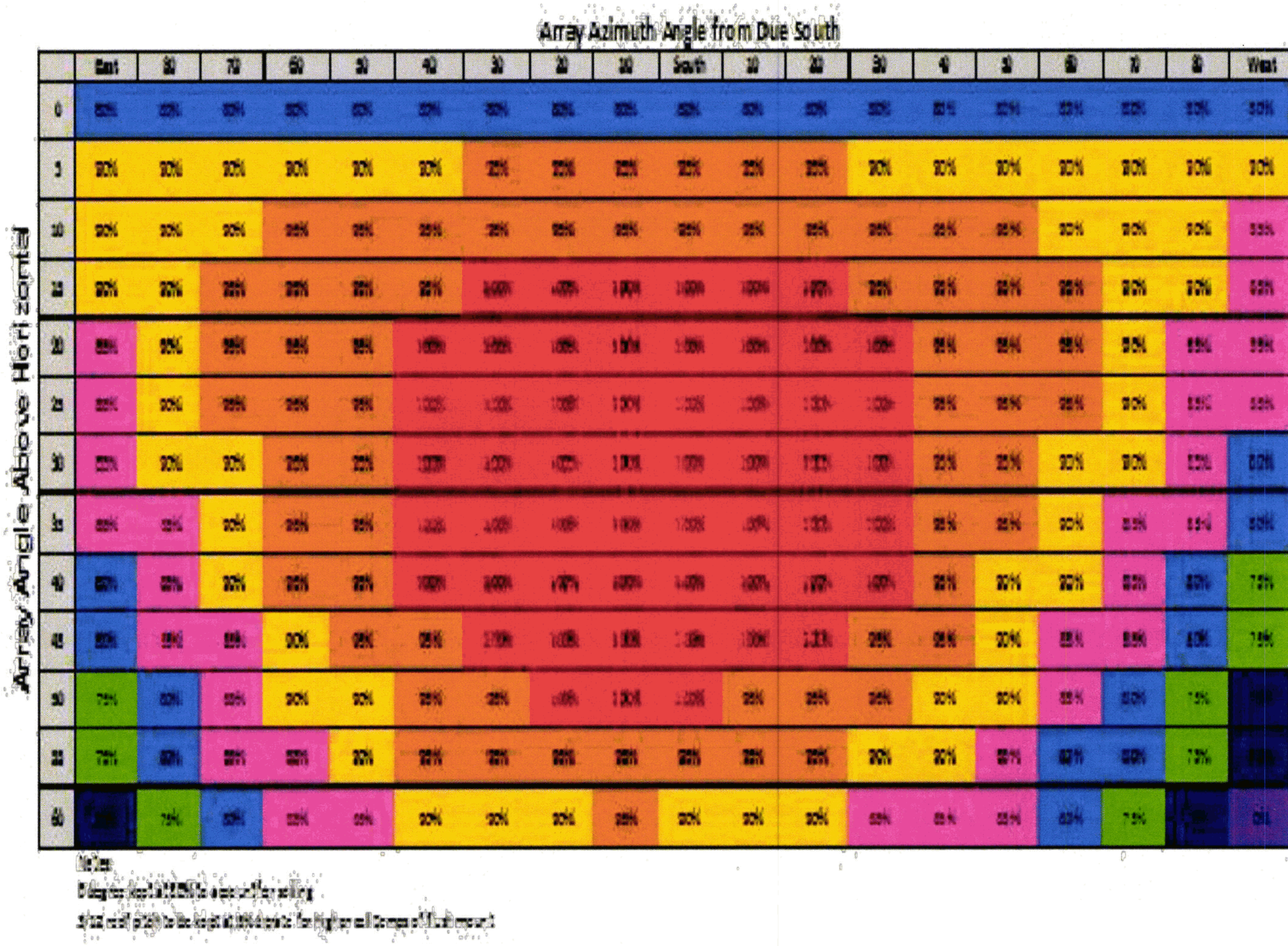
17. All Customer System installations must be completed in a professional, workmanlike and safe manner.

REVISION 0

ACC APPROVED – 1/12/10

ATTACHMENT B
SunShare PV Off-Angle & Shading Annual Energy Derating Chart

Up-Front Incentive (UFI) Payment - PV Off-Angle/Azimuth & Shading Derating Chart



Array Shading

If both off-angle and shading conditions apply, multiply the off-angle derating factor with the shading derating factor to obtain the array derating factor for the Up-Front Incentive (UFI) payment calculation.

Maximum Morning Shaded Hours	0	1	0	1	0	2	1	2	2	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Maximum Evening Shaded Hours	0	0	1	1	2	0	2	1	2	3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Percentage of Annual Energy =	100%	100%	100%	95%	90%	90%	85%	85%	75%	75%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

POWELL
GOLDSTEIN LLP

EXHIBIT
TASC 11
admitted

Principles of Public Utiliity Rates by James C. Bonbright

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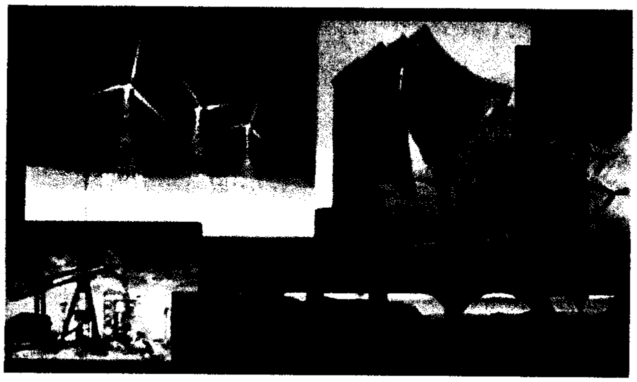

whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the demand for service. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

And in the third place, except for incidental references, we shall rule out all of those so-called "social" principles of rate making, discussed in Chapter VII, which may justify the sale of some utility services at less than even marginal or out-of-pocket costs.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. In the literature, this measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various "social" objectives of rate making. In actual practice there is usually an obvious, marked degree of correlation between the relative charges for different amounts and types of service and the relative costs of rendition. To be sure, local transit rates, with their customary flat fares regardless of distance and (even more important) regardless of time of travel come close to providing an outright exception. But intercity railroad rates, despite their many familiar departures from cost principles[6] and despite their notorious failure to accord well with any other sane principles of rate making, bear important partial correlations with

[6] Referring to railroad rates, the Interstate Commerce Commission said: "Costs alone do not determine the maximum limits of rates. Neither do they control the contours of rate scales or fix the relations between rates or between rate scales. Other factors along with costs must be considered and given due weight in these aspects of rate making." 262 I.C.C. 693, quoted by Justice Douglas in New York v. United States, 331 U.S. 284, 328 (1947).

relative costs. Thus, by and large, Pullman fares are much higher than coach fares; charges for the shipment of ten tons of any given class of freight are much higher than charges for the shipment of one ton; and freight rates from New York City to points in California are far higher than freight rates from New York City to Albany. Electric utility rates deviate from a cost standard much less than railroad rates. But it is a testimony to the prestige of this standard that, whenever actual or proposed electric tariffs are criticized for their asserted unfairness, the criticism usually takes the form of the contention that the rate relationships fail to conform to cost relationships. When this complaint is made before a public service commission, the defenders of the rates are likely to feel in a much stronger position if they can meet it on its own ground, without having to rely on value-of-service arguments in support of preferential rates to favored classes of customers.

The basic reasons in support of a cost-of-service standard of public utility rates and rate relationships have already been discussed at length in the early chapters of this book, particularly in Chapter IV. Here we may recall that the defense rests both on considerations of fairness as among the different customers and on considerations of optimum utilization or "consumer rationing." As to the issue of fairness, a cost-price standard probably enjoys more widespread acceptance than any other standard except for the even more popular tendency to identify whatever is fair with whatever is in one's self-interest. As to the issue of optimum utilization, this same standard (or, at least, a standard of the same name) comports with the "consumer sovereignty" principle, under which public utility consumers should be encouraged to take whatever types of service, in whatever amounts, they wish to take as long as they are made to indemnify the utility enterprise for the costs of rendition.

NECESSARY DEVIATIONS FROM A COST-OF-SERVICE STANDARD

In view of what has just been said, one might suppose that "the theory" of public utility rate structures or rate differentials would call for the acceptance of no basic principle of reasonable or nondiscriminatory rates other than a mere extension of the very principle already accepted in the determination of entire rate levels, namely, the principle of service at cost. Just as, under the fair-return standard, rates as a whole should cover costs as a whole, so the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the theory of rate structures would be reduced to a mere theory of cost determination through the aid of modern techniques of cost accounting and cost analysis.

Unfortunately, however, no such simple identification of "reasonable" rates with rates measured by costs of service is attainable; and this for several reasons, three of which will now be distinguished. The first of these reasons may be called "practical," whereas the other two are theoretical and are based on the non-additive character of the costs attributable to specific classes and units of service.

Excessive complexity of cost relationships. The "practical" reasons lie in the extreme difficulties of cost-of-service measurement together with the fact that, even if all specific costs could be measured, they would be found too complex for incorporation in rate schedules. Most public utility companies supply many different kinds of service even when they confine their activities to nothing but electricity, or gas, or telephone service, etc. In a very real sense, moreover, the supply of any one type of service to thousands of customers at different locations constitutes the supply of a different product to each customer. Equally truly, service rendered at any one time is not the same product as is otherwise comparable service rendered at another time.

But these millions of different service deliveries by a single public utility company are produced in combination and at total costs, most of which are joint or common either to the entire business or else to some major branch of the business. Under these circumstances, the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of serving each

* individual consumer or class of consumers would involve a hopelessly elaborate and expensive type of cost analysis.[7] For this reason

[7] John Alden Bliss has sent me a quotation from a report by Alex Dow, former chairman of the Detroit Edison Company, to the effect that his company had been obliged to reply on the one hand to the customer who thinks that rates should be uniform per kilowatt-hour and on the other hand to the man "who wants us to determine so exactly the cost of service to each customer that our power plants and distribution systems would become merely unavoidable preliminaries to the operation of a meter department." The TNEC Monograph No. 32, cited in footnote 4, *supra*, quotes at page 41 from an opinion by Chairman Maltbie of the New York Public Service Commission reading in part: "In every business, there is always a large percentage of customers, who are served at less than cost, for the reason that it has been found impracticable to devise and apply a system of cost accounting and computation which would carry out the principle literally; and if it were done, it would result in such an elaborate and complicated schedule of rates that the public could not understand it and few could apply it."

alone, the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships.

1 But even if, through the miracles of electronic computers and of modern techniques of mathematical analysis, all significant cost differentials could be measured without inordinate expense, they would then be found far too numerous, too complex, and too volatile to be embodied in rate differentials. Stability and predictability of the charges for public utility services are desirable attributes; and up to a certain point—or rather, up to an indeterminate point—they are worth attaining even at the sacrifice of nice attempts to bring rates into accord with current production costs. 2 Indeed, unless rate-making policies are sufficiently stable to permit a consumer to predict with some confidence what his charges will be *if he decides* to equip his home or his factory to take the contemplated service and then to buy the service, a cost-price system of rate making will be self-defeating when viewed as a means of securing a rational control of demand.

These practical considerations leading to the design of rate structures that ignore many cost differentials are illustrated by the general uniformity of rates for gas, electricity, telephone service, and water supply throughout an entire city, despite distances from source of supply, differences in density of population, and other differences that may have a material bearing on relative costs of service. Indeed, in some parts of the country, the rates of large electric power systems are uniform, or almost uniform, throughout the state, no distinction being made between urban and rural areas. Critics of this "blanket rate" policy may well be right in insisting that it carries the principle of uniformity too far.[8] But the criticism is leveled merely against an *excessive* disregard of cost differentials in rate making.

Failure of the sum of differential costs to equate with total costs.

[8] See Chap. VII, pp. 112–113, *supra*.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
TASC 12
admitted

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 3 OF 4

July 2, 2007

Direct Testimony of D. Bentley Erdwurm

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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Direct Testimony of

D. Bentley Erdwurm

on Behalf of

Tucson Electric Power Company

July 2, 2007

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volumetrically to kilowatt-hour sales under applicable electric schedules, and will apply to all retail system sales. It will not vary by class of service.

Q. Have transmission cost adjustment charges previously been approved by the Commission?

A. Yes. The Commission has approved a similar adjustment clause for Arizona Public Service Company.

C. <u>Time-Of-Use Rates For Residential And General Service (<200 kW) Customers.</u>

Q. Does TEP currently have TOU rates?

A. Yes. However subscription to the current Time-of-Use programs is relatively small compared to non-TOU subscription. In part, this is due to a subscription cap on General Service Time-of-Use (Pricing Plan C76). However most time-of-use plans do not have caps. Customers sometimes do not believe that the potential to save compensates them for the "inconvenience" of TOU. TEP plans to increase efforts to educate customers about the benefits of our new TOU proposals, including savings opportunities. Proposed TOU rates have been redesigned to focus on relatively short, "super-peak" periods (usually 4 consecutive hours per day). This type structure not only offers customers many opportunities to "work around" the peak, it is also well suited to helping reduce peak demand in the extreme weather conditions of the TEP service territory.

Q. Why is TEP proposing additional TOU rates?

A. Including TOU rates within the overall rate design will provide a stronger price signal to customers to shift load out of the critical peak period. Reducing peak means that less power will be needed when it is most costly. Consequently, less power will have to be purchased from the spot market during peak times. This will result in savings for the Company and its customers. TOU customers who "shave" the peak and "fill in" the off-peak valleys reduce the average price that they pay for electricity. A TOU rate rewards customers who help lower average system costs. As a DSM measure, TOU is a low-cost program with large benefits in reducing peak. Requiring new customers to be on TOU tariffs will send price signals that more accurately reflect the additional costs needed to serve new load. Further, reducing peak period demand and shifting consumption to off-peak times helps increase load factor, which also reduces cost through the more intensive utilization of fixed resources. The tariffs setting forth the proposed TOU pricing plans are attached as part of Exhibits DBE-2, 3 and 4 to my Direct Testimony.

Q. Are you proposing TOU rates under all three Methodologies?

A. Yes. TEP faces a need to control peak demand regardless of the methodology chosen. Constraints apply over the generation, transmission and distribution functions. Time-of-Use helps defer capacity additions under all methodologies. Moreover, customers should have the opportunity to achieve savings through their usage patterns under each methodology.

Q. If TOU tariffs are so beneficial, why are you only recommending that new Residential (Pricing Plan R 01) and General Service (Pricing Plan GS-10) customers be on TOU tariffs?

A. It is impractical to immediately place all these customers on the new TOU plans because of the substantial number of meters that would need to be replaced under such a comprehensive program. Simply stated, we do not want to instantly erode the savings to be achieved by load shifting with the costs associated with comprehensive meter replacement. Meter replacement for existing customers could be phased in over time, so that the meter change-out costs never completely outpace the load shifting savings.

Placing new customers on TOU is a cost effective and simple way of phasing-in the new TOU program.

Q. Why should TOU rates be mandatory?

A. It will only be mandatory for new customers to the system, although existing customers would use TOU rates if they replace their meters. By making the rate mandatory, we ensure that customers are paying for the costs they impose on the system. Absent mandatory TOU, a non TOU customer using a relatively large proportion of his energy during on-peak times places the cost of his consumption on other customers. I believe that shifting of the burden of cost from the responsible party, the peak user, to other customers is fundamentally unfair. Appropriate rate design should reflect cost causation.

Q. Could the Company achieve the same goals by keeping non-TOU rates open, but setting non-TOU rates at a higher average price to reflect their less desirable usage profile?

A. No. I believe that to do so would only prolong the problem the Company experiences with excessive load in the critical peak period. Rates for non-TOU customers must reflect the reality that these customers' costs may be higher. While TEP could structure such rates, any modification made in the rate-setting process could destroy any effective price signals in a non-TOU rate. Without effective price signals that customers understand and pay attention to, fixing old subsidies and inequities is unnecessarily prolonged. I do not believe that it is good public policy to continue to allow our highest cost-to-serve customers to pass on their costs to other system customers. We have an obligation to design rates that are fair to *every* customer, including ensuring that the principal cost-causers pay rates that reflect the true cost of power that they use.

STRATEGEN
STRATEGIES FOR CLEAN ENERGY

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EXHIBIT
TASC 13
admitted

Meet the Team

ABOUT US

- Meet the Team
  - Consultants
  - Advisors
- Who We Help
- Our Values
- About CESA
- Careers

Janice Lin

Founder and Managing Partner, Strategen Consulting LLC
Co-Founder and Executive Director, California Energy Storage Alliance (CESA)
Board of Directors and Chair of the Executive Committee, Global Energy Storage Alliance (GESA)

Janice Lin brings more than two decades of experience in clean energy strategy, market development, and corporate strategy to Strategen. During this time she has advised a diverse range of clients including renewable energy equipment manufacturers and service providers, large corporations diversifying into clean energy, and real estate developers building sustainable communities.

In 2014 Janice co-founded the Global Energy Storage Alliance (GESA), an international non-profit organization, and currently serves on the Board of Directors and as Chair of the Executive Committee. Prior to that Janice co-founded the California Energy Storage Alliance (CESA) in 2009, and currently serves on the Board of Advisors for the Energy Policy Initiatives Center (EPIC) and the Energy Storage Committee of Joint Venture Silicon Valley. Janice is also a Member of the Advisory Council of the German American Chamber of Commerce, the UCSD Strategic Energy Initiatives Advisory Council, and Chair of the annual Energy Storage North America (ESNA) conference.

Prior to founding Strategen in 2005, Janice held several senior management positions with PowerLight Corporation (now SunPower Corporation), including Vice President of Product Strategy and Vice President of Business Development. During her tenure at PowerLight, Janice led initiatives in product and new market strategies, business development, regulatory affairs, strategic partnerships, investor relations, and customer finance.

Janice holds an MBA from the Stanford Graduate School of Business, a BS from the Wharton School, University of Pennsylvania, and a BA in International Relations from the University of Pennsylvania's College of Arts and Sciences. She is the winner of ESA's 2013 Phil Symons Energy Storage Award, and NAATBATT's 2014 Market Development Award.

Email Janice

Mark Higgins

Vice President and COO

Mark Higgins is Strategen's Chief Operating Officer and leads the company's consulting practice. Mark's career in the energy industry has focused on renewables project development and utility regulatory strategy. Prior to Strategen, Mark served as Pacific Gas and Electric Company's lead on electric transmission policy work at the CAISO, where he worked on formulating PG&E policy on energy storage, demand response, generator interconnection and transmission planning issues. Prior to PG&E, Mark was Director, Utility West at SunEdison (by way of its acquisition of FRV and MMA Renewable Ventures). His responsibilities included management of California utility scale project development strategy and execution. Mark's portfolio of projects included more than 1 GW of pipeline including SunEdison's largest development asset, for which he secured 132 MW of PPAs with California utilities. Mark also served as Vice President of Finance of Hu Honua Bioenergy, a 21.5 MW biomass power redevelopment project in Hawaii that was ranked in January 2015 by state government as the "#1 Clean Energy Leader" project in Hawaii.

Mark also has a strong private equity, venture capital and investment banking background, including placing over $125 million in equity for publicly traded companies while at Roth Capital Partners, and serving as the founding Associate at Finistere Partners, where he managed the launch of a $70 million Pacific-rim focused venture fund investing in the agricultural biotech and medical devices sectors.

Mark has also worked for the U.S. Foreign Commercial Service in Auckland, New Zealand, and as a systems analyst at Deloitte Consulting's Chicago office. Mark holds a Master of Pacific International Affairs from the University of California, San Diego, and a Bachelor of Arts in government from the University of Notre Dame.

In addition to his role at Strategen, Mark also serves as an advisor to the California Energy Storage Alliance, sits on the Steering Committee of the Australian Energy Storage Alliance, and serves on the City of Lafayette, California's Environmental Task Force.

Email Mark

Cedric Christensen
Director

Cedric Christensen is a Director in Strategen's Government and Public Sector practice. He manages projects with the U.S. Department of Energy and State Energy Agencies, including the DOE Global Energy Storage Database - the wikipedia of Energy Storage (goo.gl/xAbvxG). He leads policy and value proposition work on demand side management and serves a range of clients including renewable energy equipment manufacturers, developers, and service providers as well as corporations diversifying into clean energy.

Cedric led CESA's expansion in the midst of AB2514 implementation – the Energy Storage Assembly Bill. Since he joined the organization, he has worked on a number of strategic market development initiatives with key regulatory agencies (CPUC, CEC, CAISO, and the CA Governor's Office). His work includes launching Energy Storage North America, the largest Energy Storage Conference in North America.

Prior to CESA, he was General Manager for Agrion - a global network of Fortune 500 companies focused on Energy and Sustainability. Former United Nations Strategy Consultant with extensive international experience including managing sustainability and renewable energy projects with UNDP in Ecuador, the Global Environmental Fund and Ubifrance, French embassy trade office. Cedric received his Master's Degree in Policy & International Affairs from Sciences Po Paris.

Email Cedric

Lon Huber
Director

Lon Huber is a Director in Strategen's Government and Utility Practice. Prior to joining Strategen, Lon worked for the ratepayer advocate office in Arizona where he was the staff lead on key issues facing the electric utilities in the state. In this position he shaped high profile decisions around net metering, resource procurement, and utility owned distributed generation.

Lon got his start in the policy field at a University of Arizona based energy research institute. Subsequently, he worked in the private sector for several years in positions related to energy policy and economic development. His experience spans leading project finance for a solar integrator to managing regional policy efforts for a large solar panel manufacturer. Due to his efforts in the community, Mr. Huber received a congressional recognition award for his work in educating citizens about solar energy. During this time, he was also recognized as an Arizona Daily Star "40 under 40" winner for leadership, community impact, and professional accomplishment.

Lon earned a Bachelor of Science degree in Public Policy and Management and a Master's of Business Administration from the University of Arizona.

Email Lon

Edward Burgess
Manager

Edward Burgess is a Manager in Strategen's Government and Utility Practice. Prior to joining Strategen, Ed worked as an independent consultant for Kris Mayes Law Firm and Schlegel & Associates where he served clients in the renewable energy and energy efficiency industries, including several Fortune 500 companies, major project developers, trade associations, utilities, government agencies, and foundations. His analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed generation, and transmission planning.

In addition to his consulting work, Ed also played a lead role in two major initiatives at Arizona State University: the Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona.

Ed began his career working on environmental policy at the Environmental Defense Fund in New York. He earned his bachelor's degree in Chemistry from Princeton University and two degrees from Arizona State University - Master of Science (M.S.) in Sustainability and Professional Science Master (P.S.M.) of Solar Energy Engineering and Commercialization.

Email Ed

Shana Patadia
Senior Consultant

Shana Patadia is an Consultant at Strategen Consulting. Prior to her role at Strategen, Shana worked on a range of federal consulting projects. She has developed several modeling methodologies and tools for valuing energy security, analyzing utility rate impact for renewables, and modeling large federal funds.

Shana's initial involvement in the energy sector was through green jobs analysis with UC Berkeley, the results of which were published in a widely cited paper in Energy Policy, "Putting Renewables and Energy Efficiency to Work." Subsequently Shana has worked on a range of projects including electric vehicle to grid modeling for California, renewable energy project analysis, and the economics of carbon capture.

Shana received a Bachelor of Science in Business Administration and a Bachelors of Arts in Economics from UC Berkeley. She received her Masters of Environmental Management, focused on Energy and Environment, from Duke University's Nicholas School of Environment.

Email Shana

Jin Noh
Consultant

Jin Noh is an Consultant at Strategen Consulting. Prior to joining Strategen, Jin worked as an analyst at SRI International where he worked on a range of science, technology, and innovation policy consulting projects for public and private sector clients. At SRI, he worked on several energy-related projects, such as developing clean energy innovation metrics for the New York State Energy & Research Development Authority (NYSERDA) and designing an energy and nanotechnology incubator for the King Abdulaziz City for Science & Technology (KACST).

Jin has also conducted graduate research for various energy sector clients, such as Sfuncube, Sonoma Clean Power (SCP), and Department of Energy (DOE). Notably, he conducted a comprehensive analysis of the incentives, policies, and rate structures of major energy storage procurements across the US, Japan, and Germany to provide a procurement strategy for SCP.

Jin received a Bachelor of Arts in Public Policy Studies and Economics from Duke University, and a Master's in Public Policy from the University of California, Berkeley. His master's thesis assessed state regulatory decisions on grid resilience investments on behalf of the Office of Energy Policy & Systems Analysis at the DOE.

Email Jin

Randy Fish
Consultant

Randy Fish is a Consultant in Strategen's Government and Utility Practice. He also manages the Energy Storage North America program, social media marketing, and business development activities.

Randy brings ten years of experience in international development, project management, and science communications. Most recently, Randy managed a sustainability and science field station in the Virgin Islands. In addition to educating students and visitors about the facility's microgrid and conservation measures, he successfully implemented the station's first net-energy metering interconnection. Prior to his island life, Randy began his career as a US Peace Corps volunteer in Tanzania. As an Environmental Extension Agent, he collaborated with local communities to promote adoption of small-scale, off-grid solar in homes and hospitals, increase utilization of sustainable agriculture techniques, and build consensus on water resource management issues.

Randy received a Bachelor of Arts in Geography from California State University, Chico and a Masters of Science from Michigan Technological University. His master's thesis focused on modeling the effects of climate change on water resources in Tanzania.

Email Randy

Zoe Fishman
Marketing and Events Manager

Zoe Fishman is Strategic Marketing and Events Manager for Strategen Consulting. She leads all marketing programs for Energy Storage North America, including supporting partnerships, messaging and social media.

Zoe has worked in marketing and communications for the clean energy industry for over five years. Prior to joining Strategen, she was a Content Strategist at Choose Energy, a Kleiner Perkins-backed energy choice platform, where she focused on making retail energy choices clear and engaging for consumers. She also spent four years at Antenna Group, the largest clean energy communications firm in the United States. As an Account Supervisor, Zoe led media strategy, content marketing and thought leadership campaigns for clients in the energy storage, solar energy and energy efficiency sectors. She excels at helping clients craft their message and differentiate themselves in evolving industries, and has secured several prestigious industry awards and speaking opportunities on behalf of clients, including the World Economic Forum Technology Pioneers and the Bloomberg New Energy Finance Pioneers Award.

Zoe holds a Bachelor of Arts degree in History from UC Berkeley.

Email Zoe

Bill Ehrlich
Senior Analyst

Bill Ehrlich is a Senior Analyst at Strategen Consulting. Prior to joining the team at Strategen, Bill worked at Greentech Media in business development for their solar practice.

Bill has worked in clean energy and the electrical industry since graduating from college with a degree in finance. He has blended a financial background with strong technical experience in the field in order to achieve a holistic perspective of electrical energy. In addition to his work at Greentech Media, Bill's experience includes analytical lab work on fuel cells, project management for a commercial solar integrator, and electrical work for high rise buildings in downtown Chicago. He brings a deep understanding of the energy ecosystem as well as a passion for renewable energy and energy storage.

Bill holds a Bachelor of Business Administration in Finance from the University of Notre Dame.

Email Bill

Anirudh Kshemendranath
Senior Analyst

Anirudh Kshemendranath is a Senior Analyst at Strategen Consulting. Prior to joining the team at Strategen, Anirudh worked for Bosch Energy Storage doing analytical modeling on wholesale market participation.

Anirudh has an extensive engineering background and has worked on energy storage at numerous steps of the value chain including: manufacturing research, international advanced energy business development, and building algorithms for energy storage dispatch. Anirudh assists with technical analysis and analytical modeling to optimize energy storage dispatch and accurately value energy storage grid benefits.

Anirudh holds a Master of Science (M.S.) from Carnegie Mellon's Energy Science, Technology, and Policy (ESTP) program.

Email Anirudh

Jake Bartell
Analyst

Jake Bartell is an Analyst with Strategen Consulting. Before joining the Strategen team, Jake worked at Sunrun leading a specialist advisor team.

Jake's involvement in renewable energy began with an analyst contractor position with Tucson Electric Power as an undergrad at University of Arizona. He continued developing his energy experience working with in home consumption monitoring equipment, transportation logistics, and residential solar. In addition to his experience with Sunrun and Tucson Electric Power, Jake brings a solid understanding of customer interests, a passion for grid edge technologies, and a physical science background to the team.

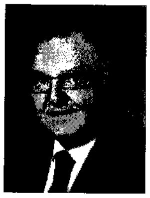
Jake holds a Bachelor of Science from the Arizona State University.

Email Jake

Advisors

Don Liddell

Senior Advisor



Don Liddell is a Principal of Douglass & Liddell, and specializes exclusively in energy business transactions and regulatory proceedings involving a broad array of energy-related products and services. He is also General Counsel for the California Energy Storage Alliance.

Don has over 30 years of experience in the private and government sectors of the industry. Prior to joining with Dan Douglass to form Douglass & Liddell, Don was Assistant General Counsel for Sempra Energy. He also served on the Board of Directors of the Independent Energy Producers Association from 1990 to 1997, including a term as Chairman. As an Adjunct Professor, he helped create and taught a course in Energy Law and Policy at the University of San Diego's School of Law. Prior to joining Sempra's predecessor companies in 1982, he was counsel to the United States Department of Energy's San Francisco office.

He received an LL.M from the London School of Economics, a J.D. from the University of California Hastings College of the Law, and his B.A. with honors from San Diego State University.

Ron Hofmann

Senior Advisor

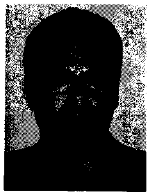
Ron Hofmann specializes in business development and technology assessment in the energy sector. Mr. Hofmann has extensive experience in developing new businesses and markets from the ground up. Currently, he sits on two Boards of Directors (Power Standards Laboratory & Sentient Energy) and one Board of Advisors (Strategen). In the recent past, he has served on two PV-related Boards of Advisors (PowerLight and PVT Solar). He also is a pro-bono advisor to several emerging energy-related technology companies and projects, and is involved in an ARPA-E project related to Micro-PMU's. Through CIEE at the University of California, he helped the California Energy Commission's PIER program develop RD&D projects and through Lawrence Berkeley National Laboratory, he advised regulators on the implications of Smart Grid technologies especially those that involved controls & communications. He is also a Venture Advisor for Claremont Creek Ventures.

Over the past 45 years, Mr. Hofmann has started several successful enterprises. In the early seventies, he helped pioneer the commercialization of engineering simulation software (PISCES) through direct sales and the use of CDC Cybernet (an early worldwide computer network of mainframes). In 1974, he co-founded and co-managed a SAIC office for 9 years. Among his long-term clients were EPRI for nuclear reactor safety software development (STEALTH codes) and ONWI/ERDA for nuclear waste isolation simulations. In 1983, he was a co-founder (and the original CEO for 10 years) of EnergyLine Systems, Inc. ELSI, acquired in 1998 by S&C Electric, developed smart (communicating) controls for commercial and industrial HVAC equipment (e.g., chillers, unitary equipment, VAV boxes, etc.) and electric utility power-distribution controls for sectionalizers (IntelliTEAM), capacitor banks, reclosers, etc.

Mr. Hofmann has a mechanical engineering degree from the University of California in Berkeley and did post-graduate studies in thermo sciences at the University of Wisconsin in Madison. For many years, he was an active (and charter) participant in the CEO Forum sponsored by the Santa Clara University Business School. In his career, he has held technical, marketing, sales, and management positions in large and small companies.

Roger Levy

Senior Advisor



Roger Levy established Levy Associates in 1980. He has been actively involved with the utility industry since the mid 1970's, completing over 200 projects in system development, planning, implementation, evaluation, and research.

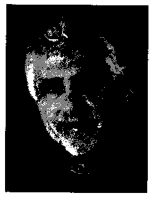
Roger was the principal consultant for the California Energy Commission advanced metering and pricing initiatives as well as the lead on the California Statewide Pricing Pilot. As a consultant to the Lawrence Berkeley National Laboratory Demand Response Research Center he developed their first comprehensive research plan, initiated the commercialization of OpenADR, and managed projects to enable dynamic pricing and demand response technology. Roger was also the lead consultant on the DOE/LBNL Smart Grid Technical Advisory Project where he provided technical, policy, and research support to NARUC and over 20 state regulatory commissions nationally. Roger also participated as senior technical advisor on several of the DOE funded Smart Grid Investment Grant Consumer Behavior pilots.

Roger has been involved with sustainable community projects, transportation planning, environmental impact evaluations, technology development, and implementation in private industry and with utilities. He began his career with the Corporate Planning group at Xerox Corporation, was a senior system analyst with RCA Computer Systems, and spent seven years as a management consultant with Arthur Young & Company and Price Waterhouse. In the mid 1970's Roger received a special appointment to the just inaugurated California Energy Commission where he managed 23 of the first PURPA pricing and load management pilots and co-managed development of the State Load Management Standards.

Roger received a BS in Management Science from the Simon Graduate School of Management at the

University of Rochester and a MBA in Quantitative Methods from the Marshall Graduate School of Business at the University of Southern California.

Ron Kenedi
Senior Advisor



Ron Kenedi has spent more than 30 years in the Solar Power industry bringing to life his core belief that "Solar Power should be a vital part of the mainstream energy solution". Today, with the Solar Power industry simultaneously experiencing turmoil, uncertainty and explosive growth, it is the right time for an experienced visionary to be available to help organizations and enterprises navigate the challenging pathways to success.

Throughout his corporate career, Kenedi oversaw the successful operation of industry-leading solar energy corporations in the U.S., Canada, Australia, Africa and Latin America. Corporations include; LDK Solar, Sharp Electronics Solar Division, Kyocera Solar Inc. and Photocomm, Inc. An expert in the field of solar energy, Kenedi has served as an industry spokesperson, appearing on television and radio and providing commentary for print and online media.

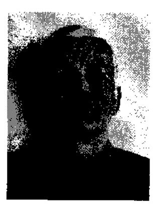
He is a current board member of Westinghouse Solar and a former board member of the Solar Alliance and the Solar Energy Industry Association (SEIA). He has worked closely with a number of industry associations, including the California Solar Energy Industry Association (CALSEIA), Arizona Solar Energy Industry Association (ARISEIA) and International Solar Energy Society (ISES). He has also worked closely with government agencies and organizations such as the U.S. Department of Energy, Sandia National Laboratory, National Renewable Energy Laboratory (NREL), California Energy Commission, Arizona Corporation Commission, Nevada Energy Commission and Florida Solar Energy Center (FSEC).

Kenedi is named to World Generation's, prestigious, Class of 2012 of the energy industry top twenty leaders along with executives from Bechtel, Siemens, GE, Google, Global Energy Zurich and the Governor of State of Oklahoma.

Jim Eyer
Advisor

Jim's entire 25 year career has involved energy efficiency, renewables and advanced energy technologies, concepts, benefits and markets. He has been Senior Analyst with Distributed Utility Associates for 13 years. Before that he held a range of positions with Pacific Gas and Electric Company related to advanced electric technology and concepts R&D, electric supply planning, and commercial energy efficiency services. For the last fifteen years Jim has focused on energy storage with an emphasis on benefits and value propositions. He has an undergraduate degree with a double major in physics and management from Sonoma State University and an M.A. in management also from Sonoma State.

Mike Katz
Advisor



Mike Katz has over 30 years experience in electric and natural gas markets, risk management, strategic planning and operations of physical assets. He has been consulting for the last 9 years. His most recent work is being an Independent Evaluator for San Diego Gas & Electric's (SDG&E's) and Southern California Edison's (SCE's) procurement RFOs. He worked at PG&E from 1983 through 2004 in various departments, including being the vice president of California Gas Transmission, Lead Director of Power Generation, Director of Generation Portfolio Management (Wholesale Energy Sales) and positions in various planning groups.

Mike graduated from the University of Massachusetts, Amherst with a B.S. in Civil Engineering and earned an M.S. in Mechanical Engineering from the University of California, Berkeley. He is a registered Mechanical Engineer in California.

Gene Hunt
Advisor

Gene Hunt is co-founder of Trevi Communications, a specialty marketing communications and PR firm focused on advancing emerging technologies and related professional services. A marketing communications strategist and writer with more than 30 years of experience, Gene works with new and established technology companies and innovators. With particular expertise in the energy sector, he combines a passion for sustainable solutions with journalistic insight to craft effective and compelling communications. Gene has created and implemented hundreds of successful programs in support of brand launches, IPOs, events, marketing initiatives and publicity campaigns.

Early in his career, Gene held communications management positions in both the U.S. and Europe for global B2B firms including Agfa-Gevaert, Bayer AG, Tyco Electronics, Raytheon and others. Since 2002, he has focused on energy storage and renewable energy, directing communications for clients covering a range of technologies including flywheels, compressed air, advanced batteries, and photovoltaic inverters. During this time (from 2003 till 2010), he also co-founded a full-service PR agency that grew to 40 employees. Gene holds a B.A. degree (magna cum laude) in communications from Suffolk University and speaks three languages.

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GESA
Global Energy Storage Alliance (/)

Advancing education, collaboration, knowledge and proven frameworks about the benefits of energy storage globally

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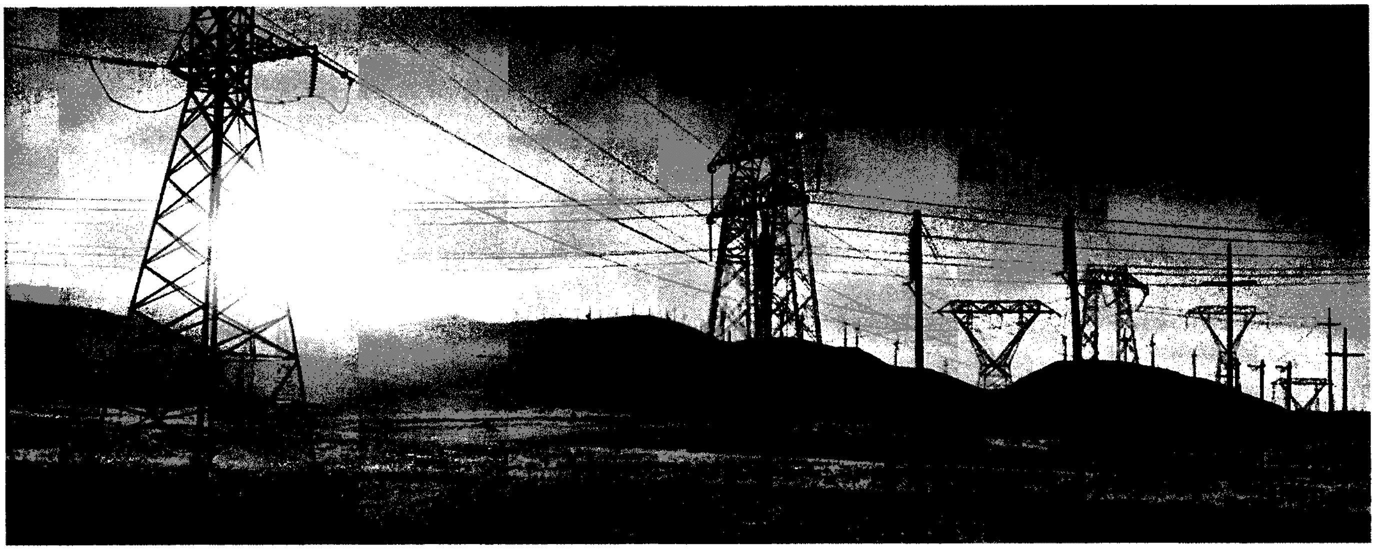
Co-Founders (/co-founders) Leadership (/leadership)

Global Energy Storage Database (http://www.energystorageexchange.org/) Contact (/contact)



Purpose

- Advance global education, collaboration, knowledge and proven frameworks about the benefits of energy storage and how to incorporate it into the electric power system in a cost effective way
- Increase ecosystem development funding pool: target foundations, NGOs and governments who share GESA's mission
- Empower local ESA's and other key stakeholders, not compete with them for funding
- Learn from local market development efforts, help proliferate best practices
- Foster collaboration among key stakeholders including policy makers, utilities, renewable energy community, financial institutions and environmental organizations
- Help establish standards and protocols to advance energy storage acceptance worldwide

Latest News

- PRESS RELEASE: IRENA Roadmap Breaks New Ground on Renewable Energy Storage (/events/19-press-release-irena-roadmap-breaks-new-ground-on-renewable-energy-storage)
- Latest Trends in Distributed Energy Storage - European Energy Centre (EEC) (/events/18-latest-trends-in-distributed-energy-storage-european-energy-centre-eec)
- Global Energy Storage Alliance Market Update - Feb.

11, 2015 (05:30am PST) (/events/15-global-energy-storage-alliance-market-update)

- Solar Resource Data Applications for Utility Planning and Operations - Feb. 23, 2015 (16:00 GMT) (/events/16-solar-resource-data-applications-for-utility-planning-and-operations-feb-23-2015-16-00-gmt)
- Innovations in Energy Storage (/purpose/2-uncategorised/14-innovations-in-energy-storage)

Tweets by @GlobalESA (https://twitter.com/GlobalESA)

Visualscope (http://www.visualscope.com)

Co-Founders

Alliance for Rural Electrification Shining a Light for Progress (http://www.ruralelec.org) BVES GERMAN ENERGY STORAGE ASSOCIATION (http://www.bves.de) CESA CALIFORNIA ENERGY STORAGE ALLIANCE (http://www.storagealliance.org) CNESA (http://www.cnesa.org) ESA Energy Storage Association (http://energystorage.org) IESA India Energy Storage Alliance (http://indiaesa.info)

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CESA
CALIFORNIA ENERGY STORAGE ALLIANCE

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EXHIBIT
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About Us

> *"CESA has been highly effective in promoting regulatory reforms for energy storage, helping to educate legislators, PUCs, utilities and others as to the true value proposition of storage. Every stakeholder stands to gain by supporting CESA and taking advantage of their advocacy and actions, both in California and at the national level."*
>
> *Judith Judson, Director of Emerging Technologies, Customized Energy Solutions*

Overview

The California Energy Storage Alliance (CESA) is a 501c(6) membership-based advocacy group committed to making energy storage a mainstream resource in helping to advance a more affordable, cleaner, efficient and reliable electric power system in California. CESA accomplishes this objective through policy development, education, outreach, and research.

Our Mission

Our mission is to make energy storage a mainstream energy resource that accelerates the adoption of renewable energy and promotes a more efficient, reliable, affordable, and secure electric power system.

Our Members

Our membership includes technology manufacturers, project developers, systems integrators, electrical contractors, software developers, profession services firms, and other clean tech industry leaders. We are technology and business model-neutral, and are supported solely by the contributions and coordinated activities of our members.

Our Achievements

CESA was founded in February 2009 and quickly established a solid track record of success:

- CESA influenced amendments and helped garner support for AB 2514 (Energy Storage Procurement Targets) now signed into law. This bill will open a storage-focused rulemaking at the CPUC.
- California legislative leaders - including Assembly Member Nancy Skinner (Chair of the Natural Resources Committee), Assembly Minority Leader Sam Blakeslee, and Senator Christine Kehoe (Chairman of the Senate Appropriations Committee), the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the California Attorney General -- all rely on CESA as the go-to source for storage information and policy input
- CESA influenced amendments and helped garner support for SB 412 (Self Generation Incentive Program expansion, now signed into law) which will open the way for incentive funding for more applications of storage
- CESA influenced amendments to SB 14 and AB 64 (Renewable Portfolio Standard bill, vetoed by the Governor) to ensure that renewables coupled with storage would be counted toward California's RPS, and in the process educated key democratic renewable energy champions in the legislature about the importance of storage
- CESA is an active participant in selected high profile CPUC proceedings, including key energy policy areas critical to storage:
    - SGIP modifications and SCE fuel cell protest
    - Smart Grid implementation
    - Feed-in Tariff implementation
    - Cost-benefit methodology for distributed energy resources
    - Demand response/permanent load shifting
    - Demand response/non generation DR (ancillary services)

- CESA is an active participant in the CEC's integrated energy policy report (IEPR) development, working both formal and informal channels at the CEC for the consideration of storage
- CESA will be an active participant in the California Air Resources Board RPS/RES implementation process (California's 33% RPS implementation is now led by CARB by Executive Order)
- CESA is a key stakeholder in the CAISO's implementation of FERC Orders 719 and 890 mandating comparable treatment of non-generation resources in wholesale markets
- CESA frequently presents at major conferences, in California, nationally and abroad
- CESA testified before the California legislature in support of key omnibus storage legislation

Next: Our Leadership »

Global Power Best Practice Series

4

EXHIBIT
TASC 16
admitted

Time-Varying and Dynamic Rate Design

RAP Energy solutions
changing world

The Brattle Group
ECONOMIC AND FINANCIAL EXPERTS

July
2012

Time-Varying and Dynamic Rate Design

Authors

Ahmad Faruqui
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Acknowledgements

Several people made important contributions in the preparation of this report. Lisa Schwartz and Jim Lazar assisted in defining the scope and organization, and provided commentary through several drafts. Frederick Weston, Peter Cappers, Riley Allen, Elizabeth Watson, Bob Lieberman, Becky Wigg and Camille Kadoch contributed to the review and final editing of this report.

Unless otherwise noted, all tables and figures used in this document were created by The Brattle Group.

Electronic copies of this paper and other RAP publications can be found on our website at **www.raponline.org.**

To be added to our distribution list, please send relevant contact information to **info@raponline.org**.

About the Global Best Practice Series

Worldwide, the electricity sector is undergoing a fundamental transformation. Policymakers recognize that fossil fuels, the largest fuel source for the electricity sector, contribute to greenhouse gas emissions and other forms of man-made environmental contamination. Through technology gains, improved public policy, and market reforms, the electricity sector is becoming cleaner and more affordable. However, significant opportunities for improvement remain and the experiences in different regions of the world can form a knowledge base and provide guidance for others interested in driving this transformation.

This Global Power Best Practice Series is designed to provide power-sector regulators and policymakers with useful information and regulatory experiences about key topics, including effective rate design, innovative business models, financing mechanisms, and successful policy interventions. The Series focuses on four distinct nations/regions covering China, India, Europe, and the United States (U.S.). However, policymakers in other regions will find that the Series identifies best — or at least valued — practices and regulatory structures that can be adapted to a variety of situations and goals.

Contextual differences are essential to understanding and applying the lessons distilled in the Series. Therefore, readers are encouraged to use the two supplemental resources to familiarize themselves with the governance, market, and regulatory institutions in the four highlighted regions.

The Series includes the following topics:

1. New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China
2. Policies to Achieve Greater Energy Efficiency
3. Effective Policies to Promote Demand-Side Resources
4. Time-Varying and Dynamic Rate Design
5. Rate Design Using Traditional Meters
6. Strategies for Decarbonizing Electric Power Supply
7. Innovative Power Sector Business Models to Promote Demand-Side Resources
8. Integrating Energy and Environmental Policy
9. Policies to Promote Renewable Energy
10. Strategies for Energy Efficiency Financing
11. Integrating Renewable Resources into Power Markets

Supplemental Resources:

12. Regional Power Sector Profiles in the U.S., Europe, India, and China
13. Seven Case Studies in Transmission: Planning, Pricing, and System Operation

In addition to best practices, many of the reports also contain an extensive reference list of resources or an annotated bibliography. Readers interested in deeper study or additional reference materials will find a rich body of resources in these sections of each paper. Authors also identify the boundaries of existing knowledge and frame key research questions to guide future research.

Please visit www.raponline.org to access all papers in the Series.

This Global Power Best Practice Series was funded by the ClimateWorks Foundation www.climateworks.org

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Acronyms

ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
Auto-DR	Automated Demand Response
BGE	Baltimore Gas and Electric
C&I	Commercial & Industrial
CAC	Central-Air Conditioning
CL&P	Connecticut Light and Power
CPP	Critical Peak Pricing
CPP-V	Critical Peak Pricing-Variable
CPR	Critical Peak Rebate
DSM	Demand Side Management
EdF	Electricite de France
EVN	Electricity Vietnam
GHG	Greenhouse Gas
HAN	Home Area Network
IHD	In-home Display
ISO	Independent System Operator
kVA	Kilo-volt Amps
M&V	Measurement and Verification
MW	Megawatt
PCT	Programmable Communicating Thermostats
PG&E	Pacific Gas & Electric
PTR	Peak Time Rebates
RCT	Randomized Control Trial
RTP	Real Time Pricing
T&D	Transmission and Distribution
TOU	Time-of-Use
TRC	Total Resource Cost Test
VPP	Variable Peak Pricing

Foreword

Together, this paper and its companion piece, *Rate Design Using Traditional Meters,* examine the wide spectrum of retail pricing practices for regulated energy services and identify those that have particular promise in contributing to the achievement of critical public policy objectives, which we might broadly categorize as equity, efficiency, and the sustainable use of our finite natural resources. The papers should prove an excellent resource for policymakers, power companies, advocates, and others as they navigate the arcana of utility pricing and engage on a topic that has, by virtue of advances in information technology and changes in the underlying economics of power production and delivery, become at once more complex, more controversial, and, too often, more distracting.

The complexity and controversy are not avoided in these papers. Though for the most part they express views that are consistent with those of the Regulatory Assistance Project, it is not true in all cases. This is a virtue. We embrace the dialectic: over the coming months and years we will continue to work on these issues, follow progress globally, and re-examine our views in the light of new findings. These papers are only our most recent look at the state of the art. There will be others.

Still, a few comments today are warranted. Regulators are constantly told to "get prices right," a refrain whose meaning is more easily understood in the speaker's mind than it is conveyed to those who must put it into practice. In our experience, the prescription must be taken with two doses of realty's practical learning: one, that getting prices "right" is by no means straightforward and, two, that, even if one manages to set prices that in some fashion might be called "right," some of the key objectives of pricing will nevertheless remain unmet. Foremost among them is overcoming society's very serious underinvestment in cost-effective energy efficiency and other clean energy resources, and it is primarily for this reason that we say that pricing reform must be dealt with in a much broader policy context.

But, first, what is "right"? The question has surely been debated since governments began pricing these services "affected with the public interest," but the form of the debate only began to take its modern shape in 1949 with the publication of Marcel Boiteux's "La Tarification des demandes en pointe," which gave renewed currency to certain prerequisites for economic efficiency: one, that those who cause a cost to be incurred should pay that cost and, two, that, by paying, the cost-causers will necessarily comprehend the real value of the resources that they are committing to their consumption.[1] Here was a practical application of neoclassical economic theory to the pricing of networked utility services, and it was very influential.

The seminal work in English on the topic followed in 1961: James Bonbright's *Principles of Public Utility Rates.*[2] In it, Bonbright identifies ten criteria to be considered when setting utility prices and acknowledges, importantly, that they cannot all be entirely satisfied simultaneously. There will always be trade-offs. Nine years later, Alfred Kahn published *The Economics of Regulation,* which, among other things, made the case for subjecting to competition certain regulated services, when those services no longer exhibit the characteristics of natural monopoly.[3] Thus, in two decades, the intellectual foundations for a range of reforms in utility regulation were set and, in the thirty years since, we've seen extraordinary changes in the provision and pricing of air travel, telecommunications, electricity, and natural gas—that is, in essential infrastructural industries—around the globe.

But, for all that, the question of how to get prices right remains. Bonbright can't be evaded. What constitutes economically efficient pricing? Should efficiency be the

1 Boiteux, 1949

2 Bonbright, 1961

3 Kahn, 1988 (Original work published 1970)

primary objective and, if so, how can it be ensured without a proper accounting of environmental damage costs and other unmonetized externalities, both positive and negative, that attend the production and consumption of electricity and gas? What are the benefits of participation in a network and do they justify approaches to pricing that will, in the eyes of some, offend Boiteaux's injunctions? What is equitable? How does the underlying market structure—monopolistic, regulated, or competitive—affect pricing? Are prices in competitive markets "better" than their administrative analogues? How does pricing influence consumer behavior, and how does that behavior influence utility incentives to invest? How will utility revenues be affected by different pricing structures or, more to the point, how will utility profitability be affected? How complex is the pricing structure? Can it be easily understood by consumers and easily administered by the utility? In short, how are the competing objectives balanced? What kinds of pricing will achieve preferred outcomes?

These are complicated questions all. Their answers deserve careful analysis and even more careful judgment. Dogmatism is unhelpful: the tools of economics, powerful and important, are nonetheless limited. It isn't enough to say "Let the market decide." On the contrary, in certain instances, it's irresponsible. Design matters. Markets may deliver what they're intended to deliver, though not always in ways expected, but rarely do they deliver that which is desired but unvalued. And it's very difficult to fix them after the fact. For proof of this, one need look no further than the United Kingdom, which is facing the unpleasant prospect that its electric markets are unlikely to produce the amounts and kinds of resources that it needs to meet its own climate protection goals. Or New England, whose forward capacity market was the first to permit end-use energy efficiency and other demand response resources to participate in the provision of reliability services, but which worries now that the market fails to properly compensate the providers of those services. Such shortcomings counsel us to move cautiously before trying to drive behavior by the passing-through to retail customers of market prices, if we cannot be confident that the consequences they bear will best serve the public good.[4]

As a general matter, encouraging customers to manage their consumption in response to price signals, so that the efficiency and value of their usage increases, is a good thing. Retail prices should relate to the underlying costs of production—all costs, including those we can't easily calculate. This is the economist's argument—at once academic and practical, for the most part uncontentious, and always invoked. Its implications, however, can overwhelm. If we find that our approach to energy production and use is impossibly sustainable, then it is no longer possible for policymakers to accept the exalted principle *and then promptly ignore it.*

But let's imagine that prices do cover all costs. There are still the practical aspects of pricing to be dealt with. How are those costs best represented in prices? George Bernard Shaw's famous snort —"If all the economists were laid end to end, they'd never reach a conclusion"—is not more aptly demonstrated than by the mavens of regulation who debate this point ad nauseum, and often at a pitch that belies the significance of the effects that their favored alternatives will likely produce. What is the thing sold? How should its prices be denominated? What should be the price's level and periodicity? Should it vary temporally and, if so, at what intervals? Should it pass through, from moment to moment, actual wholesale commodity prices or are there less volatile means of reflecting time- (and, in certain cases, location-) dependent costs? How should the costs of poles and wires be recovered? Should costs that appear fixed in the short term be collected in unvarying and unavoidable fees, unrelated to usage? Should price levels be determined with an eye to elasticities of demand?

4 Another example will demonstrate that this is not an abstract concern. Consider that under most market structures firms are rewarded for increasing the utilization of their existing capacity. In the power sector, this means that profitability will increase as system load factors (the ratio of total consumption to maximum potential consumption, given actual peak demand) increase. As a practical matter, this is achieved through the shifting of on-peak demand to off-peak hours, when marginal costs are lower. Total system costs will be lower as well; everyone is better off. But what if on-peak demand is served by low- or non-emitting resources and off-peak demand is served by highly polluting ones? This is precisely the conundrum faced at times in places where on-peak usage may be met at the margin by natural gas and hydro-electric production, while off-peak usage variations are often served by ramping the output of coal-burning plants up and down.

There are other considerations. Some of the more innovative and beguiling price structures being proposed require significant investment in new technology and data telemetry. Establishing that there are positive net benefits from these investments is by no means straightforward, especially when the full effects on behavior of the pricing structures they enable are imperfectly appreciated. And what about the customers who, for whatever reason, cannot react to the signals they are given and thus are harmed? That harm might be appropriate as a general matter (if we are true to the "the cost-causer pays" theme) and the overall public good may outweigh the losses of the relative few, but there are some customers for whom a change in the status quo can have altogether deleterious effects, whose private pain will be, along other dimensions of welfare, disproportionate to the good achieved. What sickness then is this medicine healing?

We recognize that more dynamic, time-varying pricing enabled by smart grid investment holds much promise. But, as we see it today, its value lies not so much in the responsiveness of customers to such pricing (although there is certainly value there) as in the new and expansive opportunities that it offers system operators to design and run the system that we must have, if we are to succeed in the great task remaining before us. That new system will be one in which the variability of supply, variable because the resources that drive it—sun, wind, water—do not submit easily to human timetables, will be matched by variable load, variable not so much because a million individual demanders respond to changes in price but because the exercise of their discretion will have been placed (to be sure, voluntarily) into the hands of system operators and other market actors. A decarbonized power sector will not come about merely because customers respond to price fluctuations. There are too many other influences on behavior that confound "rational" economic thinking on the parts of users. Moreover, as the dynamic pricing pilots around the United States and elsewhere are consistently demonstrating, retail responsiveness to price rarely manifests itself as overall reductions in energy use, but almost entirely in the shifting of use in time—that is, it mostly affects demand for capacity, not demand for energy. Yet, far and away, the problem—the environmental problem—is energy.

Much can be done with current technologies. The United States, for example, has had decades of experience with inclining block, seasonally-differentiated, and simple time-of-use pricing structures. They've sent meaningful, albeit rough, signals about the varying costs of production across time, and have led to significant long-term changes in consumption habits. In 2005, China adopted a policy of "differential pricing," whereby industrial users pay prices that are linked to the efficiency of their manufacturing: the less efficient the process, the higher the unit price for electricity. Five years later, China mandated that residential inclining block pricing be implemented throughout the country, and has instructed provincial regulators to design the blocks so as to best address the particular consumption characteristics of their populations. One size does not fit all.

There is much yet to learn. A number of pilots have been conducted and more will follow. Pricing will evolve over the coming years. The movement toward new forms must be deliberate and considered, calculated to yield the greatest long-term benefit for all. This will be especially challenging in a system that does not allow all the costs of production to be reflected in price and in which the consequences of this failure are not immediately felt. But even this ideal, were it achievable, would not be enough to effect the hoped-for ends. Economics is too uncomplicated a construct to provide sure solutions for so complicated a problem. Anyway, there are at our disposal less expensive means to drive investment and encourage new-shaped behavior. For these reasons and others besides, pricing must remain within the province of thoughtful public policy. Our intent with these papers is to expose to the reader the many and varied approaches to energy pricing that practice and technology afford us, and to sound too a gentle note of caution. All that glitters, as the old saw goes, isn't gold.

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Executive Summary

This report, written largely for regulators and policymakers around the globe, discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

The rate design principles presented in this report are based on the authors' first-hand experience in designing and evaluating innovative rate designs over the past three decades, conversations with other experts in the field, and the rate design and pricing literature. While the report is focused on design principles, there is much leeway in the application of the principles. Much of the success of the deployment of time-varying pricing will depend on the attitudes and preferences of the customers in the target market and the effectiveness of activities supporting the deployment by utilities, regulators, and other stakeholders. While there are many potential benefits to time-varying rate deployment, there are also risks and costs that must be addressed through careful thinking and planning. Even though experimentation and full-scale deployment in several parts of the globe have yielded valuable insights that can help mitigate risks, there remains room for additional research to further improve our understanding and facilitate the development of effective solutions to these concerns.

The key findings of the report are summarized below.

Metering technology is rapidly changing, creating the opportunity to provide time-varying rates for the mass market. Smart meters are being deployed increasingly around the globe. Roughly 64 million smart meters are currently in place and 825 million are expected to be installed over the coming decade.[5] Among many potential benefits of this new technology is the ability to provide innovative pricing schemes to retail electricity customers. While traditional electromechanical meters are read manually and on an infrequent basis, smart meters record and digitally communicate electricity consumption data on frequent intervals (e.g., 15 minutes or hourly), thereby allowing for the provision of time-varying rates.

Time-varying rate options present varying risk-reward tradeoffs to consumers. Time-varying rates include time-of-use (TOU) rates, critical peak pricing (CPP), peak time rebates (PTR), and real time pricing (RTP), as well as variations and combinations of these rate designs. Each design provides a different degree of price volatility and uncertainty for customers, and therefore presents a different opportunity to reduce their electricity bill by shifting load from higher-priced hours to lower-priced hours.

There are many potential benefits of time-varying rates. Time-varying rates have played an important role in justifying investment in smart metering. Among the *potential* benefits are avoided or deferred resource costs (including generation capacity and, to a lesser extent, transmission and distribution capacity), reduced wholesale market prices, improved fairness in retail pricing (i.e., providing a better match between the costs that customers impose on the system and the amount they are billed), customer bill reductions, facilitating the deployment of both distributed resources (such as solar electric systems) and end-use technologies (such as plug-in electric vehicles), and environmental benefits (through possible emissions reductions).

Time-varying rates also impose costs on customers. From the customer perspective, there are two main costs associated with time-varying rates. The first is the

5 Based on data provided by eMeter.

incremental monthly metering cost that customers would be required to pay. This is often the cost of smart metering net of operational benefits (e.g., avoided meter reading costs). The second cost is the loss of economic welfare associated with reducing usage during a high-cost period (curtailment) or shifting usage to a lower cost period ("hassle factor").[6]

A number of key parameters need to be defined when designing a time-varying rate. How many different pricing periods will be offered? What will be the price level in each of those periods? When will the periods occur? How and when will customers be notified of an upcoming dynamic pricing event? Will the time-varying rate be offered in combination with any other rate structure, such as inclining block (also called tiered or inverted block) rates that charge customers more per unit (kilowatt-hour) for higher levels of usage? While practices in time-varying rate design are still evolving – particularly for the mass market – some general criteria for effective rate design can be established based on theory, intuition and field experience.

Well-designed pilots are critical to proving the benefits of time-varying rates. Before deploying time-varying rates at scale, conducting pilots with a limited number of customers will help to understand what works and what does not. Prudent pilot design involves several key steps, including choosing the right type of pilot, defining the specific rates to be tested, establishing two comparable groups of customers (one enrolled in the new rates and the other serving as a "baseline" for comparison purposes), and identifying the most effective ways to recruit participants into the pilot.

We have learned a lot about time-varying rates through recent pilots. For example, weather, end-use saturation, price level, sociodemographic characteristics, and other factors all affect the degree to which customers shift load in response to time-varying rates. Load shifting increases as the strength of the price signal increases, but at a decreasing rate. Low-income customers have been found to be price responsive, although not always as responsive as the average residential customer. Impacts of time-varying rates have persisted for several years and over consecutive pricing events. And enabling technologies, such as smart thermostats, have been shown to incrementally boost price response.

New research will further inform our understanding. There are still important questions about time-varying rates that remain partially or entirely unanswered. What are customer preferences for the various rate options? Do rebates for curtailment produce the same level of price response as higher prices during peak hours (and lower prices during other hours)? Do time-varying rates lead to energy conservation? Do time-varying prices lead to fuel switching and the use of distributed generation? What is the impact of enhanced energy information on peak consumption? New research will help to answer questions such as these.

There are options for facilitating the transition to time-varying rates. Changing the way electricity has been priced for decades will not be easy. However, several tools exist to assist with the transition to time-varying rates. For example, an intensive, research-based marketing and education effort will help customers to understand the benefits and opportunities of time-varying rates. Temporary bill protection would help customers to learn about the rate first-hand, without being exposed to the risk of higher bills. Improved information about their electricity consumption patterns could provide customers with actionable ways to shift load and lower their bills. And rate designs such as two-part pricing would provide customers with the flexibility to manage the level of price volatility to which they are exposed.

6 Note that this loss of welfare should be treated similarly across all demand-side programs that may produce such an effect, and not just limited to time-varying rates.

1. Introduction

For the vast majority of electricity consumers, metering technology has remained effectively unchanged over the past 100 years. With the exception of the largest commercial and industrial facilities, most consumers are equipped with simple electromechanical meters which must be read manually. Due to the high cost of this manual approach to meter reading, meters are typically read no more frequently than once per month. This has acted as a constraint on the types of rates that an electricity provider can offer. "Flat" or "fixed" rates[7] are essentially the only option available, along with some possible alternate variations (such as the ability to increase the price as consumption increases over the course of the billing period). The lack of granularity in electricity consumption data has prevented all but a limited set of time-varying rates from being provided to all but the largest customers. However, the "digital revolution" of the past few decades has produced a new, increasingly cost-effective form of metering that is beginning to change this picture entirely.

Today, smart meters are being deployed increasingly around the globe. Roughly 64 million smart meters are currently in place and 825 million are expected to be installed over the coming decade.[8] Among many potential benefits offered by this new technology is the ability to provide innovative pricing schemes to retail electricity customers that help to foster more responsive customer demand. While traditional electromechanical meters are read manually and on an infrequent basis, smart meters record and digitally communicate electricity consumption data on frequent intervals (e.g., 15 minutes or hourly), thereby allowing for the provision of rates that vary by time of day. These new rates that are enabled by smart meters are referred to collectively in this report as "time-varying rates."

The benefits of time-varying rates have played a pivotal role in justifying investment in smart metering technology. While some smart metering investments can be justified purely on the basis of operational savings (e.g., avoided meter reading costs), many utilities have required the additional benefits of time-varying rates - such as avoided resource costs - to show that the investment would produce a net benefit to consumers. Achieving these benefits, however, requires careful planning, intelligent rate design, and a thorough understanding of the important issues that are emerging as smart meters and time-varying rates are beginning to be deployed internationally.

The purpose of this report is to provide regulators and policymakers around the globe with a resource that highlights important issues in time-varying rate design and deployment. The report also summarizes recent implementation experience with international time-varying rate offerings.

Why offer time-varying rates?

Time-varying rates represent an opportunity to improve over traditional "flat" rates that do not vary by time of day, by providing societal and consumer benefits. Potential benefits of time-varying rates include:

- **Avoided or deferred resource costs:** With prices that are higher during peak hours and lower during off-peak hours, time-varying rates encourage customers to shift consumption away from peak hours and therefore reduce system peak demand. This avoids the need to invest in expensive new peaking plants that are built to maintain a reserve margin but otherwise operate during very few hours of the year. Peak demand reductions can also lead to deferred transmission and distribution (T&D) costs that are peak-driven.[9]

7 A "flat" rate design refers to one with a uniform price per kilowatt-hour for all consumption regardless of when the consumption occurs.

8 Based on data provided by eMeter.

9 Faruqui, Hledik, Newell, & Pfeifenberger, 2007

- **Reduced wholesale market prices:** A reduction in demand during high-priced hours could reduce wholesale market prices in those hours - a benefit to all market participants.[10]

- **Fairness in retail pricing:** One notion of fairness is that cost-causers should bear their proportionate burden of costs on the system. If the underlying cost of providing electricity varies over time, then time-varying rates provide a better match between costs and bills. Under a flat rate structure, customers who consume more electricity during high-cost hours (i.e., peak hours) effectively rely on customers who consume less during those hours to ensure that all costs are recovered in rates. During time periods when costs are high, traditional flat rate structures result in an effective customer cross-subsidy relative to a well-formed time-varying rate alternative (i.e., the additional costs imposed by one group of customers are borne by other customers.)

- **Customer bill reductions:** In the short run, time-varying rates offer participants an opportunity to reduce their electricity bills by shifting consumption to hours that are priced lower than their otherwise applicable flat rate. In the long run, time-varying rates should improve the system load factor and lead to a lower revenue requirement, compared to what it would be without the demand response from time-varying rates.

- **Facilitating deployment of distributed resources:** Time-varying rates improve the economic attractiveness of certain types of distributed resources such as rooftop solar and energy storage, which allow owners to avoid consuming electricity during higher priced peak hours. Time-varying rates may also be a way to encourage more efficient charging of electric vehicles.[11]

- **Environmental benefits:** If time-varying rates reduce consumption or shift it to hours when power plants with lower emissions rates are on the margin, they can result in a net environmental benefit. This will depend on the specific characteristics of the system in which the time-varying rates are being offered.[12] To the extent that time-varying rates play a role in facilitating the integration of renewable resources, there would be associated environmental benefits as well.

Time-varying rates are not a new concept. In fact, this approach to pricing is already utilized in many other industries. Airlines, hotels, and car rental companies are some of the most common examples of industries that dynamically vary prices in response to fluctuations in demand. Commuter trains and subways often vary the price by time of day (e.g., Washington, D.C.'s Metro, which has three tiers of pricing). Some bridge and road tolls vary by time of day, such as the Bay Bridge in San Francisco and congestion charging on major roads in parts of London. Parking meters typically apply a charge only during times of high demand (generally during business hours), and in some emerging pilots the price of a parking meter is a function of the number of meters in the network that are being used. Sports teams are beginning to vary the price of tickets depending on the quality of the opponent, time of game, and other factors. In other words, the concept of time-varying rates is something that many electric utility customers already experience on a near-daily basis.

The scope of this report

While there are many potential benefits of time-varying rates, there are also significant challenges to be addressed in their implementation. For example, what are the most effective rate designs? How should the rates be developed? How should they be deployed to encourage customer adoption? These and many other issues must be addressed through careful planning before deployment. To provide guidance based on industry observation and experience, this report addresses several key topics and is organized as follows:

Section 2 provides a description and assessment of the advantages and disadvantages of the various time-varying rate options.

10 The Brattle Group, 2007

11 Faruqui, Hledik, Levy, & Madian, 2011

12 See sidebar for further discussion of potential environmental benefits.

Section 3 includes a discussion of criteria for time-varying rate design, pricing pilot design, and methods for addressing barriers to time-varying rate deployment.

Section 4 provides an overview of international experience with time-varying rate implementation, including a survey of time-varying rate pilots and lessons learned from these studies.

Section 5 includes full-deployment case studies for the United States, France, China, and Vietnam.

Section 6 presents a blueprint for full-scale time-varying rate deployment.

Section 7 concludes with a synthesis of the key points in the preceding sections, as well as insights for future research needs.

This report does not focus on rate designs that could be offered in the absence of an upgrade from a traditional electromechanical meter. For example, the report does not include inclining block rates, which are commonly used as an alternative to a flat rate to promote conservation and do not require a smart meter. Seasonal rates, which vary by time of year but not by time of day, are another example of rates that do not require advanced metering. Principles for designing and offering these types of rates are the focus of another paper titled Rate Design Using Traditional Meters. We do, however, discuss issues related to integrating these rates with time-varying rates.

The report includes static time-of-use (TOU) rates as well as dynamic rates, which both require an upgrade from a traditional, one-period electromechanical meter. TOU rates are different than dynamic rates because they are not "dispatchable," instead adhering to a schedule established in the retail tariff. With true dynamic pricing, on the other hand, the timing, price levels, or both are only made available to the customer on a day-ahead or day-of basis. While this distinction is important, both forms of time-varying rates are included in this report.

The scope of the report includes time-varying rates for all customer classes. We have a particular focus on time-varying rate issues for the residential class, which has only recently begun to receive the metering technology necessary to offer time-varying rates. As a result, many of the emerging issues and new research on time-varying rates are centered on the customers in this segment.

The Environmental Impact Of Time-Varying Rates

With growing concern over the sustainability of worldwide electricity consumption, there is interest among some policymakers about the potential environmental benefits of time-varying rates. Generally, the conservation impact of time-varying rates on the environment is expected to be small. This is mostly because high prices that would induce significant changes in a customer's electricity consumption are encountered during relatively few hours per year. For example, a critical peak pricing (CPP) design exposes customers to a higher price during only 50 to 100 hours of the year, and customers receive a discounted rate during other hours. Further, recent studies have found that while time-varying rates induce significant reductions in electricity demand during peak periods, much of that reduction is offset by increases in consumption during periods when the price is discounted. The result is little or no conservation effect from time-varying rates alone.[13]

Still, there may be environmental benefits from time-varying rates. Even in the absence of a net reduction in consumption, load shifting could result in a net emissions reduction, depending on the characteristics of the applicable generating resource mix.[14] Further, time-varying rates may encourage greater adoption and facilitate the integration of variable renewable energy resources. Basic categories of environmental impacts from time-varying rates are discussed below.[15]

Change in greenhouse gas (GHG) emissions: Whether there is a net reduction in GHG emissions from time-varying rates depends on the emissions rate of the marginal unit during peak and off-peak hours. For example, if load were shifted from hours when an inefficient oil- or natural gas-fired peaker was on the margin to hours when a more efficient gas-fired combined cycle unit was on the margin, one could expect a net decrease in GHG emissions. However, in a different service territory, there might be a gas-fired peaker on the margin during peak hours and a coal plant on the margin during off-peak hours. In this situation, an increase in GHG emissions could arise. One study of different regions in the U.S. found that the impact could range from a decrease of 0.9 percent to an increase of 0.3 percent.[16]

Change in criteria and hazardous air pollutants: Peak period load reductions from time-varying rates could also reduce other types of generator emissions such as criteria and hazardous air pollutants. In the U.S., these reductions would be particularly valuable in designated non-attainment areas where predetermined emissions levels cannot be exceeded.

Minimization of impact to wildlife and sensitive ecosystems: To the extent that peak demand reductions result in avoided investment in new generation capacity or T&D capacity, the result would be a smaller geographical footprint of the grid. This would reduce the impact to wildlife, habitat, and sensitive ecosystems.

Facilitating adoption of renewable resources: Time-varying rates could facilitate the adoption of renewable sources of energy. For example, a strong TOU rate could improve the economics of a rooftop solar system to the extent that the peak period aligns with the time of highest output from the system. Additionally, to the extent that time-varying rates result in more flexible demand, particularly through the adoption of technologies that automate load changes in response to prices, this could be valuable for integrating variable renewable energy resources.[17] However, the integration benefit still remains to be proven on a large scale.

13 This is the finding of recent time-varying rate pilots in California, Maryland, and Connecticut. However, a survey of much older TOU pilots did find that, on average, the rate design induced some conservation. See King, & De-lurey, 2005.

14 Some market operators publish information on the emission rate of marginal generating units, which would allow for this analysis to be conducted. For example, PJM (in the eastern United States) publishes this information on a monthly basis for peak and off-peak periods: http://www.pjm.com/documents/~/media/documents/reports/co2-emissions-report.ashx.

15 For details, see Environmental Defense Fund, 2009

16 Hledik, 2009. Also see Pratt, et al., 2010

17 Cappers, Mills, Goldman, Wiser, Eto, 2011

2. The Rate Options

A time-varying rate can be designed in a number of ways, depending on one's ratemaking objectives and the sophistication of the target market. The specific dimensions across which a time-varying rate design can vary are summarized in Table 1.

The most common categories of time-varying rates are TOU, CPP, Peak Time Rebates (PTR), and Real Time Pricing (RTP). Each of these rate types is described below, along with a discussion of the general advantages and disadvantages of each.[18]

Table 1

The Dimensions of Time-Varying Rate Design

Dimension	Description
Number of pricing periods	The price may change anywhere from once per day to once every hour (or even more frequently).
Timing of pricing periods	The applicable hours of each pricing period are typically designed to coincide with load and price patterns of the service territory.
Price level	Time-varying rates are almost always cost-based and revenue neutral, but within these constraints there is some flexibility in establishing the price level for each pricing period, depending on how costs are determined.
Notification	The time that elapses between when customers are informed of upcoming prices and the applicability of those prices (often on a day-ahead basis with many dynamic pricing deployments, but ranging anywhere from near-instantaneous notification to fixed TOU prices that could remain unchanged for a multiyear period between rate cases).
Incentive	Time-varying rates can include incentive schemes involving high prices for high-cost hours and low prices for low-cost hours or, alternatively, rebate payments for targeted load reductions.[19]
Combination	Time-varying rates can be combined with other rates (e.g., layered on top of an inclining block rate or flat rate).

A. Time-Of-Use

A static TOU rate divides the day into time periods and provides a schedule of rates for each period. For example, a peak period might be defined as the period from 2 pm to 6 pm on weekdays and Saturdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the average variation in the cost of supply. In some cases, TOU rates may have a shoulder (or mid-peak) period, or even two peak periods (such as a morning peak from 8 am to 10 am, and an afternoon peak from 2 pm to 6 pm). Additionally, the prices might vary by season. With a TOU rate, there is certainty as to what the rates will be and when they will occur.

A variation on the traditional TOU rate that has been explored by some utilities is a "super peak TOU rate." This design includes a very short super peak period (typically only

18 For additional discussion of the advantages and disadvantages of each approach, see Borenstein, Jaske, and Rosenfeld, 2002.

19 Some strict definitions of time-varying rates do not include rebate payments, but they are included under this paper's broad definition of time-varying rates as something that could not be offered in the absence of a technological upgrade.

a couple of hours) with a much higher price than the other periods, and only applying to a few months of the year. It may be an attractive option in hot, dry climates with a needle peak that is contained to relatively few hours of the day in the summer.

Advantages: TOU rates encourage permanent load shifting away from peak hours. They have a simple design that is predictable and easy for customers to understand (e.g., it is analogous to the pricing of cell phone minutes). TOU rates also could be used to encourage adoption of plug-in electric vehicles, solar photovoltaic systems, and distributed energy storage technologies by providing lower rates during the optimal time of charging (off-peak) and higher rates during the time of discharge or selling back to the grid. In fact, many utilities are offering specific TOU rates for electric vehicle owners. It should also be noted that offering TOU rates does not necessarily require deployment of advanced metering infrastructure (AMI), although it does require that electromechanical meters be able to record consumption during multiple time periods.

Disadvantages: TOU rates are not dynamic in that they are not dispatched based on the changes in actual wholesale market prices or in reliability-related conditions. They are therefore less useful for addressing specific events on the grid and integrating variable renewable energy resources. TOU rates don't provide as large a peak load reduction as dynamic rate designs due to the price signal being averaged over a large number of peak hours instead of a relatively limited number of very high-priced hours.

B. Critical Peak Pricing

Under a CPP rate, participating customers pay higher prices during the few days when wholesale prices are the highest or when the power grid is severely stressed (i.e., typically up to 15 days per year during the season(s) of the system peak. This higher peak price reflects both energy and capacity costs and, as a result of the capacity portion of those costs being spread over relatively few hours of the year, can be in excess of $1 per kWh. In return, the participants receive a discount on the standard tariff price during the other hours of the season or year to keep the utility's total annual revenue constant. Customers are typically notified of an upcoming "critical peak event" one day in advance.

Two variations on the CPP rate are CPP-variable (CPP-V) and variable peak pricing (VPP). CPP-V is similar to the CPP rate, with the exception that the window of critical peak hours is not fixed. The specific hours of the event are provided to participants at the same time that they are notified of the upcoming critical event (on a day-ahead basis). This provides utilities and independent system operators (ISO) with the flexibility to respond to emergencies and high-priced periods of varying lengths occurring at different times of the day. It is also possible to vary the critical peak price, rather than locking it in at a pre-specified level. CPP rates with this characteristic are called VPP rates.[20] Due to the uncertainty in timing and price level, both VPP and CPP-V can present a challenge in ensuring that the rate will recover the revenue requirement.

Advantages: Like the TOU rate, the CPP rate is simple for customers to understand. It provides a strong price signal and has produced some of the highest observed peak reductions among participants. In addition, it exposes customers to higher prices during only a very limited number of hours.

Disadvantages: Political acceptance of the rate is sometimes limited due to the relatively high critical peak price. Furthermore, some customers consider the CPP rate to be more intrusive than a TOU rate because customers are contacted each time a critical event is called.[21] Some utilities have expressed concern that they will under-collect revenue relative to their authorized revenue requirement by pushing a larger share of their fixed costs into a higher price that occurs during relatively few hours of the year.[22]

20 A further variation of VPP rates combines traditional TOU rates with RTP rates. The on- and off-peak periods are fixed, as is the off-peak price. The on-peak price varies each day, based on day-ahead market prices. See http://www.smartgrid.gov/sites/default/files/pdfs/cbs_guidance_doc_4_rate_design.pdf.

21 This concern can partly be addressed by allowing customers to designate how they would like to be contacted (e.g., phone, pager, email, text, or other options). The use of enabling technologies, which automate the customer's load reductions during critical peak events, can also help to alleviate this concern.

22 Decoupling utility revenues from sales is one way to address this concern. Another way to avoid under-collection of revenue is to call all critical peak price events for which the approved tariff rates are designed.

C. Peak Time Rebate

If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of a peak time rebate (PTR, which is also known as critical peak rebate or CPR). Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours. The PTR has mostly been offered through pilots, with opt-out deployments approved for residential customers in Maryland, Washington, D.C., and California.[23]

Advantages: While all forms of time-varying rates are designed to provide customers with the opportunity to save on their electric bill, the PTR provides a level of bill protection that is not embedded in these other rates. Because it provides a rebate during critical events but does not increase the rate during other hours, a customer's bill can only decrease under the PTR in the short run. As a result, the PTR rate is often more acceptable to regulators and policymakers. The concept is also generally easy for customers to understand. It provides a significant incentive to reduce peak demand, similar to the CPP.[24]

Disadvantages: PTR requires the calculation of each customer's baseline usage, which is necessary for determining individual rebate payments. This process is inherently inaccurate. In some instances, it can lead to payments to customers who did not actively change their electricity consumption. One study estimated that as much as 40 percent of a utility's total rebate payment would be simply due to the inaccuracies associated with estimating individual customer baselines.[25] In other cases, it may result in underpayment to customers who made significant changes. While in the short-run a PTR is a "no lose" proposition for all participants, in the long run it is possible that rates will need to increase to cover the cost of the rebate payments. The magnitude of that rate increase will depend on the accuracy of the baseline estimation method.

Further, while a PTR provides an incentive for reducing demand during the peak period, it does not convey the true time-varying cost of providing electricity and does not provide the price signal necessary to encourage adoption of plug-in electric vehicles or rooftop solar systems. There are also concerns about the potential for customers to artificially inflate their baseline energy usage in order to receive a higher rebate payment. For these reasons, the rate is considered by some to be an option for transitioning to time-varying rates and encouraging participation, rather than an ideal long-term solution.[26]

D. Real Time Pricing

Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Depending on customer class, participants are made aware of hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers (above one megawatt of load) in specific regions face hourly prices. However, there are two utilities in the United States that offer RTP to residential customers: Ameren and Commonwealth Edison.[27] These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption at the most expensive times.

Advantages: The main advantage of RTP rates is that they provide the most granularity in conveying accurate hourly price signals to customers. These rates also provide a dynamic price signal that responds to changing market conditions. They have a long history of full-scale deployment among large commercial and industrial (C&I) customers.

Disadvantages: Generally, without automating technologies it is difficult for customers to respond to prices on an hourly basis – response tends to happen at a less granular level.[28]

23 It should be noted here that the opt-out provision from a PTR initiative is, as a practical matter, unnecessary because PTR already protects customers from rate increases. Nevertheless, it exists in certain pilots as yet additional assurance of protection.

24 For further discussion of the incentives provided by CPP and PTR rates, see section "CPP versus PTR" in Section 4.

25 Williamson & Marrin, 2008

26 A U.S. DOE-funded pilot underway in Vermont will be testing the effectiveness of this transition strategy.

27 See, for example, Star, Isaacson, Haeg, Kotewa, 2010

28 For example, see Navigant Consulting, 2011

E. Rate Combinations

The rate options described above can also be offered in combination to take advantage of the relative advantages of each. One common combination is CPP and TOU. The TOU component of the rate reflects the average daily variation in peak and off-peak energy prices. The CPP component during a small percentage of hours each year reflects the cost of capacity during the seasonal system peak. Together, these rates can facilitate greater energy awareness among customers and provide a greater opportunity for bill savings through a more heavily discounted off-peak rate. However, the added complexity of a combination rate design means that additional customer education is necessary for the rate to be effective and improve customer satisfaction.

It is also possible to layer time-varying rates on non-time-varying rate designs. Some time-varying rate pilots, such as the California Statewide Pricing Pilot, have measured the effect of time-varying rates combined with an inclining block rate. Combining a time-varying rate with an inclining block rate can encourage peak load reductions as well as conservation. Where rates are unbundled – in other words, separate prices for energy and delivery services – it is straightforward to implement an inclining block delivery rate and a TOU/CPP power supply rate in a fairly transparent fashion, since prices are already separated along those lines. However, without rate unbundling, there are challenges associated with communicating this rate structure to customers in a way that is easy to understand. The utilities in California have used a two-step approach to simplify this message. First, the inclining block rate is presented to customers as their volumetric rate and their consumption is billed using this structure. Then, they receive a credit for consumption during off-peak hours, and a surcharge for consumption during peak hours. The net result is their final bill.

Seasonal differentiation can also be effectively integrated into TOU or dynamic rates. In regions that are distinctly summer-peaking, for example, it may be desirable to offer higher peak period prices only during summer months. This concentrates the events during the window of time when they are most beneficial to the system. A discount could then be provided and spread over the remaining hours of the year, or instead constrained to the summer season in order to provide a greater incentive for load shifting.

Typically, the existing rate for medium and large C&I customers will be structured differently than that of residential and small non-residential customers. For example, larger customers often have a demand charge, and mass market customers typically do not. Class differences will need to be recognized when developing the time-varying rates, whether they are layered on top of the existing rate or replacing it. For example, some or all of the capacity cost that is recovered through demand charges for C&I customers might instead be recovered through the critical peak price of a CPP rate.

F. Enabling Technologies

Technology options are available to help customers manage their electricity consumption in response to time-varying price signals. These are typically referred to as "enabling technologies." For example, for residential customers, devices such as programmable communicating thermostats (PCTs) can receive a signal during a critical peak pricing event and automatically reduce air-conditioning usage to a level that is specified by the customer. This ability to "set it and forget it" reduces the need to manually respond to high-priced events. This concept could be extended to control other end-uses and appliances through a home area network (HAN). For larger C&I customers, automated demand response (or "Auto-DR") technology works in a similar fashion, allowing customers to automate electricity consumption reductions in a range of processes and sources of load through integration with the facility's energy management system.

Enabling technologies can also help customers manage their electricity consumption by providing new information about energy use that the customers otherwise would not have access to. For example, in-home displays can give customers information such as the amount of electricity that they are using, what this is costing them, how that translates into their carbon footprint, how close they are to energy savings goals, and other such data. The information could be provided through a smartphone, website, plug-in device, or other means. A discussion of how enabling technologies have helped customers respond to time-varying rates is provided in Section 4.

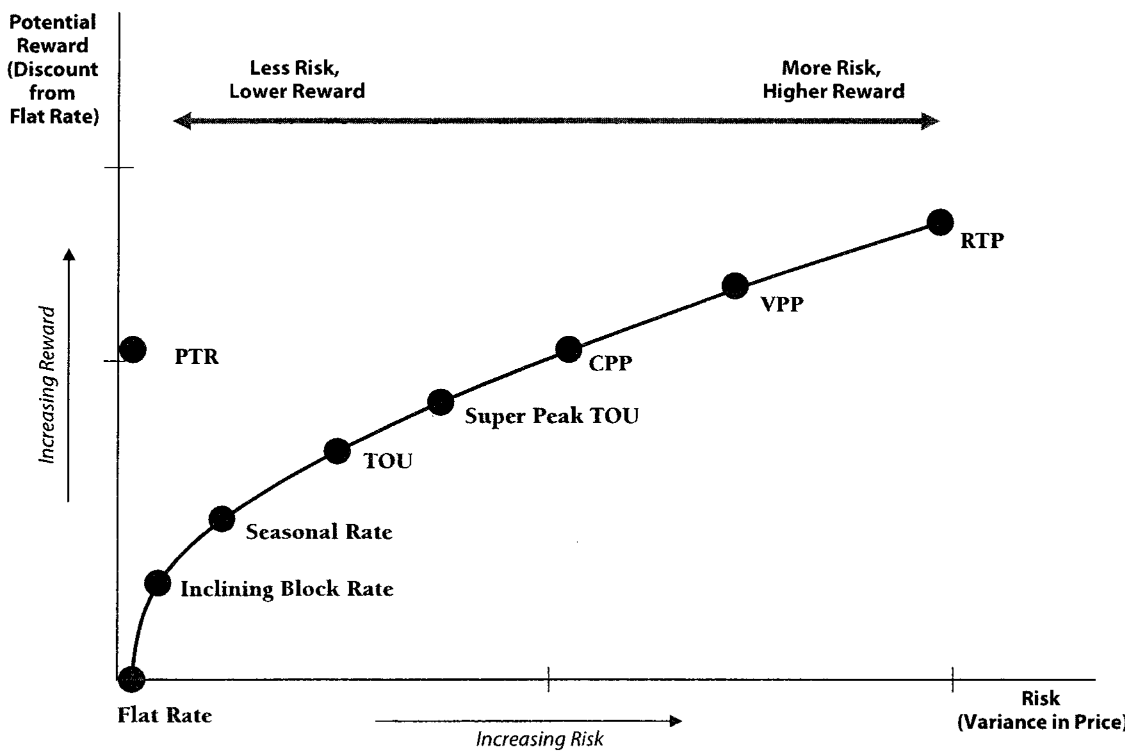
G. The Risk-Reward Tradeoff Of Time-Varying Rates

From a customer's perspective, the time-varying rate options can all be organized across the classic spectrum of risk and reward. Generally, those rates offering the most reward (in terms of bill savings potential) are also the most risky (in terms of exposing the customer to the volatility of wholesale electricity markets). Which rates customers select will be determined by their risk tolerance. This risk-reward tradeoff is illustrated in Figure 1.The figure is illustrative and not intended to provide precise estimates of the risk and reward associated with each rate option.

It should be noted that the short-term view represented in Figure 1 presents a PTR as a risk-free option for participants, relative to the flat rate. However, in the longer term there is risk to participants and non-participants alike, because an overall rate increase may be needed to cover the cost of the rebate payments. This would be the case if the capacity and energy savings from the program prove not to be greater than the cost of rebates and administration, due largely to baseline inaccuracies and potential overpayments.

Figure 1

Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates



3. Design Criteria

Just as there are many different types of time-varying rates that can be offered, there are also many ways in which to design a specific rate. While there will be specific ratemaking objectives that are likely to vary by jurisdiction, there are some common qualities that have been observed in effective design of time-varying rates.

Once the rates are chosen and designed, it is common practice to test their effectiveness through a pilot if not enough is known about the likely impact of the rates in full-scale deployment. The design of the pilot will determine the statistical validity and usefulness of its results. To provide assistance in rate and pilot design, this section presents general recommendations based on deployments around the globe.

A. Time-Varying Rate Design Criteria

The following are elements of effective time-varying rates, as observed or otherwise established by this report's authors through experience in assisting various industry stakeholders in designing and implementing time-varying rates.

Short peak period: The on-peak period should be kept as short as possible while still reasonably spanning the period during which the system peak occurs. A shorter peak period makes it easier for customers to shift load to the lower-priced off-peak period. For example, a four-hour peak period, say from 2 pm to 6 pm, would reasonably allow customers to shift the use of some of their appliances, such as dishwashers or clothes dryers, before or after the period's duration. A long peak period would be less likely to induce response, as customers would need to shift usage to the early morning or late night hours, requiring more significant behavioral changes. Many voluntary TOU rates in the industry feature very long peak periods and very few customers are enrolled in such rates.

Strong price signal and opportunity for significant bill savings: For rate designs targeting capacity reduction during peak demands, the rate should convey a strong price signal to customers. In other words, the differential between peak (or critical peak) and off-peak prices should be large (as long as it is economically justified, including the cost of capacity). This large differential gives the customer a significant incentive to reduce consumption when the price is high, and produces the opportunity for greater bill savings by creating a large off-peak discount. The customer needs to notice that there is a substantial difference in prices during these two periods. A small differential sends a weak price signal to customers and could be too insignificant for them to care about changing their consumption patterns. Examples of the relationship between the strength of the price signal and the magnitude of customer response are discussed in more detail in Section 4.

Customers are less likely to voluntarily enroll in the time-varying rate if they do not see an opportunity for material bill savings. Similarly, once customers are on the rates, they are more likely to produce large peak reductions if doing so allows them to save material amounts of money through load shifting. To create such a rate, the off-peak discount should be substantial and applicable during hours and seasons when participants have control over discretionary load (and therefore an ability to shift their electricity consumption).

Rates should reflect system costs: While a significant price signal is important, the rate should still reflect the cost of providing power to the customer. The peak period rate should reflect both the higher average variable cost of generation, as well as the cost of capacity necessary to meet peak demands. The off-peak rate is a reflection of the lower average cost of meeting customer demand during hours with lower loads. This is what drives the differential between the peak and off-peak rates.

This approach is generally the same in both restructured (liberalized) markets and non-restructured regions, although there are some nuanced differences. In regions where there are robust wholesale energy and capacity markets, the market prices typically serve as the cost-basis for the rates when they are developed by the default service provider.[29] In restructured markets with retail competition, the rates could be offered in a variety of forms by competitive retail suppliers. In non-restructured areas, marginal energy costs are typically based on hourly modeling simulations, and marginal capacity costs are based on projections from the utility's long-term resource procurement plan or other estimates of the cost of installing or contracting for new peaking capacity.

Simplicity is important: Time-varying rates should be easy for the customer to understand. If the customer does not understand how the rate works, or is overburdened with information, then he or she will not be able to appropriately respond to the price signals and shift load.

Rates should account for the "hedging premium": Flat rates – those that do not vary by time of day– are costly for suppliers to service, because they transfer all price and volume risk from the customers to the suppliers. To remain profitable, the utility or retail supplier has to hedge against the price and volume risk embodied in such an open-ended fixed price contract. The supplier can compensate for the cost of doing so by estimating the magnitude of the risk and charging customers for it through an insurance or hedging premium. The risk and associated cost depend on the volatility of wholesale prices, the volatility of customer loads, and the correlation between the two. Empirical work suggests this risk premium is higher when the existing rate is fixed and time-invariant, and smaller when the existing rate is time-varying or partly dynamic.[30] To the extent that the risk premium can be quantified or is generally known by the retail electricity provider, customers who move to time-varying rates should be credited for the premium.[31]

B. Pilot Design Criteria

Pilots are used to draw statistically meaningful and generalizable conclusions about the impacts of time-varying rates on customer usage patterns. These results help policymakers to determine which rate designs are more effective at altering these usage patterns in a way that produces the largest benefits to the utility, its ratepayers and the participating customers. While a well-designed pilot is informative and defensible, there are many potential threats to the validity of pilot studies, in general, that must be addressed through careful planning and execution. This section discusses recommendations for pilot design, based on the experience and observations of this report's authors.[32]

It is important to note that there is not one single "right" way to design a pilot. Often, the theoretically ideal approach can impose requirements that are too strict given available budget, time, resources, and other practical considerations. Often tradeoffs must be made to satisfy these practical constraints while sacrificing as little as possible in the validity of the results. Identifying the optimal way to make the tradeoffs is often more art than science.

Generally speaking, there are six steps in setting up a pricing pilot. These are summarized in Table 2 (page 20).

1. Choosing the right type of pilot

The first step in setting up a pilot to assess a time-varying rate proposal, with or without smart grid involvement, is to decide on the type of experiment. This will largely be determined both by the objectives for the experiment and by constraints on time and resources. The three types of pilots are demonstrations, quasi-scientific experiments, and controlled experiments.[33]

Demonstration pilots are used when the primary goal of the pilot is to prove that a given technology or set of technologies can feasibly be implemented in a real-world setting. At the other end of the spectrum are *controlled experiments*. These are rigorous studies that are designed to estimate the impacts of a future full-scale smart grid

29 Adjustments to these prices may still need to be made to ensure neutrality relative to the utility's existing revenue requirement.

30 Neenan, Cappers, Pratt, & Anderson, 2005

31 For guidance in quantifying the risk premium, see Faruqui, Hledik, & Neenan, 2007.

32 An additional useful reference on pilot design is a collection of guidance documents listed in Appendix A.

33 For further discussion of approaches to pilot design, see the U.S. DOE's guidance document on this topic: http://www.smartgrid.gov/sites/default/files/pdfs/cbs_guidance_doc_7_randomized_experimental_approaches.pdf.

Table 2

Major Steps in Designing a Time-Varying Rate Pilot

Step	Description	Key Questions
1	Choose type of pilot	Will it be a demonstration, quasi-experiment, or controlled experiment?
2	Define treatments	What rates and technologies will be tested? Why? What are the performance metrics of interest? What is the ultimate pilot objective?
3	Establish experimental and control group or quasi-experimental control design, as applicable	Is there a control group representative of the greater population of customers? If so, will the control group know that it is "participating"? In quasi-experimental designs, what are the techniques for controlling for non-treatment factors?
4	Recruit customers	Will customers be asked to opt-in, opt-out, or be required to participate in the pilot? How will self-selection bias be addressed?[34]
5	Collect pre-treatment data	What is the timeframe over which data can be collected?
6	Compare treatment & control	Are the two groups statistically comparable? Are the differences statistically significant and practically meaningful?

program on a broad population of customers. *Quasi-experiments* fall between demonstrations and controlled experiments. While quasi-experiments typically do not involve the same level of rigor of a scientific experiment, they often include enough participants to draw some statistically meaningful conclusions, but may be limited in their ability to be generalized.[35]

Controlled experiments typically span a timeframe of more than one year (to capture seasonal and persistence effects in the study) and involve a large number of participants (hundreds or thousands).[36] They involve a comparison of treatment groups (customers who are enrolled in one or more pricing programs) against a control group (customers who are comparable to the treatment group customers, but are not enrolled in any new pricing programs). There are strict requirements about the way in which participants are recruited and the type of information and incentives that they can be given, in order to minimize various forms of bias that would make the results otherwise not representative of the larger population.

2. Selecting the appropriate treatments

There are several important factors to keep in mind when determining which treatments to test in the pilot.

Anticipate the importance of measuring incremental impacts. In testing the impact of a combination of rates and technologies, there is often interest in the incremental impact of one product relative to another. For example, a customer on a time-varying rate, with an in-home display (IHD) and a PCT, may reduce his or her peak demand in response to a critical peak pricing signal. To determine how much of the peak reduction is attributable to the PCT, how much is attributable to the IHD, and how much is attributable to other actions taken in response to the time-varying rate,

34 "Self-selection bias" refers to a situation where various factors cause specific types of customers to enroll in the pilot, with these enrollees not being representative of the larger population of customers.

35 In technical terms, this implies that quasi-experiments may have internal validity, but lack external validity. Internal validity refers to the ability to accurately assess cause and effect with respect to the study population. External validity refers to the ability to extend the established relationships to a broader population.

36 The longer the pilot lasts, the greater the ability to measure persistence and control for the effects of anomalous external factors such as weather.

the technologies would need to be tested in isolation and in sequence. It may be discovered that the impact of one rate or technology is made redundant by the other, or that the impact from the application of a combination of rates and technologies is not the same as the sum of the incremental impacts of each.

Emphasize side-by-side testing of alternatives. A utility or regulator may be choosing between two alternative rate options. The best way to inform this choice is to test both in the same pilot. For example, there has been ongoing debate in the industry over whether rebates or time-varying prices are more effective for achieving peak demand reductions. Until fairly recently, the two approaches had not been tested side-by-side at the same utility, so there was no definitive way to answer the question. It is only in the newest generation of pilots that the two alternatives are being tested together on participants drawn from the same pool of customers.[37]

Engage in market research. A lower-cost alternative to including many treatments in a pilot is to instead gauge customer preferences or response rates through market research. For example, rather than offering two rates as separate treatments in order to determine customer preference, a sample of customers could be surveyed about which they think they would adopt if given a choice. This approach is less effective than an actual price offering in a pilot setting, because it will capture customers' *stated* preferences rather than their *demonstrated* preferences. However, it could still be an effective approach to learning which treatments to exclude from the pilot due to limited resources.

3. Establishing a control group

In addition to including a number of treatment groups, a well-planned pilot, based on controlled experimental design principles, will also have a control group. The control group is a collection of customers who do not receive any new programs, technologies, or information. Often, the control group is not aware of their "participation" in an experiment in order to avoid influencing their behavior as a result of feeling that they are being "watched." The purpose of the control group is to establish a "baseline" against which the impact of the various treatments can be measured. Throughout the experiment, the behavior of the control group is considered representative of what the customers in the treatment groups would have done in the absence of the introduction of the treatment. In other words, the control group helps to isolate the impact of the treatment and account for the influence of external factors (such as changes in the weather or the economy).

4. Recruiting participants

Another key aspect of pilot design, which is subject to some debate, is the way in which participants are recruited into the pilot. Ideally, customers should be recruited into a pilot in the same way that the program will be offered when it is deployed full-scale. If the ultimate deployment plan is to offer a program on an opt-in basis, then that should be the same mechanism by which customers enroll in the pilot. Alternatively, if in the future customers may be automatically enrolled in a program with the option to proactively elect not to participate, then opt-out recruitment (which is still voluntary) may be used.

Regulators and utilities are often unwilling to enroll residential customers in a pricing pilot using opt-out recruitment. However, if customers are simply enrolled on an opt-in, first-come-first-served basis, then the participants will likely be dominated by "early adopters" who are not representative of the larger population of customers. This is one form of "self-selection bias." The dilemma, then, is how best to recruit participants who approximately represent the larger population of customers in a way that is acceptable to regulators and customers.

A voluntary, opt-in recruitment method called *random selection with affirmation*, or *random encouragement design,* helps to approximate the impacts of large scale deployment by minimizing self-selection bias. With this approach, individual customers are randomly contacted and invited to participate in a pilot. If they accept, they are randomly assigned to a treatment cell. If they decline, another customer is randomly contacted and invited to join. The process continues until the desired number of participants

37 This has been tested in recent pilots by Baltimore Gas & Electric and Pepco (in Washington, D.C.). It will also be tested in pilots that are funded by the U.S. DOE. See Faruqui, Sergici, & Akaba, 2011 and eMeter Strategic Consulting, 2010.

is reached. Importantly, the "decliners" are tracked as part of the "treatment" group in order to avoid sample bias. A control group is established outside of this recruitment process by randomly selecting customers from the greater population in a manner that ensures a representative sample from the larger population.

A twist on this approach that has recently garnered attention in smart grid pilots is called the "randomized control trial" (RCT). Customers are randomly invited to participate in the study, just as in the random selection with affirmation approach. However, upon accepting the invitation, customers are randomly assigned to a treatment group or the control group. In theory, this is a better way to establish comparability between the control and treatment group participants. However, there are practical challenges associated with inviting customers to participate in a pilot and then assigning them to a control group with no new technologies or features. This can be addressed by managing the potential participants' expectations up front, so that they know that they could be assigned to either group. Alternatively, a "recruit and delay" approach could be used, which informs customers that they may not be in the treatment group in the first year, but that everyone will have a chance to participate in the treatment group in the second year.

It is common practice to provide pilot enrollees with a small appreciation payment for their participation in the pilot. This is considered compensation for the added effort that they must provide for activities such as filling out pre- and post-pilot surveys and as compensation for the perceived risk of being "experimented upon." However, appreciation payments run the risk of introducing bias into the pilot results because they are presumably not something that would be provided to all customers in a full-scale program rollout. Ideally, they would not be offered for this reason. However, if appreciation payments are deemed necessary to sufficiently meet recruitment goals, then there are a few key things to keep in mind to minimize the introduction of bias in the pilot:

- Keep the payment relatively small, to avoid making it the primary reason for participation.

- Provide the payment at the end of the pilot, to avoid free-riders who sign up, receive the payment, and then drop out. This will help to minimize the pilot's attrition rate (and will in fact provide an additional incentive to remain enrolled).

- A one-time cash payment is the best incentive. Gift cards or other types of gifts can influence the types of customers who sign up. For example, a gift card for products purchased online would only be useful to people with frequent internet access. It is important never to provide the incentive in a way that would encourage customers to use energy differently, such as a rate discount.

- Frame the payment as an "appreciation/thank you" payment. Disassociate the payment from energy use to avoid having any effect on electricity consumption behavior.

5. Collecting Pre-Treatment Data

Data should be collected on all of the pilot participants before the pilot begins. This would include, for example, hourly electricity consumption patterns. Pre-treatment data collection is important, because it provides a reference point against which to compare the participants' behavior after they have been exposed to a treatment.

External factors, such as weather differences, could also lead to pre- and post-treatment differences. This is why it is also important to have a control group, which can be used to control for the impact of external factors. It is important to collect pre-treatment data for both the treatment and control groups. Ideally, pre-treatment data would be collected for at least a full year for these customers. That allows for capturing the full impact of seasonal effects.

6. Testing Treatment and Control Groups for Comparability

Once treatment and control groups have been recruited, and once data have been collected for these customers (e.g., through load research data, surveys, and a pre-treatment data collection effort), an important final step is to confirm that the groups are comparable. The objective is to identify, and then determine the best approach to address and minimize, any underlying differences between the treatment and control groups, the impact of which could be mistakenly attributed to the treatment itself.

There are a few ways to compare the treatment and control groups. Variations on these basic tests can be used to varying degrees of statistical rigor:

- **Seasonal consumption patterns.** Compare average daily usage between the groups, by month, to identify any differences in the size and seasonal consumption patterns of the two groups.

- **Weekly consumption patterns.** Compare average daily consumption across the groups for each month to determine whether there are any differences in weekly patterns of consumption.

- **Daily consumption patterns.** Compare average hourly consumption profiles for each group to determine whether there are differences in the way electricity is used over the course of a day.

- **Sociodemographic characteristics and appliance saturations.** Using pre-pilot surveys and other market research information, compare the distributions of sociodemographic characteristics across the groups such as income, age, education, family size, and dwelling type. The comparison should also consider the distribution of appliance saturations, including central air-conditioning, window air-conditioning, electric heat, and heated pools, for example.

If the characteristics of the treatment and control groups are largely similar, then the control group can be considered a fair representation of the "baseline" behavior of the treatment groups.[38] If there are some dissimilarities between the two groups that are primarily related to consumption, then these differences can typically be addressed through statistical techniques in the measurement and verification (M&V) phase of the pilot. However, large differences in sociodemographic or appliance saturation characteristics may need to be addressed in advance through additional recruitment or sampling activities.

C. Addressing Barriers To Time-Varying Rates

In this section, we discuss commonly encountered barriers to adoption of time-varying rates and identify methods for addressing them. Specifically, we focus on the following barriers:

- Regulatory/market coordination issues
- Rate freezes, price caps, and other legislative constraints
- Lack of AMI
- Customer fear of price volatility
- Ineffective rate designs
- Concerns about impacts on low-income households

Regulatory/market coordination issues

In regions with traditional markets and vertically integrated utilities, retail rates are established by regulators, the utilities' boards, or oversight agencies. In these regions, utilities can establish time-varying rates to reflect the hourly marginal costs of generation and the associated marginal capacity costs for generation, transmission and distribution.[39] If wholesale contracts mask the hourly variation in marginal energy and capacity costs, then it becomes difficult to transmit time-varying cost-based price signals to customers at the retail level.

The picture becomes more complex in restructured markets where system operators or power exchanges run wholesale markets. Retail rates are still set by local entities but key elements - the cost of energy and generation capacity - are set in wholesale markets. Depending on how those wholesale costs are developed and allocated, it may be easy or difficult to create time-varying retail rates that reflect wholesale market conditions. In this case, coordination across the various entities may be improved through forums and workshops that bring key staff together to discuss and address the issues.[40]

Rate freezes, price caps, and other legislative constraints

Another problem for time-varying rates arises if retail rates are frozen or subject to price caps and other legislative/regulatory constraints. For example, in response

38 There are specific statistical methods that can be used to measure the differences between the two groups. For details on these methods, see: http://www.smartgrid.gov/sites/default/files/pdfs/cbs_guidance_doc_5_impact_evaluation.pdf.

39 For distribution-only utilities, generation costs can be based on short-term and long-term contracts for power purchases, and transmission costs can be similarly based on contracts for transmitting power.

40 The U.S. Federal Energy Regulatory Commission has initiated such an effort with its National Action Plan on Demand Response. FERC Staff, 2010.

to the California energy crisis of 2000-2001, the California Assembly froze the rates in the first two tiers of the residential inclining block rate (through Assembly Bill 1X). This effectively makes it impossible to roll out time-varying rates as the default rate. The rate freeze will be lifted once the long term power supply contracts entered into by the state expire.

How can the challenge of rate freezes and price caps be addressed? The answer will depend on the specific requirements of the policy. In California, time-varying rates can still be offered on an opt-in basis, and that is one approach being pursued by the utilities. Additionally, peak time rebates, which leave the retail rate unchanged, can be offered as a proxy for time-varying rates.

Lack of AMI

As described in Section 1 of this report, time-varying rates cannot be offered in the absence of the appropriate metering technology. Without AMI, time-of-use rates can be offered as a proxy to genuine dynamic rates, although this still requires a meter that can track at least two billing periods – peak and off-peak. Also, non-pricing programs such as utility control of selected end-uses like central air conditioning, pool pumps and water heating can be offered to address peak load concerns. Alternative rate options, such as inclining block rates, could be used to achieve policy goals related to conservation and may provide some peak load reduction.[41] Financial incentives for investing in AMI, such as tax credits or accelerated depreciation of the technology, could be pursued depending on the specific policy goals of the region.

Customer fears of price volatility

Many customers equate time-varying rates with price volatility, and some simply equate it with high prices. This perception may stem, in part, from a concern that time-varying rates could eventually become the mandatory rate offering. However, this concern over price volatility is a perceptual problem that can be remedied through customer engagement and education. It is important to convey the message that time-varying rates are not simply an invention of economists for the electricity sector. They are a byproduct of the normal workings of a competitive market and promote efficiency in the use of scarce resources. To identify the specific message that would best resonate with customers and be the most effective in furthering understanding of the benefits of time-varying rates, focus groups and other market research could be conducted. This is a common early-stage practice among utilities that are beginning to implement dynamic pricing pilots.

In addition to developing a clear and effective educational message that resonates with customers, there are other ways to help customers understand and benefit from the volatility in time-varying rates. One is to provide temporary bill protection (meaning that the customer's bill on the time-varying rate could be no higher than it would have been under the otherwise applicable tariff). This would give customers a chance to become familiar with the rate and experiment with approaches to energy conservation and load shifting before being exposed to the risk of a bill increase. Additionally, customers could be provided with enhanced information about their energy use and potential to shift peak load, whether through a detailed bill insert, a web portal, or by some other means. This information would advance their understanding of their energy consumption patterns and help them identify ways to reduce their electricity bills.[42]

Another way to help customers manage the volatility in time-varying rates is to offer "two-part rates." In this approach, customers are allowed to buy a predetermined amount of power at a fixed rate (analogous to how most customers buy their electricity today). The remaining amount of power that they consume is purchased according to the time-varying rate. This would add flexibility by allowing more risk-averse customers to purchase a larger share of electricity at the predetermined rate, and less risk-averse customers to purchase more electricity at the time-varying rate.[43]

Ineffective rate designs

Time-varying rates need to be designed carefully to accurately reflect costs and they also need to be designed so that they are easily understood by customers. Furthermore, the rates need to enable customer response. For example, if the rates are designed with broad peak periods, they may make it difficult for customers to respond. Ultimately, each

41 Faruqui, 2008

42 American Council for an Energy-Efficient Economy (ACEEE), 2010

43 Berg, 1999

customer is different, especially when it comes to trading off lower bills for higher price volatility. See the earlier section in this section titled "Time-Varying Rate Design Guidelines" for more information on qualities of effective rate design.

Regulators and utilities that wish to promote time-varying rates for residential and small nonresidential customers can offer a spectrum of rates, from flat rates to conventional time-of-use rates to dynamic rates such as critical peak pricing. If regulators wish to increase up-take of time-varying rates, they should consider opt-out enrollment, which garners significantly higher levels of participation.[44] Under this approach, all customers in the rate class would be placed on a time-varying rate but can opt out at any time to a flat rate.

Concerns about impacts on low-income households

It is sometimes argued that low-income households would be adversely affected by time-varying rates. However, empirical work to-date has shown that low-income households are likely to come out ahead with time-varying rates, due both to flatter-than-average load shapes and a demonstrated ability to shift load to lower-priced off-peak periods.[45] Still, measures can be taken to limit the exposure of these customers to bill volatility. The approaches described above, such as increased access to energy information, temporary bill protection, and two-part rate designs, are all applicable options.

44 Momentum Market Intelligence, 2003

45 See Section 4 for a detailed discussion of these observations.

Issues In Cost-Benefit Analysis of Time-Varying Rates

Some regard time-varying rates as good business practice, not requiring a cost-benefit analysis. In other words, they are on par with activities such as load research and cost-of-service studies, none of which are subjected to such analysis. These proponents say that if time-varying rates require a cost-benefit analysis, then flat rates, the current norm, should also be subjected to a cost-benefit analysis because flat rates cannot be carried out without the installation of analog meters and appropriate billing systems.

However, not everyone agrees with this viewpoint. The contention is made that because time-varying rates cannot be carried out without AMI, a cost-benefit analysis should be performed, akin to analyses for conventional demand-side management programs. In such analyses, costs and benefits are evaluated from multiple perspectives.[46] The dominant perspective often is the total resource cost (TRC) test, which takes a holistic view. If programs pass this test, then additional insights are gained by looking at the participants' perspective and the utility's perspective and also the perspective of non-participants. If the benefits are evaluated using social measures of avoided cost that account for externalities and which use a "social" discount rate, then the holistic test becomes a societal test. Since trade-offs often exist between these perspectives, regulators in each state have established their own set of priorities. Some states have long given priority to the total resource cost test while others have given priority to the non-participant test. In the academic literature on cost-benefit analysis, the perspective that is most taken is to compute changes in the "social surplus," defined as the sum of consumer surplus and producer surplus.[47] However, this test is rarely used in regulatory proceedings.

In the case of time-varying rates, from a holistic perspective the main cost element is the cost of AMI, which includes the cost of meters as well as the cost of associated software and billing systems and communications equipment. And as discussed below, customer costs or inconvenience incurred to help secure some of the promised energy and capacity benefits would also be included in a holistic measurement of costs and benefits. The benefits are the avoided cost of capacity (generation plus transmission and distribution) and energy, plus all monetizable non-energy benefits. Environmental impacts of dynamic pricing are discussed

continued on next page

Issues In Cost-Benefit Analysis of Time-Varying Rates
continued from previous page

in Section 1, and can be positive or negative, depending on the marginal resources in the area where they are implemented.

It should be noted that, while AMI is the key cost-driver in this scenario, there are additional benefits associated with smart meters that should be "netted out" of its full cost.[48] These benefits are operational savings such as avoided meter reading costs, reduced outage management costs, and the ability to remotely connect and disconnect accounts. These benefits typically range between 50 percent and 100 percent of the cost of AMI. In cases where the operational benefits do not exceed the costs, then the benefits of time-varying rates must make up the difference in order to be deemed cost-effective.

From the participant perspective, there are two main cost elements for time-varying rates. The first is the incremental monthly metering cost that customers would be required to pay. This is often the cost of AMI net of operational benefits. The second cost is the loss of welfare associated with reducing usage during a high-cost period (curtailment) or shifting usage to a lower cost period (hassle factor).[49] These are often valued at one-half of the difference between the price before CPP (which does not trigger behavioral change) and the price after CPP which does trigger this change. The benefit is the reduction in the monthly bill. Note that this result would not be identical to changes in consumer surplus which provides an alternative view of participant benefits.

From the utility perspective, the focus is on measuring changes in revenue requirements (or aggregate customer bills). The benefits are the same as in the total resource cost test. The costs include all the AMI-related costs and any incentive payments that are made to recruit customers.

From the non-participant perspective, the focus is on measuring changes in average rates. The benefits are the same as in the total resource cost test. On the cost side, in addition to all the elements included in that test, the cost of any incentives that will be paid by the utility to recruit and retain customers is included (as in the utility cost test) and so is any revenue loss that would accrue to the utility.[50]

46 California Public Utilities Commission, 2001

47 Harberger, 1971

48 Electric Power Research Institute, 2010

49 Note that this loss of welfare should be treated similarly across all demand-side programs that may produce such an effect, and not just limited to time-varying rates.

50 Revenue loss could result, for example, if the time-varying rate produces an overall conservation effect in which customers consume less electricity than expected under the utility's revenue projection. Of the economic perspectives discussed, such revenue losses are relevant only to the non-participant measurement of costs.

4. Time-Varying Rate Pilots

Time-varying rates have been available to large C&I customers for decades. Many of these large customers – particularly those in restructured markets - are placed on a default real time pricing rate. Others have the option of choosing RTP rates with day-ahead or hour-ahead notice. However, for residential customers, access to time-varying rates has mostly been limited thus far to pilots, with some options to enroll in voluntary TOU or CPP rates.[51]

In the late 1970s and early 1980s, the first wave of electricity pricing experiments was carried out under the auspices of the U.S. Department of Energy and its predecessor agency, the Federal Energy Administration. Those experiments were focused on measuring customer response to simple (static) time-of-day and seasonal rates.[52] Five large experiments were analyzed collectively in a project carried out by the Electric Power Research Institute.[53] The results were quite conclusive: customers responded to higher prices during the peak period by reducing peak period usage, or shifting it to less expensive off-peak periods, or both. The results were consistent around the country after normalizing for weather conditions and appliance holdings. Customer response was higher in warmer climates; response was higher for customers with central air conditioning systems.

However, despite the conclusive findings, time-varying rates were not widely accepted. In part this was due to the high cost of TOU metering at the time. It was also because the peak periods that were offered in these rate designs were much too broad for customers to cope with and produced price differentials that did not induce customers to want to cope with them. This lack of acceptance was also because the cost of peaking capacity did not vary sufficiently from the cost of off-peak capacity to bother offering TOU. Further, the rates were not heavily marketed due to concern that they could result in a loss of revenue to the utilities.[54]

The California energy crisis of 2000-2001 rekindled interest in time-varying rates. A variety of academics, researchers and consultants called for the institution of rates that would be dynamically dispatchable during critical-price periods.[55] These occur typically during the top one percent of the hours of the year where a significant amount of annual peak demand could be concentrated. It is very expensive to serve power during these critical peak periods and even a modest reduction in demand during such periods can be very cost-effective.[56]

The following sections summarize the results of several new time-varying rate experiments that have been carried out in North America, Europe, and Australia. The review of these pilots reveals that time-varying prices are effective in reducing electricity usage.

A. Survey Of Pilot Results

Our survey included 24 recent residential pricing pilots that were conducted by utilities in North America, Europe, and Australia between 1997 and 2011. Durations of the pilots lasted anywhere from a single season to four years. In total, the pilots tested 109 combinations of time-varying rates and enabling technologies (each combination is referred to as a "treatment"). The number of participants in each treatment cell ranged from as few as 70 to thousands. Rates tested included TOU, CPP, PTR, and RTP. Enabling

51 For example, Arizona Public Service offers a voluntary TOU rate that has achieved 50 percent enrollment among residential customers. Electricite de France has offered a residential CPP rate since the late 1990s. PG&E offers a residential CPP rate option. See the case studies in this paper.

52 Faruqui & Malko, 1983

53 Caves, Christensen, & Herriges, 1984

54 Methods for addressing this concern are discussed in Borenstein, Jaske, and Rosenfeld, 2002.

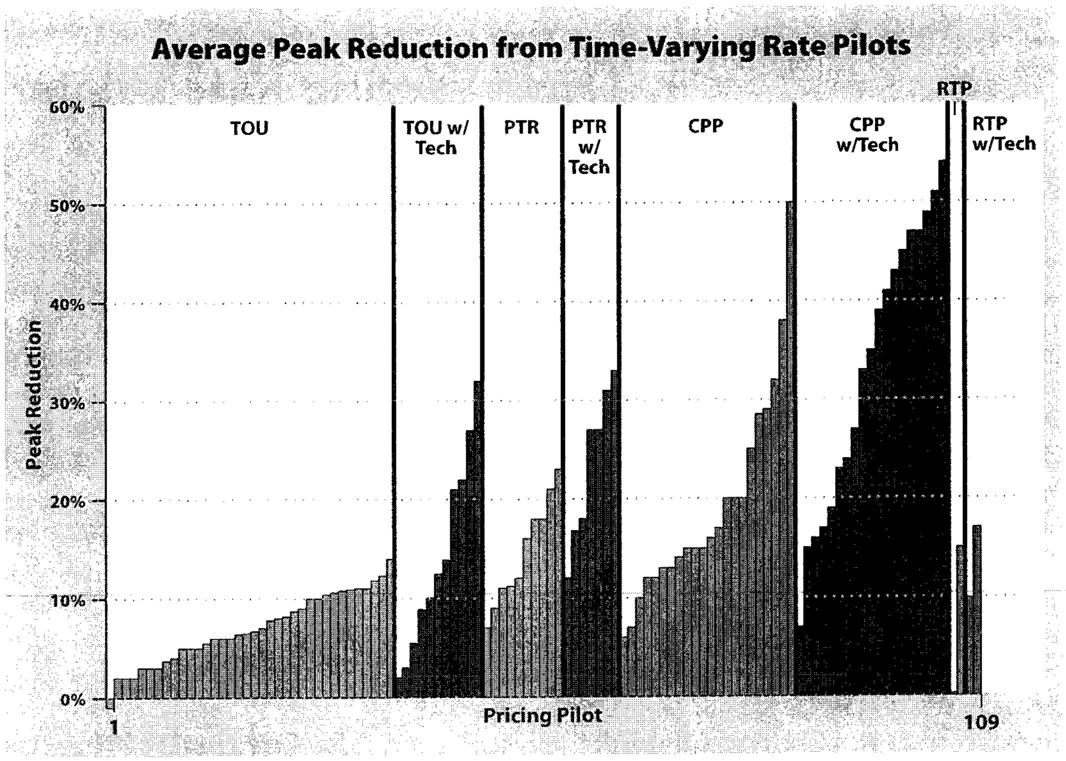
55 Bandt, et al., 2003

56 Faruqui, Hledik, Newell, & Pfeifenberger, 2007

technologies included smart thermostats, air-conditioner switches, and in-home information displays. Results of the impact of each treatment are summarized in Figure 2.[57]

Across the pilots, it is apparent that time-varying rates induce peak load reductions. In general, CPP programs supported with enabling technologies that automate the customers' response result in the largest reductions in load. However, CPP programs alone (without an enabling technology) also achieve significant reductions in load. TOU programs without enabling technologies reduce load somewhat; however, when TOU programs are supported with enabling technologies, the average load reduction is larger.

Figure 2

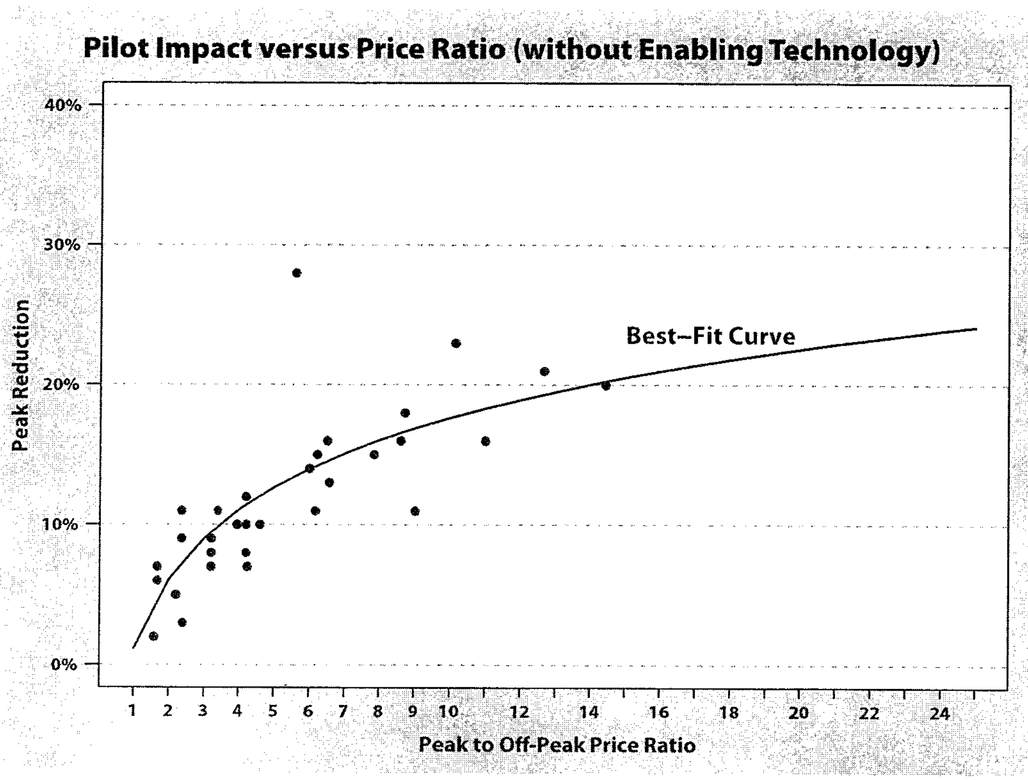


There are several explanations for the observed variation in rate impacts:

- **Pilot design:** Some pilots have a more scientifically valid design than others and do a better job of addressing issues like self-selection bias.
- **Price signal:** The peak-to-off-peak price ratio is a key driver of customer response, because a large price differential provides greater savings opportunities and more incentive to shift consumption.
- **Central-air conditioning (CAC) saturation:** CAC is a large load that can easily be curtailed during a pricing event, with pre-cooling during the peak or critical peak period.
- **Type of enabling technology:** Control technologies like programmable communicating thermostats, which enable consumers to pre-set heating and cooling equipment to automatically adjust temperature in response to price signals, tend to produce larger load reductions than enhanced information, which still requires manual action by the customer.
- **Weather:** Heat and humidity both affect price responsiveness. Hotter days tend to elicit a higher response, but more humid climates have tended to produce smaller load reductions (all else equal).
- **Sociodemographic factors:** Factors such as age, income, and education may impact a customer's price responsiveness.
- **Marketing/incentives/education:** Pilots pursued varying degrees of customer education and outreach.

57 For more information about the pilots discussed in this section, see Faruqui & Sergici, 2010.

Figure 3



residential customers, they have little discretion in their power usage and are thus unable to shift load depending on price. As a result, those consumer advocates are concerned that low-income customers would be hurt by time-varying rates.[58]

However, empirical evaluation has indicated that most low-income customers would immediately save money on their electricity bills from time-varying rates. First, across the residential class as a whole, we expect roughly half of the customers placed on a revenue-neutral time-varying rate to immediately see bill increases and half to see bill decreases. Customers who use more electricity in the peak hours than the average customer would see higher bills, while customers who use less electricity in the peak hours than the average customer would see lower bills.

The electricity bills of a representative sample of low-income households and residential customers (as a whole) from a large urban utility were calculated using flat and CPP rates.[59] As expected, roughly half of the residential customers had higher bills on the time-varying rates, and half had lower bills. However, because low-income customers tend to have flatter load shapes, roughly 65 percent of the low-income customers were immediately better off on the CPP rate than on the flat rate, according to the calculations. In other words, even without any change

Of these factors that influence customer response, the price signal is of particular importance. As illustrated in Figure 3, across pilots without enabling technology, response increases with price ratio, but at a decreasing rate.

B. Lessons Learned From Time-Varying Rate Pilots

Beyond simply demonstrating that customers reduce electricity consumption when exposed to higher prices, recent time-varying rate pilots have provided new and interesting insights. These insights specifically relate to the impact of time-varying rates on low-income customers, the persistence of time-varying rate impacts over several years, and the impact of enabling technologies on price response.

Impacts on Low-Income Customers

There is significant debate in the industry about the impact of time-varying rates on low-income customers, and the issue deserves careful attention by regulators. Some consumer advocates are concerned that because low-income households typically use less power than other

58 For example, see AARP, et al., 2010

59 See Faruqui, Sergici, Palmer, 2010. While the magnitude of the bill changes is dependent on the specific rate design (i.e., the peak-to-off-peak price differential), the share of customers experiencing higher or lower bills is fairly robust across rate designs.

Figure 4

Distribution of Bill Impacts When Moving From Flat Rate to CPP Rate

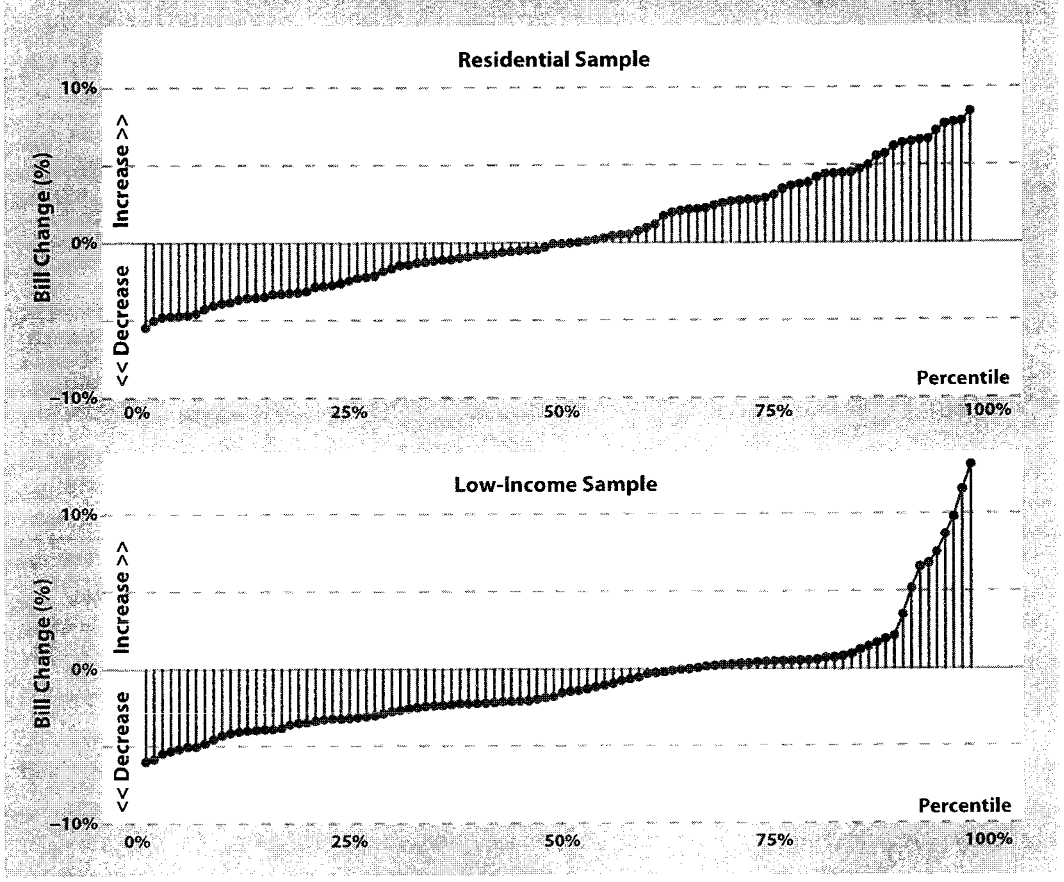
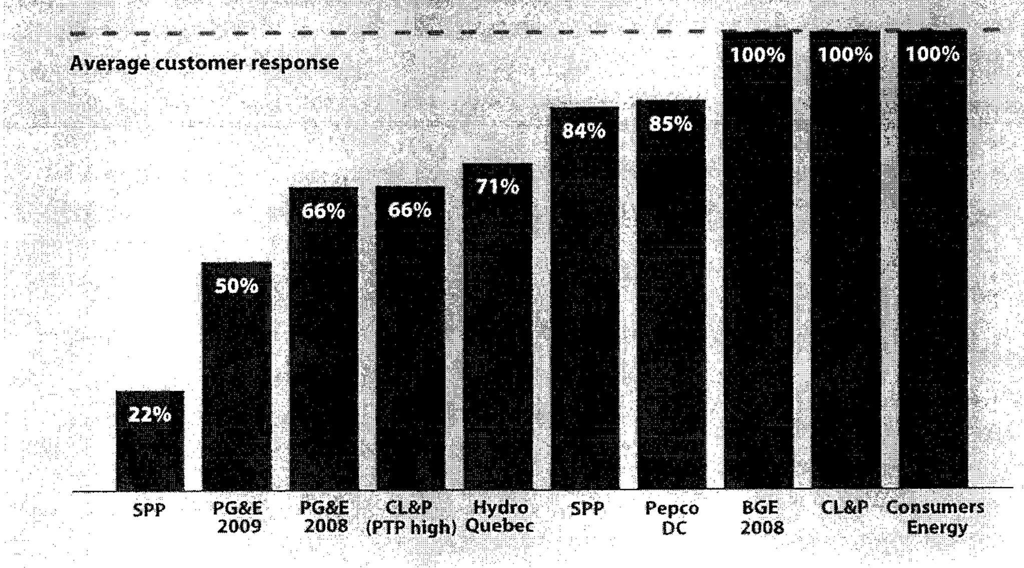


Figure 5

Low-income Price Response Relative to Average Customer



in electricity usage, more than half of low-income customers are better off on a time-varying rate. The results for the CPP rate are shown in Figure 4.

There are a number of tools available to address the concern that customers could experience a bill increase under time-varying rates, especially during a transition period, such as temporary bill protection, "shadow bills" in advance of rate application that show what the customer would pay under future rate options, additional information about ways to conserve energy and reduce bills, and rebates for energy efficiency measures.

Second, results from several studies show that low-income customers do reduce peak load in response to time-varying rates. A review of 10 pilots reveals that low-income customers are responsive to time-varying rates and that their degree of responsiveness relative to that of average customers varies across the studies reviewed.[60] Some studies found that low-income customers were equally as price responsive as higher-

60 Faruqui, Sergici, Palmer, 2010

income customers (as in the Connecticut Light and Power (CL&P), Baltimore Gas and Electric (BGE), and Consumers Energy programs); others found they were less responsive compared to higher-income customers (but still with statistically significant peak reductions).[61] Figure 5 shows how the low-income customers responded relative to the average customer in each of the 10 pilots.

Persistence of Time-Varying Rate Impacts

It is important to understand the extent to which time-varying rate impacts will persist over a multiyear horizon. Persistence across multiple years has been demonstrated most significantly in a recent pilot in Maryland. At BGE, thousands of customers have participated in a PTR pilot over four summers (the pilot began in 2008 and is still running).[62] To test persistence, the PTR rate was offered during each summer to the same set of 400 customers. Econometric analysis revealed that these customers maintained the same level of price responsiveness across all four summers.[63]

Significant peak reductions also appear to persist over time in full-scale rollouts. In May 2008, Pacific Gas and Electric (PG&E) began to offer its CPP program (called "SmartRate") to all residential customers as part of a full-scale rollout. Enrollment exceeded 10,000 customers by the end of that year. By the end of summer 2010, 24,500 customers were enrolled. Analysis showed the average peak reduction impact to be 15.0 percent in 2009 and 14.1 percent in 2010.[64] A case study of the SmartRate program is provided in Section 5. Additionally, in Illinois, ComEd's residential RTP program has reported significant and persistent peak load reductions in every year between 2005 and 2010.[65]

Time-Varying Rates, Customer Feedback, and Enabling Technologies

During the past few years, a variety of new technologies have been introduced to help customers understand their usage patterns (through web portals and in-home displays, for example), to automatically control the function of their major end-uses such as central air conditioning and space heating equipment (smart thermostats), and to manage all their other appliances and plug-loads (home energy management systems). Empirical evidence shows that enabling technology enhances the impacts of time-varying rates on electricity consumption patterns.

BGE's time-varying rate pilot tested a variety of time-varying rates with and without enabling technologies in the years 2008 and 2009. The technologies included an "energy orb" that changed color depending on the price of electricity, and a switch for cycling central air conditioners when rates reached a specific price. It found that the peak impact with the energy orb was greater than the peak impact with price alone, and that the peak impact with both the energy orb and the air conditioner switch was even greater. Other analogous information or customer feedback systems have been used in automobiles and other energy displays, including plug meters, personal computer web displays, and audits. These feedback systems help to spur a phenomenon that is sometimes referred to as the Prius Effect, where consumers are challenged and motivated to alter behavior through the provision of timely information about energy consumption. For example, in 2008, the peak reduction with the PTR alone was estimated to be 21 percent. Adding the energy orb led to a peak reduction of 27 percent, and adding enabling technology on top of that led to a peak reduction of 33 percent. This demonstrates that both information and automating technologies can play a significant role in increasing customer price responsiveness.

Similarly, CL&P's Plan-It Wise Energy Program, conducted in the summer of 2009, tested multiple rates with the following technologies: smart thermostats, air-conditioning switches, energy orbs, and in-home displays. While the energy orbs and in-home displays were not found to have a statistically significant incremental effect on-peak reductions beyond what was achieved through time-varying rates, the presence of an air-conditioning switch or smart thermostat increased the impacts for the CPP and PTR groups. The air conditioning switch and smart thermostat increased the peak reduction from 11 percent to 18 percent for residential PTR customers,

61 Titles of the impact evaluations for these pilots are provided in the Additional Reading section of this report.

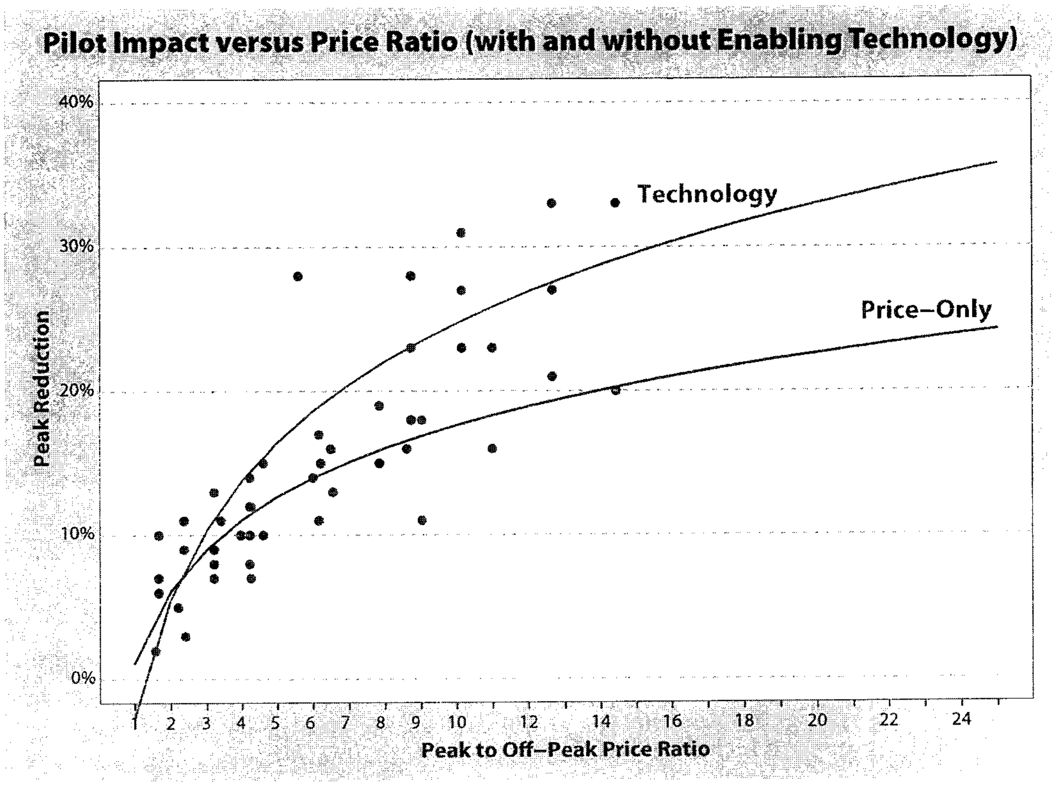
62 Faruqui & Sergici, 2011

63 Results will be published in a forthcoming report, "Impact Evaluation of the 2011 SEP Pilot" (expected publication date early-2012).

64 Faruqui, Sergici, Akaba, 2011

65 Navigant Consulting, 2011

Figure 6



and from 16 percent to 23 percent for residential CPP customers. Similar relationships were observed among small commercial and industrial customers.

For pilots that tested time-varying rates with and without enabling technology, a plot of price response against the peak-to-off-peak ratio shows that impacts with enabling technology tend to be higher than without. This is illustrated in Figure 6.

C. Questions That Remain To Be Answered

Despite all that we have learned from time-varying rate pilots, there are still important questions that remain to be answered through further study. In the next few years, it is anticipated that some of these questions will be addressed through a new wave of pricing pilots that have been funded in part by the U.S. Department of Energy.[66]

Customer preferences for rate types: One of the areas most critically in need of further research is that of customer adoption rates. In the absence of full-scale deployments, limited information is available regarding the share of customers that are likely to voluntarily sign up for a new time-varying rate, or the share that might opt-out of a rate. Additionally, little empirical research has been conducted to date regarding customer preferences when presented with a menu of rate options. Effective market segmentation and marketing approaches for promoting time-varying rate adoption are important areas for future research as well.

Impact of CPP versus PTR: While several pilots have tested equivalent CPP and PTR rates side-by-side, there is not yet conclusive evidence as to whether the two produce the same impacts from participants. Pilots in California, Michigan, and Maryland have found no statistically significant difference in price response from customers enrolled in these two rates. However, pilots in Connecticut and Washington, D.C., have both found that CPP induces a larger response (in one case, the response was more than twice as large). These results are summarized in Figure 7.[67] Also important to consider is the cost of CPP versus PTR programs, as discussed earlier in this paper.

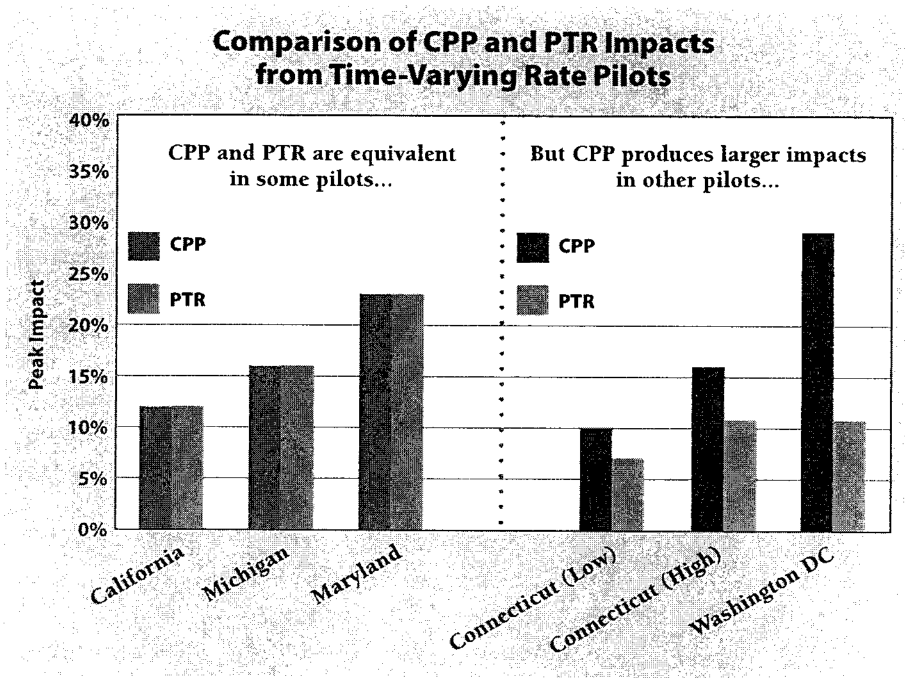
One school of thought is that the "opportunity cost" of not reducing peak demand on a PTR rate is equivalent to the higher price paid during the peak period of a CPP rate, so the two should produce the same response from rational customers. Others believe that customers inherently respond more dramatically to a perceived penalty than to a reward, and therefore are more price responsive on the CPP rate.

66 More information can be found at www.smartgrid.gov.

67 For California, Michigan, and Maryland, CPP impacts are simulated using a PTR-equivalent rate design and price elasticities from the respective pilots.

Conservation impact of time-varying rates: Most of the recent time-varying rate pilots have not found a significant conservation impact from time-varying rates (it is typically less than 1 percent).[68] However, the results of older TOU pilots suggested that the conservation impact could be between two and four percent.[69] One possibility is that conservation impacts will be observed to increase over time, as customers become increasingly aware of the cost of energy and transition from behavior-based load reduction activities to technology-based load reduction.

Figure 7



Fuel switching impacts: Another issue to be examined is whether high prices in a time-varying rate would encourage customers to utilize backup generation rather than purchasing electricity from the grid. From an environmental impact perspective, this could be negative if the source of backup generation was a diesel-fired turbine.[70]

The impact of enhanced information on peak demand: While a couple of pilots, such as those of BGE and CL&P, have tested the impact of in-home displays on peak demand reductions, the results have largely been inconclusive. Further study is needed on the peak impacts of enhanced energy information, both coupled with time-varying rates and also in the absence of new rate designs.

68 See the pricing pilot impact evaluations provided in the Additional Reading section of this report for details.

69 King & Delurey, 2005

70 One way to address this concern is illustrated in RAP's model rule for distributed generation emissions. See RAP, 2003. See, www.raponline.org/docs/RAP_Weston_ModelAirEmissionsRule_2002_10_31.pdf.

5. Full Deployment Case Studies

Full-scale deployments of time-varying rates have primarily been offered to large C&I customers that are exposed to hourly market prices in restructured electricity markets, and through TOU tariffs that are available to these customers as well as (to a lesser extent) some smaller customers. Otherwise, experience with full-scale deployments of innovative time-varying rates is fairly limited. Therefore it is not possible to discuss time-varying rate developments in some regions that are of interest, because thus far there has been little activity in this area. This may change as AMI deployments increase around the globe. However, to provide an overview of time-varying rates that have been practically deployed on a large scale, this section presents four brief case studies of countries with diverse power sectors, economies, and political environments. The countries are the United States (California), France, China, and Vietnam.

A. The United States (California)

Residential time-varying rates are an area of significant interest among many industry stakeholders due to the large role that they play in many AMI business cases. In the United States, the largest residential CPP deployment is offered by PG&E, which serves much of northern California. Due to strict reporting requirements in California, extensive information is available regarding the rate's impacts.[71]

PG&E began offering its CPP rate (called "SmartRate") in May 2008, with the initiation of its system-wide smart metering deployment. As of April 2011, enrollment in the rate had reached 24,500 customers. The rate is being offered on a voluntary (opt-in) basis, meaning that customers must take the initiative to move from their current rate to the new CPP rate. Eligibility to enroll in the CPP rate is expanding as smart meters continue to be deployed across the service territory.[72]

Rate features

Specific features of the rate are as follows:

- Applicable season: Summer (May 1 through October 31)
- Timing of peak period: 2 pm to 7 pm
- Maximum number of peak events: 15 per summer
- Notification of peak event: 3 pm the preceding day
- Peak surcharge: 60 cents/kWh
- Off-peak discount: 3 cents/kWh to 4 cents/kWh
- Implied peak-to-off-peak price ratio: Ranges from 4-to-1 to 11-to-1[73]
- Overlay: The rate is an overlay on other residential rate offerings (including an inclining block rate and an inclining block rate/TOU combination) using the surcharge and credit approach described in Section 2 of this report

Peak impacts

In 2010, PG&E called 13 peak events. Across all participants and all 13 events, the average reduction in demand during peak hours was 14 percent. This adds up to more than 6 MW of load across the participants. There was no discernible change in overall energy consumption (in other words, there was no "conservation effect").

71 Much of the information in this section is derived from George, Bode, Hartmann, 2011.

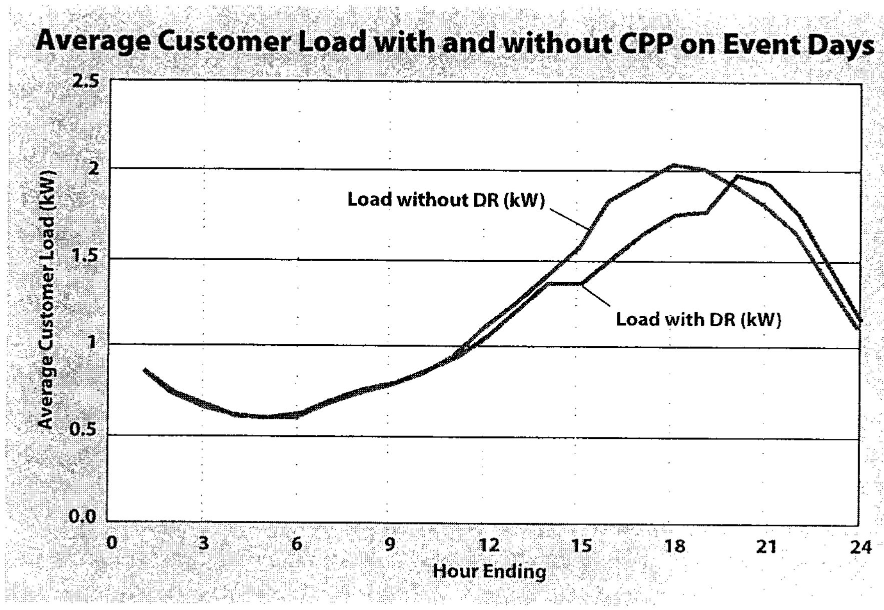
72 The SmartRate will be replaced with a different CPP rate design, as ordered by the California Public Utilities Commission. The transition is pending. For more information, see the California Public Utilities Commission's November 2011 decision on this topic: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/153342.htm.

73 Due to the underlying inclining block rate design, the price ratio depends heavily on whether the customer is a large user (and therefore in the more expensive tiers of the inclining block rate) and whether the customer receives a low-income discount.

Figure 8 illustrates the average customer load on a peak event day with and without a CPP rate.[74]

Across events, the average peak reduction ranged between six and 21 percent. A failure to deliver notification to a large segment of customers contributed to the low end of this range of impacts. Otherwise, the low end was in the range of 10 percent to 12 percent.

Figure 8



Bill impacts

During summer months, when the CPP surcharge and discount applied, customers saved an average of $53 (8.2 percent) compared to their otherwise applicable tariff. Overall, 88 percent of participants reduced their electricity bill. Presumably as a result, the vast majority of customers who signed up for the rate have remained on it. Over more than two years, the average attrition rate for the program was 0.3 percent per month.

Low-income customer impact

The CPP rate was offered to customers in PG&E's low-income program, which provides a rate discount to qualifying participants (the same CPP surcharges and credits still apply). As a percent of peak demand, these customers provided reductions that were roughly one-third of that of the average customer who is not in the low-income program. However, once the low-income response was normalized for factors such as central air-conditioning ownership, it was found that there was no statistically significant difference between the load reductions.

B. France

A CPP rate has also been offered to residential customers in Europe, and for much longer than in California. Electricite de France (EdF) began offering its CPP rate (called the "Tempo Tariff") to residential customers across France in 1996. Since then, roughly 400,000 customers have enrolled in the rate.

Rate features

The Tempo rate is a bit different than a conventional CPP rate in the sense that both the peak and off-peak prices are not known to participants until the preceding evening. Each evening, customers are informed that one of three different price schedules will be in place the next day. Each day is assigned a color depending on the price schedule:[75]

Table 3

Tempo Tariff Rate Structure

Day Designation	Peak Price (Euro Cents)	Off-Peak Price (Euro Cents)	Applicable Days per Year
Blue	3.8	3.0	300
White	7.8	6.5	43
Red	35.5	12.4	22

Other rate design features are as follows:

- Applicable season: Winter (November 1 through March 31)
- Timing of peak period: Very long, from 6 am to 10 pm
- Trigger: Load forecast (red days called on expectation of highest load)

74 Figure is reproduced from George, Bode, Hartmann, 2011.

75 Prices are presented as defined by EdF in 2005.

- Notification: 8 pm the evening before
- Method of notification: Many customers are equipped with a plug-in device that changes color depending on the pricing period and the announcement of the next day's color; others receive notification via phone or the internet

EdF also offers various options for customers to sign up to have their appliances automatically controlled to run only during lower-priced periods and days.

Peak Impacts

The total peak load reduction that has reportedly been achieved through the Tempo program is 450 MW. This is due to an average peak load reduction of 45 percent from participants on red days (and 15 percent on white days). This level of price responsiveness is much higher than that which has been observed in pricing pilots in other parts of the world, possibly due to the program's long history, an extensive customer education program (including in-home visits), and the wide range of load control technologies and informational devices that are offered.

Bill Impacts

Participants have reportedly achieved an average bill savings of 10 percent relative to other rate options. EdF estimates that as many as 7 million of France's customers could benefit by enrolling in the tariff, but that many do not appear to be willing to do so unless it could save them more than $150 per year. Overall, 90 percent of the program's participants report to be satisfied with the tariff.

C. China

In the past decade, the People's Republic of China has developed various demand-side management (DSM) programs to address increasing electricity demand, declining load factors, and power shortages. Most load management in the country has been compulsory load shedding, with mandatory load reductions ordered by the government. To a limited extent, the new load management strategies have focused on more customer-friendly options, including TOU pricing and inclining block rates, which vary by region.[76] The following are descriptions of these programs in various Chinese provinces, to the extent that information is publicly available.[77]

Beijing

In Beijing, where the load factor had been steadily decreasing, DSM programs have enabled the load factor to remain around 81 percent from 1997 to 2003. Roughly 62 percent of the population was on TOU rates by the end of 2003, causing 700 MW to shift to off-peak hours. Beijing has also added 443 ice storage air-conditioning units and heat storage boilers, which have reduced peak load by more than 300 MW and benefit from the peak-to-off-peak price differential inherent in the TOU rate.

Guangdong

Guangdong has had three-period TOU prices for industrial customers since 2001, with variation in rate design between cities. The TOU rates have led to total peak reduction of about 500 MW. Due to a year-long power shortage in 2004, Guangdong also implemented involuntary load interruption for industrial customers, leading to a peak reduction of half of a percent in peak hours and an increase of two percent in off-peak hours.

Hebei

Like many of the other provinces, Hebei is experiencing a decline in load factor, due to an increase air conditioning load. Facing a gap of about 3,000 MW between power supply and demand, Hebei has implemented some important DSM programs. 40,000 customers (about half of all sales) are on TOU rates. The TOU rates have reduced peak load by about 1,100 MW. Additionally, Hebei has instituted a mild CPP rate, with a critical peak price 10 percent higher than the standard peak price.

Jiangsu

TOU pricing, which had been applied to industrial customers since 1999, has been offered to residential customers on a voluntary basis since 2003.

76 China has a nationwide policy of TOU pricing for industrial customers. TOU pricing for residential customers is newer and only available in some provinces.

77 This section is largely derived from Charles River Associates, 2005 and Wang, Bloyd, Hu, & Tan, 2010. Some of the programs described here may have changed or been replaced with newer programs.

Shanghai

In Shanghai, customers face a TOU rate with a 4.5-to-1 peak to off-peak price ratio.[78] Additionally, during the period from 1 pm to 3 pm, the maximum load of large customers must be lower than 90 percent of their daily maximum demand; otherwise, the price doubles.

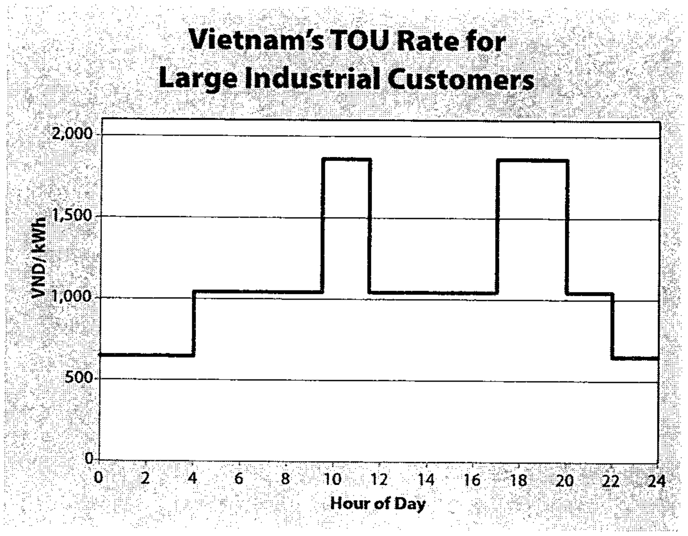
D. Vietnam

Vietnam experienced demand growth at the staggering rate of over 20 percent per year throughout the 1990s, and it is expected to continue to grow at a rate of 14 percent per year through the coming decade. The capitalization needed to support this growth in demand for both electricity and other commercial energy sources has placed a tremendous strain on Vietnam's financial resources. To address this peak demand problem, reduce instances of supply shortage, and avoid costly investment in new power plants, the national utility (Electricity Vietnam, or EVN) has implemented TOU pricing for its largest customers.

EVN first introduced a TOU tariff in 1998 and has supported this with the purchase and installation of TOU meters for all customers with loads over 50 kVA or consumption in excess of 5,000 kWh per month. By the end of 2001, EVN and its power companies had installed about 5,600 TOU meters in customer premises, and by December 2002, over 20,000 customers had received TOU meters. Economic growth is expected to increase the number of eligible customers by about 8.5% annually. An illustration of the TOU rate is provided in Figure 9.

This is a mandatory program for larger customers, and early indications are that many customers have responded by shifting loads from peak hours to off-peak periods. With the support of the external funding, EVN will continue encouraging large customers to shift their energy consumption, and will deploy TOU meters for all commercial, service and agricultural (irrigation) customers with transformer capacity over 50 kVA. The cutoff for eligibility is expected to drop in

Figure 9



order to encourage additional participation over the coming decade. The total estimated peak load reduction from this program is about 70 MW, sufficient to save $46 million in new capacity investments.

A key program element is marketing and information campaigns that would accompany the TOU meter installations, so customers could understand the TOU tariff and meter and receive information on load shifting and energy efficiency options they could avoid an increase in their overall electricity bill. EVN initially experienced customer resistance to TOU pricing due to a lack of understanding of the potential benefits of the rate. For example, a number of customers have responded by installing stand-by generation units and disconnecting from the grid during peak times to avoid the higher peak price. This customer pushback has led to additional efforts by EVN to reach out to medium and large customers with energy and bill saving suggestions.

78 As of December 2003.

6. A Blueprint For Offering Time-Varying Rates

Section 6 consolidates the recommendations that have been discussed in the preceding sections into a concise blueprint for deploying time-varying rates across a service territory. The blueprint assumes little experience with time-varying rates and introduces several steps for arriving at a point where rates can be rolled out to all customers. The steps are: understand the impact of today's rates, develop a consistent and comprehensive set of ratemaking objectives, identify the menu of possible rate options, perform preliminary assessment of potential impacts, conduct preliminary market research, conduct time-varying rate pilots to identify preferred options, and as appropriate, deploy time-varying rates at scale.

Step 0: Understand the Impacts of Current Rates

Before beginning the transition to innovative rates, it is first necessary to focus on understanding the impacts of the current rates. To evaluate the load impacts of existing rates, load research data should be collected for a representative sample of customers in each rate class. With robust data extending over a sufficient time horizon, econometric modeling can be used to evaluate the load impacts of recent rate changes (if any) after controlling for economic and weather variables. This would potentially provide valuable insight regarding customer price responsiveness.

Additionally, focus groups and surveys could be conducted to determine customer perception and awareness of recent rate changes. How many customers claim to have noticed the rate change? And what is their overall attitude toward the new rates? This subjective analysis would provide insights regarding how they might react to a more significant transition to new rate forms and could inform the customer education plan for that transition.

Step 1: Develop A Consistent and Comprehensive Set of Ratemaking Objectives

Ratemaking objectives should be established to advance the policy goals of the state or region. It is important to ensure that ratemaking objectives do not conflict. There is not a single rate that can accomplish all goals. Specifically, policymakers should ask whether there are specific needs, rather than merely broad welfare objectives, that need to be met. It is also important to consider developing a second tier of objectives that would be specific to individual customer classes. Initiating internal focus groups, customer interviews, and stakeholder meetings would be one way for getting started on this journey.

An intelligently designed rate can be effective in accomplishing a number of different objectives. In the 1960s, James Bonbright established ten criteria that have served as guiding principles in electricity ratemaking for the past half century.[79] For details on these objectives, see Rate Design Using Traditional Meters.[80] Generally, reasonable ratemaking criteria can be collapsed into four broad requirements: promote economic efficiency, promote equity (or current perceived equity), facilitate customer choice, and clearly and effectively communicate prices and costs.

Step 2: Identify the Menu of Possible New Rate Options

With the ratemaking objectives established, the next step is to develop a deeper internal knowledge base of the potential future rate options that could be provided. This includes researching innovative rate designs that are currently being examined by other utilities as well

79 Bonbright, Danielson & Kamerschen, 1988

80 Additionally, see Weston, 2000

as surveying ongoing experimental pricing pilots and AMI filings. In conducting this review, consider the distinguishing characteristics of the various rate forms and screen out any options that are entirely infeasible or not in line with the state's or region's energy strategy and policies.

All of the rate designs described in Section 2 provide varying degrees of opportunities for customers to reduce their bills through demand response and also expose the customers to varying degrees of price volatility. Generally, "flatter" rates provide customers with a hedge against price volatility and provide less opportunity for bill savings.

Appropriately designed time-varying rates will account for the level of risk that the customer assumes by enrolling in the rate (or not opting out). For example, a customer on an RTP rate assumes the full risk implicit in the volatility and uncertainty of the hourly wholesale market prices. For these customers, the utility can simply pass the wholesale prices through to the customer. The utility itself does not incur any risk associated with hedging to provide the customer a fixed price. Thus, the cost for the utility to serve RTP customers is typically lower than the cost to serve customers on a flat rate. The spectrum of rates between the flat rate and the RTP reflects varying degrees of risk avoidance from the utility's perspective.

Step 3: Perform Preliminary Assessment of Potential Impacts

For each customer class of interest, develop illustrative rate designs using real system data. The potential impacts of these rates should be simulated using the best available models tailored to the utility's system conditions. Sensitivity analysis should be performed through the course of these simulations to capture the range of uncertainty in the projections. Ultimately, use the simulations to develop a preliminary strategy for the pricing transition and to narrow down the range of potential rate offerings.

There are two steps in developing estimates of time-varying rate impacts: developing illustrative rates based on system data, and then identifying the appropriate models and assumptions to tailor the simulation results to specific conditions.

Designing Illustrative Rates

Begin by designing illustrative rates that are representative of the types of rates that might be offered once the pricing transition is complete. These rates would be developed using existing load research and system cost data. There are several key elements to designing successful time-varying rates that produce both significant peak reductions and high customer acceptance rates. Refer to Section 3 for more information.

Simulating Rate Impacts

Estimating demand response to time-varying rates requires an understanding of the empirical studies on price-driven customer response as well as the ability to tailor the information in these studies to the utility's specific system conditions.

To generate meaningful simulations for a given utility service territory, the results of recent pricing pilots should be calibrated to the utility's system characteristics, such as weather conditions, load profiles, saturation of central air conditioning and existing rates.[81] When combined with a forecast of the number of customers participating in the rate, the result is a system-wide forecast of annual peak demand reductions. The peak demand reductions are expected to yield supply-side benefits, such as lower capacity and energy costs, as well as additional benefits like mitigation of high wholesale market prices.

Step 4: Conduct Preliminary Market Research

Market research is necessary to avoid repeating the mistakes that have already been encountered by other time-varying rate deployments. First, survey the international experience with time-varying rate design and develop a list of "lessons learned" through recent pricing pilots (some of which are summarized in Section 4 of this report). Then, conduct primary market research to understand customer reactions to the rate designs through interviews, surveys, and focus groups. This will serve as a departure point for beginning the customer education process.

81 The Price Impact and Simulation Model (PRISM) is designed to assist with this calibration. See The Brattle Group, 2008. The model is available on the web: http://www.eei.org/industry_issues/electricity_policy/advanced_metering_infrastructure.htm.

Specific objectives of the focus groups could be to:

- Gauge customer understanding of the time-varying rates
- Assess customer interest in and concerns about different time-varying rate options in terms of both the prices and the rate structure
- Identify information that would be most useful to customers on the time-varying rates
- Obtain customer reactions to bill savings under alternative rate designs
- Determine effective ways to communicate about the time-varying rates to customers
- Determine effective ways to notify customers about critical days
- Gather customer reactions to control technologies and an information display, and
- Obtain feedback on how to effectively recruit customers for the pilot (including appreciation incentives)

The survey instruments could include questions to gather information on customer demographics, customer satisfaction, understanding of the rates, understanding of the bill impacts, understanding of information presented, recruitment strategies, importance of enabling technologies, and customer acceptance. The survey could also be used to gather reactions to and additional information on alternative prices, times of day, durations, frequencies, types of automation mechanisms, and information delivery.

Step 5: Conduct Time-Varying Rate Pilots

With an understanding of the various innovative pricing options and their potential impacts, the next step is to conduct pilots in the relevant service territory. First, establish objectives for the pilot. Then, determine the final rates to be tested in the experimental pricing pilot. The number of customers to be included in the treatment and control groups will need to be defined in a way that will provide statistically significant results. The sampling plan should be designed to ensure that the participants are representative of the applicable customer base. Then, identify data to be collected through the pilot, including demographic characteristics of the participants and hourly load data. Final steps are to develop customer recruiting instruments for the pilot and a schedule for pilot implementation. Guidelines for effective pilot design are provided in Section 4 of this report.

Step 6: Full-Scale Deployment of Innovative Rates

Upon evaluating the pilot results, identify the rate types to be offered to each customer class. The appropriate rate deployment plan (opt-in, opt-out, mandatory) will also need to be determined. Finally, it will be necessary to identify key barriers to adoption of the new rates through focus groups and stakeholder interviews and to develop a strategic approach to addressing the barriers before, during, and after rate deployment.

Rates can generally be offered in three ways. The first is opt-in deployment, in which customers would have to proactively select to leave their current rate and sign up for the new rate. The second method of deployment is opt-out recruitment. Customers would automatically be enrolled in the new rate, but would have the option not to accept the new rate and thus stay on the current rate. The third option is mandatory deployment, in which customers are given only one rate choice and that is the new rate. Flexibility could be incorporated into the mandatory rate offering, in which customers are required to sign up for a new rate but are given the option of two or more rates to choose from. Choice of multiple rate designs could also be applied to opt-in and opt-out rate deployment plans.

Generally, it has been found that the deployment plan for a specific rate has a significant effect on its ultimate adoption, and customer participation rates can vary widely as a result. A general rule of thumb that has been developed through experiments such as the California Statewide Pricing Pilot is that participation in an opt-out rate could be as high as 80 percent of the eligible population, while participation in an opt-in rate might be closer to 20 percent.[82] The individual regulatory climate and specific corporate goals would both play a significant role in ultimately determining how the new rates will be offered.

82 Momentum Market Intelligence, 2003

7. Conclusions

This report has discussed a variety of ways in which time-varying rates can be designed, evaluated and deployed. It has surveyed empirical results from pilots, experiments and full-scale deployment from around the globe. The discussion has focused on customers in mass markets that traditionally have had access to time-varying rates.

Given the rapid rate at which AMI is being deployed throughout the globe, it has become feasible to offer time-varying rates to customers in the mass market segment. However, while AMI is a prerequisite for the deployment of most types of time-varying rates, its existence by itself does not suffice to make these rates available in the mass market.

All the key stakeholders in the rate making process have to buy into the provision of these rates. These include utilities, regulators, governing bodies and ultimately the customers themselves. Rate design is rarely a single-step process; the initial design is often going to create "winners" and "losers" and trigger debate.[83] By modifying the initial rate design to accommodate the interests of the various parties, better solutions can be found. However, it will rarely be the case that a win-win solution will be found that will please everyone.

Changes in rate design have been fraught with controversy from the beginning of the electricity industry. The British writer D. J. Bolton put it well when he noted in the preface to his 1938 textbook on "Costs and Tariffs in Electricity Supply":

> *There has never been any lack of interest in the subject of electricity tariffs. Like all charges upon the consumer, they are an unfailing source of annoyance to those who pay, and of argument in those who levy them. In fact, so great is the heat aroused whenever they are discussed at institutions or in the technical press, that it has been suggested that there should be a "close season" for tariff discussions. Nor does this discussion exaggerate their importance. There is general agreement that appropriate tariffs are essential to any rapid development of electricity supply, and there is complete disagreement as to what constitutes an appropriate tariff.*[84]

The discussions become particularly acrimonious when it comes to time-varying rates. This was noted in 1971 by William Vickrey, a noted economist at Columbia University who went on to win the Nobel Prize in 1986. He said the main difficulty with such rate designs was "likely to be not just mechanical or economic, but political." He felt that despite living in the twentieth century, people still believed in the medieval notion of a just price as an ethical norm, and that prices that varied according to the circumstances of the moment were intrinsically evil. Vickrey opined prophetically:

> *The free market has often enough been condemned as a snare and a delusion, but if indeed prices have failed to perform their function in the context of modern industrial society, it may be not because the free market will not work, but because it has not been effectively tried.*[85]

So the design of time-varying rates has to be viewed as an iterative process that will only converge when the multiple objectives of the various participants in the process have all been met up to a certain point that implementation becomes practical.

The most frequently cited objective in rolling out time-varying rates is to improve efficiency in the allocation of scarce capital and fuel resources to the electricity sector. But it is important to state what specific type of efficiency improvement is being considered. Is it economic efficiency (maximize the social surplus, defined as the sum of consumer and producer surplus), energy efficiency

83 Sioshansi, 2012

84 Bolton, 1938

85 Vickrey, 1971

(minimize energy consumption), demand response efficiency (maximize load factors) or environmental efficiency (such as reducing greenhouse gas emissions)? Each one has different consequences for rate design and it will be the job of the rate analyst to quantify these and lay them out in a manner that can help policy makers make a well-informed choice.

Another major objective is equity. Rates should reflect costs, and customers that cost more to serve should pay higher rates and those that cost less to serve should pay lower rates. Some people argue that the purpose of time-varying rates is simply to transmit cost-based price signals, regardless of whether they improve efficiency.

Policy makers may wish to pursue time-varying rates due to one or both objectives. In all cases, they will need to grapple with another major issue: how many customers should be placed on time-varying rates? If the rates are mandatory, then all customers will be on those rates. That has been the practice for large commercial and industrial customers in many regions. If time-varying rates are the default rates, then a high percentage of customers will stay on those rates and a low percentage will optout to alternative rates. If instead time-varying rates are offered on an opt-in basis, then it is likely that a low percentage of customers will take them.

In most cases, overall efficiency and equity benefits will rise in proportion to the number of customers who receive electricity service on time-varying rates. But moving everyone simultaneously and abruptly from standard to time-varying rates is likely to engender chaos and backlash. So a way has to be found to make a gradual transition.

One approach is to move all customers to the time-varying rate but to simultaneously provide them bill protection during the first few years of the transition period. In the first year, they could be given full bill protection and pay the lower of the two bills – the bill they would have paid had they stayed on the traditional rates or the bill they would pay on the time-varying rate. This bill protection would then be phased out after a transition period during which customers have adapted to the new pricing regime.

Another approach is to offer a two-part pricing signal, the first part non-time-varying and the second part time-varying. The main question is how to construct the first part. In one approach, it is set based on historical usage patterns either of the class as a whole or of individual customers. The first part would be served on the standard rate. As long as customers consume at a level equal to their historical pattern, they would pay the same bill. The second part would apply to variations from their historical pattern. It would be priced on a time-varying basis. If customers use more during peak periods than their historical pattern, they would pay a rate that reflects the full marginal costs of providing peak power. If customers use less, they would get a credit. Alternatively, customers can pick their own first part and "buy" it based on forward prices, and then buy their second part based on market prices.

In mature economies, much has been learned about how customers respond to time-varying rates, based on pilots and experiments, but even in these regions, relatively little is known about how customers will respond in full-scale deployments. There is no substitute for field experience and only time will provide this. Moreover, in developing countries similar pilots and experiments have not been carried out and it would be useful to do so. They are a prerequisite to full-scale deployment.

Another area in which research is needed pertains to customer preferences and understanding of time-varying rate options. What type of rate appeals to which customer segment and why? What can be done to improve customer understanding of how different rate choices will affect their economic well-being? How are customer participation rates going to differ between opt-in and opt-out deployment scenarios? Even in developed countries these questions are poorly understood today and the area remains ripe for further work.

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Appendix A:
Additional Reading

The reports and articles presented in this appendix are intended to provide a few helpful starting points for further research on time-varying rate issues. This is not intended to be a comprehensive list of every relevant report on the topic.

Pricing Pilot Impact Evaluations

Pricing pilot impact evaluation reports are a helpful source for understanding the impacts of time-varying rates on customer electricity consumption patterns and electricity bills. The reports typically also provide detail on the design of the pilot and how it was implemented. Examples of some comprehensive pilot impact evaluations are provided below:

- *Impact Evaluation of the California Statewide Pricing Pilot*, prepared by Charles River Associates (2005, March 16).

- *Impact Evaluation of the SEP 2010 Pilot*, by A. Faruqui, S. Sergici, & L. Akaba (2011, March 22). Prepared for Baltimore Gas and Electric Company.

- *PowerCentsDC Program Final Report*, prepared by eMeter Strategic Consulting (2010, September).

Full-Scale Deployment Studies

In addition to pilot results, studies on the impacts of full-scale pricing deployments also provide useful insight regarding time-varying rate impacts. These also include useful information about customer adoption. Three such studies are as follows:

- *A Survey of Utility Experience with Real Time Pricing*, by G. Barbose, C. Goldman, & B. Neenan (2004). Lawrence Berkeley National Laboratory: LBNL-54238.

- *2010 Load Impact Evaluation of Pacific Gas and Electric Company's Time-Based Pricing Tariffs*, by S. George, J. Bode, & E. Hartmann (2011, April 1). Prepared for Pacific Gas & Electric.

- *Evaluation of the Residential Real Time Pricing Program, 2007-2010*, by Navigant Consulting (2011, June 20). Prepared for Commonwealth Edison Company.

The Value of Time-Varying Rates

Several studies have been conducted on the value of time-varying rates. Many of these are in the context of utility business cases that are filed to support AMI investment. One example business case, as well as two whitepapers, are provided below:

- *Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism*. Application A.07-07-__ filed with California Public Utilities Commission on July 31, 2007.

- *Quantifying the Benefits of Dynamic Pricing in the Mass Market*, by A. Faruqui & L. Wood (2008, January). Prepared for the Edison Electric Institute.

- *Quantifying Demand Response Benefits in PJM*, by The Brattle Group (2007). Prepared for PJM Interconnection, LLC and the Mid-Atlantic Resources Initiative.

Other Resources

FERC's annual survey of the status of AMI deployment and time-varying rates in the United States:

- *2011 Assessment of Demand Response and Advanced Metering*, by FERC Staff (November 2011).

The Brattle Group's survey and concise summary of the results of recent international residential dynamic pricing pilots:

- *Household Response to Dynamic Pricing of Electricity: a Survey of 15 Experiments,* by A. Faruqui & S. Sergici (2010). Journal of Regulatory Economics 38:193-225.

A collection of U.S. Department of Energy Guidance Documents for designing and implementing time-varying rate pilots:

- DOE website: http://www.smartgrid.gov/recovery_act/reporting_resources

The state of California's authoritative document on cost-effectiveness tests for evaluating demand-side programs:

- *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001).

The University of California Energy Institute's overview of dynamic pricing issues and fundamentals:

- *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets,* by S. Borenstein, M. Jaske, & A. Rosenfeld (October 2002).

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The Top 10 Questions about Demand Charges

PRESENTED TO

EUCI Residential Demand Charges Symposium

PRESENTED BY

Ryan Hledik

May 14, 2015

THE Brattle GROUP

EXHIBIT

TASC-17

admitted

The top ten questions about residential demand charges

10. Why offer a demand charge?
9. What do we know about existing demand rates?
8. How will customer bills be affected?
7. How should a demand charge be designed?
6. Is a demand charge a fixed charge?
5. Can customers understand demand charges?
4. Will customers respond to a demand charge?
3. How will utility revenues be affected?
2. What will be the role of enabling technology?
1. When is the right time to introduce a demand charge?

10. Why offer a demand charge?

Why offer a demand charge?

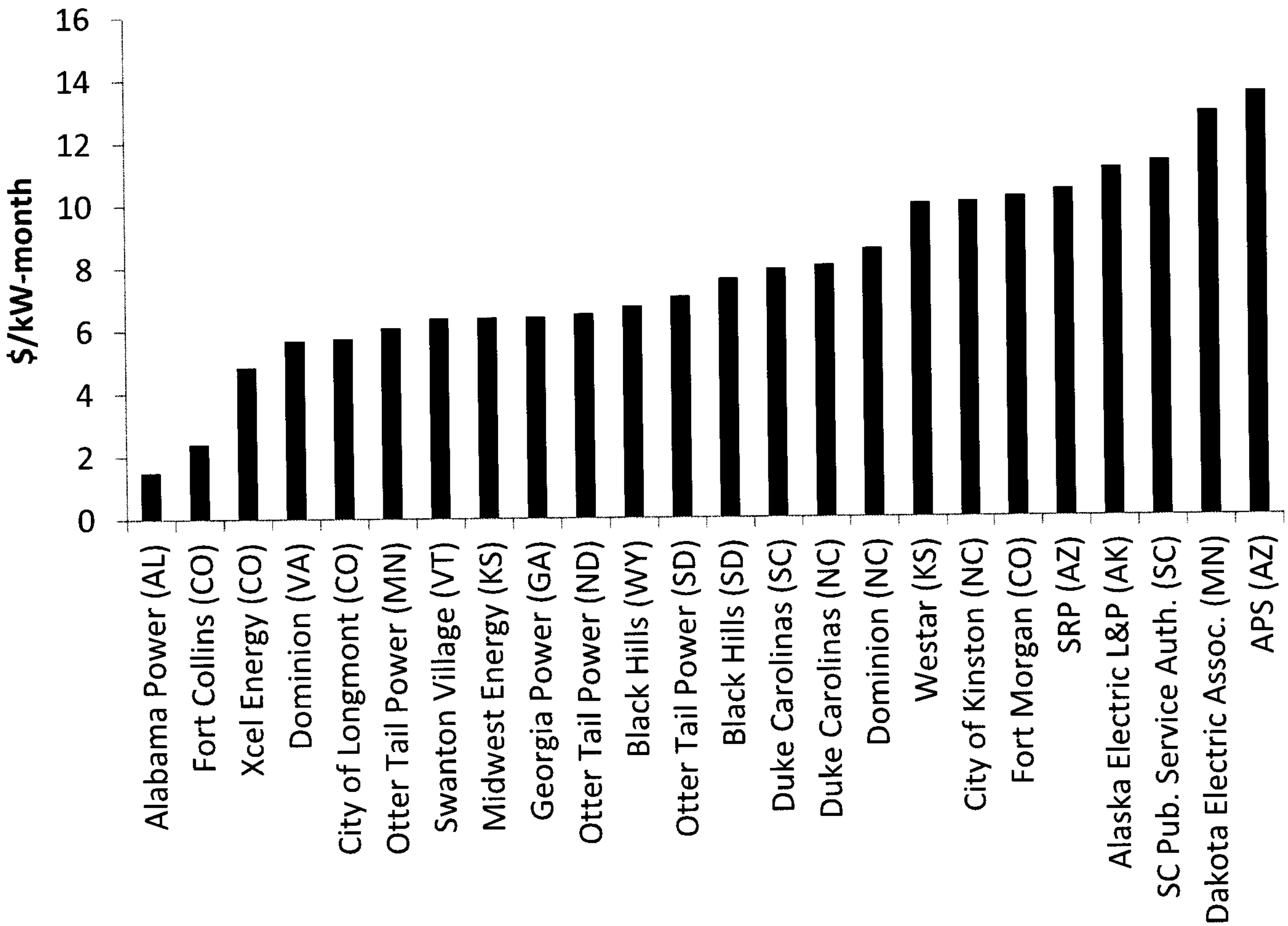
Thank you, Ahmad and Cass!

1 down, only 9 to go...

9. What do we know about existing demand rates?

At least 19 U.S. utilities currently offer residential rates with demand charges

Summer Demand Charges in Existing Rates



Comments

- 24 unique rate offerings across 14 states
- 10 IOUs, 7 municipal utilities, 2 rural electric cooperatives

Observations about existing demand rates

Mostly offered on opt-in basis, sometimes mandatory for sub-classes

Emerging trend toward new rollouts and enhanced marketing

Low enrollment but not necessarily due to lack of interest

Typical enrollee at least 2x size of average customer

There is no one-size-fits-all approach across the 19 offerings

- 10 vary by season
- 8 combined with time-varying energy charge
- 6 measure demand during peak period
- 2 measure demand over a 60 minute interval

Observations about existing demand rates (cont'd)

Reasons for offering the rates have changed

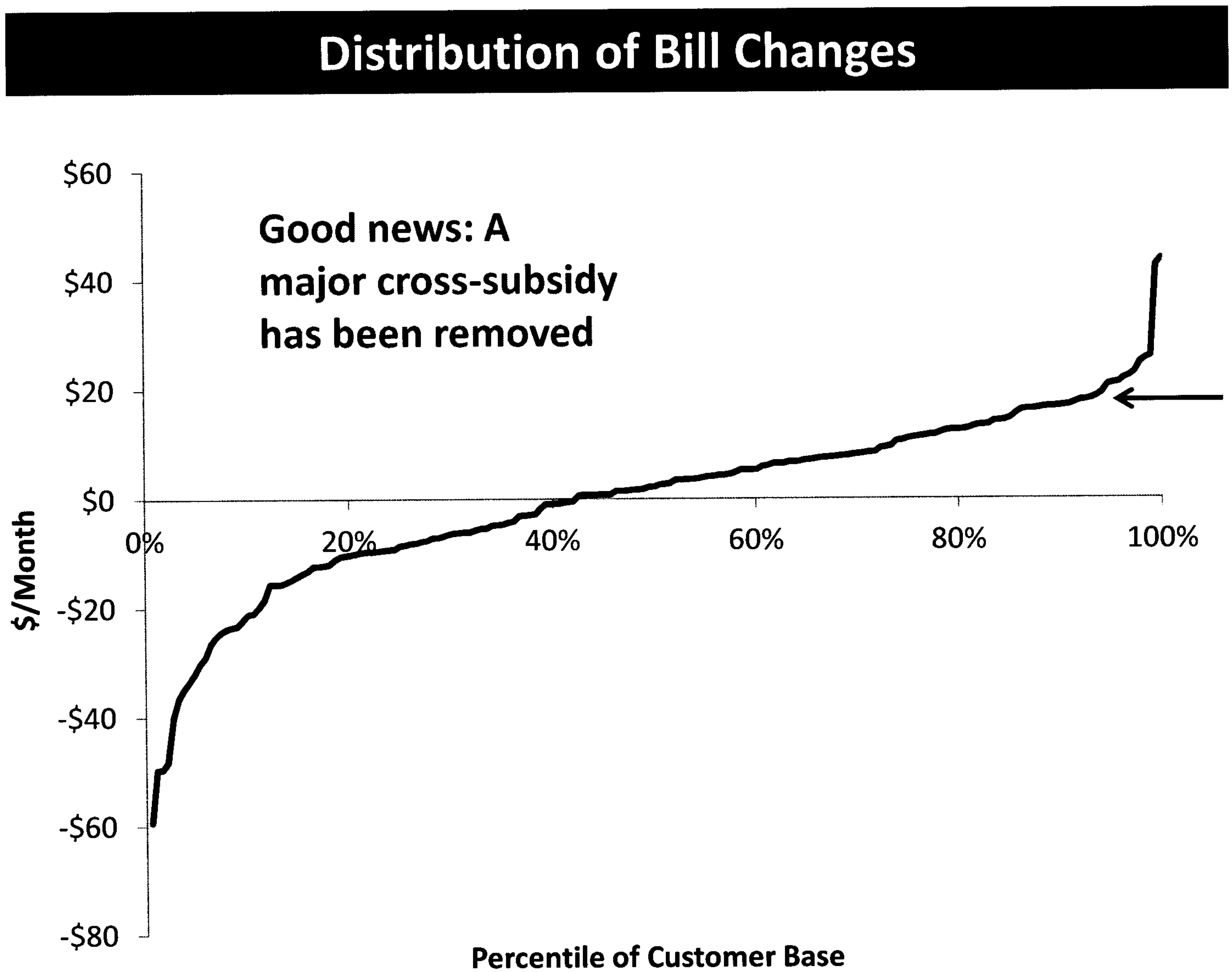
- Older rates: Improve load factor (opt-in)
- Newer rates: More equitable cost recovery (opt-in)
- Future rates: Equity and fairness, (opt-out or mandatory)

Rates typically recover distribution and generation capacity costs and sometimes transmission, but with a price cap

Little empirical assessment of the rates' impacts has been conducted

8. How will customer bills be affected?

The rate change will affect each customer's bill differently

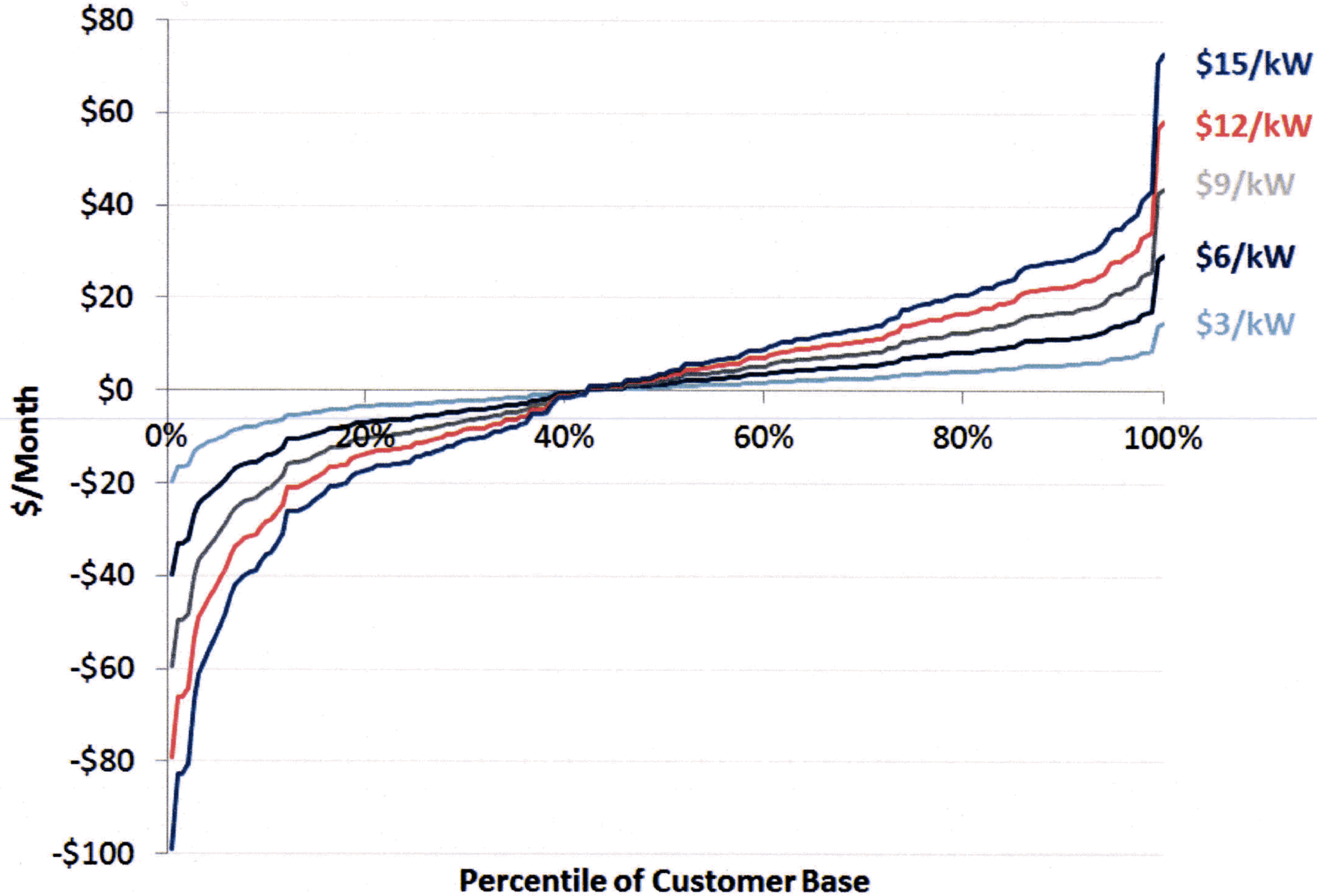


Bad news: Some customers will experience bill increases

More good news: Transition plans help facilitate the change for these customers

Bill impacts will depend on the rate's design

Distribution of Bill Changes for Revenue Neutral Rates



7. How should a demand charge be designed?

Designing a demand charge is a complex endeavor requiring careful consideration of many key factors

Decision	Options	Considerations
How to define demand	- System coincident peak - Class coincident peak - Billing demand (max of month) - A combination of these	Is the charge intended to convey system-level capacity costs (e.g., generation capacity), distribution-level costs (e.g. transformers), or some combination?
Time interval of demand measurement	- 15 mins - 1 hour - etc.	Does load diversity necessitate 15-minute measurement? There are tradeoffs between precision and customer acceptance.
Relationship to other charges	- Fixed charge - Time-varying energy charge	Is there overlap in the costs being recovered through each charge type? What is the most effective way to convey price signals to customers?
Applicable customer segment	- Size eligibility constraints - Variation by geographic location	Should the charge vary with the size of a customer? Should it be higher in congested areas of the grid?
Seasonality	- Seasonal differentiation - Year-round - Demand ratchet	What is the relationship between summer and winter demand-related costs? Is demand measured on a monthly or annual basis (or somewhere in between?)
Customer enablement features/requirements	- Demand subscription - Enabling technology	Should the rate be coupled with the provision of demand limiters or other technology? Should customers subscribe in advance to a certain demand level?

Commercial and industrial (C&I) rate provide a well-tested model for rate design

Demand charges have been included in C&I rates for decades

However, at least one design element in C&I rates should be re-examined before incorporating into residential rates

The interval of demand measurement in existing residential demand rates is between 15 minutes and 60 minutes

In some cases, it is dictated by constraints of the metering/billing system

But in most cases, it is simply chosen to be consistent with existing demand rates for commercial and industrial customers

Shorter intervals have the advantage of precision but could lead to a significant increase in customer bill volatility; bills could jump unexpectedly

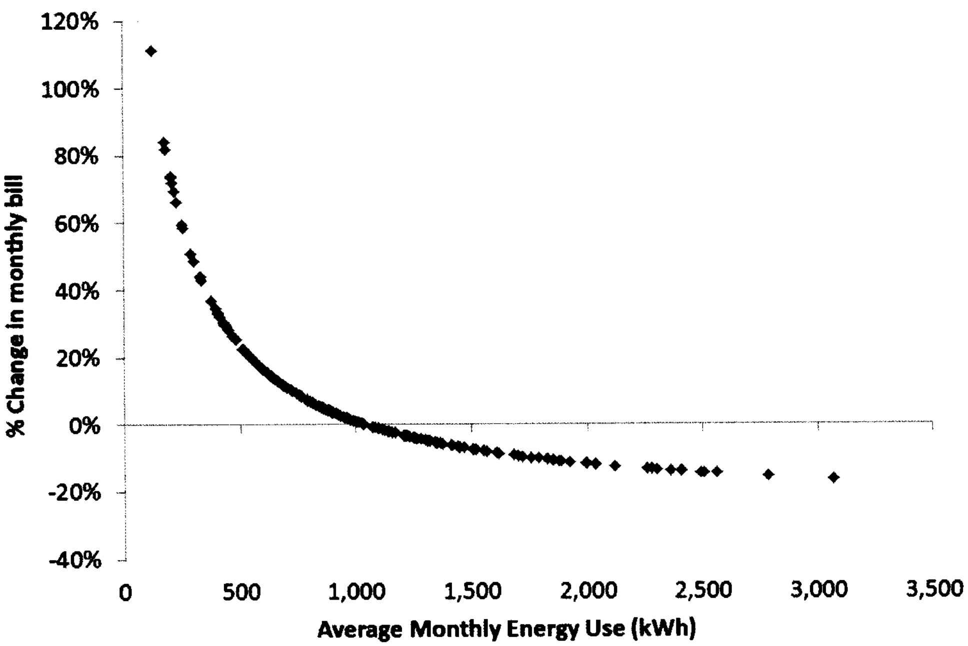
Careful consideration should be given to this assumption

6. Is a demand charge a fixed charge?

(Spoiler: The answer is <u>NO</u>)

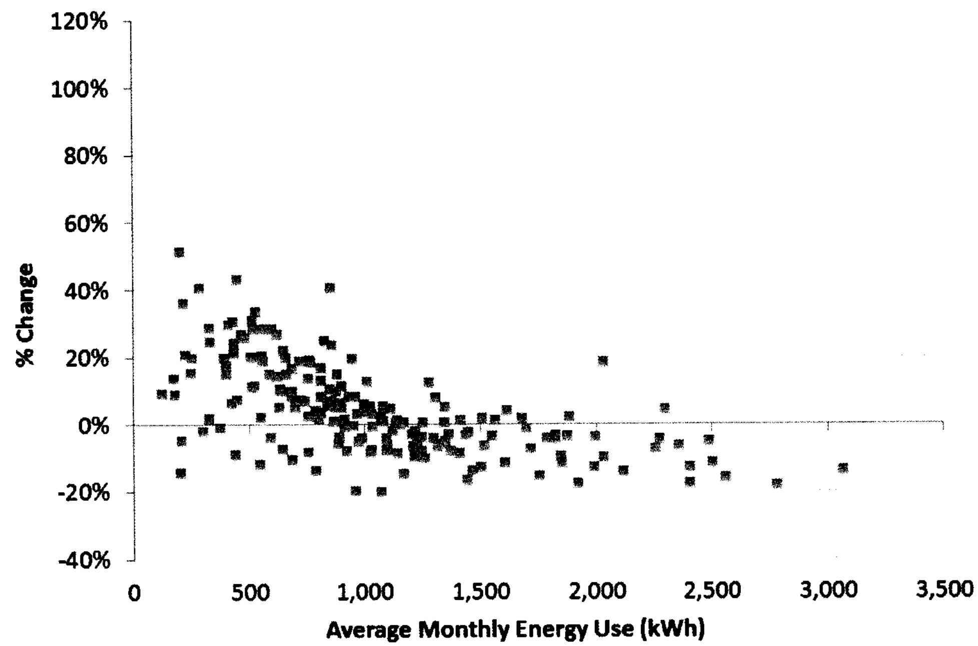
Demand charges do not automatically increase bills for small customers

With Increased Fixed Charge



Note: The three-part rate includes a monthly fixed charge of $10, an energy charge of $0.077/kWh, and a demand charge of $6/kW. The revenue-neutral two-part rate includes a monthly fixed charge of $40 and an energy charge of $0.083/kWh.

With New Demand Charge



Note: The three-part rate includes a monthly fixed charge of $10, an energy charge of $0.060/kWh, and a demand charge of $9/kW. The revenue-neutral two-part rate includes a monthly fixed charge of $40 and an energy charge of $0.083/kWh.

- Correlation between bill impact and customer size is stronger with increased fixed charge
- Whether small customers are low income customers is another question entirely…

Additionally, demand charges…

- ✓ Are more closely aligned with the costs that they recover
- ✓ Provide customers with an opportunity for bill reductions through demand response and energy efficiency
- ✓ Could lead to improved load factors and reduced resource costs
- ✓ Can compensate distributed generation for its capacity value

(But demand charges do require smart/interval meters)

5. Can customers understand a demand charge?

Customers don't need to be electricity experts to understand a demand charge

Responding to a demand charge does <u>not</u> require that the customers know exactly when their maximum demand will occur

If customers generally know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs

This simple message should be stressed in customer marketing and outreach initiatives associated with the demand rate

The following example is a hypothetical illustration of the composition of the typical customer's maximum demand (8.5 kW), and the benefits of staggering the use of a few key appliances

Staggering the use of a few key appliances could lead to significant demand reductions

Avg. Demand Over 30-min

Appliance	Avg. Demand (kW)	
Dryer	4.0	Flexible Load (7.5 kW)
Oven	2.0	
Stove	1.0	
Hand iron	0.5	
Misc. plug loads	0.2	Inflexible Load (1 kW)
Lighting	0.3	
Refrigerator	0.5	
Total	**8.5**	

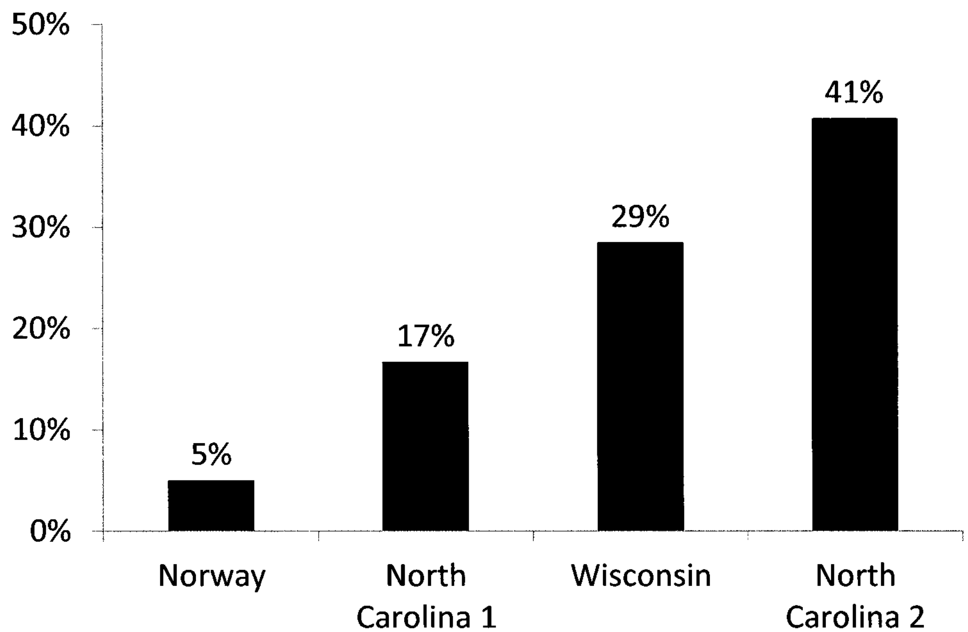
Comments

- Use of some of the appliances is inflexible (1 kW)
- Use of other appliances could be easily staggered to reduce demand
- Simply delaying use of the dryer until after the oven, stove, and hand iron had been turned off would reduce the customer's maximum demand by 3.5 kW
- This would bring the customer's maximum demand down to 5 kW, **a roughly 40% reduction in demand**

4. Will customers respond to a demand charge?

Three experiments suggest that customers will respond

Average Reduction in Max Demand



Note: The North Carolina pilot was analyzed through two separate studies using different methodologies; both results are presented here

However...

- Two of the pilots are old and the third is from a unique climate
- The impact estimates vary widely
- Findings are based on small sample sizes
- New research is needed

We have developed a model to simulate customer response to demand charges

The model is based on a widely accepted methodological framework that captures two key effects

- Load shifting in response to a change in rate structure
- Conservation (or the opposite) in response to a change in average rate level

The model draws on an extensive library of customer price elasticity estimates found in more than 40 pricing pilots over the past decade

Our simulation for a hypothetical demand rate found that the average customer would reduce their max demand by 5%

Residential class peak-coincident demand would drop by 1.7% due to load diversity; demand during system peak would drop by a slightly lower amount

New empirical research would improve our understanding of customer response

There are at least two viable approaches for reliably testing the impact of demand charges

Experimental pilot

- Scientific approach designed to provide statistically robust estimates
- Randomly selected treatment and control group to avoid bias
- Pre- and post-treatment data collection

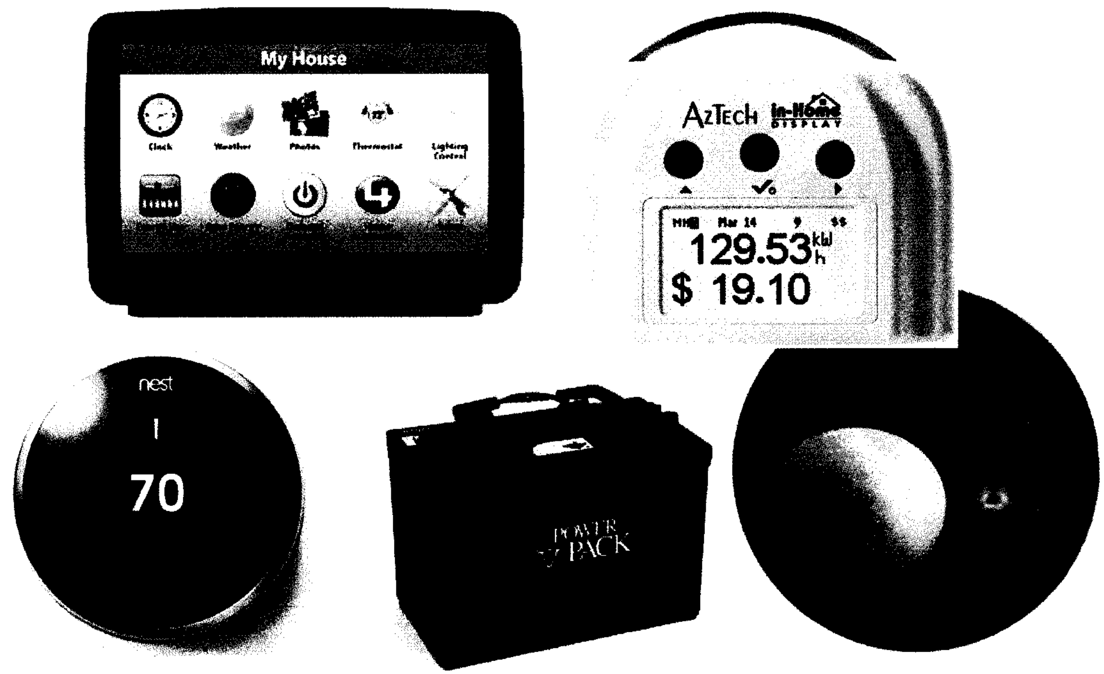
"Test and learn" deployment

- Rates are deployed full scale and modified regularly to assess impacts
- "Before and after" data can still be collected
- A quasi-control group can be created from non-participants
- Less scientific, but facilitates faster deployment

3. What is the role of enabling technology?

Technology will help customers manage demand

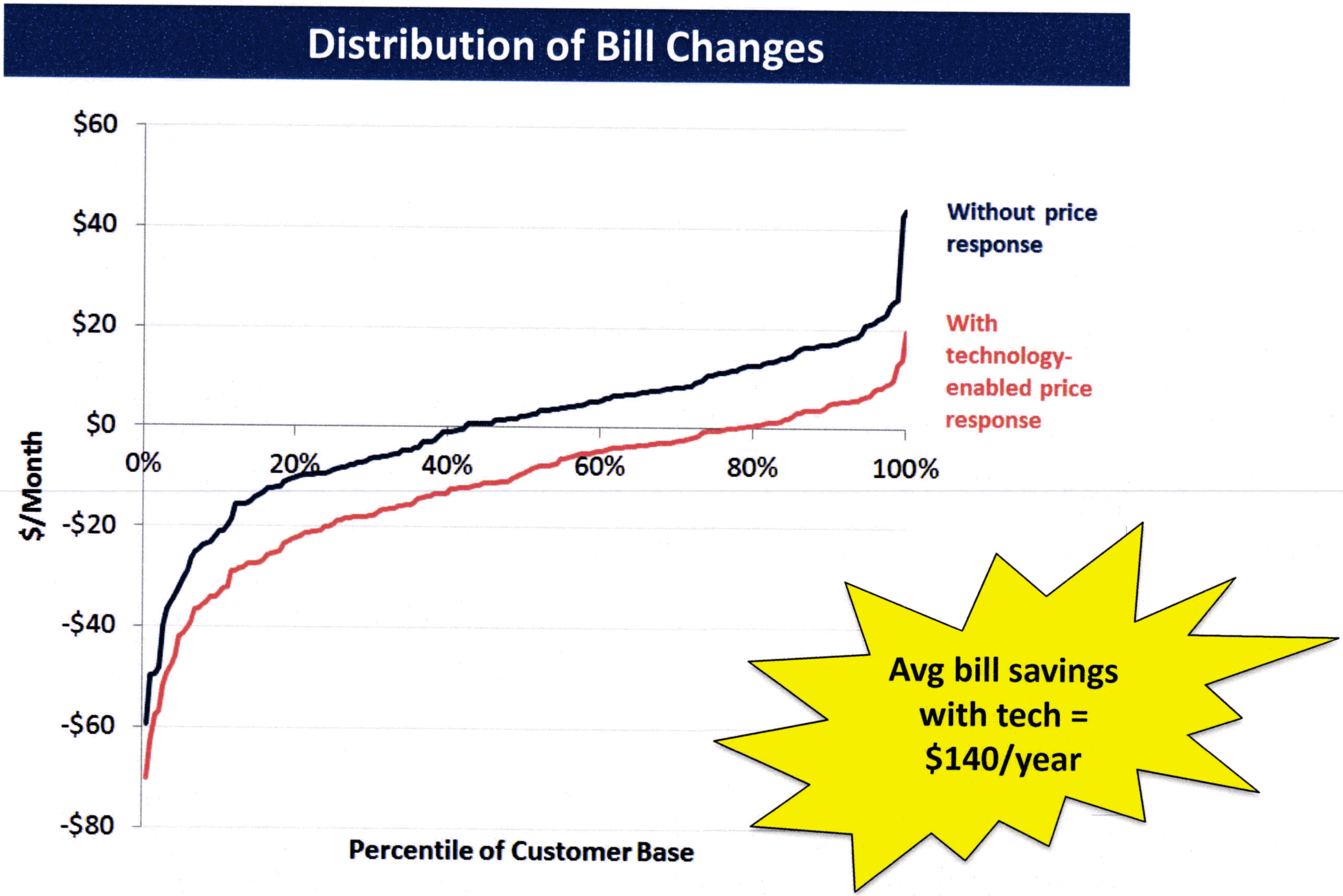
Smarter demand management will be enabled by new technologies



And third parties will compete to be the customer's energy advisor

comverge energy made better
OPOWER
ENERNOC
Google

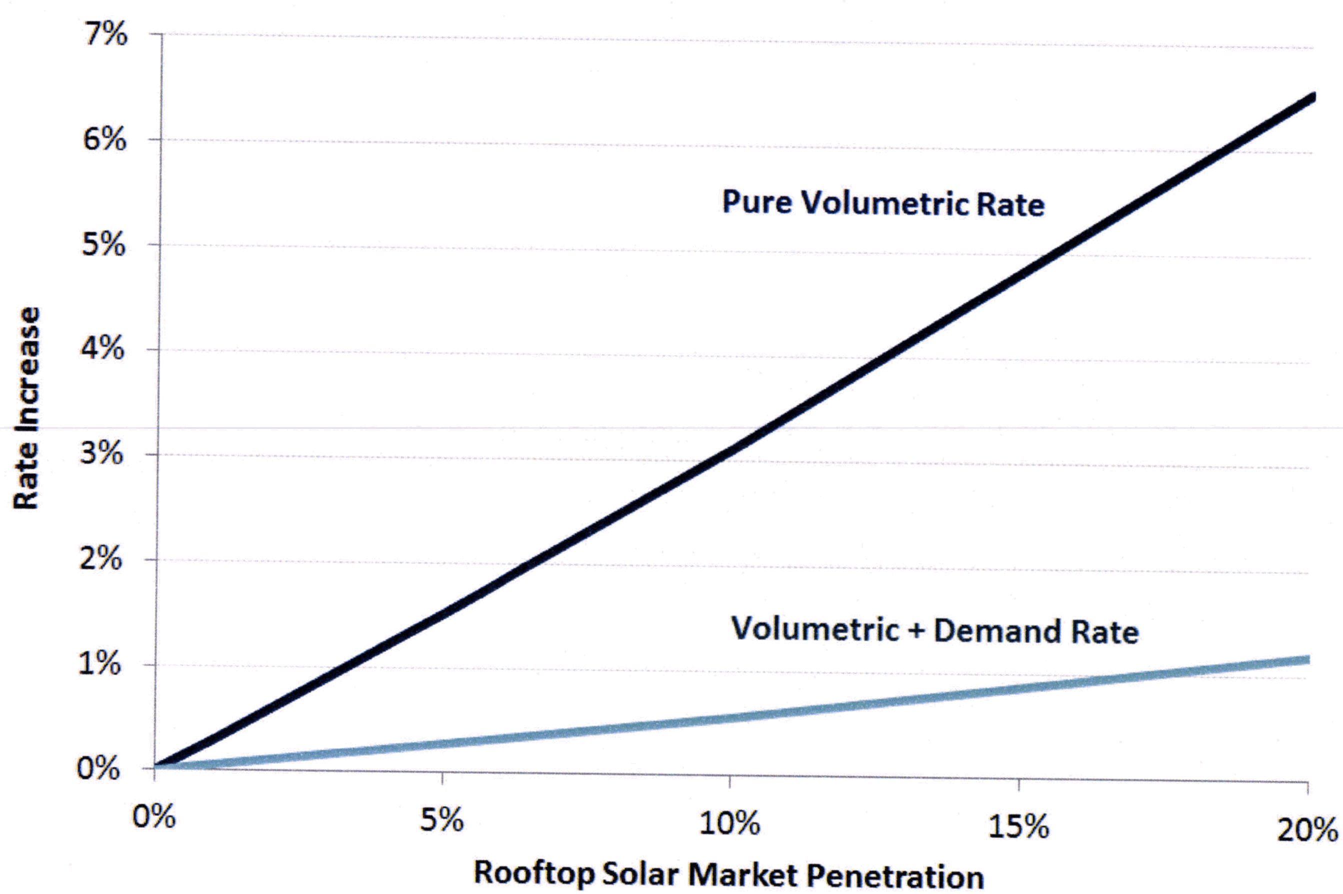
Bill savings could increase significantly with technology



2. How will utility revenues be affected?

Demand charges would reduce a hidden subsidy for customers with distributed generation

Rate Increase due to Rooftop Solar Adoption



Comments

- This is a highly stylized example that should be refined through utility-specific analysis
- Rate impacts do reflect avoided energy and capacity costs
- Rate impacts do not reflect additional costs associated with net metering such as interconnection costs, billing administration, etc.

But there is a revenue loss risk associated with any voluntary rate offering…

In one analysis, if all customers switch to the demand rate when beneficial, residential revenue would drop by 5%

Accounting for realistic rate switching behavior, revenue loss would be more like 3%

One approach to mitigating the revenue impact has been to build the anticipated revenue loss into the new rate design

Another approach is to recover the lost revenue from the customers who are on the old flat rate

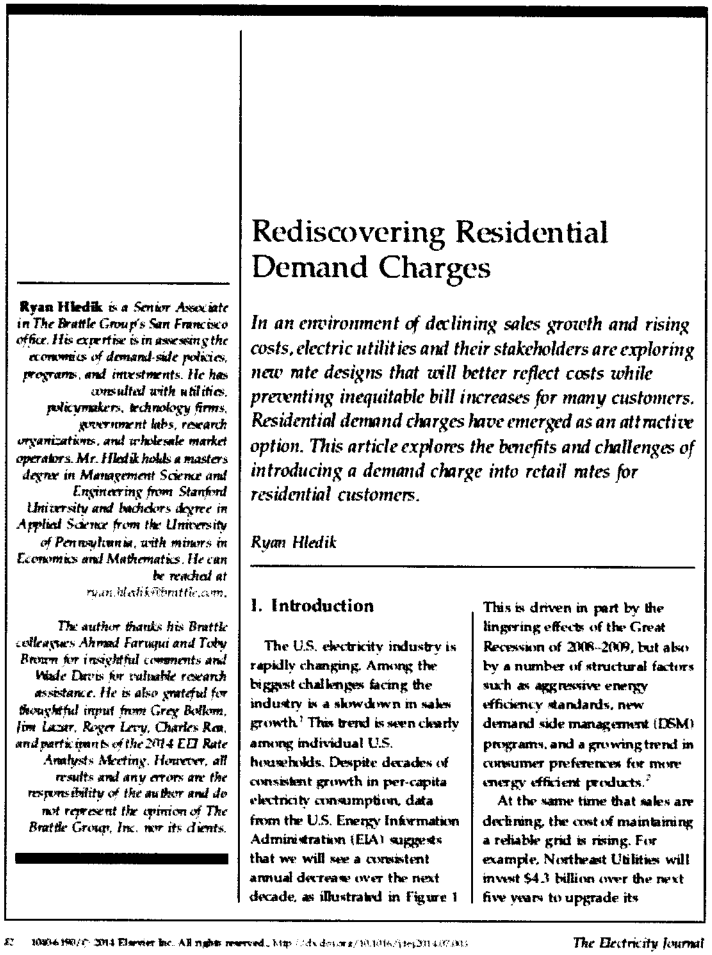
1. When is the right time to introduce a demand charge?

The transition to a demand charge will take time and require careful planning

Rate Design	Pilots	Impact Analysis	Transition Plans	Regulatory Activity
Rate benchmarking	Pilot design	Load impacts	Multi-year rate rollout strategies	Rate case testimony
Cost structure review	Sample selection	Bill impacts	Protections for vulnerable customers	Stakeholder outreach and education
Formation of ratemaking objectives	Process evaluation	Revenue impacts	Customer education	Conferences, whitepapers, webinars, etc.
Rate development	Customer satisfaction surveys	Conservation impacts		
	Load impact analysis	Societal costs & benefits		

For more information…

The Electricity Journal



Ryan Hledik is a Senior Associate in The Brattle Group's San Francisco office. His expertise is in assessing the economics of demand-side policies, programs, and investments. He has consulted with utilities, policymakers, technology firms, government labs, research organizations, and wholesale market operators. Mr. Hledik holds a masters degree in Management Science and Engineering from Stanford University and bachelors degree in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. He can be reached at ryan.hledik@brattle.com.

The author thanks his Brattle colleagues Ahmad Faruqui and Toby Brown for insightful comments and Wade Davis for valuable research assistance. He is also grateful for thoughtful input from Grey Bolkom, Jim Lazar, Roger Levy, Charles Rea, and participants of the 2014 EEI Rate Analysts Meeting. However, all results and any errors are the responsibility of the author and do not represent the opinion of The Brattle Group, Inc. nor its clients.

Rediscovering Residential Demand Charges

In an environment of declining sales growth and rising costs, electric utilities and their stakeholders are exploring new rate designs that will better reflect costs while preventing inequitable bill increases for many customers. Residential demand charges have emerged as an attractive option. This article explores the benefits and challenges of introducing a demand charge into retail rates for residential customers.

Ryan Hledik

I. Introduction

The U.S. electricity industry is rapidly changing. Among the biggest challenges facing the industry is a slowdown in sales growth.[1] This trend is seen clearly among individual U.S. households. Despite decades of consistent growth in per-capita electricity consumption, data from the U.S. Energy Information Administration (EIA) suggests that we will see a consistent annual decrease over the next decade, as illustrated in Figure 1. This is driven in part by the lingering effects of the Great Recession of 2008–2009, but also by a number of structural factors such as aggressive energy efficiency standards, new demand side management (DSM) programs, and a growing trend in consumer preferences for more energy efficient products.[2]

At the same time that sales are declining, the cost of maintaining a reliable grid is rising. For example, Northeast Utilities will invest $4.3 billion over the next five years to upgrade its

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Presenter Information

Ryan Hledik is a Principal in The Brattle Group's San Francisco office. Mr. Hledik specializes in the economics of policies and technologies that are focused on the energy consumer. He assists clients confronting complex issues related to the recent slowdown in electricity sales growth and the evolution of utility customers from passive consumers to active managers of their energy needs.

Mr. Hledik has supported utilities, policymakers, law firms, technology firms, research organizations, and wholesale market operators in matters related to retail rate design, energy efficiency, demand response, distributed generation, and smart grid investments. He has worked with more than 50 clients across 30 states and seven countries.

A frequent presenter on the benefits of smarter energy management, Mr. Hledik has spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam. He regularly publishes articles on complex retail electricity issues.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.

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The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

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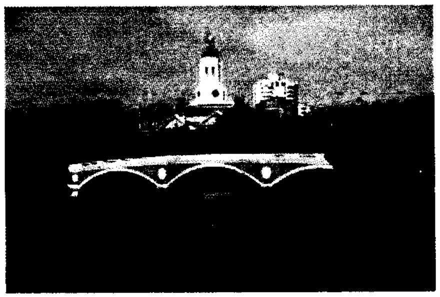

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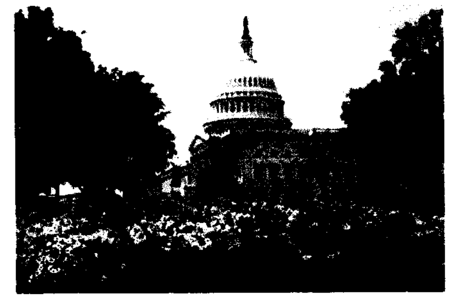

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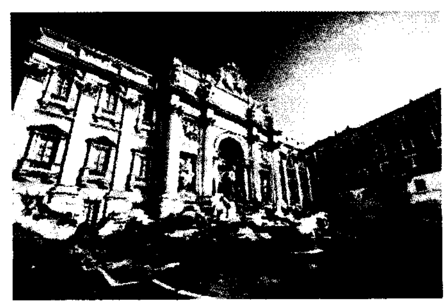

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Further reading

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Appendix

Existing Residential Demand Rates

#	Utility	Utility Ownership	State	Residential Customers Served	Effective Date of Rate	Fixed Charge	Demand Charge ($/kW-month) Summer	Demand Charge ($/kW-month) Winter	Timing of demand measurement	Demand interval	Peak Hours Summer	Peak Hours Winter	Combined with energy TOU?	Applicable Residential Customer Segment
1	Alabama Power	Investor Owned	AL	1,241,998	7/14/2011	14.50	1.50	1.50	Any time	15 min	NA	NA	Yes	All
2	Alaska Electric Light & Power	Investor Owned	AK	13,968	12/7/1990	11.49	11.11	6.72	Any time	15 min	NA	NA	No	All
3	Arizona Public Service	Investor Owned	AZ	1,019,292	7/1/2012	16.68	13.50	9.30	Peak Coincident	60 min	12:00 - 19:00	12:00 - 19:00	Yes	All
4	Black Hills	Investor Owned	SD	54,617	4/1/2010	12.25	7.61	7.61	Any time	15 min	NA	NA	No	All
5	Black Hills	Investor Owned	WY	2,153	6/1/2010	12.25	6.75	6.75	Any time	15 min	NA	NA	No	All
6	City of Fort Collins Utilities	Municipal	CO	60,464	1/1/2015	5.37	2.40	2.40	Any time	15 min	NA	NA	No	All
7	City of Kinston	Municipal	NC	9,776	7/1/2014	14.94	10.05	7.81	Peak Coincident	15 min	13:00 - 19:00	7:00 - 9:00 & 14:00 - 20:00	Yes	All
8	City of Longmont	Municipal	CO	34,697	1/1/2014	15.40	5.75	5.75	Any time	15 min	NA	NA	No	All
9	Dakota Electric Association	Cooperative	MN	94,924	9/11/2014	11.00	12.90	9.30	Any time	15 min	NA	NA	No	All
10	Dominion	Investor Owned	NC	101,158	11/1/2012	12.00	8.55	5.00	Peak Coincident	30 min	13:00 - 21:00	6:30 - 12:00	Yes	All
11	Dominion	Investor Owned	VA	2,105,500	1/25/2014	12.00	5.68	3.95	Peak Coincident	30 min	11:00 - 22:00	7:00 - 11:00	Yes	All
12	Duke Energy Carolinas, LLC	Investor Owned	NC	1,608,151	11/1/2013	13.83	8.03	4.01	Peak Coincident	30 min	12:00 - 19:00	7:00 - 12:00	Yes	All
13	Duke Energy Carolinas, LLC	Investor Owned	SC	460,178	10/1/2013	13.83	7.92	3.98	Peak Coincident	30 min	13:00 - 19:00	7:00 - 12:00	Yes	All
14	Fort Morgan	Municipal	CO	5,273	2/1/2015	6.13	10.22	10.22	Any time	15 min	NA	NA	No	All
15	Georgia Power	Investor Owned	GA	2,072,622	1/1/2015	11.00	6.42	6.42	Any time	30 min	NA	NA	Yes	All
16	Midwest Energy Inc	Cooperative	KS	29,951	7/1/2014	22.00	6.40	6.40	Any time	15 min	NA	NA	No	All
17	Otter Tail Power Company	Investor Owned	MN	47,699	10/1/2011	16.00	6.08	5.11	Any time	60 min	NA	NA	No	All
18	Otter Tail Power Company	Investor Owned	ND	44,910	12/1/2009	16.00	6.52	2.63	Any time	60 min	NA	NA	No	All
19	Otter Tail Power Company	Investor Owned	SD	8,648	6/1/2011	16.00	7.05	5.93	Any time	60 min	NA	NA	No	All
20	Salt River Project	Political Subdivision	AZ	891,668	1/4/2015	32.44 - 45.44	9.59 or 17.82 or 34.19	3.55 or 5.68 or	Peak Coincident	30 min	13:00 - 20:00	17:00 - 21:00	Yes	DG only
21	South Carolina Public Service Authority	State	SC	140,126	12/1/2013	24.00	11.34 or 4.85	11.34 or	Peak Coincident	30 min	13:00 - 19:00	6:00 - 10:00	No	All
22	Swanton Village Electric Department	Municipal	VT	3,208	4/16/2013	25.05	6.38	6.38	Any time	15 min	NA	NA	No	All
23	Westar Energy	Investor Owned	KS	323,581	Proposed	15.00	10.00	3.00	Any time	30 min	NA	NA	No	All
24	Xcel Energy (PSCo)	Investor Owned	CO	1,182,093	10/30/2009	40.00	4.84	4.84	Any time	15 min	NA	NA	Yes	All

Notes:

Peak periods are applicable from Monday through Friday excluding following holidays : New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas.

4-5: Blacks Hills also offers an optional time-of-use rate for customers owning demand controllers; the rate can be combined with a demand charge that is measured during the peak period.

7: Between May and September peak hours are from 13:00 to 19:00. For October and April peak hours are from 7:00 to 9:00 and 14:00 to 20:00. Between November to March peak hours are from 7:00 to 9:00.

9: This rate is available to residential customers with at least 5 kW of controlled electric heating units. Members requesting service under this rate schedule must remain on this rate schedule for a minimum of twelve months.

17-19: Otter Tail Power Company determines demand based on the peak one-hour reading recorded during the winter period for the most recent 12 months.

20: This rate schedule is only for residential customers that have a solar DG connection. The demand charge is tiered and applies to demand with thresholds of the first 3 kW, the next 7kW, and all remaining kW.

21: South Carolina Public Service Authority has two demand charges based on time-of-use. The peak demand charge is $11.34/kW and the off-peak demand charge is $4.85/kW.

23: Westar Energy's rate has been proposed by the utility in an ongoing regulatory proceeding but has not yet been approved.

EXHIBIT
TASC 18
admitted

plan comparison

plan comparison
- standard
- time advantage 7 pm-noon
- combined advantage 7 pm-noon
- peak plans
- time advantage super peak
- renewable energy plans
- green choice plans
- adjustors

When it comes to energy usage, different people have different needs. We offer several service plans so you can find the one that's most convenient for your lifestyle and saves you the most money.

compare & apply

*login required

service plans to fit your lifestyle

Our service plans have a variety of benefits depending on how you use energy. Compare them and find out which one is right for you.

standard plan

time advantage plan 7 pm-noon

time advantage super peak plan

combined advantage 7 pm-noon

time advantage 9 pm-9 am (frozen)

combined advantage 9 pm-9 am (frozen)

renewable energy plans

when you use less energy

This plan helps those who use less energy save money. It doesn't matter what time of day you use electricity, you're billed at a single rate.

best if you

- use 1,000 kilowatt hours (kWh) or less each month
- live in a home or apartment that is 1,110 square feet or less
- don't have a swimming pool or spa that's electrically heated

analyze your energy use

learn how you use energy and to find new ways to save.

start now

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EXHIBIT
TASC 19
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	DOUG LITTLE COMMISSIONER	

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **DIRECT TESTIMONY OF MARK FULMER**

The Alliance for Solar Choice hereby provides notice of filing the Direct Testimony of Mark Fulmer in the above-referenced matter.

Respectfully submitted this 6th day of November, 2015.

Court S. Rich
Rose Law Group pc
Attorney for TASC

Arizona Corporation Commission

Original and 13 copies filed on this ____ day of November, 2015 with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **DIRECT TESTIMONY OF MARK FULMER**

Direct Testimony of Mark Fulmer

On Behalf of

The Alliance for Solar Choice

November 6, 2015

Contents

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Mark E. Fulmer. I am a Principal and Co-owner at MRW & Associates, LLC ("MRW"). MRW is an energy consulting firm founded in 1986 that specializes in power and gas market assessments, regulatory matters, litigation support, expert witness testimony, contract review, and negotiations. My business address is 1814 Franklin Street, Suite 720, Oakland, California 94612.

Q: Please summarize your professional and educational background.

A: I have been an energy consultant with MRW since 1999. During that time, I have worked with non-utility retail energy service providers (both gas and electric), independent power producers, municipalities, end-use customers, consumer advocates, trade organizations, and financial institutions on a variety of matters related to natural gas and electric industry regulation and policy, utility ratemaking, price forecasting, demand-side management and asset valuation. Previously, I worked at Daniel, Mann, Johnson, & Mendenhall, where I consulted to utilities and others on energy efficiency. Prior to that, I worked at Tellus Institute in Boston, Massachusetts, where I consulted to numerous state agencies and non-governmental organizations on integrated resource planning and natural gas and electric industry restructuring.

I hold a Master of Science in Engineering from Princeton University and a Bachelor of Science degree in Engineering from the University of California at Irvine.

Q: Have you previously provided expert witness testimony before state public utility commissions?

A: Yes. I have testified before state utility commissions in California, Hawaii, New Mexico, Pennsylvania, Rhode Island and Washington. Here in Arizona, I have provided testimony before the Arizona Corporation Commission on behalf of Constellation Energy and Direct

Energy on direct access issues. Please see Exhibit MEF-1 for my qualifications and a list of my testimonies.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of The Alliance for Solar Choice ("TASC"). TASC is an organization comprised of some of the nation's most prominent companies in the rooftop solar industry. TASC advocates for maintaining successful distributed solar energy policies throughout the United States.

Q: What is TASC's interest in this proceeding?

A: TASC is committed to supporting retail net energy metering ("NEM"), which empowers customer choice by providing fair credit to homes, businesses, churches, schools, public agencies, and other neighborhood places when solar systems generate on-site energy. As such, TASC is interested in ensuring that UNS's residential rate design does not hamper customer choice.

Q: Please summarize your conclusions and recommendations.

A: UNS Electric ("UNS" or "Company"), primarily through its renewables witness, Mr. Tilghman, inappropriately paints distributed solar in a very poor light, characterizing it as unreliable and a hindrance to grid operation. However, his statements are overly broad, not supported by evidence, and in some cases incorrect or grossly misleading. Even though all of the issues that Mr. Tilghman raises are being successfully addressed in other jurisdictions including those with significantly higher distributed solar penetration levels than UNS service territory, his only recommendation is to implement a rate design that will stifle further distributed solar. Furthermore, there are numerous benefits of distributed solar that go unmentioned that should be considered when making NEM policy and before consideration of any rate design change to disadvantage distributed solar.

The ACC should take Mr. Tilghman's concerns with a very large lump of salt and remember that the purpose of the Renewable Energy Standard and Tariff and associated Distributed Energy Requirement are in place for a reason, and that rate designs counter to the intent of these policies—such as what UNS is proposing here—are counterproductive and should be rejected.

II. UNS'S ANTI-DISTRIBUTED, CUSTOMER-SITED PV STANCE IS NOT SUPPORTED

Q: What part of Mr. Tilghman's testimony are you addressing?

A: One of the stated purposes of Mr. Tilghman's testimony is to "provide a general discussion regarding the impacts of renewable energy, particularly solar and distributed generation ("DG") resources, on the utility's operations." (p. 2)

Q. Is Mr. Tilghman's discussion of the impacts of solar and distributed generation offered in direct support of any policy change?

A. Yes. Mr. Tilghman's discussion of these impacts is in light of the Company's request to fundamentally shift its distributed generation policy by: eliminating NEM in favor of a scheme that pays customers a "Renewable Energy Rate" for all exports of electricity; and instituting a mandatory three-part rate for NEM customers. In this way, Mr. Tilghman's allegations of negative cost impacts carry significant policy implications and should be closely scrutinized.

Q: What is the difference between net energy metering and the Company's proposal?

A: Net energy metering is valuing the output of the behind-the-meter DG at the customer's retail rate when that DG is generating more electricity than is used on-site. i.e., it is exporting power. The Company's proposal calls for a specific rate to be credited to the customer whenever their DG system is generating more power than is consumed on-site. This "Renewable Energy Rate" is lower than the retail rate, is subject to regular adjustments, and can get even lower as UNS develops or contracts with new central renewable resources.

Q: On pages 4 through 6 of his testimony Mr. Tilghman notes three "well documented" integration issues relating to customer-side solar DG. Does Mr. Tilghman provide any documentation or reference to documentation substantiating these claims of distributed generation integration issues?

A: No. Mr. Tilghman provides no "documented" examples of where distributed generation has caused UNS to incur costs on account of managing these issues.

When queried in discovery about his sources for his assertions, Mr. Tilghman responded:

> Whitepapers, presentations, and other forms of documentation are widely available from organizations such as National Engineering Laboratory (sic) ("NREL"), Massachusetts Institute of Technology ("MIT"), Lawrence Berkley (sic) Engineering Laboratory (sic) ("LBEL" (sic)), Solar Electric Power Association ("SEPA"), and others. All of these documents are public and easily attainable by TASC.[1]

As I will show, many of these sources produce reports and whitepapers, which I cite specifically, that call into question Mr. Tilghman's integration issues.

To support these allegations, I would have expected UNS to provide analysis of how current and expected levels of distributed generation interact with its system. It did not provide this information. In terms of whether these alleged integration issues represent a cost to UNS and other ratepayers, I would expect UNS to discuss whether current interconnection policies adequately capture these integration issues and appropriately assign costs to the cost-causer at the time of interconnection. There is insufficient information from Mr. Tilghman's discussion to substantiate the current existence or extent of integration issues and the relative incremental costs of addressing those issues (as

[1] Response to TASC 1.06(a).

distinguished from normal operational costs). The information provided can hardly justify the creation of an arbitrary customer class subject to a discriminatory rate.

Q: Has UNS performed a solar integration study to quantify the potential integration costs that it alleges are associated with current or projected distributed generation on its system?

A: No. Solar integration studies have been undertaken in several other jurisdictions, but when asked if UNS had conducted any studies on its system to support its asserted integration issues, or demonstrate their magnitudes on the UNS system, the answer was always "no."[2]

Q: Mr. Tilghman states that residential solar DG applications have "increased by more than 25% per month, year over year" from May 2014 (when UNS's solar incentives ceased) to May 2015 (p. 3). Is this accurate?

A: I believe that Mr. Tilghman misspoke. I think that he meant to point out that the annual increase from June 2014 to June 2015 was 25%. This is quite different—and much lower—than a 25% per month increase. Even so, a 25% annual increase from a year ending May 2014 to year ending May 2015 is misleading. Figure 1 shows UNS residential NEM applications from January 2014 to July 2015. The orange triangle depicts June 2014, when the utility incentives were eliminated. While there were spikes in October 2014 and May 2015, there is no obvious trend upward in residential NEM applications from June 2014 to June 2015.

[2] Responses to TASC 3.01, 3.02.

Figure 1

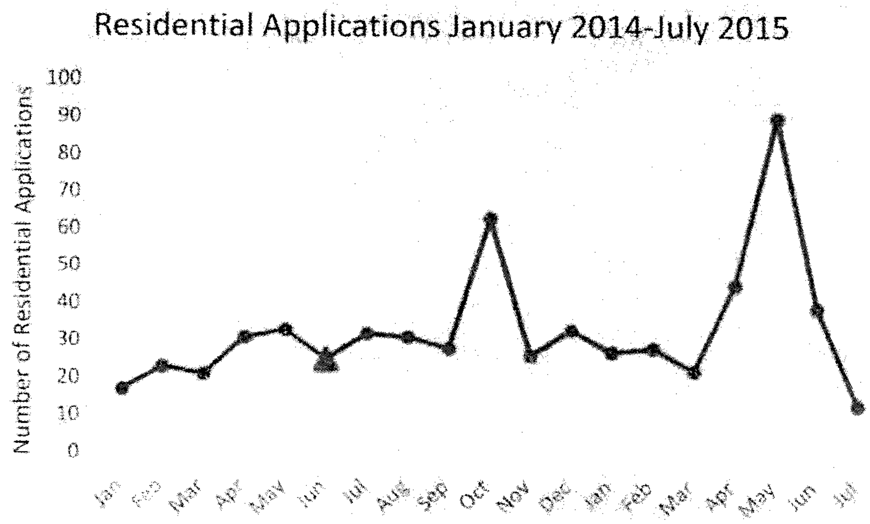
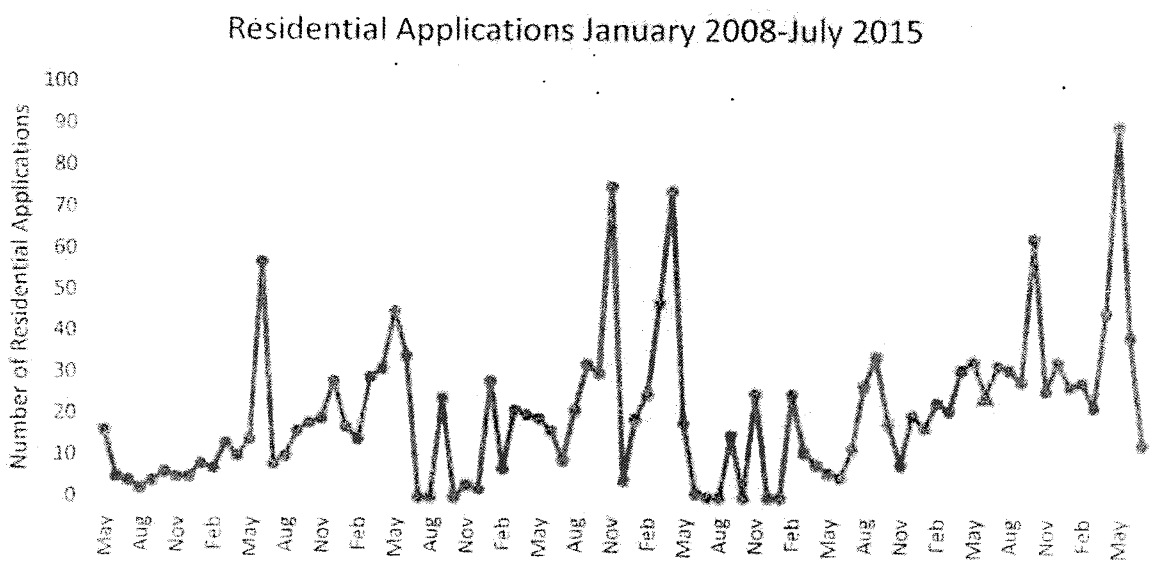


Figure 2 below shows the applications for residential NEM solar received by UNS over the past 6½ years. As this figure shows, there is no clear upward trend in the number of residential NEM applications. To suggest that there is some marked systematic increase in residential NEM applications from May 2014 to May 2015 is misleading.

Figure 2



Q: Mr. Tilghman also states, "the proliferation of the solar leasing model and the continued decline in solar panel prices, coupled with policies such as net metering, has effectively tripled the market penetration even though all utility incentives have been eliminated [in June 2014]"(p. 4). What does it mean for market penetration to triple?

A: Market penetration is a measure of the amount of sales or adoption of a product or service compared to the total theoretical market for that product or service.[3] Thus, if market penetration for NEM solar has tripled since June 2014, then there should be three times as much NEM capacity in May 2015 as there was in May 2014.

Q: Does UNS's data support this?

A: No. In response to a data request, UNS provided the number of NEM installations and solar capacity installed by year from 2008 through July 2015.[4] This is shown in Table 1 below. Even though the figure does not show monthly data, I cannot see how market penetration could have tripled since June 2014. Assuming that the incremental NEM capacity in the second half of 2015 is the same as the first, then the market penetration would have increased by 20%, not triple (300%).

Table 1. NEM Capacity in UNS Service Area

Year	Incremental NEM capacity (kW)	Cumulative NEM capacity (kW)
2008	112	112
2009	778	890
2010	1,678	2,568
2011	2,809	5,377
2012	4,851	10,228
2013	2,279	12,507
2014	3,940	16,447
2015 (YTD)	1,876	18,323
2015 (extrap.)[5]	3,752	20,199

[3] http://www.investopedia.com/terms/m/market-penetration.asp Accessed November 2, 2015.
[4] Response to UDR 2.09(a).
[5] Extrapolated from the year-to-date value to a full year.

Q: What is the first of the "well documented" issues Mr. Tilghman alleges?

A: The first integration issue that he identifies is the intermittency of renewable generation. However, it is a concern that is being successfully addressed in numerous jurisdictions, including those with significantly higher DG penetration than UNS service territory. Simply pointing out that intermittent resources can create a challenge for grid operators while not acknowledging that the challenge is manageable is misleading.

Q: He goes on to note that "[t]his problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to "bank" as many credits as possible for use later" (p. 4). Do you agree that net metering encourages customers to oversize their systems beyond average load?

A: No. Net metered customers are credited for annual excess energy at utility wholesale costs, which are well under retail electric rates. Accordingly, solar customers are not incentivized to size solar systems to provide more energy than the home's annual usage. In addition, the Commission's administrative rules place a cap on the size of the system compared to the customer's load making it illegal for customers to install systems in excess of that cap.

Q. Is the intermittency of solar PV an inherent problem to grid operations or are there mitigating factors to consider that may relieve Mr. Tilghman's concerns?

A: The distributed nature of solar PV engaged in net metering provides a number of mitigating factors. First, a number of studies illustrate that spreading out the solar resources geographically mitigates much of the intermittency problem. Random clouds, such as fair weather cumulus —which are a greater concern than predictable clouds (such as a storm front)—do not cover all of the DG sites at one time. Just like having more, smaller power plants result in greater reliability than one or two large ones, having a greater number of geographically dispersed smaller solar sites decreases the grid intermittency. For example, 10 MW of PV capacity geographically dispersed over a few square miles (or more) via behind-the-meter systems will result in much less variability than 10 MW in one location.

A number of studies corroborate this conclusion. With roughly 80% of solar PV installed on residential rooftops corresponding to approximately 2.1 MW of output, the Pal Town neighborhood in Ota City, Japan serves as a good example of how geographic dispersion of PV acts to smooth out the inherent variability of the resource. A recent study at this location compared the output from one home with that of the aggregate, finding that overall grid variability decreased exponentially with increasing solar PV penetration.[6] The specific intermittency decrease depended on the timescale.[7] For timescales greater than 1 second, the reduction in variability eventually stabilized at an aggregation of about 100 homes, suggesting that a majority of the value of decreased intermittency could be achieved through a relatively modest penetration of PV; variability decreased indefinitely with additional homes at the 1 second timescale. A comparison analysis between the Ota City, Japan site and a 19 MW PV plant in Alamosa, Colorado further corroborated these results, finding that larger single-location PV system had significantly larger intermittency impact than the same amount of PV that is geographically disperse.[8]

A recent study by the Australian Renewable Energy Agency and CAT Projects investigated the impact of solar variability on grid stability.[9] The study evaluated the deployment of 10 MW of solar PV onto the Alice Springs grid in Australia, using actual grid monitoring stations deployed across the local grid. The study concluded that the distribution grid "encounters a significant level of load variance as part of normal

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[6] Lave, Matthew, Joshua S. Stein, Abraham Ellis, Clifford W. Hansen, Eichi Nakashima, and Yusuke Miyamoto. "Ota City: Characterizing Output Variability from 553 Homes with Residential PV Systems on a Distribution Feeder." Sandia National Laboratories, November 2011. http://energy.sandia.gov/wp-content/gallery/uploads/Ota_City_Analysis-SAND2011-9011.pdf. Accessed October 14, 2015

[7] Effectively, timescale corresponds to measuring the voltage variability over a specific amount of time: 1 second, 10 seconds, 30 seconds, 1 minute and 10 minutes for this study.

[8] Lave, Matthew, Joshua S. Stein, and Abraham Ellis. "Analyzing and Simulating the Reduction in PV Powerplant Variability due to Geographic Smoothing in Ota City, Japan and Alamosa, CO." In *Photovoltaic Specialists Conference (PVSC), Volume 2, 2012 IEEE 38th*, 1–6. IEEE, 2012. http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6656719. Accessed October 14, 2015

[9] Australian Renewable Energy Agency , "Investigating the Impact of Solar Variability on Grid Stability." CAT Projects ABN 74 126 787 853, March 2015.

operation…without compromising on operational outcomes."[10] Furthermore, the intermittency variance created by the installation of an incremental 10 MW of geographically dispersed PV is very similar to the intermittency variance that currently occurs in the network in the absence of PV. ARENA concludes by stating, "while it is not surprising that the impact of solar intermittency can be reduced by geographically dispersing PV arrays, the statistical significance of the impact was beyond initial expectation."[11]

Researchers at Lawrence Berkeley National Laboratory studied 23 time-synchronized solar isolation sites, spaced between 40 and 450 km (25 to 280 miles) apart.[12] They found that "[a]ggregation of multiple sites at the system level leads to significant smoothing of ramps, particularly over short time-scales." As such, geographic dispersion of PV can have positive intermittency impacts both on the local distribution scale, as well as the system level.

Finally, the wind energy industry can be viewed as an example of how problems related to intermittent generation can be overcome. Wind, like solar, is variable, yet it has been integrated at scale.[13]

Q: What other alleged integration challenges does Mr. Tilghman mention?

A: Mr. Tilghman mentions that the grid operator (utility) cannot monitor or control the small, distributed solar systems. His also expressed concern by the fact that NEM solar sometimes generates more electricity than is used on site and thus exports this power onto the general grid. He points to a number of potential negative outcomes from this export.

[10] *Ibid.*, p. 3.
[11] *Ibid.*
[12] Mills, Andrew, and Ryan Wiser. "Spatial and Temporal Scales of Solar Variability: Implications for Grid Integration of Utility-Scale Photovoltaic Plants." p. 13. Presented at the Electricity Markets Policy Utility-Scale PV Variability Workshop, Lawrence Berkeley National Laboratory, October 7, 2009. http://uvig.org/wp-content/uploads/2013/01/11-Mills-GeographicDiversityAndPV.pdf. Accessed October 14, 2015
[13] Curtright, Aimee E., and Jay Apt. "The Character of Power Output from Utility-Scale Photovoltaic Systems." *Progress in Photovoltaics: Research and Applications* 16, no. 3 (May 2008): 241–47. doi:10.1002/pip.786. Accessed October 14, 2015

Q: Does he demonstrate that these concerns are present on UNS's system?

A: No. Sound planning requires that the utility should both be aware of potential issues and proactively study how these issues might impact their unique system. Mr. Tilghman does not do this. His concerns are overstated and reflect largely **theoretical** and not **actual** current or near future implications. Moreover, while NEM exports can require changes by a grid operator, these changes are manageable and are being managed by grid operators elsewhere even where the grid has significantly greater solar DG penetration than UNS's system.

Q. Are technological advancements helping to mitigate the operational concerns associated with distributed solar generation?

A: Yes. For example, in December of 2014, the California Public Utilities Commission adopted new standards for so-called advanced inverters with the aim of overcoming the lack of grid operator visibility and control of distributed generation. These are devices that offer "easier and lower cost interconnection of distributed generation because of their ability to monitor and respond to grid conditions."[14] Smart inverters enable grid operators to remotely monitor and control distributed generation, either directly through a control system or by requiring settings that enable autonomous response to local grid conditions. These devices, which are commercially available today, have defined IEEE upcoming UL testing standards, and have been successfully deployed with utilities in various venues across the country. Smart inverters are ideally suited to provide increased visibility and control of variable generation solar PV to grid operators.

Furthermore, Hawaii Electric Power Company ("HECO") collaborated with a distributed solar provider and the National Renewable Energy Laboratory ("NREL") to

[14] Clean Coalition. "California Adopts Nation's First Advanced Inverter Standards," January 6, 2015. http://www.clean-coalition.org/site/wp-content/uploads/2015/01/California-establishes-advanced-inverters-standards-press-release-09_jb-6-Jan-2015.pdf. Accessed October 19, 2015

demonstrate the impact of commercially available smart inverters.[15] In particular, the demonstration examines how smart inverters can address potential transient over-voltage (both load rejection overvoltage and ground fault overvoltage) with the aim of enabling increased penetration of rooftop PV on the distribution grid.[16] As explained by the director of NREL's power systems engineering described the research as focused on "conducting investigations into how solar inverters can be programmed and controlled to trip on and off in response to grid voltage fluctuations, or to perform other grid balancing tasks."[17] Tapping into the inherent capability of these smart inverters will enable HECO to connect an additional 2,500 NEM PV systems onto its grid.

Portland General Electric ("PGE") installed a prototype PV Enhanced Inverter at a proof-of-concept solar demonstration site with the goal of preventing inverters from disconnecting during periods of peak demand. Mark Osborn, PGE's Distribute Resources Manager said, "Two-way communications with the inverters, combined with constant measurements from the synchrophasors, enables us to use the inverters to mitigate against sags and flicker much more effectively." Additionally, PGE's custom-designed control system, GenOnSys aims to treat all inverters equally, creating a kind of "virtual power plant" whereby large-scale PV becomes an asset, not a burden.[18]

Q: Does Mr. Tilghman's suggestion of technological solutions to integration challenges offer any ways UNS is actively addressing these concerns?

A: No. Given that this portion of Mr. Tilghman's testimony is in support of a proposed replacement to the existing net metering tariff, it appears the only action UNS is currently

[15] John, Jeff St. "HECO and SolarCity to Put Smart Solar Inverters Through Real-World Testing," December 8, 2014. https://www.greentechmedia.com/articles/read/HECO-and-SolarCity-to-Put-Smart-Solar-Inverters-Through-Real-World-Testing. Accessed October 19, 2015

[16] Nelson, A., A. Hoke, S. Chakraborty, J. Chebahtah, T. Wang, and B. Zimmerly. "Inverter Load Rejection Over-Voltage Testing," 2015. http://www.nrel.gov/docs/fy15osti/63510.pdf. Accessed October 19, 2015

[17] "NREL: Technology Transfer - NREL's ESIF Offers Equipment Testing on Grand Scale." *Smart Grid Today*, April 14, 2015. http://www.nrel.gov/technologytransfer/news/2015/16491.html. Accessed 19 October 2015

[18] Scharf, Mesa, and Michael Mills-Price. "Laying the Foundation for the Grid-Tied Smart Inverter of the Future." Advanced Energy: SEGIS Program Concept Paper, 2011. http://solarenergy.advanced-energy.com/upload/File/White_Papers/SEGIS-Laying%20the%20Foundation-2-FINAL.pdf. Accessed October 19, 2015

taking is to change the value proposition for customers that would like to install and use onsite solar generation. To the extent reducing the rate of distributed solar generation growth would reduce integration challenges, I suppose that modifying the net metering tariff to be less advantageous will have the desired result of slowing the rate of customer-sited solar growth, but he does not show that this will address his concerns.

Q: Does Mr. Tilghman provide any other rationale of how UNS's proposed changes to its net metering tariff might address these integration-related concerns?

A: No. He simply summarizes the rate changes proposed by Mr. Dukes. Mr. Tilghman does not reference any of the widely available utility demonstration efforts related to successfully integrating increasingly high penetrations of rooftop PV. For practical purposes, the only way that this rate change can "address" his operational concerns is by depressing distributed solar adoption. I believe this is the intent.

III. OTHER BENEFITS SHOULD BE CONSIDERED

Q: UNS proposes that the Renewable Credit Rate be a rate "equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric's affiliate, TEP." Are there benefits of distributed generation that may not be reflected in a utility-scale avoided cost rate?

A. Yes. As many studies have discussed and illustrated, there are unique values to distributed solar generation. First, when a generation resource is located behind a customer's meter, it is avoiding line losses when compared to more remote generation that is delivered across transmission and distribution facilities. Second, distributed solar generation may enable a utility to avoid or defer capital distribution projects. Benefits such as this, among others, are not going to be reflected in a utility-scale power purchase rate.

Additionally, it is important to consider that net metered solar PV represents a resource that leverages private funds to bring the resource to the grid. A utility does not incur any direct costs to bring this capacity online. If a net metered system helps to reduce a utility's revenue requirement overtime, then it will necessarily put a downward pressure on rates. For example, a recent study conducted by Synapse Energy Economics for the Mississippi Public Service Commission showed that instituting a net metering program in that state would put downward pressure on rates.[19]

I will provide further testimony on benefits in the next round of testimony related to cost of service and rate design.

Q: Can solar DG be cost-effective relative to other resources?

A: Yes. However, in order to understand how, one must look at the benefits beyond simple reductions of short-term utility energy purchases or generation. In particular, one needs to take a longer view to be able to see and quantify the contributions that solar DG makes. I briefly mention a few of these below.

Q: Can solar DG provide reliability benefits and reduce a utility's reserve margin requirement?

A: Yes. For example, a 2005 article by Duke, Williams and Payne in the *Energy Policy Journal* notes that PV deployment makes it possible to reduce the reserve margins needed to ensure power system reliability.[20] Duke *et al.* point out that grids with large generation facilities require a higher reserve margin since an unanticipated loss of output from even a single generating facility could affect service continuity. In contrast, a power system with a large number of distributed PV systems alleviates reserve requirements because individual systems are far smaller than central-station plants, and the risk of unexpected technical failure is uncorrelated across different PV systems.

This is echoed in a 2011 report prepared for the New York State Energy Research and Development Authority (NYSERDA), which noted that in general, distributed generation can increase system reliability by increasing the number and variety of

[19] Synapse Energy Economics, Inc, "Net Metering in Mississippi: Costs, Benefits and Policy Considerations." Prepared for the Public Service Commission of Mississippi, September 19, 2014.

[20] "Accelerating residential PV expansion: demand analysis for competitive electricity markets" Duke et al., *Energy Policy* 33, 2005 (Duke 2005) p. 1922

generating technologies; reducing the size of generators and the distance between generators and load; and by reducing loading on distribution and transmission lines.[21]

The reserve margin benefit issue is illustrated by an example cited in the NYSERDA study:

> During the last wave of nuclear plant construction, single units were built as large as 1100 MW in capacity. Seabrook I is an example. At the time Seabrook I came into service, its loss became the single largest risk to the reliability of the New England grid and substantially increased the risk of system outages. To remedy this situation, the New England Power Pool had to increase the required reserve margin for every utility in New England by several percentage points. A two percentage point increase in the region's required capability would amount to something on the order of 500 MW. The cost savings implicit in reducing the size of plants and dispersing them can be appreciated from that observation.[22]

While UNS is not contemplating adding a large nuclear plant, its acquisition of 138 MW (Gila Bend) out of a system of 400 MW does represent a large fraction of UNS's supply portfolio.

Q: Beyond providing reliability benefits by lowering reserve margin requirements, can solar DG provide other grid support or ancillary services?

A: Yes. According to a 2013 meta-study by the Rocky Mountain Institute, grid support services provided by solar DG can include reactive supply and voltage control, frequency regulation and response, supporting energy imbalances, providing operating reserves, and scheduling and forecasting benefits to ensure operational safety.[23] The study notes that differing standards and rules based on different systems could affect the valuation of solar

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[21] "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies." Prepared for NYSERDA by Pace Energy and Climate Center and Synapse Energy Economics 2011 (NYSERDA 2011) p.17

[22] NYSERDA 2011, p. 17

[23] "A Review Of Solar PV Benefit & Cost Studies", Rocky Mountain Institute 2013 (RMI 2013) p. 15

DG grid support services,[24] however it is likely that with changes in technology, the net value proposition of solar DG as grid support will increase.[25]

This fundamental conclusion that solar DG can provide grid support is corroborated by reports and studies prepared for NREL[26] and NYSERDA.[27]

Q: Can solar DG provide a hedge against volatile fuel prices?

A: Yes. A 2013 paper by the Interstate Renewable Energy Council notes that solar DG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility.[28] It further notes that solar DG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. Solar DG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices effectively blending price stability into the total utility portfolio.

Q: Does solar DG offer any environmental benefits?

A: Environmental benefits are a commonly referred to benefit of renewable power generally, and solar DG specifically. These benefits include reduced carbon emissions; avoided health costs resulting from reduced criteria air pollutants and improved air quality; avoided environmental compliance costs since solar DG is a zero-emissions technology; reduced stress on land and water resources.

These benefits can, of course, also be achieved through central solar facilities. However, solar DG also offers the same negligible water use and zero emissions as UNS central solar PV proposal, but without the potential habitat, visual and cultural impacts associated with utility-scale solar plants.[29]

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[24] RMI 2013 p. 33
[25] RMI 2013 p. 34
[26] "Photovoltaics Value Analysis," Prepared for National Renewable Energy Laboratory by Navigant Consulting 2008 (NREL 2008) p. 13
[27] NYSERDA 2011 p. 18
[28] "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation", Interstate Renewable Energy Council 2013 (IREC 2013) p. 30
[29] "The SunShot Vision Study," Department of Energy, February 2012 (DOE 2012) p. 170

Q: Does solar DG offer any socio-economic benefits?

A: Yes. As discussed in 2013 paper by the Interstate Renewable Energy Council, installation and construction associated with onsite generation facilities is inherently local in nature, as contractors or installers must be within reasonably close geographic proximity to economically install a system and be present for building inspections. Accordingly, the solar industry creates local jobs, thereby generating local revenue. Economic activity associated with the growing rooftop solar industry can create additional tax revenue at the state and local levels, as installers purchase supplies, goods and other related services subject to state and local sales tax, and pay payroll taxes. Locally spent dollars displace those frequently sent out of state for fuel and other supplies.[30]

These jobs impacts are backed up by data. Overall, from 2010 to 2014, the solar industry has added nearly 80,000 jobs in the US, an 86% increase,[31] and is expected to add another 36,000 jobs in 2015.[32] Installers make up the largest part of the solar workforce, with most working on small, distributed systems: 59.6% on residential systems and 23.6% on small to medium commercial systems (less than 200 kW).[33]

Q. Should all of these benefits be considered in determining whether a shift away from the existing net metering policy is justified or advisable?

A. Yes. It is appropriate to consider the full range of benefits provided by net metered solar in determining whether there is a compelling basis to fundamentally change the policy and justify a waiver of the net metering rules as well as the creation of an arbitrary class of customers subject to a discriminatory rate.

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[30] IREC 2013 p. 35

[31] The Solar Foundation, *National Solar Jobs Census 2014,* Page 1. http://www.thesolarfoundation.org/wp-content/uploads/2015/01/TSF-National-Census-2014-Report_web.pdf Accessed November 2, 2015.

[32] *Ibid.*, p. 3

[33] *Ibid.*, p. 15

IV. POLICY RESPONSE: ACC SHOULD SUPPORT –OR AT LEAST NOT HINDER—DISTRIBUTED PV

Q: Does Arizona have any policies concerning distributed generation?

A: Yes. Arizona's Renewable Energy Standard and Tariff ("REST") order, ACC Decision No. 69127, set out specific requirements for utilities in the state with respect to the acquisition of renewable energy to serve their retail customers. Included in that REST were requirements for amounts of a utility's Annual Renewable Energy Requirement that must be met by distributed energy ("DE") resources. The RES requirements and the set-asides for DE resources reflect the Arizona policymakers' intent for renewable energy in general, and distributed renewables in particular, to be included in the state's energy portfolio. This is not simply because they result in the lowest possible rates. If that were the case, the REST would not be necessary. But the REST and DE requirements exist because they offer benefits, such as those I enumerated above, that cannot be easily reflected in a simplistic short term analysis.

Rate designs that directly or indirectly suppress renewable DE generation are at odds with this general policy direction. In setting rates, which will be explicitly addressed in the next round of testimonies, the ACC must keep in mind that customers who have, or are wishing to install, solar DG must not be not discriminated against through the imposition of unique and onerous tariffs.

Q: Does this conclude your testimony?

A: Yes.

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1999 - Present)
Conduct economic and technical studies in support of clients involved in regulatory and legislative proceedings and power project development. Advise clients on the economic issues associated with taking electricity service from non-utility sources or self-generating power. Work includes expert testimony on rate matters; economic analysis of end-use energy-efficiency projects, retail rate and wholesale price forecasting, and pro forma analysis of cogeneration and distributed generation facilities.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas industry deregulation issues. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track transportation energy use and emissions and used the model to evaluate state-level transportation policies. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991
B.S., Mechanical Engineering, University of California, Irvine, 1986

SELECTED PUBLICATIONS

1. A Technical and Economic Assessment of the Co-Production of Electricity and Alcohol From Sugar Cane. Presented at the *International Engineering Conference on Energy Conversion (IECEC-90)*. American Institute of Chemical Engineers. New York, NY. August 1990. Principal author and presenter.

2. Cogeneration Applications of Biomass Gasifier/Gas Turbine Technologies in the Cane Sugar and Alcohol Industries. Proceedings, *Energy and Environment in the 21st Century*, MIT Press. Cambridge, Massachusetts. 1991. Co-author.

3. The Environmental Impacts of Demand-Side Management. Electric Power Research Institute report TR-101673. 1992. Co-author.

4. The Role of Gas Heat Pumps in Electric DSM. Presented at the 6th National Demand-Side Management Conference. Miami Beach, Florida. March 1993. Principal author and presenter.

5. Applying an Integrated Energy/Environmental Framework to the Analysis of Alternative Transportation Fuels. Invited paper at the European Council for an Energy Efficient Economy (ECEEE) 1993 Summer Study. Principal author.

6. Mistakes, Misconceptions, and Misnomers in DSM Cost-Effectiveness Analysis. Peer reviewed paper at the ACEEE 1994 Summer Study. Principal author and presenter.

7. A Social Cost Analysis of Alternative Fuels for Light Vehicles. *Energy Strategies for a Sustainable Transportation System*, ACEEE. Washington, DC. 1995.

8. Strategies for Reducing Energy Consumption in the Texas Transportation Sector. Project for the Texas Sustainable Energy Development Council. Austin, Texas. June 1995. Co-author.

9. Evaluation of Food Processing Effluent Treatment Alternatives. Paper presented at the American Chemical Society meeting, Las Vegas, Nevada. December 1997. Co-Author.

10. Market Transformation Effect Indicators for Government, Utilities, Retailers and Manufacturers. Invited panelist in a roundtable discussion at the American Council for an Energy Efficient Economy (ACEEE) 1998 Summer Study.

11. California: Crisis Over? Project Finance NewsWire, Chadbourne & Parke. October 2001. Co-author.

12. California: Back to Basics or Déjà Vu? Natural Gas & Electricity, Volume 20, Number 12. July 2004. Co-author.

13. Nuclear Fuel Reprocessing: Issues and Future Prospects. Report for the California Energy Commission. (Final Draft). March 2006. Co-author.

14. AB 1632 Assessment of California's Operating Nuclear Plants. California Energy Commission, CEC-100-2008-005-F. October 2008. Co-author.

15. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-fired Power Plants in California. California Energy Commission, CEC-700-2009-009-F. May 2009. Co-author.

PREPARED TESTIMONY

1. Rhode Island Public Utilities Commission No. 2025
   Prepared Testimony on Behalf of Rhode Island Department of Public Utilities and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029
   Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania, particularly the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206
   Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

4. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
   Rebuttal Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2002.

5. FERC Docket Nos. EL00-95-075 and EL00-98-063
   Affidavit on Behalf of Duke Energy Trading and Marketing LLC. March 20, 2003.

6. CPUC Rulemaking 01-10-024
   Prepared Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003.

7. CPUC Rulemaking 01-10-024
   Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

8. Arizona Corporation Commission No. E-00000A-02-0051
   Reply Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

9. Arizona Corporation Commission No. E-01345A-03-0437
   Direct Testimony on Behalf of Constellation NewEnergy and Strategic Energy, Inc. February 3, 2004.

10. Arizona Corporation Commission No. E-01345A-03-0437
Cross Rebuttal Testimony of Mark E. Fulmer on Behalf of Constellation NewEnergy and Strategic Energy, Inc. March 30, 2004.

11. CPUC Rulemaking 03-10-003
Direct Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Community Choice Aggregation Transaction Costs. April 15, 2004.

12. CPUC Rulemaking 03-10-003
Reply Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 7, 2004.

13. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 20, 2004.

14. CPUC Rulemaking 04-04-003
Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 6, 2004.

15. CPUC Rulemaking 04-04-003
Rebuttal Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 20, 2004.

16. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. April 28, 2005.

17. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning SCE's Test Year 2006 General Rate Case Application. May 6, 2005.

18. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. May 16, 2005.

19. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning SCE's Test Year 2006 General Rate Case Application. May 25, 2005.

20. CPUC Application 06-03-005
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of the PG&E's 2007 General Rate Case Marginal Cost, Revenue Allocation and Rate Design. October 27, 2006.

21. CPUC Application 07-01-045
Testimony of Mark E. Fulmer on Behalf of The Alliance for Retail Energy Markets and The California Manufacturers and Technology Association Concerning SCE's Application to Update is Direct Access and Other Service Fees. June 22, 2007.

22. CPUC Rulemaking 08-03-002
Testimony of Mark Fulmer Behalf of Debenham Energy, LLC. Concerning Tariffs Supportive of Green Distributed Generation. October 31, 2008.

23. CPUC Application 09-02-022
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning PG&E's 2009 Rate Design Window Application. July 31, 2009.

24. CPUC Application 09-02-019
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning the Cost Recovery Proposed By PG&E in its Application to Implement a Photovoltaic Program. August 14, 2009.

25. Superior Court of San Francisco
Deposition of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. CCSF. (Verbal deposition only.) September 2, 2009.

26. California Superior Court of San Francisco Court Case No. CGC-07-470086 Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. City and County of San Francisco. (Trial exhibits only in electronic file.) September 25, 2009.

27. CPUC Application 09-12-020
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 1 of PG&E's Test Year 2011 General Rate Case. May 19, 2010.

28. CPUC Application 10-03-014
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of PG&E's Test Year 2011 General Rate Case Application. October 6, 2010.

29. CPUC Rulemaking 07-05-025
Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). January 31, 2011.

30. CPUC Rulemaking 07-05-025
Testimony of Mark E. Fulmer on Behalf of the Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. January 31, 2011.

31. CPUC Rulemaking 07-05-025
Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. February 25, 2011.

32. CPUC Rulemaking 07-05-025
Rebuttal Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of The Joint Parties on a Fair And Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). February 25, 2011.

33. CPUC Application A.11-03-001, 11-03-002, 11-03-003
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. June 15, 2011.

34. CPUC Application 11-03-001, 11-03-002, 11-03-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. July 11, 2011.

35. CPUC Application 11-06-004
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets concerning PG&E's 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-bypassable Charges Forecast. August 26, 2011.

36. CPUC Application 11-05-023
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retail Energy Markets and the Western Power Trading Forum concerning the Application of SDG&E for Authority to Enter into Purchase power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. September 22, 2011.

37. CPUC Application 11-06-007
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of SCE's Test Year 2012 General Rate Case Application. February 6, 2012.

38. CPUC Application 11-12-009
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retails Energy Markets and the City and County of San Francisco Concerning PG&E's Application to Revise Direct Access and Community choice Aggregation Service Fees. May 14, 2012.

39. CPUC Rulemaking 12-03-014
Testimony on Behalf of the Alliance for Retail Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. June 25, 2012.

40. CPUC Rulemaking 12-03-014
Reply Testimony on Behalf of the Alliance for Retail Energy Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. July 23, 2012.

41. CPUC Application 12-03-001
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning PG&E Company's Application to Implement Economic Development Rates for 2013-2017. August 24, 2012.

42. CPUC Application 12-02-001
Rebuttal Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning PG&E's Application to Implement Economic Development Rates for 2013-2017. October 19, 2012.

43. CPUC Application 12-04-020
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding PG&E's Application to Establish a Green Option Tariff. October 19, 2012.

44. CPUC Application 12-04-020
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding PG&E's Application to Establish a Green Option Tariff. November 9, 2012.

45. CPUC Application 11-11-002
Testimony of Mark Fulmer on Behalf of the City of Long Beach. November 16, 2012.

46. CPUC Application11-11-002
Rebuttal Testimony of Mark Fulmer on Behalf of the City of Long Beach. December 14, 2012.

47. CPUC Investigation 12-10-013
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the Rate Treatment of the San Onofre Nuclear Generating Station. September 10, 2013.

48. CPUC Application 13-06-015
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding SDG&E's Application for Approval of an Amended Power Purchase Tolling Agreement with Pio Pico Energy Center. September 20, 2013.

49. CPUC Investigation12-10-013
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the Rate Treatment of the San Onofre Nuclear Generating Station. September 23, 2013.

50. CPUC Application 13-06-015
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding SDG&E's Application for Approval of an Amended Power Purchase Tolling Agreement with Pio Pico Energy Center. October 4, 2013.

51. CPUC Application 13-08-004

Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition Regarding the SCE's 2014 "ERRA" Forecast. November 20, 2013.

52. CPUC Application 13-06-011
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning PG&E's Core Gas Capacity Planning Range. November 20, 2013.

53. CPUC Application 13-04-012
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of PG&E's Test Year 2014 General Rate Case Application. December 13, 2013.

54. CPUC Application 13-06-011
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning PG&E's Core Gas Capacity Planning Range. December 18, 2013.

55. CPUC Application 13-12-012/Investigation 14-06-016
Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning Core Transport Issues in PG&E's Gas Transmission and Storage Rate Case and Consolidated Order Instituting Investigation. August 11, 2014.

56. New Mexico Public Regulation Commission Case No. 13-00390-UT
Direct Testimony of Mark E. Fulmer on Behalf of Renewable Energy Industries Association of New Mexico. August 29, 2014.

57. CPUC Application 14-05-024
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition. September 2, 2014.

58. CPUC Application 13-12-012
Rebuttal Testimony of Mark Fulmer on Behalf of the Core Transport Agent Consortium Concerning Core Transport Issues In PG&E's Gas Transmission and Storage Rate Case. September 15, 2014.

59. CPUC Rulemaking 12-06-013
Direct Testimony of Mark Fulmer on Behalf of the Interstate Renewable Energy Council, Inc. Concerning Residential Electric Rate Design Reform. September 15, 2014.

60. CPUC Application 14-06-011
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and the Public Agency Coalition. October 3, 2014.

61. Washington Utilities & Transportation Commission Docket UE-140762 ET AL.
Direct Testimony of Mark Fulmer on Behalf of the Alliance for Solar Choice. October 10, 2014.

62. CPUC Rulemaking 12-06-013
Rebuttal Testimony of Mark Fulmer on Behalf of the Interstate Renewable Energy Council, Inc. Concerning Residential Electric Rate Design Reform. October 17, 2014.

63. Washington Utilities & Transportation Commission Docket UE-140762 ET AL.

Cross-Answering Testimony of Mark Fulmer on Behalf of the Alliance for Solar Choice. November 14, 2014.

64. CPUC Application 14-06-014
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of SCE's Test Year 2015 General Rate Case Application. March 13, 2015.

65. CPUC Application 14-06-014
Testimony of Mark E. Fulmer on SCE's Application to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. March 13, 2015.

66. CPUC Application 13-12-013
Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. May, 8, 2015.

67. CPUC Application 14-11-003
Testimony of Briana Kobor, Laura Norin, and Mark Fulmer on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for SDG&E and SoCal Gas. May 15, 2015.

68. CPUC Application 13-12-013
Rebuttal Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. June 12, 2015.

69. CPUC Application 14-12-017
Testimony of Mark Fulmer on Behalf of the City of Long Beach, Gas & Oil Department. June 22, 2015.

70. CPUC Application 14-12-007
Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. July 15, 2015.

71. Federal Energy Regulatory Commission Docket Nos. EL02-60-007, EL02-62-006 (Consolidated)
Answering Testimony of Mark Fulmer on Behalf of Shell Energy North America (US), L.P. July 21, 2015.

72. CPUC Application 14-12-007
Rebuttal Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. August 3, 2015.

73. CPUC Rulemaking 14-07-002
Joint Solar Parties Net Energy Metering Successor Tariff Rebuttal Testimony of R. Thomas Beach, Mark Fulmer and Jose Luis Contreras. September 30, 2015.

ORIGINAL

EXHIBIT

TASC 20

admitted

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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **DIRECT TESTIMONY OF MARK FULMER (RATE DESIGN AND COST OF SERVICE)**

The Alliance for Solar Choice hereby provides notice of filing the Direct Rate Design and Cost of Service Testimony of Mark Fulmer in the above-referenced matter.

Respectfully submitted this 9th day of December, 2015.

Arizona Corporation Commission
DOCKETED
DEC 09 2015
DOCKETED BY

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Contents

I. Introduction

Q: Please state your name.

A: Mark Fulmer.

Q: Did you provide testimony on behalf of The Alliance for Solar Choice (TASC) in this proceeding on November 6, 2015.

A: Yes.

Q: What is the purpose of this testimony?

A: In this testimony I address the reasonableness of UNS's proposed residential three-part rate and Rate Riders 10 and 11.

Q: Please summarize your conclusions.

A: First, while it may allow a utility to more easily collect its revenue requirement, UNS's proposal to place all residential and small commercial distributed generation (DG) customers onto a three-part rate (Rider 10) is fundamentally flawed in numerous ways. As such it must be rejected.

Second, UNS's proposal to credit DG exports at a rate that can change based on the price of a power purchase agreement (PPA) for power purchased by a different utility that may have very different attributes than UNS is unreasonable and should be rejected. The current policy of banking credits month-to-month should be continued.

Third greater use of optional time of use (TOU) rates, be they for full-service customers in addition to customers with DG, can reflect cost causation as well as send customers price signals to which they can actually respond. As such, if one were to choose, it is better to encourage greater use of optional TOU rates than to pursue residential demand charges.

II. There Are Fundamental Policy Problems With UNS's Proposal

Q: Please summarize UNS's proposed residential rate design changes for DG customers.

A: First, UNS is proposing to create two "three-part" residential rates: RES-01 Demand and RES-01 Demand TOU. These rates would consist of (1) a monthly customer charge, (2) a per-kilowatt-hour (kWh) energy charge, and (3) a charge based on the peak demand of the residential customer that occurred during the billing period (Table 1). These two rates would be optional for standard residential customers, but residential DG customers whose systems are installed after June 1, 2015 would be required to take service under one of the three-part rates.

Table 1. Proposed Three-Part Residential Rates

	RES-01 Demand	RES-01 Demand TOU
Basic Service Charge	$20/mo.	$20/mo.
Demand Charge		
0 – 7 kW	$6.00/kW	$6.00/kW
Over 7kW	$9.95/kW	$9.95/kW
Energy Charge		
All	$0.054260/kWh	
Summer on-peak		$0.111110/kWh
Summer off-peak		$0.043900
Winter on-peak		$0.108960
Winter off-peak		$0.043579

Second, UNS is proposing Rider 10, Net Metering for Certain Partial Requirement Service (NM-PRS), to take effect on June 1, 2015. Rider 10 applies to:

> ...any Customer with a facility for the production of electricity on its premises using Renewable Resources, a Fuel Cell or Combined Heat and Power (CHP) to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise. (Rider 10, sheet 710)

Thus it applies to ALL customers with qualifying behind-the-meter DG, regardless of whether or not that customer exports any electricity to the grid. Rider 10 also requires that customers with DG must be on a demand-based rate. Lastly, Rider 10 requires that, "If at any time within a billing month the Customer's generation facility's energy production exceeds the energy consumed by the Customer, the Customer's bill for the same billing period shall be credited for the excess generation priced at the approved Renewable Credit Rate" (Rider 10 sheet 710-1). Thus this Rider is not technically "net-metering," which under FERC PURPA standards requires that excess generation be used to offset "electric energy provided by the electric utility to the electric consumer during the applicable billing period."[1] In addition, the Corporation Commission's own Net Metering Rules set forth that net metering involves a kWh for kWh credit for exported energy.[2]

Rider 11 specifies the Renewable Credit Rate at which DG customers would be compensated for excess generation. The Renewable Credit Rate would be set at "the rate equivalent the most recent utility scale renewable energy Power Purchase Agreement (PPA) connected to the distribution system of the Company's affiliate, Tucson Electric

[1] *See*, Section 1251 (a) of the Energy Policy Act of 2005.
[2] *See*, R14-2-2306(D)

Power Company."

Q: What concerns do you have about how the Renewable Credit Rate in Rider 11 is set?

A: I have five concerns. First, DG solar can provide greater benefit to the grid than utility-scale generation[3]; therefore the price of utility-scale resources is not an accurate or appropriate proxy and would not adequately compensate the system owner for the DG solar system's output.

Many of these benefits, such as potential transmission and distribution savings, apply also when solar DG is compared to central solar stations. As I pointed out in more detail in my November 6th testimony in this docket, DG solar offers a distinct benefit to the utility and its ratepayers and offsets the variability issues inherent in utility scale solar. The fact that DG is distributed makes it a more reliable and steady source of power than even smaller utility scale projects.[4] In addition, solar DG offers the same emissions savings as central solar PV, but without the potential habitat, visual and cultural impacts associated with utility-scale solar plants. For example, the Department of Energy's SunShot Vision study from February 2012 draws from the draft *Solar Programmatic Environmental Impact Statement (Solar PEIS) on Solar Energy Development on BLM-Administered Lands in the Southwestern United States* to note that the primary ecological and other land-use impacts of solar development relate to land used for utility-scale PV

[3] E.g., "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies" Prepared for NYSERDA by Pace Energy and Climate Center and Synapse Energy Economics 2011; "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation", Interstate Renewable Energy Council 2013.
[4] See, Testimony of Mark Fulmer, November 6, 2015, at 13:19-15:16.

and concentrating solar (rooftop installations have negligible direct land-use impacts).[5] Even with the most careful land selection, utility-scale solar development may have significant local land-use impacts, especially in areas of the southern United States where there is large potential for solar.[6] The impacts of utility-scale solar development include direct impacts, such as soil disturbance, habitat fragmentation, and noise, and indirect impacts, such as changes in surface water quality because of soil erosion at the construction site.[7]

Q: What are your second and third concerns?

A: Second, the Rider 11 rate is set based upon a transaction of a different utility: the most recent renewable PPA with Tucson Electric Power (TEP). While TEP is an affiliate of UNS, it is not UNS. This begs the question, "why not Arizona Public Service (APS) or Salt River Project (SRP) or even Nevada Power, whose load center (Las Vegas) is closer to the bulk of UNS's load than Tucson is?"

Third, the potential variability of this payment rate is concerning. It can change significantly from year-to-year, depending upon the resource needs of TEP and the PPAs it enters into to meet those needs. If UNS is treating excess generation more like a supply resource, which I believe it is with this proposal by applying a utility scale electricity purchase price to much smaller solar DG electricity, pricing the supply at an uncertain value is not fair. I cannot imagine that a developer of a utility-scale solar project would enter into a contract with a provision to base the PPA price upon the price of a contract entered into by a different utility and a third-party solar provider, which would change

[5] "The SunShot Vision Study," Department of Energy, February 2012 (DOE 2012) p. 170
[6] *Ibid.*
[7] *Ibid.*

unpredictably the next time that utility entered into a new PPA. Under these conditions, a utility-scale project would likely not even be able to secure financing. This kind of variability and uncertainty is not even appropriate for a feed-in-tariff. Certainly, if UNS is committed to treating its residential customers as if they are for profit PPA providers, it should be prohibited from forcing terms on those residential customers that a PPA provider would outright reject.

Q: What is your fourth concern with Rider 11?

A: Fourth, the value of renewable power is not the same across technologies. TEP might acquire through a PPA with a geothermal project, which could provide baseload power and thus likely have a lower price than solar, even though solar provides power during times of high system load when power is more valuable. Or it might be tied to a wind project, whose generation profile would also differ from that of solar PV and thus provide a different—and likely lower—value to the utility.

Q: What is your fifth concern?

A: Last, I understand there to be concerns around taxation of income derived from exported power sold to the utility in this manner, as well as potentially jeopardizing access to the federal solar tax credit. TASC has raised these concerns when similar proposals have been raised both in Arizona and elsewhere.[8]

Q: What is the impact of Rider 11 on a UNS customer contemplating DG?

[8] Reply Comments of The Alliance For Solar Choice, Solar Energy Industries Association And California Solar Energy Industries Association On Party Proposals, Appendix C. Submitted to the California Public Utilities Commission in Rulemaking 14-07-002. September 15, 2015.

A: Not knowing at what rate the customer would be compensated for any power he or she exports adds a serious layer of uncertainty in the decision-making process of whether or not to adopt solar DG. As described above, the Rider 11 rate will be based on a utility-scale project that contributes fewer benefits to UNS's system than DG, such as reductions to line losses and peak load, and potential deferral of transmission, distribution, and generation investments.[9] As a result, the Rider 11 rate will undervalue the electricity that customers generate with DG solar. Further, as proposed, Rider 11 will likely act more like a ratchet, ever going down. This obviously creates a problem for someone considering an investment in a fixed asset.

Moreover, I know of no contracts for utility-scale power with pricing based on a contract between an unrelated entity and a utility serving a different jurisdiction. A plant subject to such a pricing scheme could never get financed. Applying this to DG-generated power is just as unreasonable.

Q: How does UNS justify its three-part rate and proposed requirement that DG customers be on it?

A: UNS witness Dukes states that a "Demand charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve the individual peak load"[10] He further states that such a rate design will move some of the so-called "fixed" costs into a rate component that DG customers must pay.[11]

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[9] *See* footnote 3.
[10] Dukes at p. 17.
[11] *Ibid.*, at p 23.

Q: Do you find this rationale compelling?

A: No. UNS's arguments supporting the three-part rate focus solely on cost recovery and do not consider other ratemaking factors and objectives.

Q: What other factors must be reviewed when considering a major rate changes such as this?

A: A major concern that I have is that the arguments for the three-part rate, as well as its design, are based on a shortsighted view of costs and cost causality. In UNS's cost-causation world, there are two kinds of costs: sunk (fixed) and variable. The only variable costs are those associated with the operating costs of power plants. As Mr. Dukes states in his testimony, "The only completely avoidable cost is the variable cost related to the energy production, primarily fuel, purchased power and any O&M costs directly related to energy production or procurement."[12] Everything else is sunk and treated as fixed.[13]

Q: Do you agree that all costs that are not associated with fuel and power plant O&M are fixed?

A: No. While perhaps this division of variable and fixed costs may be true in the short run, in the long run it clearly is not. Costs that are now sunk were based on assumptions of the future. For example, in proposing to purchase Gila Bend, UNS did not simply consider the cost of the plant.[14] If the cost of capacity were the only consideration, UNS could have acquired a simple-cycle combustion turbine for less. But UNS instead chose a plant whose capital costs, which as soon as the ink is dry on the contract becomes a

[12] Dukes at p. 10.
[13] *Ibid.*
[14] UNS Integrated Resource Plan, pp. 245-247.

sunk fixed costs, are higher in order to reap the benefit of lower operating (variable) costs in the future.

In the time running up to the purchase of a capacity asset, the prudent utility will look at its needs in the future and consider all the options for meeting those needs in a least-cost fashion, be it fossil generation, demand response, energy efficiency, or something else. That is the heart of integrated resources planning.

Considering only very short-term costs in ratemaking ignores the long view. If you can take actions NOW that can save ratepayers money (or reduce risk or meet some other planning goal) in the future, at higher costs today, they are likely the correct actions to take.

In order to make those kinds of decisions with respect to ratemaking, long-run avoided costs must be considered. Even through reducing the load on a distribution circuit now might not change its immediate costs, it very well might extend its life or mitigate the need to install a greater capacity line in the future.[15] This long-run marginal cost view is already being used in Arizona to evaluate energy efficiency investments, not the fixed-variable split being proposed here for ratemaking.

By not taking the longer view and fixating on short run avoided costs and cost recovery in their ratemaking, UNS will be implementing rates that may allow it to more easily collect its return on investment at the expense of higher rates in the future. While this may be beneficial to UNS, it is detrimental to its ratepayers.

Q: While UNS focused on cost recovery by proposing residential demand charges, what are some of the other factors that should be considered in making rates?

[15] *See* footnote 3.

A: Mr. Duke cites to the authoritative text on rate design, John Bonbright's *Principle of Public Utility Rates*, on a number of "foundational principles." These include simplicity, understandability, public acceptability, free from controversies as to proper interpretation, avoidance of undue discrimination, efficiency to discourage wasteful use of service, revenue stability, and effectiveness in yielding total revenue requirement.[16] I find that UNS has focused on the last two listed here—revenue stability and yielding total revenue requirement, at the expense of some of the other principles. As I discuss throughout this testimony, UNS's proposal to double the monthly customer charge and require new DG customers to be on a three-part rates violates the principles of understandability, public acceptability, avoidance of undue discrimination, and wastefulness.

III. UNS's Riders 10 and 11 Are Discriminatory Towards DG Customers

Q: Is requiring DG customers to be on one of the two RES-01 DEMAND tariffs fair?

A: I do not believe so. Even setting aside my general concerns with a residential three-part rate, the way that UNS is applying it via Rider 10 is unreasonable.

First, it is discriminatory towards those customers who have chosen to use a particular technology in their home. It doesn't matter if they never export power to the grid, they would still be required to take service on a tariff that may not—and likely will not—be in their best interest. In essence, UNS is proposing to "look behind the meter" into someone's home (or at minimum on their roof) to see if they are using a particular technology and then force them onto a different rate. This strikes me as unreasonably

[16] Dukes at pp. 8-9.

invasive of customers' privacy.[17] UNS does not require customers with particularly efficient (or inefficient) appliances to register and be placed on a special rate. Doing so for customers who take a different action that changes their metered electricity profile is not reasonable.

Furthermore, as UNS witnesses have pointed out, there are other low-usage customers who may not be paying what UNS characterizes as their fair share of utility costs: apartments, small efficient homes, seasonal residences and vacant homes.[18] From a kilowatt-hour per month perspective, without looking into the home, these customers are not distinguishable. As witness Dukes has pointed out, "approximately two-thirds of the bills issued in the last 4 years to residential customers (applying the current RES-01 rate) did not provide fixed cost recovery equivalent to the class average."[19] While UNS is partially addressing this concern through its proposed increase in monthly customer charges, from $10 to $20 per month, a lack of fixed cost collection is also the major rationale for requiring DG customers to be on a three-part tariff. But since there are a significantly greater number of customers with similarly less-than-average usage who would not be subject to Rider 10, applying it only to customers with DG is clearly discriminatory. Residential customers with DG do not constitute a separate rate class, and as such should not be treated as one.

[17] The only exception to this is when something on the customer-side of the meter could affect safety. Hence it is appropriate for interconnection but not for billing.
[18] Dukes at p. 11.
[19] Dukes at p. 13.

IV. UNS's Analysis Supporting Rider 10 Is Misleading

Q: How does UNS Witness Dukes characterize the impact of the proposed RES-01 DEMAND tariff on residential customers who install solar PV after June 1, 2015?

A: Mr. Dukes shows the average bill for a customer using an average of 500 kWh per month, 900 kWh/month; 1,200 kWh/month and 1,500 kWh/month under four cases: RES-01 full requirements (i.e., no DG); RES-01 with net metering and banking, RES-01 excess power purchased per Rider 11, and RES-01 DEMAND plus Riders 10 and 11.[20] He then focuses on the percentage bill savings experienced under the proposed rates for customers with solar DG, characterizing them as "significant."[21] In presenting the information this way, he is implying that the impacts are not great and would not dramatically impact the economics of installing DG.

Q: Would the economics of installing DG be dramatically changed under the UNS proposal?

A: Yes. This is clearly seen by looking at the same data Mr. Dukes used in his tables in two other ways. First, rather than comparing the DG customer bill under the UNS proposal to the bill with no DG, it is illuminating to compare the bill for a customer with DG under the current tariff to that under the proposed tariff. This comparison is shown in Figure 1 and Table 2. As the figure shows, for most DG customers, their UNS bills would be <u>more than double</u> under the proposed tariffs as compared to continuing to allow net metering (with banking). Numerically, the annual UNS bill for a small user (500

[20] Dukes at p. 29.
[21] Dukes at pp. 29-30.

kWh/mo. average) would be nearly $240 more under the proposal relative to NEM with banking (status quo). For a large user (1,200 kWh/mo.), for whom solar DG would likely be more attractive, the rate difference is over $530 per year.

Figure 1. Annual Average Bill for a Customer with Solar DG

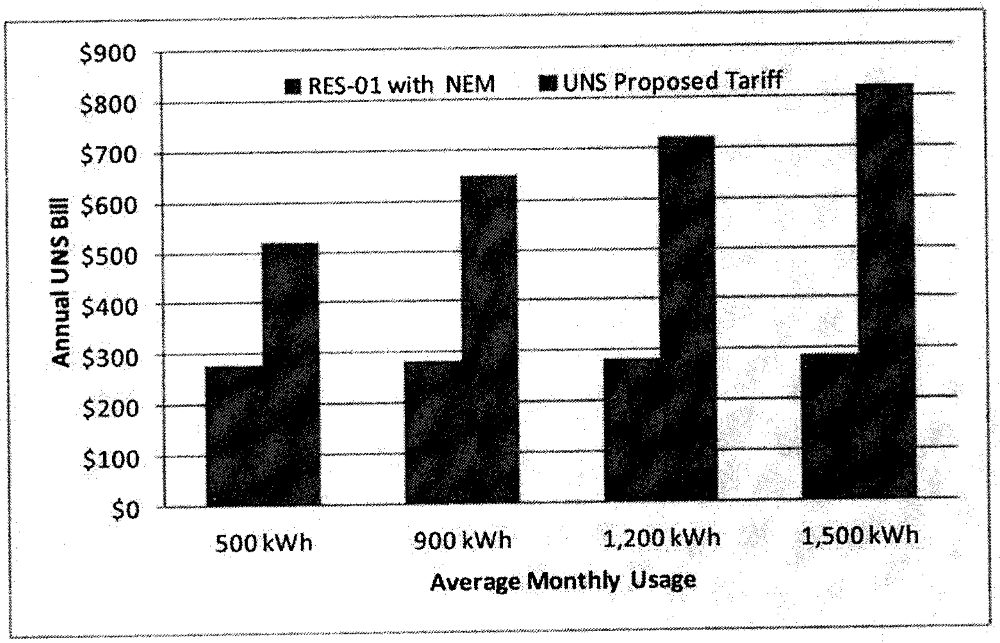


Table 2. Impact on Residential DG Customer's UNS Bill Under Company Proposal (relative to RES-1 with NEM and banking)

Average Monthly Usage	Increase in DG Customer Bills Under UNS's Proposal	
	Percent	Annual
500 kWh	85%	$238
900 kWh	130%	$367
1,200 kWh	154%	$437
1,500 kWh	186%	$532

Q: Isn't it true that UNS's proposed Rider 10 won't be raising anyone's rates as it only applies to future customers with solar?

A: No. UNS's rate changes are proposed to affect any DG customer who made the decision to supply a portion or all of their own power after June 1, 2015. Consequently, should the Commission approve the change, anyone who has chosen to self-generate after that date until the time of the tariff change would see increased rates.

Q: Do the results of the proposed rate changes on future DG customers appear gradual, fair or prudent?

A: No. I have never seen a utility commission approve a rate structure that says all new customers of a certain type will pay more than double the amount of existing customers taking the same service. For example, it is almost impossible to imagine a commission approving a rate on all new residential customers resulting in those new customers paying upwards of 185% more than existing ones.

Q: How else might a customer considering solar DG or a solar DG provider look at this?

A: When considering the financial impact of a solar DG system, a key factor is the bill savings that can be achieved. Paramount to this is identifying the price at which the solar system would need to achieve in order to break even with utility service. In other words, if the levelized cost of the DG system (or, if owned by a third party, the lease rate) is less than the offset retail rate, then it might make financial sense; if not, then not.

If the prospective customer was able to take service under UNS's proposed RES-

01 rate, the breakeven price for electricity from the DG solar unit would be approximately 10.5¢/kWh.[22] Under RES-1 DEMAND it would be 38% less at 6.5¢/kWh. As I will discuss in the next section, this difference can make a profound impact on the viability of rooftop solar.

V. UNS's Proposal Will Likely Have Large Impact On PV Adoption

Q: Mr. Dukes noted that there were a number of other utilities in the U.S. that have three-part residential rates containing a demand charge. Were these three-part residential tariffs optional or mandatory?

A: In all the jurisdictions identified by Mr. Dukes but one, the residential three-part rate was voluntary.[23]

Q: Did any of the utilities cited require customers with DG to take service under the three-part rate?

A: Yes. Here in Arizona, starting earlier this year, Salt River Project (SRP) began requiring all customers installing new DG system to take service under a new Tariff, E-27. Although the new tariff was approved by the SRP Board in February 2015, it was applied retroactively to when the rate was initially proposed, December 8, 2014.

Q: How does SRP's E-27 tariff compare to UNS's proposal for customers with DG?

A: Table 3 shows SRP's E-27 rates and UNS's proposed RES-01 DEMAND. SRP's rate differs from the UNS proposal by (a) having higher monthly charges; (b) differentiating

[22] Energy Delivery Charge for usage over 400kWh/month plus Power Supply Charges plus riders.
[23] The exception is Black Hills Power (Wyoming).

energy and demand rates by season; (c) using the highest demand during the peak period as the demand billing determinant; (d) having higher peak-demand rates while at the same time measuring demand over 15 minutes rather than one hour; (d) having two time-of-use periods (on-peak and off-peak) for energy charges. It is similar to UNS's proposal in that the SRP E27 avoidable energy charges are low (4-6¢/kWh) and effective fixed charges are relatively high.

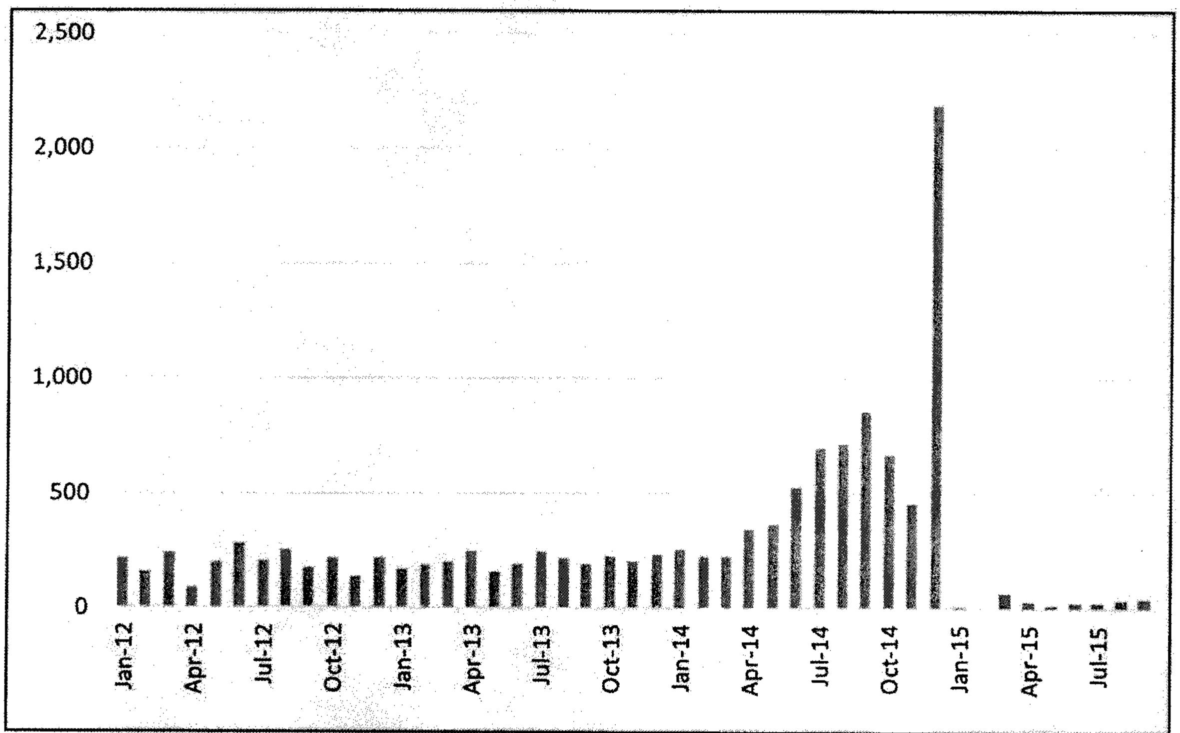
Table 3. SRP E-27 and UNS's Proposed RES-01 Demand plus Rider 10

Utility & Tariff	Months	Monthly Charge ($/mo.)	On-peak energy ($/kWh)	Off-Peak Energy ($/kWh)	On-Peak demand ($/kW)	Max. Demand (Tier 1) ($/kW)	Max. Demand (Tier 1) ($/kW)
SRP E-27	Summer (Jul-Aug)	$30.94	0.0633	0.0423	$17.52	N/A	N/A
	Shoulder (May, Jun, Sep, Oct)	$30.94			$14.63	N/A	N/A
	Winter (Nov-Apr)	$32.44			$5.46	N/A	N/A
UNS RES-1 Demand TOU	Summer (May-Oct)	$20.00	0.1111	0.0439	N/A	$6.00	$9.95
	Winter (Nov-Apr)	$20.00	0.1090	0.0436	N/A	$6.00	$9.95

Q: Has this new rate affected the adoption of residential solar DG in the SRP territory?

A: Yes, it has had a dramatic if not catastrophic effect. Figure 2 shows the monthly applications for solar DG submitted to SRP from 2012 through September, 2015. In 2012 and 2013, there were, on average, 201 applications for solar DG per month. In 2014, but for December, there were on average 486 applications per month. In the first nine months of 2015, the number of applications plummeted to 24 per month, a 95% decrease. One month in 2015, in fact, experienced zero applications.

Figure 2. SRP Solar DG Applications



Source: www.ArizonaGoesSolar.org. Accessed November 24, 2015

The dramatic number of applications in December was due to individuals wanting solar DG but knowing that it would not be cost-effective if they were placed on the new rate. In fact, ALL of the December 2014 applications occurred in the first eight days of the month, with a majority being submitted on December 8.

Clearly, rates that collect much of the revenue through monthly fixed charges and quasi-fixed demand charges can decimate, and in SRP territory has decimated, the market for distributed solar. I firmly believe that if UNS's proposal is adopted, a similar plunge in residential DG will be experienced in its territory.

VI. Customers Will be Confused

Q: Do you believe that customers will understand demand charges?

A: I am skeptical that customers, particularly residential and small commercial ones, will be able to understand demand charges. Residential consumers have experience with their energy use, in kilowatt-hours, because that is the basis on which they have been billed in the past. They do not have experience with the concept of demand, measured in kW, which is the rate at which a customer uses energy as a function of time. In mathematical terms, it is the first derivative of energy use with respect to time.

Q: What evidence do you have that customers will not understand demand charges?

A: In 2013, the three major investor owned electric utilities in California commissioned a customer survey as part of the CPUC's comprehensive rulemaking proceeding on residential rate design.[24] The survey found "Possible that concept was confusing and respondents did not understand that it varies based on kW demand levels, which made demand charges appear low relative to monthly service fee."[25] This lack of understanding of rates in general is reflected elsewhere, where barely half of California consumers realized that they were on a tiered rate plan.[26] This despite the fact that California has had default tiered residential rates since the late 1980's.

Furthermore, customers have also shown a strong preference for simplicity in their rates. In a survey conducted for San Diego Gas & Electric Company concerning rates for DG, when asked what they would prefer if NEM was not available, only 17% of

[24] California Public Utilities Commission, Rulemaking 12-06-013. June 21, 2012.
[25] Hiner and Partners, Inc. "RROIR" Customer Survey, April 16, 2013. at p. 22. Submitted as part of California Public Utilities Commission, Rulemaking 12-06-013.
[26] *Ibid.* at p. 7.

customers preferred demand charges, making demand charges one of the least preferred options.[27] When queried about the choice factors preferences (i.e., what they would like in a solar rate), 57% stated save money, 39% said simple, and 34% said "fits my habits and lifestyle."[28] UNS's proposal is clearly out of step with the second and third choice factor preferences. It is not simple, and in order to meet the first factor—save money—would, as discussed later, likely require unrealistic and/or potentially expensive changes in habits and preferences.

Q: What does witness Dukes say about the price signals that demand charges send?

A: Mr. Dukes says that a "...Demand Charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve their individual peak load. They then can make proper usage and equipment purchase decisions that would reduce that portion of their bill while producing system benefits."[29]

Q: Do you find this to be reasonable?

A: No. First, as I have already discussed, the demand charge may reflect the cost of current system resources, it does not reflect the long run marginal cost of providing those system resources. Second, also as discussed, most of those costs are not to meet an individual's peak but the system peak that reflects load diversity. In fact, for some solar customers, maximum demand may occur during off-peak hours. Thus, the price signal being sent is inappropriate: reduce demand at times where there already is plenty of capacity. Third, I do not believe that a demand charge will provide a signal upon which customers can take

[27] Hiner & Partners, Inc. "Solar (NEM) Rate Preferences Survey Results," Prepared for SDG&E. June 2015, at p. 7.
[28] *Ibid.* at p. 17.
[29] Dukes at p. 17.

concrete action to reduce their demand charge. I expect that aside from an air conditioner or perhaps an electric water heater, customers do not have a good idea of what appliances have a large kilowatt demand and as such are unable to accurately monitor their use. Additionally, some appliances, such as refrigerators, run or cycle automatically, eliminating the ability of a customer to anticipate or control their associated demand.

Furthermore, in order to reduce a demand charge, the customer must not operate high demand appliances at the same time, consistently throughout the billing period. For example, the demand charge will be assessed on the one instance during the month where a customer has the air conditioner (or in the winter a heat pump or other electrical heating system), hair dryer, and laundry all running at the same time. Essentially, a customer will have to be conscious of their individual appliance use, and the appliance use of every member of their household at all times, in order to have any impact on the demand charge. One slip-up and the customer will be paying a high demand charge. As such, while a demand charge might send an economists' "correct price signal," it is not an easily actionable one that people can change their behavior in response to. It is one thing to send a price signal; it is another thing to have that price signal be one that customers can effectively react to in a positive manner.

Q: Mr. Dukes also says that the demand charge will help improve a customer's load factor and thus save them money.[30] Is this reasonable?

A: No. Mr. Dukes' arguments are implicitly based on customers increasing their load factor by decreasing their demand. Given that customers cannot easily reduce their peak demand, this argument is not sound. The easiest and primary way that customers can

[30] Dukes at pp. 24-26.

improve their load factor is to consume more power. This result would incent customers to use more electricity, as each unit decreases their average cost. For example, under the RES-1 demand tariff, a customer using 900 kWh in a month with a maximum demand of 5 kW would be paying an average rate of 10.7¢/kWh. If they simply left their lights on more or their computer or TV on, their usage could increase to (for example) 1200, which would lower their average rate to 9.6¢/kWh. "The more you use, the more you save," is not a message that I believe UNS should be sending.

Q: Mr. Dukes points out that "Customers continue to have more options to save in the future when technology can help them manage and reduce demand."[31] He follows this statement with a hypothetical of a customer installing device(s) that would ensure that the pool pump and air conditioner do not operate simultaneously. What issues does this raise?

A: It raises three issues applicable to all residential customers, not just those with DG. First, enabling devices can help customers react to a demand charge. With this I agree. However, it also assumes that the customer has both the financial means to install such a device as well as a home to which it could be applied. Lower-income customers cannot likely afford such equipment. Second, his simple example of a customer with a backyard pool suggests that such demand charge-avoiding technologies would, at least initially, be available only to those with financial means. Third, such devices would face the classic split-incentive problem that energy efficiency programs experience.[32] A landlord would be the likely party paying for any building energy management systems while their

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[31] Dukes at p. 26.
[32] Arizona Corporation Commission Decision No. 74885, at p. 22. Docketed December 31, 2014.

tenants would be the ones reaping the savings (through no action of their own). As such, the landlord has no financial incentive to install such devices. Thus while enabling devices are good in theory and may play a role in the future, they cannot be counted upon to assist customers in managing demand charges in 2016.

Q: How do mandatory demand charges affect those considering solar DG?

A: A three-part rate, especially coupled with an uncertain buyback rate for excess generation, makes it much more difficult for a homeowner to determine if solar makes financial sense. Such rate design makes it nearly impossible for customer to calculate the benefit of their investment. In particular, what should they assume about demand charges? They would require a great deal of data on their own consumption patterns, as well as different panel orientations, to do a proper analysis, and such an analysis would be based on past energy demand patterns. Future demand patterns may be wildly different as families grow and appliances change.

Compare the situation that those with DG would be in under the new tariffs to the situation that every other UNS customer would be in if they were considering the purchase of any single other energy saving piece of equipment. Customers looking to upgrade their heat pump, their refrigerator, their stove, their hair dryer, or even their lightbulbs could reasonably calculate their bill savings and therefore the value of their investment, but those looking to save energy with solar would no longer be able to calculate their bill savings and would have to guess about the benefit of such an investment. On their face, these proposed tariffs appear to be aimed at singling out solar technology for negative financial treatment.

Q: Does UNS propose any programs to educate customers about the three-part rate?

A: No. It is unconscionable to propose such a radical change in rates without public participation hearings or without supporting it with some kind of education effort. As discussed above, demand charges can be confusing and difficult to respond to. If UNS is permitted to implement the residential demand rates, even if they are not mandatory for customers with DG, then a customer education program plan should be submitted to and approved by the Commission prior to the rate's implementation.

VII. Time-of-Use Rates Are Superior to Three-Part Rates

Q: You do not support demand charges for residential customers. Do you have an alternative to more effectively align rates and utility costs?

A: In general, I believe that well-designed optional time of use rates are a better tool to send capacity-related prices signals to residential and small commercial customers. First, from a customer's point of view, they are much more easily understood than demand charges. Older customers should still remember earlier telephone rate designs, where prices were higher during the daytime and lower during the nighttime hours and on weekends. Explaining that electricity rates are more expensive during the summer late afternoons and evenings should be much simpler than trying to communicate the notion of what is effectively the first derivative of energy (kWh), which is power (kW).

Second, customers can much more readily respond to time of use rates. Knowing that the electricity they purchase during peak hours is more expensive, they can take easy and appropriate steps to reduce their usage and thus, in aggregate, reduce UNS's peak demand. As noted earlier, in order to get a positive financial response (i.e., a bill reduction) to a demand charge, expensive equipment must be purchased and even then action must be consistently taken each and every hour by multiple members of a household. One slip-up and the reductions enacted every other day are for naught. Customers who realize this will likely ignore the demand price signal and treat it as a "fixed" element of their bill. But with an optional peak-period TOU rate, even though any individual home might not reduce every hour of every afternoon, averaged across all customers, demand reductions will occur.

Third, time-of-use rates can reflect utility cost causation. UNS has already determined hours of peak system demand and can adjust its on-peak rates to reflect capacity-related costs.

Fourth, demand charges can be counter to conservation. Once peak demand has been hit, a customer is less incentivized to conserve throughout the month as their incremental usage has less impact on their bill.

Fifth, time of use rates already existence, which would limit the need for customer education programs.

Q: UNS expresses concern about collecting certain costs from low-use customers. Is there a better alternative than a demand charge to do this?

A: Yes. A minimum bill provision, combined with a purely volumetric energy rate, could be effective in collecting the appropriate fixed costs from ALL low-use customers, and not just those with DG. A minimum monthly bill amount could be set that collects a reasonable amount of UNS's fixed charges. If at the end of the monthly billing cycle a customer's bill (based on their usage and the volumetric rate) is less than the minimum bill amount, then the customer pays that minimum. This allows UNS to collect a minimum amount, from all low-use accounts, be they part-year residences, vacant buildings, those with DG or other.[33]

Q: Have you calculated what an appropriate minimum bill would be for UNS?

A: No, I have not. I raise it here as an example of a rate that would meet UNS's primary concern of revenue collection, but also be easily understood and send actionable price signals to ratepayers for conservation.

VIII. Miscellaneous

Q: Does TASC have a position on UNS's proposed Lost Fixed Cost Recovery Mechanism (LFCR)?

A: While I am not an attorney, I know it is TASC's position that the LFCR mechanism violates the Arizona Constitution and that it as an illegal rate making mechanism. As a result, TASC believes the LFCR cannot be permitted to continue moving forward and UNS's proposal in that regard must be rejected. Moreover, TASC's position is that any previous amounts collected under this illegal device since UNS's last rate case must be returned to UNS's ratepayers to avoid an illegal result. I am not offering this answer in an effort to explain or support TASC's position but rather simply to state the fact that this is TASC's position. TASC will be briefing the legal issues supporting this position as part of the hearing process.

[33] Provisions of course should be made for low-use low-income customers.

Q: Can solar DG have a positive impact on Arizona's economy?

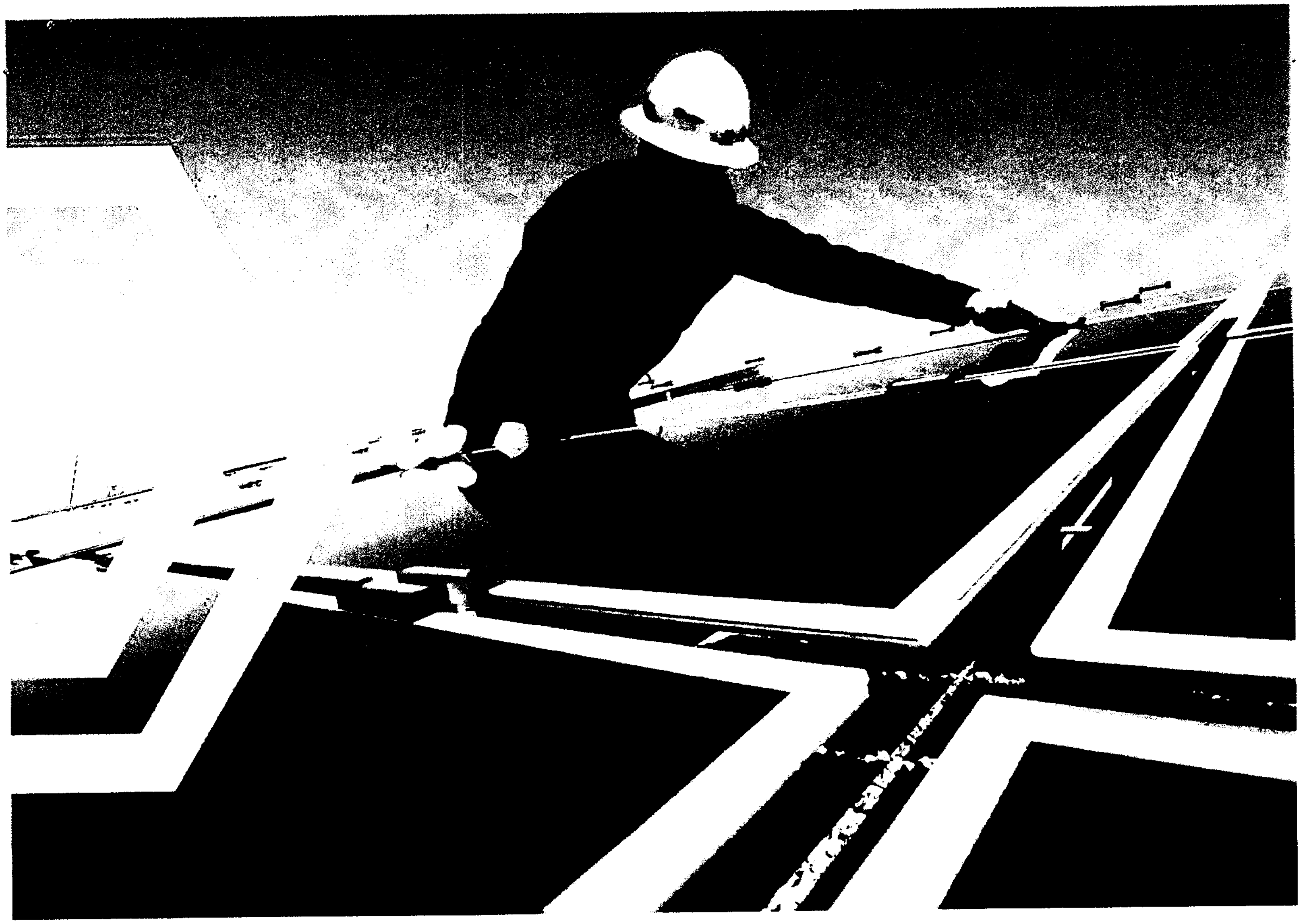
A: I believe that it can, and in fact already does. Attached as Exhibit MEF-2 is the *2014 National Solar Jobs Census*, conducted by The Solar Foundation and the George Washington University. The report found that in 2014 the solar industry was adding workers at a rate nearly 20 times the overall economy and that solar industry employment had increased by over 20% from 2013.[34] Of the nearly 120,000 solar installer jobs nationwide, over 83% are dedicated to installing primarily residential and small commercial systems.[35] Continuing to foster solar DG in Arizona will allow the continued expansion of well-paying jobs in the UNS service territory and throughout the state.

Q: Does this conclude your testimony?

A: Yes.

[34] *2014 National Solar Jobs Census*, at p.1.
[35] *Ibid.*, at 15.

Exhibit MEF-2



National Solar Jobs Census

GW Solar Institute

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RESEARCH PARTNERSHIP

JANUARY 2015

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The Solar Foundation® (TSF) is a national 501(c)(3) nonprofit organization whose mission is to increase understanding of solar energy through strategic research that educates the public and transforms markets. In 2010, TSF conducted its first *National Solar Jobs Census* report, establishing the first credible solar jobs baseline and verifying that the solar industry is having a positive impact on the U.S. economy. Using the same rigorous, peer-reviewed methodology, TSF has conducted an annual *Census* in each of the last five years to track changes and analyze trends.

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We also want to thank all the solar employers that participated in the survey. Your responses were critical in providing us with accurate and timely data.

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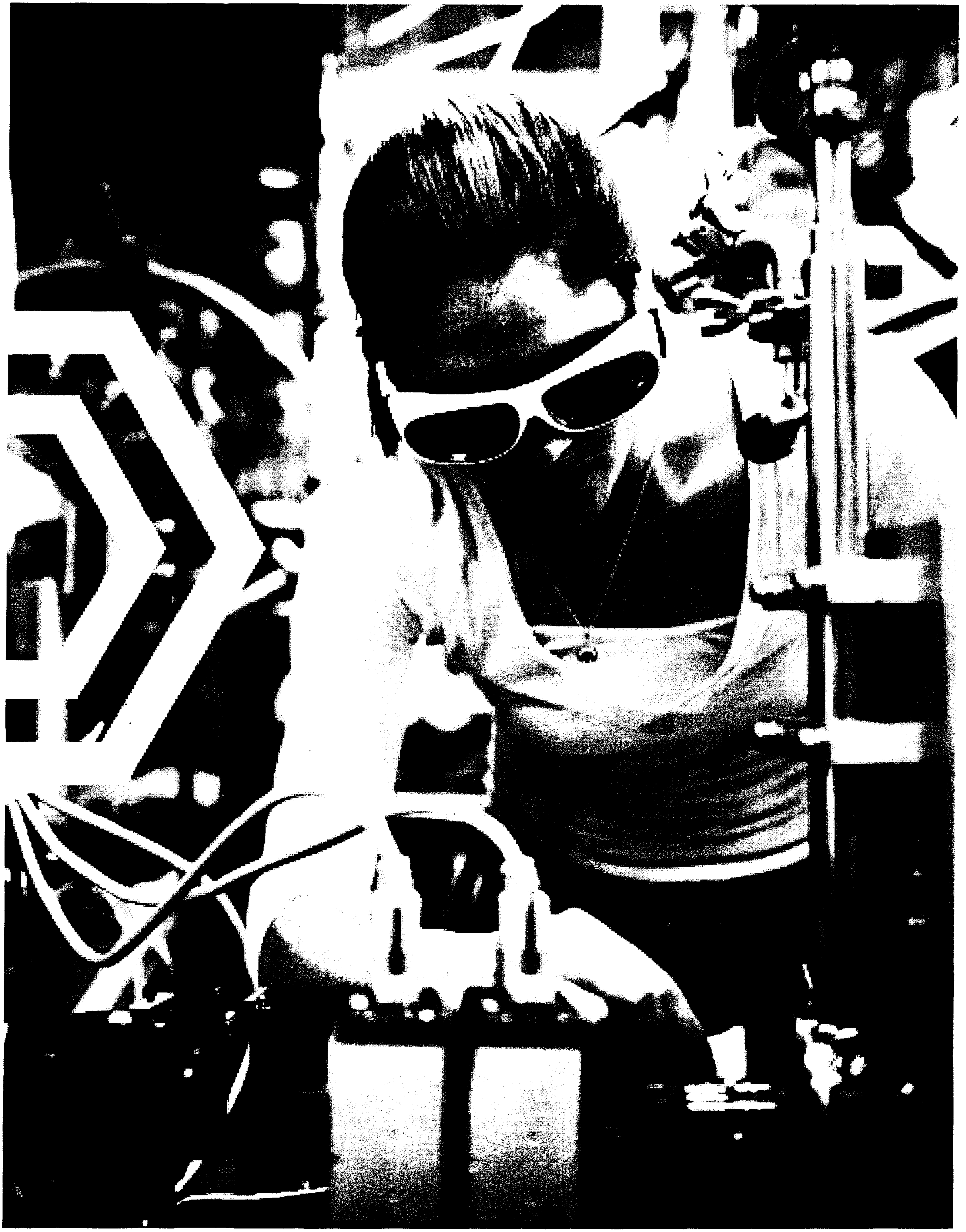

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Executive Summary

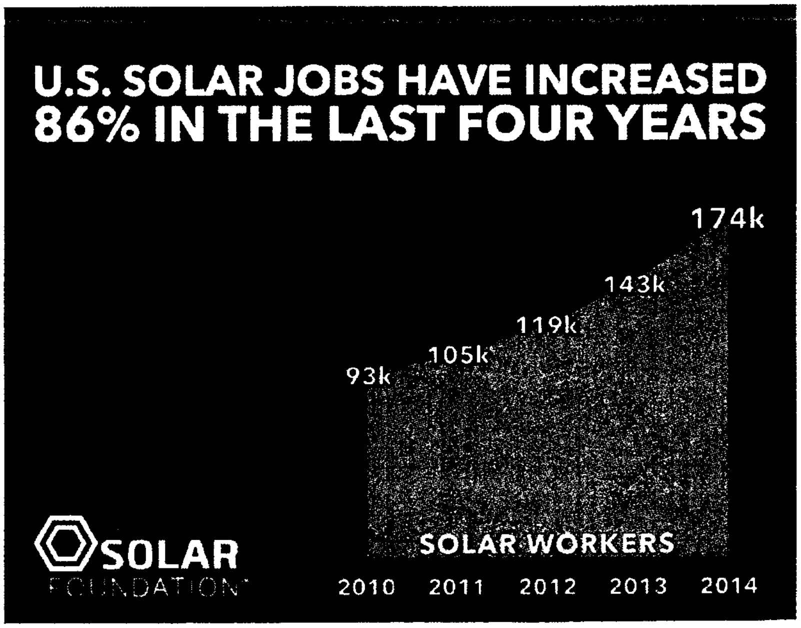
The Solar Foundation's *National Solar Jobs Census 2014* is the fifth annual update of current employment, trends, and projected growth in the U.S. solar industry. Data for *Census 2014* is derived from a statistically valid sampling and comprehensive survey of 276,376 establishments throughout the nation, in industries ranging from manufacturing, to construction and engineering, to sales. Rapid change in this industry has warranted annual examinations of the size and scope of the domestic solar labor force and updates on employers' perspectives on job growth and future opportunities.

This year's *Census* found that the industry continues to exceed growth expectations, **adding workers[1] at a rate nearly 20 times faster than the overall economy and accounting for 1.3% of all jobs created in the U.S. over the past year. Our long-term research shows that solar industry employment has grown by 86% in the past five years, resulting in nearly 80,000 domestic living-wage jobs.** The installation sector, made up of men and women placing these systems in service, crew managers or foremen, system designers and engineers, and sales representatives and site assessors, remains the single largest source of domestic employment growth, more than doubling in size since 2010.

With leading market analyses continuing to project record-breaking increases in annual installed solar capacity before the 30% federal investment tax credit (ITC) expires at the end of 2016, it is very likely that the national solar workforce will continue growing at its remarkable pace in the short term. However, if the ITC reverts to the 10% level in 2017, solar employment growth is likely to slow or may even experience significant job losses.

As of November 2014, the solar industry employs 173,807 solar workers, representing a growth rate of 21.8% since November 2013. Since *Census 2013*, U.S. businesses added more than 2 million jobs, a growth rate of 1.1%, meaning employment in the solar industry grew nearly 20 times faster than employment in the overall economy. Over the next 12 months, employers surveyed expect to see total employment in the solar industry increase by 20.9% to 210,060 solar workers.

1 In this survey, solar employees are defined as a worker that spends at least 50% of their time on solar-related work. However, we have consistently found that 90% or more of these workers spend 100% of their time on solar-related work.



This report includes up-to-date information on the solar industry, quantifying employment growth since last year's study and trends since the publication of *Census 2010*. These research findings also provide stakeholders with current information on the potential for further growth and the factors that are likely to impact the industry over the coming years. Based on the observed growth in solar employment in this and previous *Census* reports, we draw the following conclusions.

As of November 2014:

- **Solar industry employment increased by nearly 22% since November 2013, which is almost twenty times the national average job growth rate.** There are 173,807 solar workers in the U.S., up from 142,698 for the previous year. 2014 was the second consecutive year in which solar employment both grew by approximately 20% or more and exceeded Census growth projections.

- **Employment in the U.S. solar industry increased nearly 86% over the past four years.** Since the first *National Solar Jobs Census* was published by The Solar Foundation in September 2010, the solar industry increased 85.9%, adding over 80,000 workers.

- **Solar is a major source of new U.S. jobs.** Of the more than 31,000 new solar jobs added since November 2013, 85 percent are new jobs (rather than existing positions that have added solar responsibilities), representing approximately 26,600 new jobs created.

- **The solar industry created 1.3% of all new U.S. jobs.** One out of every 78 new jobs created in the U.S. since Census 2013 was created by the solar industry – representing 1.3% of all new jobs.

- **The solar industry expects to add over 36,000 solar jobs over the next 12 months.** If realized, this 20.9% growth rate would make 2015 the third consecutive year that annual solar job growth was near or above twenty percent. This estimate compares with a projected 1% increase in employment in the overall economy over the next year.

- **Of the 173,807 solar workers in the United States, approximately 157,500 are 100% dedicated to solar activities.** The "all-solar" percentage of workers is effectively unchanged since 2013.

- **The U.S. solar industry is becoming more efficient, to less than 15.5 jobs per megawatt of installed capacity.** This is down from 19.5 jobs per megawatt in 2012.

- **Including indirect and induced impacts, the solar industry supports approximately 700,000 U.S. jobs.** *Census* data include occupations critical to meeting domestic installation demand. These include most of the direct jobs and many of the indirect jobs in the solar industry, with the exception of some indirect jobs in the component and materials supply chain. Those jobs, combined with induced impacts of the industry, support an additional 531,200 jobs, bringing the total employment impact for the U.S. solar industry to over 705,000.

- **Wages paid to solar workers remain competitive with similar industries and provide many living-wage opportunities.** Solar installers pay an average wage of $20-24 per hour, with the mean wage for these workers rising by 1.6% over the previous year. Manufacturers pay their assemblers nearly $18 per hour, while internal sales people at these firms earn approximately $44 per hour. Overall, salespeople have a wide range of pay, from about $30 to more than $60 per hour, and solar designers receive between $30-40 per hour.

- **Solar workers are increasingly diverse.** Demographic groups such as Latino/Hispanic, Asian/Pacific Islander, and African American, along with women and veterans of the U.S. Armed Forces now represent a larger percentage of the solar workforce than was observed in *Census 2013.* These higher percentages, coupled with overall growth in solar employment, means workers from these groups are growing in number as well as percentage of the workforce. Women account for over 37,500 solar workers – 21.6% of total – up from around 26,700 in 2013. Nearly 17,000 veterans are employed by solar establishments, compared with just over 13,000 the previous year.

National Solar Jobs Census 2014 continues to demonstrate that the U.S. solar industry is having a positive and growing impact on the national economy and supports jobs across every state in the nation.

As with the previous *Census* studies, this report includes information about all types of companies engaged in the analysis, research and development, production, sales, installation, and use of all solar technologies – ranging from solar photovoltaics (PV), to concentrating solar power (CSP), to solar water heating systems for the residential, commercial, industrial, and utility market segments.

The findings presented herein are based on rigorous survey efforts that include 66,986 telephone calls and over 25,655 emails to known and potential solar establishments across the United States, resulting in a maximum margin of error for employment-related questions of +/- 2.03%.

Unlike economic impact models that generate employment estimates based on economic data or jobs-per-megawatt (or jobs-per-dollar) assumptions, the *National Solar Jobs Census* series provides statistically valid and current data gathered from actual employers. This analysis also purposefully avoids artificially inflating its results with questionable multiplier effects often found in analyses of other industries.

About The Solar Foundation®

The Solar Foundation® (TSF) is an independent 501(c)(3) nonprofit organization whose mission is to increase understanding of solar energy through strategic research that educates the public and transforms markets. TSF is considered the premier research organization on the solar labor workforce, employer trends, and the economic impacts of solar. It has provided expert advice to leading organizations such as the National Academies, the Inter-American Development Bank, the U.S. Department of Energy, and others during a time of dynamic industry growth and policy and economic uncertainty.

While TSF recognizes that solar energy is a key part of our energy future, it is committed to excellence in its aim to help people fairly and objectively gauge the value and importance of these technologies.

About BW Research Partnership

BW Research is widely regarded as the national leader in labor market research for emerging industries and clean energy technologies. In addition to the *Census* series, BW Research has conducted rigorous solar installation and wind industry labor market analysis for the National Renewable Energy Laboratory, wind energy and energy retrofit studies for the Natural Resources Defense Council, a series of comprehensive clean energy workforce studies for the Commonwealth of Massachusetts, Illinois, Vermont, Florida, Pennsylvania, Iowa, and California and numerous skills and gap analyses for community colleges, workforce investment boards, state agencies, and nonprofit organizations.

BW Research provides high-quality data and keen insight into economic and workforce issues related to renewable energy, energy efficiency, transportation, recycling, water, waste and wastewater management, and other environmental fields. The principals of the firm are committed to providing research and analysis for data-driven decision making.

Overview

The Solar Foundation's *National Solar Jobs Census 2014* is the fifth annual review of the size and scope of the U.S. solar industry's employment landscape, and represents the most significant analysis of solar labor market trends to date. This year's *Census* survey went out to more than 55,000 U.S. business establishments and includes data gathered from more than 7,600 of them, with full survey completions from over 2,000 solar establishments. The data illustrate a rapidly growing industry that is gaining strength and efficiency while showing no signs of slowing down in the near term.

Between November 2013 and November 2014, solar employment grew nearly 20 times faster than the overall economy. U.S. businesses added more than 2 million jobs since *Census 2013*, a growth rate of 1.1%.[2] **One out of every 78 new jobs created in the U.S. since *Census 2013* were created by the solar industry – 1.3% of all jobs.**[3]

Solar employment reached 173,807 jobs (at 25,491 locations) as of November 2014, an increase of 85.9% from September 2010 to November 2014. This has been driven largely by the massive growth in the demand for solar energy systems over the same time frame; rising from 929 megawatts (MW) installed in 2010 to 7,243 MW expected in 2014.[4] Global demand, which drives much of domestic manufacturing, has grown from just over 17,000 MW in 2010 to an estimated 50,000 MW in 2014.[5]

Installation firms account for nearly 56% of all solar jobs, while manufacturing accounts for almost 19%. Collectively, demand-side sectors (installation, sales and distribution, and project development) make up 76% of overall solar industry employment.

2 Class of Worker Employment EMSI 2014.3, see methodology for further information on data sources

3 Current Employment Estimates, Bureau of Labor Statistics, for period of Nov 2013 - Oct 2014, Revised Jan 9, 2015.

4 SEIA/GTM Research Solar Market Insight Q3 2014

5 REN 21 Global Status Report 2014; IEA Solar Thermal Electricity Technology Roadmap 2014

Table 1: 2014 Sector Employment

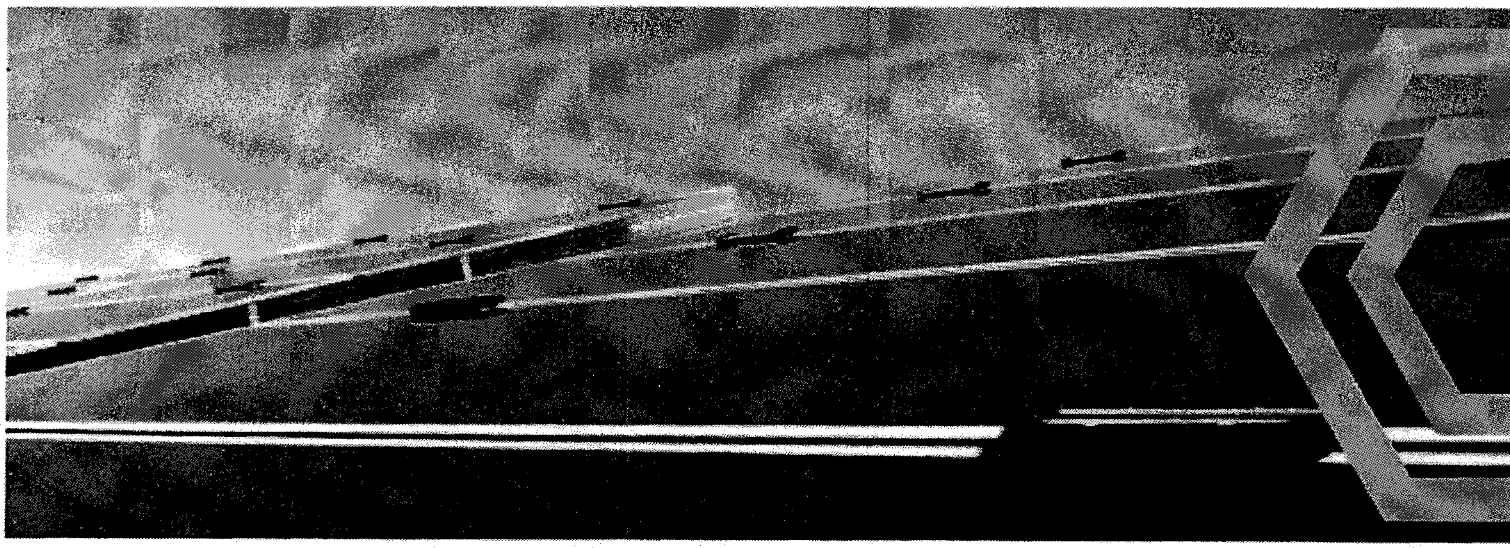
	Employment	% of Total Employment
Installation	97,031	55.8%
Manufacturing	32,490	18.7%
Sales & Distribution	20,185	11.6%
Project Developers	15,112	8.7%
All Other	8,989	5.2%
Total	173,807	100.0%

Solar firms added more than 31,000 jobs since *Census 2013,* representing 21.8% growth in employment from November 2013. Installers were responsible for 27,373 of these new jobs, or 88% of total growth. However, all sectors, with the exception of "Other," grew over the past year.

Table 2: 2010 – 2015 (Projected) Sector Employment[6]

	2010	2011	2012	2013	2014	Projected 2015
Installation	43,934	48,656	57,177	69,658	97,031	118,942
Manufacturing	24,916	37,941	29,742	29,851	32,490	37,194
Sales & Distribution	11,744	13,000	16,005	19,771	20,185	25,480
Project Developers	no category	no category	7,988	12,169	15,112	18,004
All Other	12,908	5,548	8,105	11,248	8,989	10,439
Total	93,502	105,145	119,016	142,698	173,807	210,060

6 Due to rounding, yearly sector employment may not sum to overall yearly total.



While "Other" is a catchall category that includes various critical supporting elements of the solar industry, it is notable that early stage investments (Seed, Series A, and Series B), from both public and private sources, are down sharply over the past several years.[7] This lack of funding is likely negatively impacting employment at companies in research and development.

While solar energy still represents only 1% of total US electricity generation, the solar installation sector is already larger than well-established sectors of fossil fuel generation, such as coal mining (93,185 jobs). In addition, the solar installation sector added nearly 50% more jobs in 2014 than the total created by both the oil and gas pipeline construction industry (10,529) and the crude petroleum and natural gas extraction industry (8,688).[8]

Solar employers' reported projected growth of 20.8% in 2015 is nearly eight times greater than the growth expected in the oil, gas, and coal industries over the same period. Moreover, the solar industry will add roughly the same number of jobs in the coming year as the much larger fossil fuel industry.[9] While the growth projection of solar employers may seem overly optimistic, consider that solar employers have exceeded their predictions in each of the last two years by 2.7% and 6.2%, respectively.

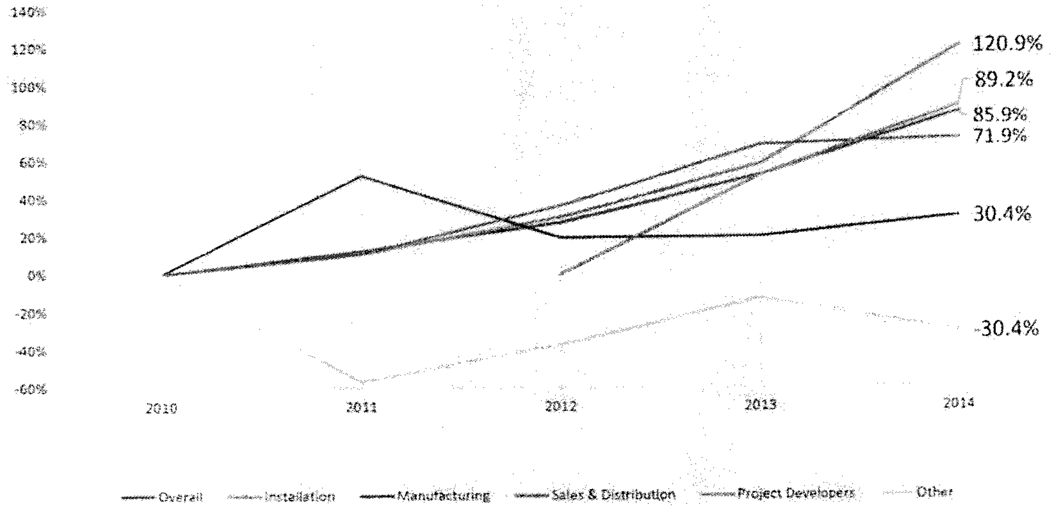
Since 2010, installation firms have added more than 50,000 jobs, representing more than 120% employment growth. Solar sales establishments have added 8,500 jobs while manufacturers have increased their payrolls by 7,500 workers, with growth rates of 72% and 30%, respectively.

7 Cleantech Group i3 data, reviewed December 19, 2014.

8 EMSI Class of Worker Employment 2014.3. Note that applying industry-wide employment change from 2012 through 2014 (8.1% decline) in coal mining to the National Mining Association's 2012 report's findings of 144,580 non-transportation jobs (which are excluded from this *Census'* solar employment total) results in 133,870 coal mining jobs, which is 23% smaller than U.S. solar employment.

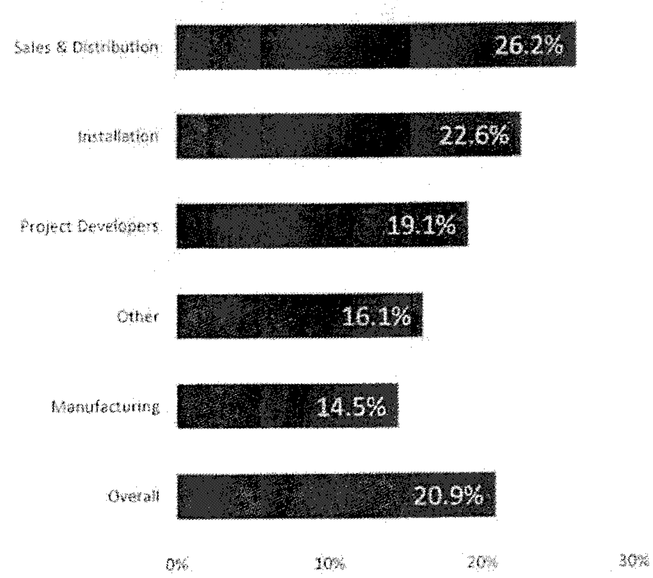
9 *Id.* The 21 NAICS industries that make up the oil, gas, and coal industries are projected to add 37,206 jobs over the period, up 2.7%.

Figure 1: Solar Employment Growth From 2010-2014 (Overall and by Sector)[10]



Employers expect to see total employment in the solar industry reach 210,060 solar workers (a 20.9% increase) by the end of 2015. This compares with only 1% employment growth projected overall in the U.S. over the same period. Solar sales firms expect the fastest percentage growth at 26.2% (adding almost 5,300 jobs), while installation firms expect to add almost 22,000 jobs over the coming year (22.6% growth).

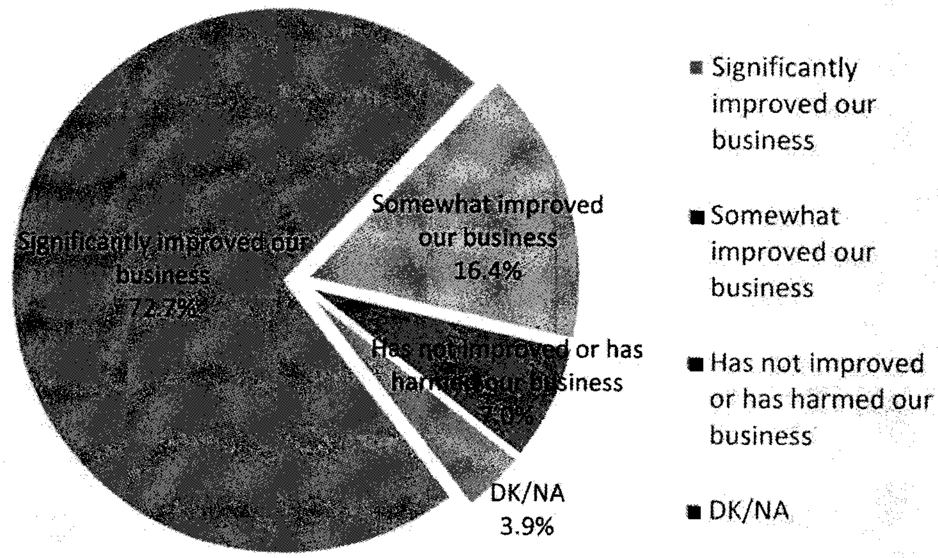
Figure 2: Expected Solar Employment Growth From 2014-2015 (Overall and by Sector)



10 Project Developer growth is set to 2012, the first year the category was used.

About three out of every four businesses state that the 30% Investment Tax Credit (ITC), an income tax credit for renewable installations, has significantly helped their business.

Figure 3: Perceived Effect of the ITC on Solar Businesses



However, nearly 40% of all respondents believed that lowering the ITC to 10% after 2016 for commercial projects and eliminating the ITC for residential projects would not impact their workforce. This is possibly due to a large number of companies that work in sectors not eligible for the tax credit, including manufacturers, companies that primarily sell products and services abroad and companies that sell solar pool heaters (which don't qualify for the ITC). In addition, some respondents were in states that expect to be least impacted by scheduled changes to the ITC or are facing more pressing challenges to market growth from other policy or regulatory changes. Moreover, solar installers, which make up the largest solar sector and accounted for 88% of job growth in the past year, felt the ITC was vital to their sector.

The solar industry is becoming increasingly diverse. A greater percentage of women, minorities and veterans of the United States Armed Forces were employed by solar firms in 2014 as compared to 2013. Employers were also asked to report about their workers' union membership for the first time since 2012. Approximately 6.2% of the solar workforce belong to a union, totaling nearly 11,000 jobs.

Table 3: Solar Worker Demographic Breakdown 2013 vs. 2014

	2013	2014
Women	18.7%	21.6%
Latino or Hispanic	15.6%	16.3%
Veterans of the U.S. Armed Forces	9.2%	9.7%
Asian or Pacific Islanders	6.7%	7.0%
African-American	5.9%	6.0%

Installation

The installation sector represents the end of the solar value chain and is the largest sector of the U.S. solar industry. Nearly 9 out of 10 new solar jobs since *Census 2013* were created by the installation sector. Composed of companies that primarily install photovoltaic, solar water heating, and other solar energy technologies, the installation sector's growth is primarily driven by installed solar capacity gains.

The installation sector is still primarily comprised of small firms – more than half of all installers have 10 or fewer employees – yet since the first *National Solar Jobs Census* was conducted in 2010, the number of large firms, defined as having more than 100 employees, has more than doubled to almost 10%.

Solar installers employ a wide range of workers, though the majority are connected to the building trades, particularly electricians, construction laborers, and plumbers. They work on systems of all sizes, including smaller residential systems as well as large commercial and utility-scale systems.

Big News in Installation:

- **Leading market research suggests that 2014 was a banner year for solar installations across the U.S.** Over 7,200 megawatts (MW) of solar energy are expected to have been installed in 2014, enough to power nearly 1.2 million U.S. homes. If achieved, this capacity figure will represent 40% growth over the total new solar capacity installed throughout 2013.[11]

- **Installation growth was particularly strong in certain market segments in several states,** including California, North Carolina, Massachusetts, New Jersey, Arizona, Nevada, New York, and New Mexico. This continued growth in capacity, however, is seeing solar spread to new states. Georgia, for example, is expected to have installed over 100 MW of solar this past year for the first time ever, narrowly edging out Hawaii for a spot in the top 10 states for 2014. Driven by large amounts of utility-scale solar, states like Indiana, Virginia, and Tennessee will install more solar capacity this year than in all previous years combined. In addition, some major solar markets are experiencing precipitous growth in the residential market segment, with New York, Texas, and Massachusetts seeing capacity grow by 100% or more compared with the previous year.[12]

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11 SEIA/GTM Research Solar Market Insight Q3 2014

12 SEIA/GTM Research Solar Market Insight Q3 2014 and IREC Solar Market Trends 2013

Tina Long

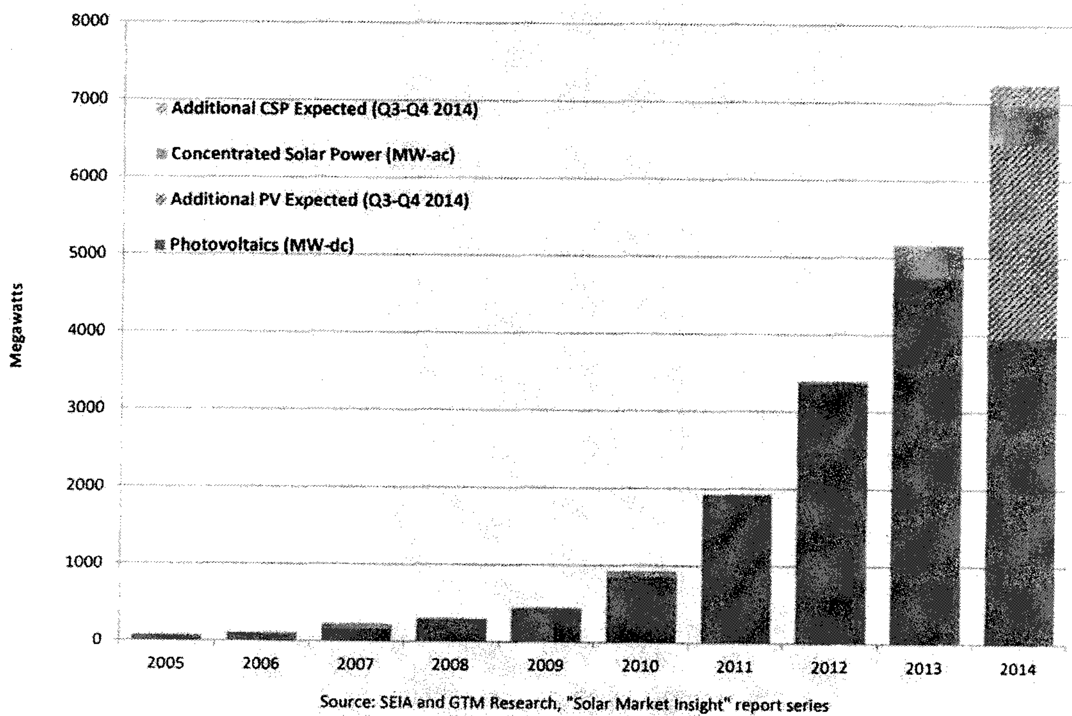
Occupation: Electrician Foreman
Company: Bombard Electric
Years at Occupation: 8
Location: Las Vegas, NV

Tina Long serves as the foreman of a two-man crew that installs solar on residences throughout the Las Vegas Valley and in Mesquite, Nevada. Her work entails designing efficient PV array layouts for customers, ordering materials, performing safety checks on her crew, and working directly with homeowners to ensure they are satisfied with their systems and experience in going solar. Ms. Long is an active leader, providing hands-on support to every facet of the installation process, including getting on the roof and installing the racking system for the array and bending the conduit and electrical tie-ins to the main service panels.

Before joining the company, Ms. Long completed a 5 year apprenticeship through the IBEW local 357, through which she obtained her full-time job. She has attended 2 photovoltaic courses through the local Joint Apprenticeship and Training Committee and passed the local OSHA-required test to obtain the state-required PV installers certification card. Most of her solar-specific training occurred while on the job. She is currently preparing to take the North American Board of Certified Energy Practitioners (NABCEP) entry-level exam in April.

Her favorite part of her job is having a satisfied customer. "I enjoy seeing the customer happy when they see their system running and feeling relief when they can save on energy costs," she explained. She also enjoys the physical and mental challenges presented by her work, and being able to overcome these with the focus on craftsmanship provided by her training. For other workers looking to get into the installation field, she recommends not allowing oneself to be intimated by the physical or mental demands of the work, noting that the pride she receives in knowing she has the knowledge and skills to capture power from the sun makes the challenges worth it. As a concluding thought, she had this to say "I would advise people not to give up, especially women in the solar workforce; women can do this job as well as men."

Figure 4: Annual Solar Power Capacity Installations, 2005-2014



- **Several big players in the installation sector made major announcements in 2014.** In August, Verengo Solar was recognized by Inc. Magazine as one of the fastest-growing companies in the nation. Shortly thereafter, the company announced plans to expand to new markets on both coasts.[13] Throughout the year, SolarCity has continued to make progress toward its goal of opening 20 new operations centers across seven states, an expansion that is expected to create 600 new jobs.[14]

- **Growth in annual installed capacity continues to be primarily driven by the falling installed costs of solar energy.** As shown in Figure 5 below, capacity-weighted average installed costs have declined by nearly 35% for residential installations, 49% for non-residential systems, and 61% for utility-scale projects since the beginning of 2010.[15]

This decline in installed costs continues to make solar more cost-competitive with conventional electricity generation. For utility-scale solar PV projects, a 5-year average percentage decrease of 78% was observed in the unsubsidized levelized cost of energy (LCOE), with the latest averages ranging from $0.072 - $0.086/kWh.[16]

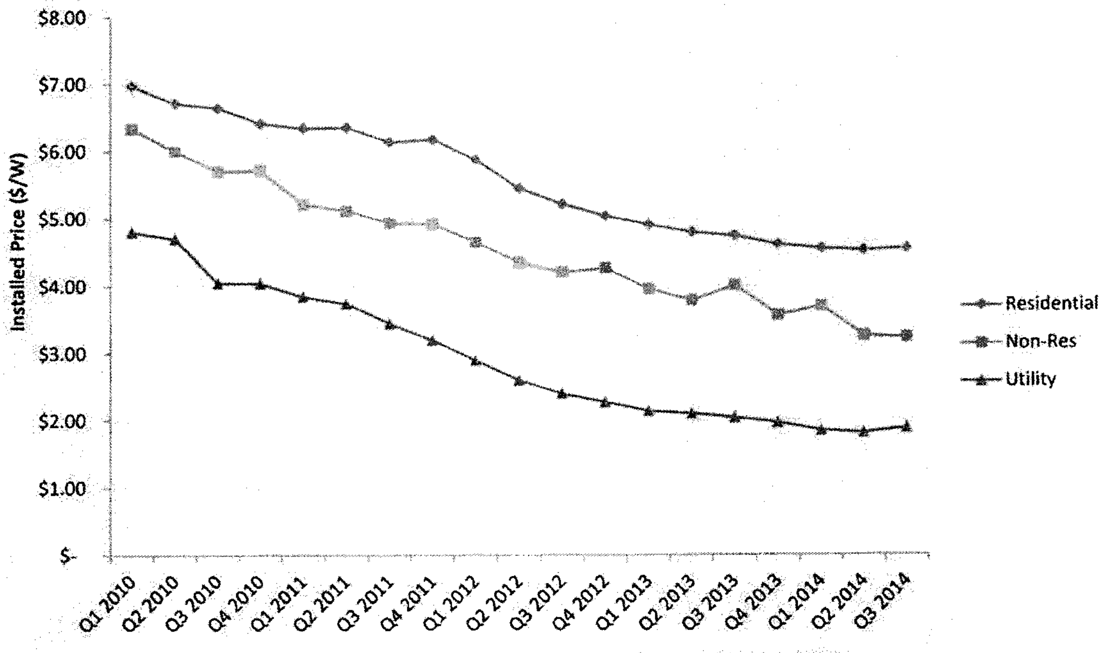
13 See: "Verengo Reaches 75 MW Residential Solar Milestone", from Energy Industry Today at: http://energy.einnews.com/pr_news/224038570/verengo-reaches-75-mw-residential-solar-milestone

14 See: "SolarCity is opening a Baltimore County operations center", from Baltimore Business Journal at: http://www.bizjournals.com/baltimore/news/2014/09/05/solarcity-is-opening-a-baltimore-county-operations.html

15 SEIA/GTM Research Solar Market Insight report series, 2010-2014

16 Lazard Levelized Cost of Energy Analysis - Version 8.0

Figure 5: Capacity-Weighted Average for Installed Costs of Solar Energy Systems, 2010-2013



Source: SEIA and GTM Research, *Solar Market Insight* report series

This section includes a summary of key findings from information gathered from nearly 1,000 U.S. solar installation companies.

Installation companies now employ 97,031 workers, growing by nearly 40% since November 2013 and 120% since September 2010, and now account for 56% of total industry employment.

More Americans work at solar installation companies than work at petroleum refineries in the United States.[17] The installation sector anticipates adding the most new jobs in 2015 as well, reaching nearly 120,000 jobs by year's end with an expected employment growth rate of 22.6%.

17 EMSI Class of Worker Employment, 2014.3

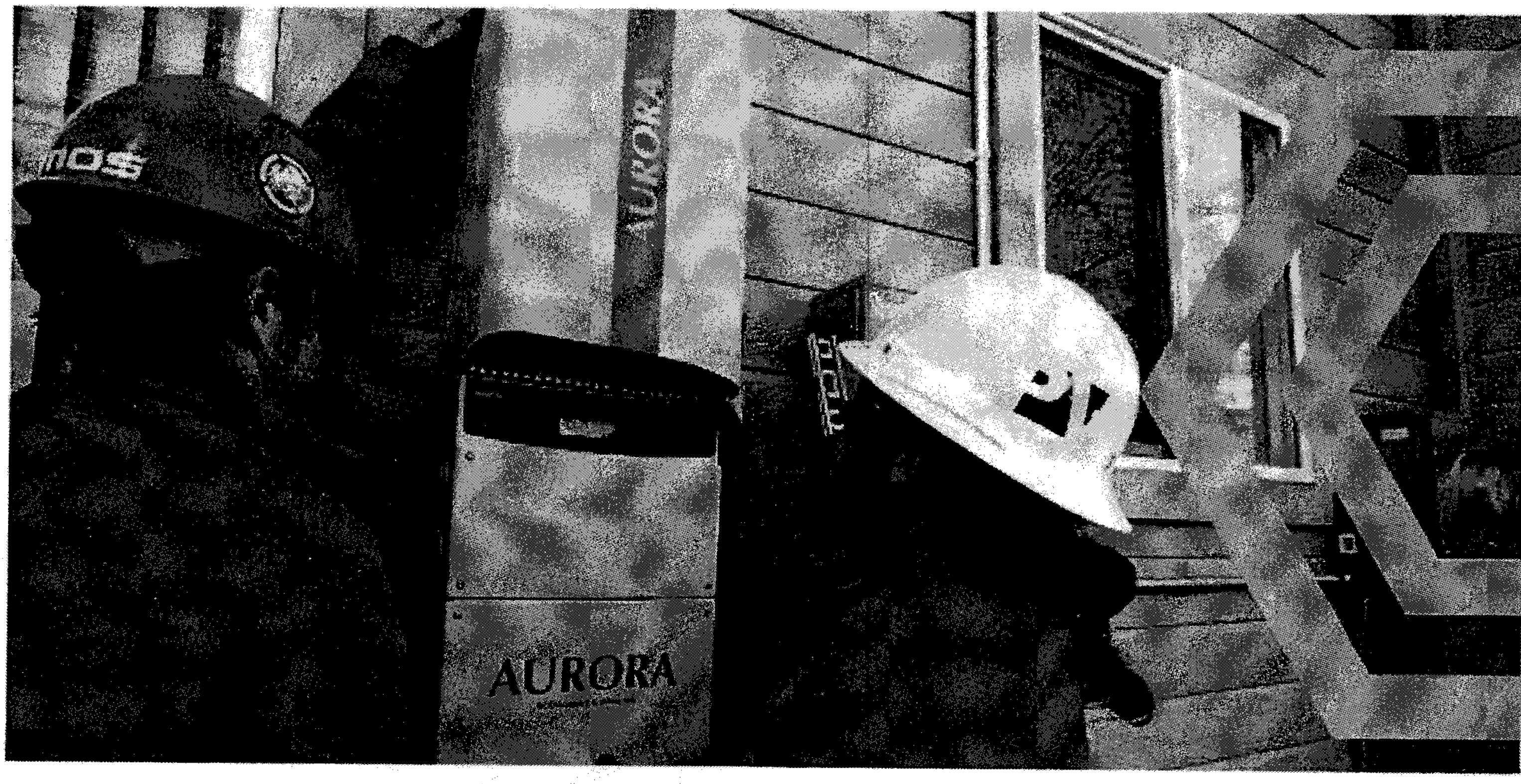
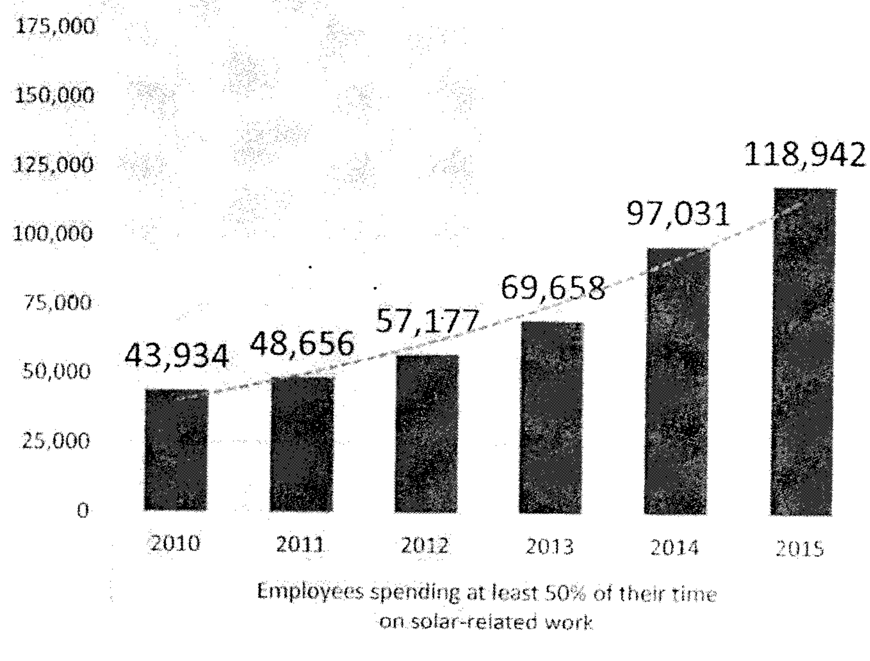


Figure 6: Installation Employment Growth from 2010 to 2015 (Projected)



59.6% of solar installers work primarily on residential systems, while another 23.6% report working on small to medium commercial systems up to 200 kW.

There are some significant differences between these types of establishments, including that installer median wages are about 20% higher at firms that predominantly work on utility-scale projects than those that install commercial or residential systems.

Table 4: Installation Market Segments

	Median Labor Hours for 5kW Residential PV	% Pure Solar	% Experienced Difficulty Obtaining Financing	Average Solar Workers Hired per Firm in last 12 Months
Overall	32.0	53.5%	62.3%	7.31
Residential	32.0	62.7%	64.6%	9.39
Commercial	40.0	50.6%	66.1%	4.30
Utility-Scale	24.0	50.0%	16.7%	7.79

Nationally, installers report that about half of residential systems are financed or leased through the company (as opposed to purchased outright), while about 70% of commercial systems are financed/leased as opposed to purchased.

These results correspond with established trends and observations in financing for various market segments. In six states representing approximately 75% of the total capacity expected in the national residential market in 2014, third-party ownership accounts for approximately 70-90% of all new residential installations.[18] Taken together, third-party owned residential systems in these states will account for nearly 60% of all residential installations projected nationwide this year.

Commercial projects seem to rely more on third-party owned systems, presumably due to the comparatively greater upfront cost of these systems and the greater responsibility for system operation and maintenance that would fall onto a commercial owner-operator. For example, companies such as Walmart – the largest single corporate user of solar energy – has financed most, if not all, of these installations through third-party ownership.[19] The same is true of Walgreen's, another top corporate user of commercial solar, which recently contracted a developer to install, own, operate, and maintain systems on 200 of its stores. There are, of course, notable exceptions to this trend. IKEA has nearly 40 MW of solar installed on its facilities around the country, and it owns and operates each of these installations.[20]

While third-party ownership has driven significant growth, many installation companies are also offering zero-down loans as part of their sales strategy. Current monthly costs for zero-down loans and solar leases (power purchase agreements) are strikingly similar in many markets,[21] and the popularity of loan versus leased systems will be an important trend to watch in 2015.

18 SEIA/GTM Research Solar Market Insight Q3 2014
19 SEIA Solar Means Business Report, available at http://www.seia.org/research-resources/solar-means-business-report
20 See: "Financing Options Open Up for Commercial Solar", from Solar Industry Magazine at http://www.solarindustrymag.com/issues/SI1401/FEAT_01_Financing-Options-Open-Up-For-Commercial-Solar.html
21 See: "Solar Leasing vs. $0-down Solar Loan – Scenarios in 10 States" from CleanTechnica at http://cleantechnica.com/2014/02/09/solar-leasing-vs-0-solar-loan-scenarios-10-states/

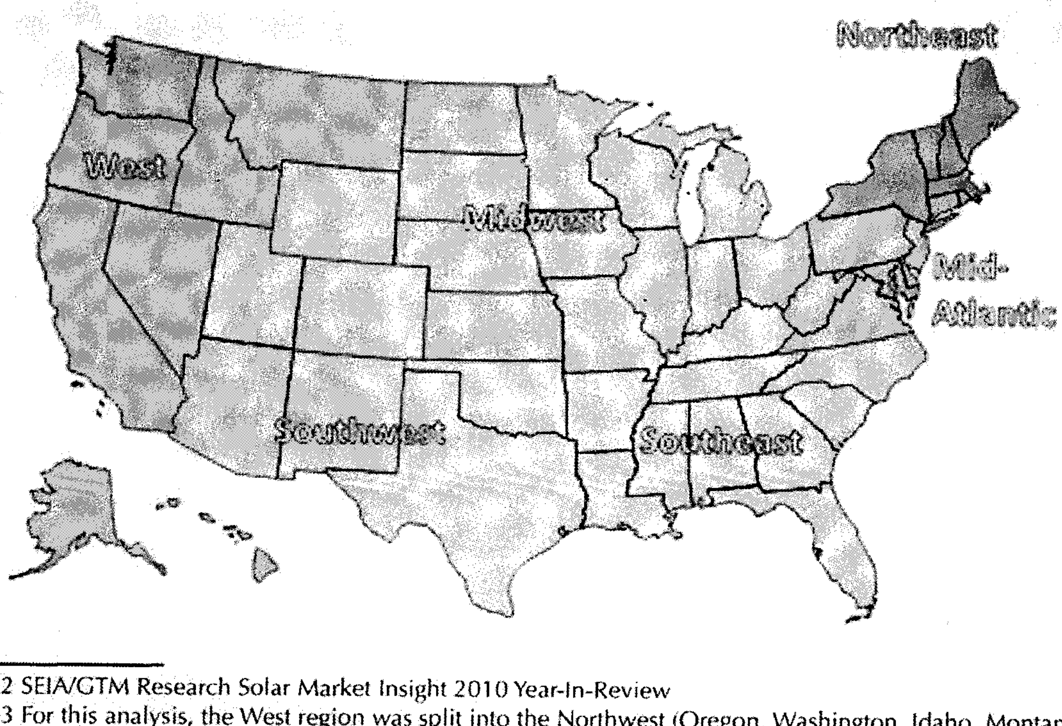
While PV dominates in all markets, nearly half of all installation firms in the Southeast work with solar water heating technologies, including pool heaters.

Table 5 below shows the breakdown of installer companies' reported activities by region. Installers of solar photovoltaic systems account for most activity in all regions of the country. Solar water heating installers are more likely to be found in the Southeast, which (in the last year for which data are available) accounted for over one-third of cumulative installed solar water and pool heating in the U.S.[22]

Table 5: Installed Products by Region[23]

	Overall	Northwest	Pacific	Southwest	Midwest	Southeast	Mid-Atlantic	Northeast
Photovoltaic	92.1%	97.2%	96.3%	84.4%	94.1%	92.1%	92.0%	89.6%
Water heating, which includes pool heating	28.4%	22.2%	23.2%	27.2%	22.0%	48.2%	26.8%	29.9%
Concentrating solar power	5.9%	5.6%	8.3%	4.8%	2.5%	9.6%	3.6%	4.9%
Other	7.5%	8.3%	5.0%	6.8%	9.3%	9.6%	9.8%	6.9%

*Does not equal 100% as many companies work across multiple technologies.



22 SEIA/GTM Research Solar Market Insight 2010 Year-In-Review

23 For this analysis, the West region was split into the Northwest (Oregon, Washington, Idaho, Montana, and Alaska) and the Pacific (California, Nevada, and Hawaii) regions.

Installers were the most concerned that changes to the ITC would force job losses.

Almost every installer company surveyed (94%) believes the 30% ITC has significantly improved their business. When asked how eliminating the residential credit and reducing the commercial credit after 2016 would impact their hiring decisions, 61.7% said they would likely lay off staff and/or contractors.

Such a dramatic expected decrease in employment in this sector makes sense as annual capacity additions in a given state are highly correlated with the number of solar jobs in that state (the single largest category of which are installation jobs), and that nearly every market segment in every state is expected to experience a decrease in annual installed capacity in 2017, when substantial changes to the ITC are scheduled to take effect.[24]

About half of all solar installer firms receive all of their income from solar goods and services.

Compared with previous *Census* reports, this figure has grown over the past several years and demonstrates that more companies are "pure-play" solar firms as the industry continues to trend toward consolidation and maturation.

Installer companies employ more African-Americans and Latinos than their counterparts in other solar sectors, and are generally more diverse than related sectors such as oil, gas, coal, and construction.

In addition, 8.9% of the installation sector's solar employment in 2014 are veterans of the U.S. armed forces, and 9.4% are members of a union. While the solar installation sector employs a higher percentage of women than the construction industry, the coal industry and the oil and gas extraction industries, there are fewer women working in the installation sector than in other solar sectors. Table 6 below includes additional information on the demographics of solar workers in the installation sector in 2014.

24 SEIA/GTM Research Solar Market Insight Q3 2014

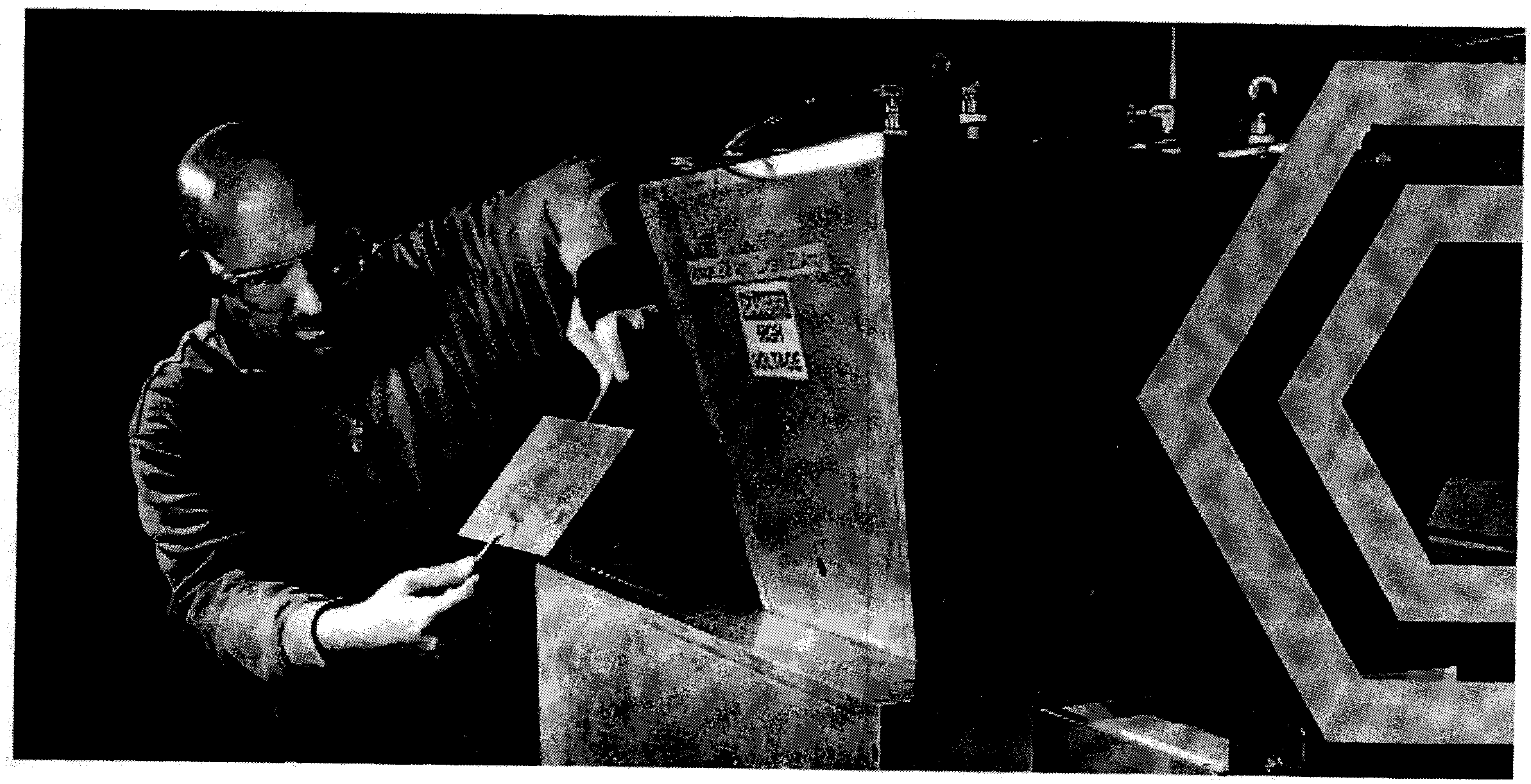


Table 6: 2014 Installation Solar Worker Demographic Breakdown[25]

	Employment	% of Installation Employment	% of total U.S. Workforce	% of Construction Industry Employment	% Oil and Gas Extraction Indus Empl.	% of Coal Industry Employment
Latino or Hispanic	18,821	19.4%	13.0%	16.7%	19.1%	3.0%
Women	17,137	17.7%	49.6%	14.4%	16.6%	6.3%
Belong to a Union	9,105	9.4%	n/a	n/a	n/a	n/a
Veterans of the U.S. Armed Forces	8,649	8.9%	7.0%	n/a	n/a	n/a
African-American	6,269	6.5%	11.7%	5.3%	5.1%	2.4%
Asian or Pacific Islanders	6,013	6.2%	5.2%	2.1%	2.1%	0.4%

25 See: EMSI Class of Worker 2013.4; The Employment Situation – November 2014, Bureau of Labor Statistics, available at: http://www.bls.gov/news.release/pdf/empsit.pdf.

Manufacturing

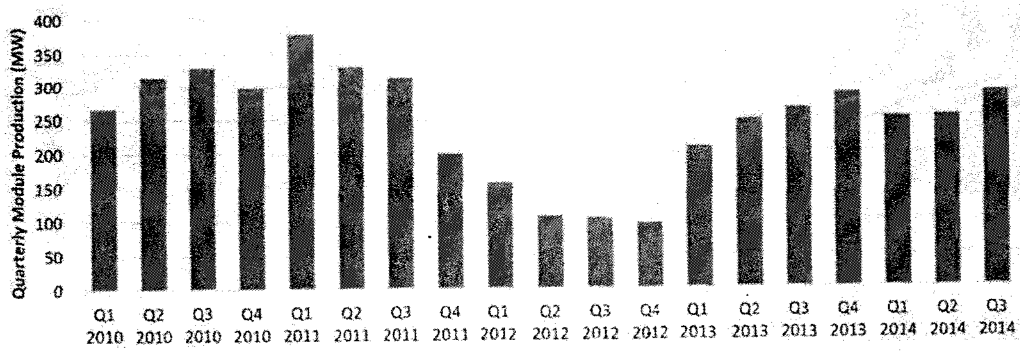
Solar manufacturers produce a variety of finished products and components for domestic and international markets. From solar water heaters to photovoltaic modules, U.S. production of solar goods and services is growing, thanks to a rapidly expanding global market.

Big News in Domestic Manufacturing:

- **An improved balance of supply and demand in global markets has benefited domestic module manufacturing.** As shown in Figure 7 below, Q3 2014 saw the greatest domestic module production in two years, with output up over 275% since the low levels observed in mid-2012.[26]

  Domestic production of PV components (e.g., polysilicon, cells, wafers, inverters) is also up year over year and/or quarter over quarter.[27]

Figure 7: U.S. Domestic Solar Module Production, 2010-2014



Source: SEIA and GTM Research, *Solar Market Insight report series*

- **2014 saw several notable additions or announcements of new domestic manufacturing capacity.**
  - Mission Solar Energy opened a new 100 MW cell and module facility in fall 2014 in San Antonio, Texas, which is expected to create over 400 new jobs in the area.[28]
  - Georgia-based Suniva announced it plans to open a second U.S. manufacturing facility in Michigan. Once fully-operational, the 200 MW facility is

26 SEIA/GTM Research Solar Market Insight series, 2012-2014
27 SEIA/GTM Research Solar Market Insight Q3 2014
28 See "Mission Solar producing solar panels" from My San Antonio at http://www.mysanantonio.com/business/local/article/Mission-Solar-producing-solar-panels-5768001.php

expected to create 350 new jobs in the community.[29]

- In November 2014, REC Silicon announced its plans to expand polysilicon production capacity at its Moses Lake, Washington facility by 3,000 metric tons. Though not expected to be completed until late 2016, this expansion will represent a 20% increase in overall U.S. polysilicon capacity (compared with Q3 2014 figures).[30, 31]
- In June of 2014, Solar City announced its acquisition of solar manufacturer Silevo and its plans to build a 1 GW module production facility in New York State. Construction began on the facility in September 2014.[32]
- This year also saw progress made on plans for a Wacker Chemie production facility in Charleston, Tennessee. Thus far, 200 employees have been hired to staff the facility, with an additional 450 people expected to be brought on through 2015.[33]
- In November 2014, First Solar announced plans to add two new production lines and hire 120 employees at its manufacturing facility in Perrysburg, Ohio.[34]
- Also during the fall, SolarWorld announced its plans to add a new module production line at its Oregon factory, increasing production capacity at the facility by nearly 40%. This expansion, along with the addition of 100 MW of cell production capacity, is expected to create 200 jobs in early 2015.[35]

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29 See "New Tariffs on Chinese Solar-Panel Makers Split the US Solar Industry" from GreenTech Media at http://www.greentechmedia.com/articles/read/commerce-department-hits-chinese-panel-makers-with-higher-tariffs

30 See "REC Silicon ExpandingPpolysilicon Production and Mulling 20,000MT JV in Saudi Arabia" from PVTech at http://www.pv-tech.org/news/rec_silicon_expanding_polysilicon_production_and_mulling_20000mt_jv_in_saud

31 SEIA/GTM Research Solar Market Insight Q3 2014

32 See "SolarCity Breaks Ground on 1GW Silveo fab in New York" from PV Tech at http://www.pv-tech.org/news/solarcity_breaks_ground_on_1gw_silevo_fab_in_new_york

33 See "Wacker Still Looks for 2015 Start-up" from Cleveland Daily Banner at http://clevelandbanner.com/view/full_story/25935045/article-Wacker--still-looks-for-2015-start-up?instance=yourstories

34 See "First Solar to Add 120 Workers at Perrysburg Township Plant" from The Toledo Blade at http://www.toledoblade.com/Energy/2014/11/13/First-Solar-to-add-120-employees-at-local-plant.html

35 See "SolarWorld Announces Expansions of Solar Panel and Advanced Cell production in Oregon" from SolarWorld at http://www.solarworld-usa.com/newsroom/news-releases/news/2014/solarworld-announces-expansions-in-oregon

- **Given current trends, U.S. module manufacturing capacity could increase to more than 3.5 GW by 2018 (compared with 1.6 GW currently), and cell manufacturing capacity could increase to 2.0 GW (up from 0.7 GW) in the same time frame.**[36] Such efforts stand to benefit from additional investments aimed at manufacturing process improvements. One example is the Smart Manufacturing Innovation Institute announced by the White House in December. This public-private partnership will seek to leverage $140 million to improve the energy efficiency of manufacturing processes in energy intensive industries, including solar cell manufacturing.[37]

- **Unfortunately, the ongoing U.S.-China solar trade conflict created unintended consequences for some of the U.S. solar industry.** In December 2014, U.S. polysilicon manufacturer Hemlock Semiconductor was forced to close its Clarksville, Tennessee production facility largely due to retaliatory restraints on U.S. polysilicon exports to China.[38] The new $1.2 billion dollar facility had yet to enter commercial production. Most of the approximately 50 affected employees will have the opportunity to relocate to other Hemlock Semiconductor or Dow Corning sites.[39] Hemlock Semiconductor will continue to manufacture and sell materials from its Hemlock, Michigan, site, which has been in operation for more than 53 years, and has received more than $2.5 billion of investment in the last 10 years.

36 See "SunShot Q2/Q3 '14 Solar Industry Update (October 31, 2014)" from U.S. Department of Energy SunShot Initiative at http://ny-sun.ny.gov/-/media/NYSun/files/Meetings/2014-11-06/SunShot-Solar-Industry-Update.pdf
37 See: "FACT SHEET: President Obama Launches Competitions for New Manufacturing Innovation Hubs and American Apprenticeship Grants" from the White House at: http://www.whitehouse.gov/the-press-office/2014/12/11/fact-sheet-president-obama-launches-competitions-new-manufacturing-innov
38 See "Hemlock Semiconductor Group Closes Tennessee Manufacturing Facility as a Result of Industry Oversupply, International Trade Disputes" from Hemlock Semiconductor at http://www.hscpoly.com/content/hsc_comp/hsc-tennessee-manufacutring-facility-closure.aspx
39 Id.

Worker Profile

Sina Khiev

Occupation: Production Technician Lead
Company: SolarWorld USA
Years at Occupation: 6
Location: Hillsboro, OR

As a lead production technician at SolarWorld, Mr. Khiev is the subject matter expert responsible for the operation and troubleshooting of automated equipment and tools for PV module assembly, as well as for driving tactical scheduling and decision making for specific work groups on the production floor.

Before obtaining his current position, Mr. Khiev studied construction engineering management and electronics in college. However, much of his training has been through the hands-on experiences received during his twenty years in the semiconductor industry. Some of that training has included company trips to Germany to build PV modules by hand. After moving into the region, he wanted a job with an exciting company that valued his experience, which he has found at SolarWorld.

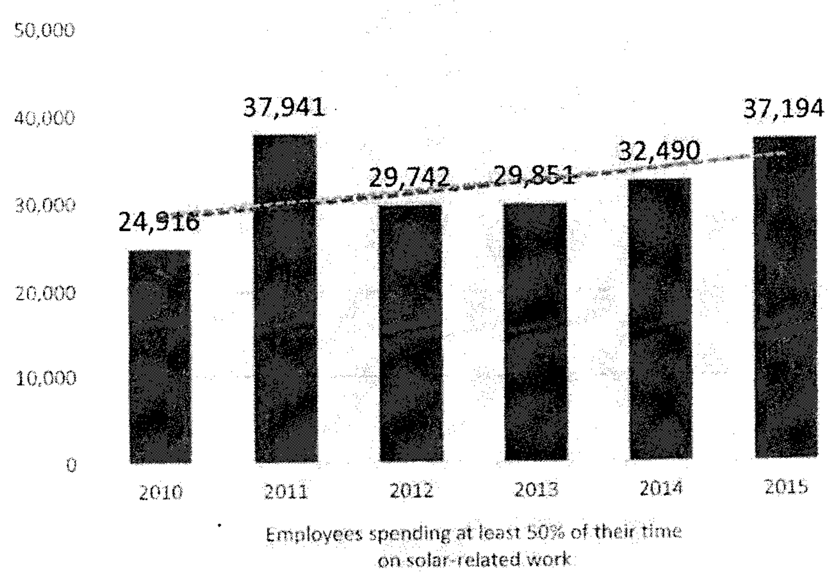
The part of his job he enjoys the most is the fact that, though he and his coworkers all have their own tasks and areas of focus, they all share a deep feeling of teamwork as they all rely on each other to successfully coordinate module assembly. His advice for jobseekers is to "focus on finding what you like to do, then do it to the best of your ability. With enough passion you can acquire the skills to do whatever you hope to achieve."

This section includes the key findings from the data gathered from more than 250 solar manufacturers.

Manufacturers currently employ 32,490 solar workers, equating to growth of 8.8% since November 2013 and 30% since September 2010.

By way of comparison, overall manufacturing employment in the United States has grown by only 3.2% since 2010 and declined between 2013 and 2014 by 1.6%.[40] Solar manufacturers predict strong employment growth of 14.5% through the end of 2015, adding about 4,700 new jobs. Meanwhile, the overall manufacturing sector in the United States is expected to shed more than 130,000 jobs, a decline of 1.1%, over the same period.[41]

Figure 8: Manufacturing Employment Growth from 2010 to 2015 (Projected)



Manufacturers largely produce photovoltaic modules or components.

Seven in ten manufacturers produce photovoltaic modules or components, while another 18.4% report producing goods related to solar water heating. This figure has been relatively consistent over the last few years, with 19.9% of manufacturing firms involved in solar water heating in 2012, and 18.8% in 2013.

As shown in Table 7 below, the majority of solar manufacturers across all regions of the country produce photovoltaic modules or components, reflecting the fact that solar electric systems are currently in higher demand not only nationally, but globally. While manufac-

40 EMSI Class of Worker Employment 2014.3.

41 Id.

turers are not constrained by local demand considerations, the large concentration of manufacturers producing solar water heating equipment and components in the Southeast may be due to the fact that Florida led the nation in cumulative total solar water heating (SWH) and solar pool heating (SPH) installations in 2010 (the last year for which reliable data is available). At the time, Florida had installed 80% more SWH systems and 27% more SPH systems than California, the next largest state market for solar thermal systems.[42]

Table 7: Manufactured Products by Region

	Overall	West	Southwest	Midwest	Southeast	Mid-Atlantic	Northeast
Photovoltaic	70.7%	74.0%	69.4%	65.2%	66.7%	87.1%	59.3%
Water heating, which includes po	18.4%	18.2%	13.9%	17.4%	25.6%	16.1%	18.5%
Concentrating solar power	8.2%	7.8%	11.1%	10.9%	5.1%	9.7%	3.7%
Other	19.9%	19.5%	13.9%	26.1%	20.5%	19.4%	18.5%

*Does not equal 100% as many companies work across multiple technologies.

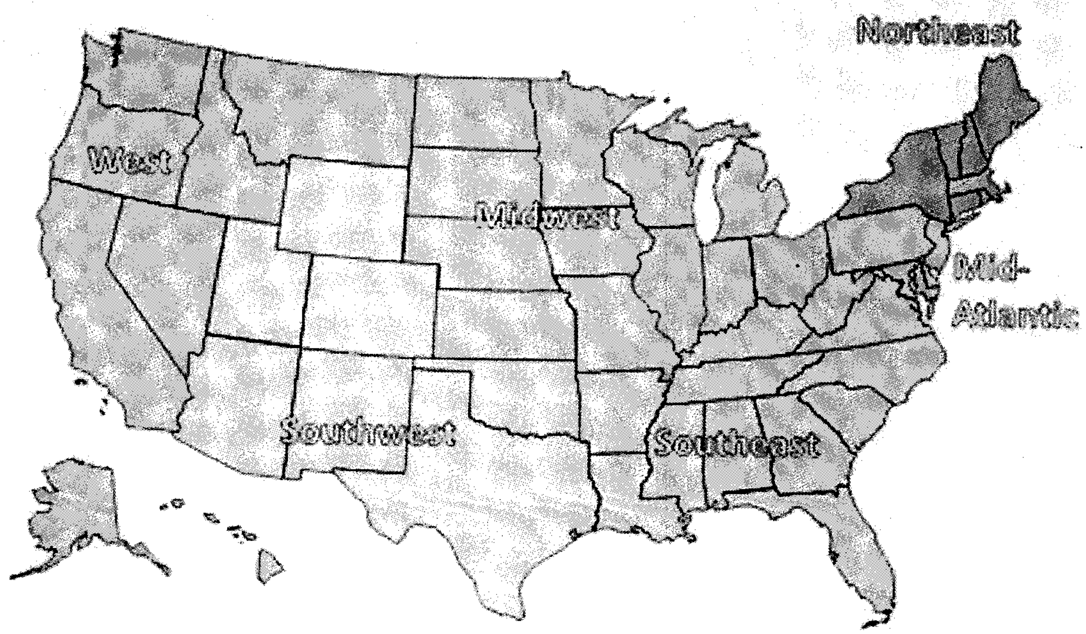


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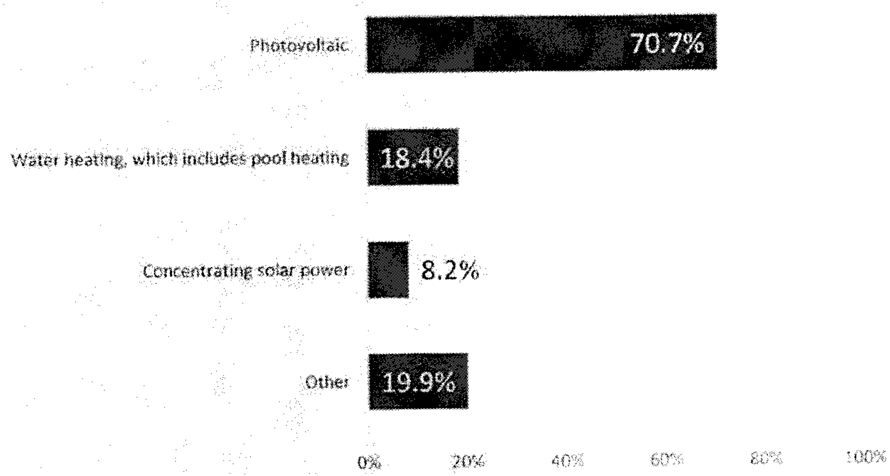
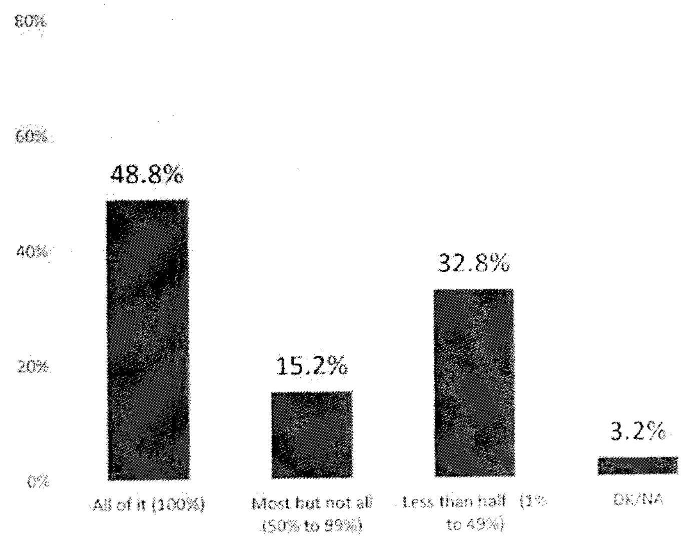
Figure 9: Solar Products Produced by Manufacturers



About half of all solar manufacturing establishments exclusively produce solar goods and services.

Only one in three solar manufacturing establishments derive less than half of their revenues from solar products. As with other sectors within the solar industry, more manufacturing firms report that solar represents a majority source of revenue. This figure correlates with an increase in the number of large solar manufacturers, suggesting that solar is becoming more integrated into mainstream production by firms that offer multiple, related products rather than remaining a niche industry. This movement is similar to other production industries that have had comparable trajectories, such as organic food production, mobile software application development, and LED light bulb manufacturing.

Figure 10: Company Revenues Attributable to Solar



Compared with the installation sector, many fewer manufacturers expect to be impacted by the ITC expiration.

Domestic manufacturers will likely see little impact with the expiration of the ITC because they sell the bulk of their product as components or feedstock to foreign manufacturers (e.g. polysilicon, backsheets, metal pastes) or because the products they sell are not eligible for the ITC (e.g. solar pool heaters). Moreover, a significant portion of the companies are not "pure-play" solar manufacturers, and over half of these establishments expect to not be impacted by the ITC decline. By comparison, firms focusing solely on solar see themselves as less likely to not be impacted by changes to the ITC, with some domestic manufacturers of heavy products for mostly domestic consumption (including module, racking, and inverter manufacturers) potentially face a more challenging market in 2017.

Table 8: Solar Manufacturer Action for Anticipated ITC Decline by Amount of Firm Revenue Attributable to Solar Products

Action	100% Solar	99% or less Solar	Combined Results
No impact	31.9%	55.6%	42.6%
Expect to increase our workforce in 2017	14.9%	6.2%	10.8%
Expect to lay off staff	20.2%	13.6%	17.0%
Expect to lay off subcontractors	3.2%	2.5%	2.8%
Expect to lay off staff and subcontractors	29.8%	22.2%	26.1%

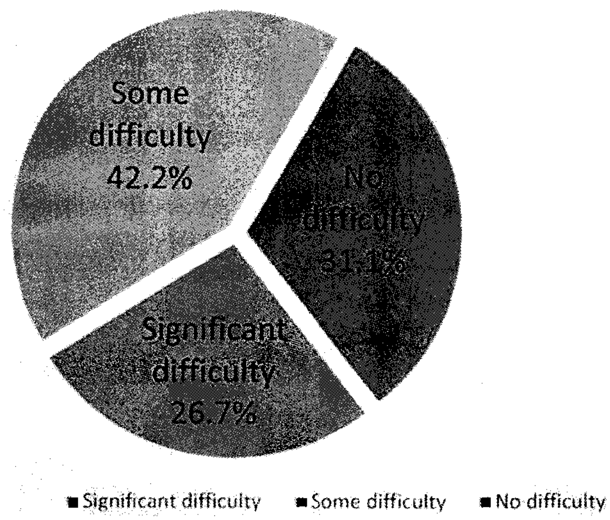
Table 9: Percent of Manufacturers that Work with Solar Products by Amount of Firm Revenue Attributable to Solar Products[43]

Solar Products	100% Solar	99% or less Solar
Photovoltaic	74.6%	67.2%
Water heating, which includes pool heating	19.7%	17.2%
Concentrating solar power	7.4%	9.4%
Other	18.0%	21.9%

43 Multiple responses permitted, may sum to more than 100%

About 30% of solar manufacturers sought financing over the last 12 months, seeking both loans and equity investments. About one in four experienced significant difficulty obtaining financing, a trend that bears watching to ensure that lack of capital does not derail potential growth in the sector.

Figure 11: Difficulty Trying to Obtain Financing over Past 12 Months



The manufacturer workforce is more diverse than other segments, particularly for women, Latino/Hispanic workers, and veterans. Table 10 illustrates the 2014 demographics of solar workers in the manufacturing sector.

Table 10: 2014 Manufacturing Solar Worker Demographic Breakdown[44]

	Employment	% of Manufacturing Employment	% of U.S. Workforce	% of U.S. Manufacturing Industry
Women	7,929	2[redacted]%	49[redacted]	28.4%
Latino or Hispanic	6,072	18.7%	13.0%	13.9%
Veterans of the U.S. Armed Forces	3,853	11.9%	7.0%	n/a
Asian or Pacific Islanders	3,063	9.4%	5.2%	5.8%
African-American	2,382	7.3%	11.7%	9.3%

44 See EMSI Class of Worker 2014.3; The Employment Situation – November 2014, Bureau of Labor Statistics, available at: http://www.bls.gov/news.release/pdf/empsit.pdf.

Sales and Distribution

The solar sales and distribution sector is made up primarily of wholesale and retail trade establishments engaged in selling (but not installing) solar and other ancillary services to customers and/or warehousing and distributing U.S. and foreign made solar goods to installers. Because this report delineates companies by the activities at each business location to gather the most accurate employment information, much of the data for this section includes data from sales offices and distribution warehouses from companies across other segments of the value chain.

As the industry matures and companies grow, much of this work is carried out in-house, while developing markets are likely to be more reliant on distributors – since such markets may not be sufficiently large to account for direct sales.

Big News in Sales and Distribution:

- **2014 saw continued federal support for firms seeking to streamline solar sales efforts, helping to reduce soft costs.** Through its SunShot Incubator Program, the U.S. Department of Energy (DOE) has continued to make investments in firms with promising ideas for reducing customer acquisition soft costs, thus enabling greater efficiency in sales efforts for solar firms and lower installed costs for customers. Since fall 2013, DOE has invested nearly $6 million in a half dozen firms developing new tools to reduce customer acquisition costs.[45]

- **A number of solar companies with establishments active in the sales and distribution sector announced new expansions or partnerships.**

    - Oakland-based Sungevity is in the process of building out a new sales and service center in Kansas City, Missouri.[46] Once fully staffed, the new location will employ nearly 600 workers – approximately 20% of the total number of solar jobs in the state in 2013.

    - This past summer, the solar crowd-funding company Mosaic announced a partnership with microinverter manufacturer Enphase aimed at offering $100 million in solar loans designed to help homeowners finance new installations.[47]

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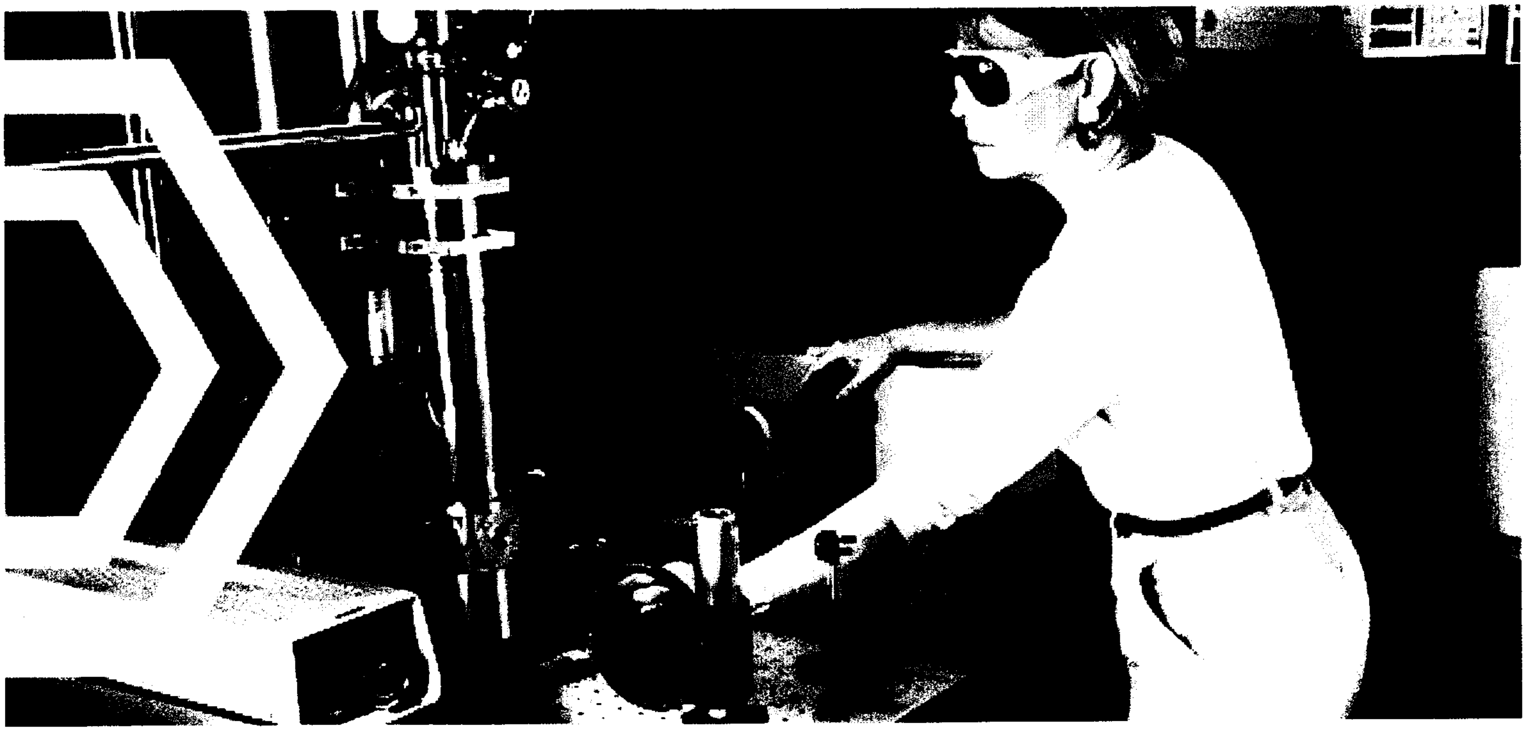
45 See "Current SunShot Incubator Projects" from U.S. Department of Energy Office of Energy Efficiency and Renewable Energy at http://energy.gov/eere/sunshot/current-sunshot-incubator-projects

46 See "Sungevity Shines on with Office Build, Hiring Spree" from the Kansas City Business Journal at http://www.bizjournals.com/kansascity/news/2015/01/06/sungevity-shines-on-with-office-build-hiring-spree.html

47 See "Enphase and Mosaic Join Forces in a Bid to Push Solar Loans and Supplant the Lease" from GreenTech Media at http://www.greentechmedia.com/articles/read/how-to-take-the-risk-out-of-residential-solar-loans



- Late 2014 saw the announcement of a strategic partnership between First Solar and Colorado-based Clean Energy Collective to expand CEC's efforts to develop and market utility-owned community solar projects.[48]

- In October 2014, the nation's largest independent power producer, NRG Energy, acquired Pure Energies Group, which created an online and telephone-based solar customer acquisition platform. The acquisition, along with other recent acquisitions by NRG Energy, position it as potentially one of the nation's largest vertically integrated solar company featuring sales, financing, and installation services.[49] These types of acquisitions illustrate the growing trend that many sales and distribution establishments are offices or subsidiaries of firms that belong to other sectors (e.g., most of NRG Energy's establishments focus on project development).

- EnergySage, based in Cambridge, Massachusetts, announced several new partnerships in 2014. East Coast Petroleum, Staples, Walgreens, World Wildlife Fund, and many local chambers of commerce and cities have partnered with EnergySage in the last year to provide their employees, customers, and other constituents with a central marketplace for receiving and comparing price estimates from multiple solar installers at the same time.[50]

48 See "First Solar takes stake in Louisville-based Clean Energy Collective" from The Denver Post at http://www.denverpost.com/business/ci_27104211/first-solar-takes-stake-louisville-based-clean-energy

49 See "NRG Acquires Pure Energies to Lower the Cost of Winning Solar Customers" from GreenTech Media at http://www.greentechmedia.com/articles/read/NRG-Acquires-Pure-Energies-to-Lower-the-Cost-of-Winning-Solar-Customers

50 See "News/Press" page from EnergySage at https://www.energysage.com/news

Worker Profile

Melinda Kershaw

Occupation: Director of Marketing
Company: Day and Night Solar
Years at Occupation: 5
Location: Collinsville, IL

As Director of Marketing, Ms. Kershaw is responsible for driving the marketing and sales operations for Day and Night Solar. With her 22 years of experience in sales, marketing, and operational management and a key focus on sales and operation infrastructure for emerging technologies, she was a natural fit for the position, which she obtained through the company's regular application process.

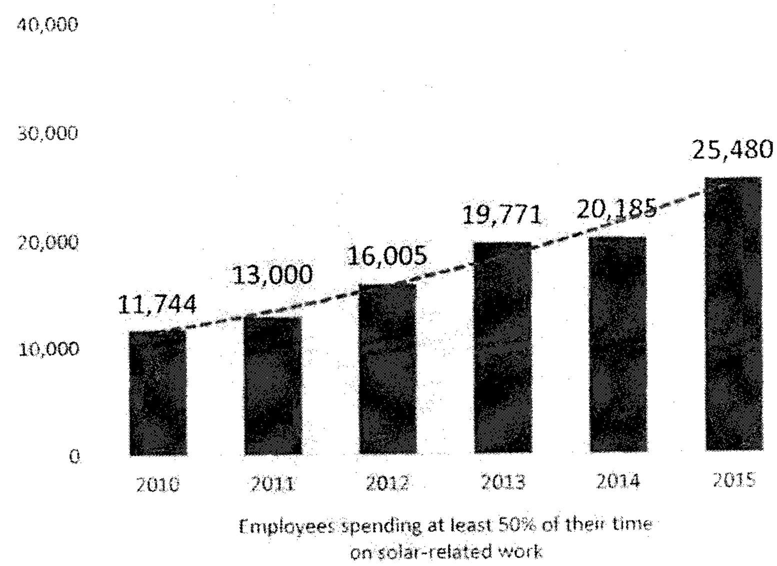
Her favorite aspects of her job are the changing nature of the challenges it presents, as well as the opportunity to be involved in an industry that she believes is helping to change the nation's energy landscape. To job seekers looking to replicate her success, she offers this advice: "Have the ability to be flexible. Changes are daily in this exciting industry and if you are not able to adapt, it will become overwhelming."

This section includes highlights from the responses of nearly 300 solar sales firms.

Solar firms primarily engaged in sales and distribution currently employ 20,185 solar workers, an increase of 72% since September 2010.

By comparison, the national wholesale and retail trade sectors grew by a rate less than 1/10th of the solar sales and distribution sector, showing just over 6% growth over the same period.[51] However, solar sales firms posted the weakest growth of any solar sector at 2.1% over the past 12 months, though this is still three times the growth expected in the national retail and wholesale sectors over the same period.[52]

Figure 12: Sales and Distribution Employment Growth from 2010 to 2015 (Projected)

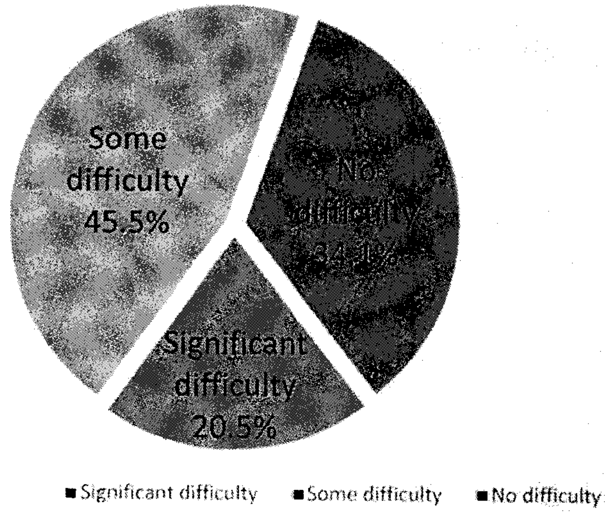


Employers are optimistic, expecting gains of 26.2% (5,295) through 2015, the fastest growth rate of any sector.

About one in three sales and distribution firms applied for financing and nearly two-thirds of those had at least some difficulty obtaining financing (with 20.5% experiencing significant difficulty).

51 EMSI Class of Worker Employment 2014.3
52 Id.

Figure 13: Difficulty Trying to Obtain Financing over Past 12 Months

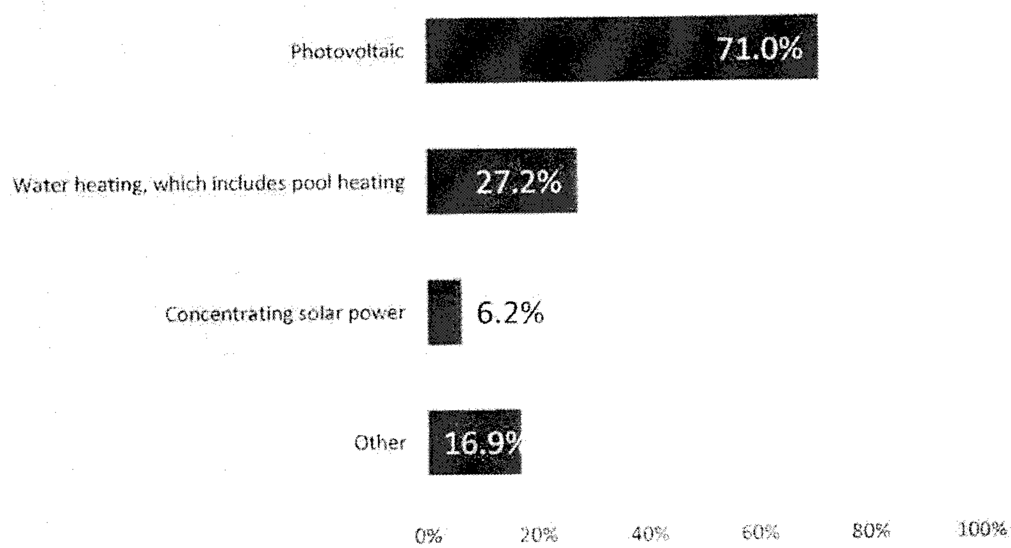


Solar sales and distribution firms most typically pursued loans or other debt financing when seeking capital over the past year. It will be important to determine whether and to what extent lack of capital is to blame for the weaker performance of the solar sales sector, and whether policies or incentives could help free capital for these businesses. Alternatively, it is likely that solar is comprising a larger share of business for existing distributors. Thus, despite demand for solar products growing in the last year, increasing efficiency and labor productivity among these established businesses may have been largely sufficient to meet the higher volume of sales.

Fewer sales and distribution firms indicated that they fully understand the Investment Tax Credit and the impact it has on their business. Perhaps as a result, the majority believe that it will not harm their business prospects.

A growing number of sales and distribution firms are working with solar water heating products (though the percentage of the total is declining as the number of PV firms is growing at an even faster rate). Currently, about one quarter (27.2%) of solar sales and distribution firms work with solar water heating products, while the overwhelming majority work with photovoltaics.

Figure 14: Solar Products Sold by Sales and Distribution Firms



Sales and distribution firms offer many opportunities for women, but are less diverse than other sectors of the solar industry.

Table 11 demonstrates the demographic breakdown of the solar sales workers over the past year.

Table 11: 2014 Sales and Distribution Solar Worker Demographic Breakdown[53]

	Employment	% of Sales & Distribution Employment	% of U.S. Workforce	% U.S. Wholesale Trade Industry
Women	4,850	24.0%	49.6%	30.5%
Veterans of the U.S. Armed Forces	1,525	7.6%	7.0%	n/a
Latino or Hispanic	1,385	6.9%	13.0%	12.9%
Asian or Pacific Islanders	1,352	6.7%	5.2%	5.6%
African-American	682	3.4%	11.7%	6.9%

53 See EMSI Class of Worker 2014.3; The Employment Situation – November 2014, Bureau of Labor Statistics, available at: http://www.bls.gov/news.release/pdf/empsit.pdf.

Project Development

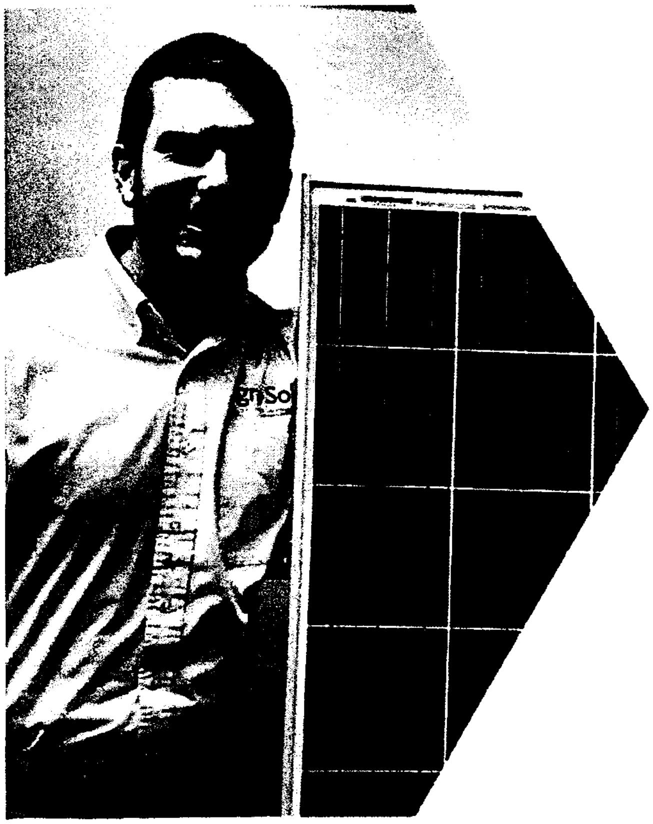
The project development sector includes companies that work on the largest, utility-scale solar projects. Predominantly using photovoltaic or thermal electric generation (concentrating solar power or CSP), these facilities generate and sell bulk power to utilities or directly to consumers as part of the electricity grid system.

Project developers and utilities require a wider range of workers and contractors, including civil engineers, land surveyors, and power plant operators. Permitting, finance, and land acquisition is more complex, requiring more administrative and professional workers as well. Employers in the sector tend to be larger and highly efficient with specialized labor for each component of the project.

Big News in Project Development

- **By the end of 2014, the U.S. is expected to install a record-high 4,900 MW of utility-scale solar capacity** (including both PV and CSP), approximately 50% more than was installed in the previous year.[54]
- **A number of noteworthy utility-scale solar projects came online in 2014.** Near the start of the year, BrightSource's Ivanpah Solar Electric Generating System – a 392 MW concentrating solar power plant – came online, with the capacity to provide enough solar electricity to power 140,000 average U.S. homes.[55] Also this year, First Solar's Topaz Solar Farm, currently the largest solar project in the world at 550 MW, began producing electricity.[56]
- **Drivers of this growth** include the sharp decline in installed costs observed since 2010, the value of solar in providing a hedge against fuel price volatility (possible with competing conventional technologies), the use of solar energy to replace retired coal capacity, and the desire of some utilities to "front load" large projects in their RPS compliance timeline to ensure these facilities will be completed in time to benefit from the 30% ITC.[57]
- **The short-term outlook for utility-scale installations remains healthy,** with still greater levels of annual installed capacity expected in this market segment in 2015 and 2016. These projections are in line with employers' expectations of continued employment growth over the next few months. **However, a reduction in the federal ITC to 10% at the end of 2016 can be expected to result in 2017 annual capacity additions that are over 80% lower than those expected in 2016, leading to a large contraction in employment in this sector.**[58]

54 SEIA/GTM Research Solar Market Insight Q3 2014
55 See "What You Should Know: The 7 Notable Solar Power Plants of 2014" from Forbes at http://www.forbes.com/sites/uciliawang/2014/12/31/what-you-should-know-the-7-notable-solar-power-plants-of-2014/.
56 Id.
57 SEIA/GTM Research Solar Market Insight Q3 2014
58 Id.



Ryan Marlborough

Occupation: Commercian Sales Analyst
Company: groSolar
Years at Occupation: 2
Location: Columbia, MD

As a Commercial Sales Analyst for the project developer groSolar, Mr. Marlborough moves projects along the sales and development process, including site walks and assessment, financial modeling, proposal writing, contract negotiations, and other project due diligence activities. He's been in his current position for two years, and before then he worked for an electrical distributor selling solar equipment to installers throughout the country. Much of Mr. Marlborough's solar expertise came from experience on the job and attending numerous solar training classes over his six years in the solar industry.

Mr. Marlborough made the transition from equipment sales to project developer through an opening he discovered on an online solar job board. When asked about his favorite aspects of his job, Mr. Marlborough noted that "the dynamic nature of the solar industry keeps the job both exciting and challenging. There is never a day where I am not trying to solve a problem or learn something new." For others looking to follow a similar career path in solar, Mr. Marlborough recommends jobseekers think about the sector of the industry that most interests them, research firms in that sector, and identify positions within those firms that align with their skills and passions. He added: "The industry has scaled to the point where there are positions available for a wide assortment of backgrounds and interests."

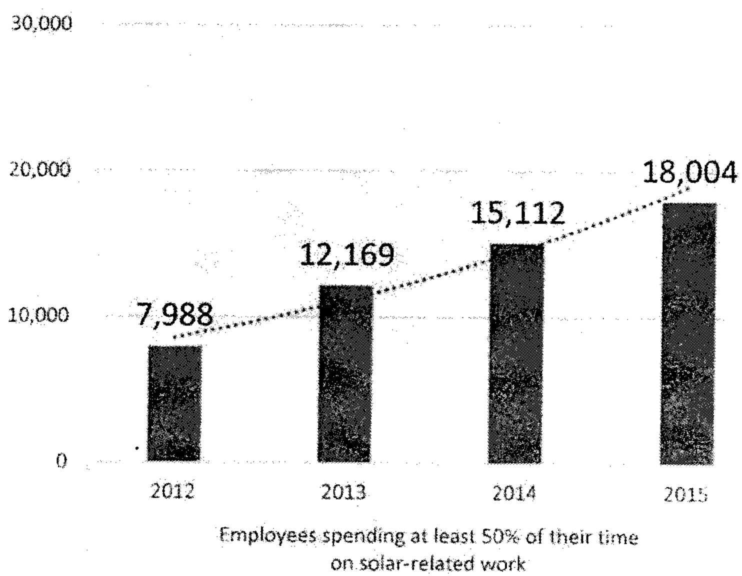
Annual utility-scale installed capacity has grown by nearly 170% since 2012, while employment has grown by 89%.[59] At the same time, these installations represent 63% of solar capacity added over the same period,[60] yet due to the efficiencies of scale associated with these larger systems as well as increased labor efficiency,[61] only 13% of all new jobs since November 2012 were created in this sector.

This section includes the key findings from nearly 200 project developers and utilities.

Project development is one of the fastest growing solar sectors, gaining nearly 3,000 jobs to total 15,112 solar workers, a growth rate of 24.2% from November 2013 to November 2014.

Developers expect to add approximately 3,000 more solar jobs over the coming 12 months, at a growth rate of 19.1%.

Figure 15: Project Developer Employment Growth from 2012 to 2015 (Projected)[62]



Developers are more likely to be "pure-play" solar firms, with over half receiving all of their revenue from solar. This is logical given the large size of the projects they work on; however, about one in four receives less than half of their revenue from solar projects.

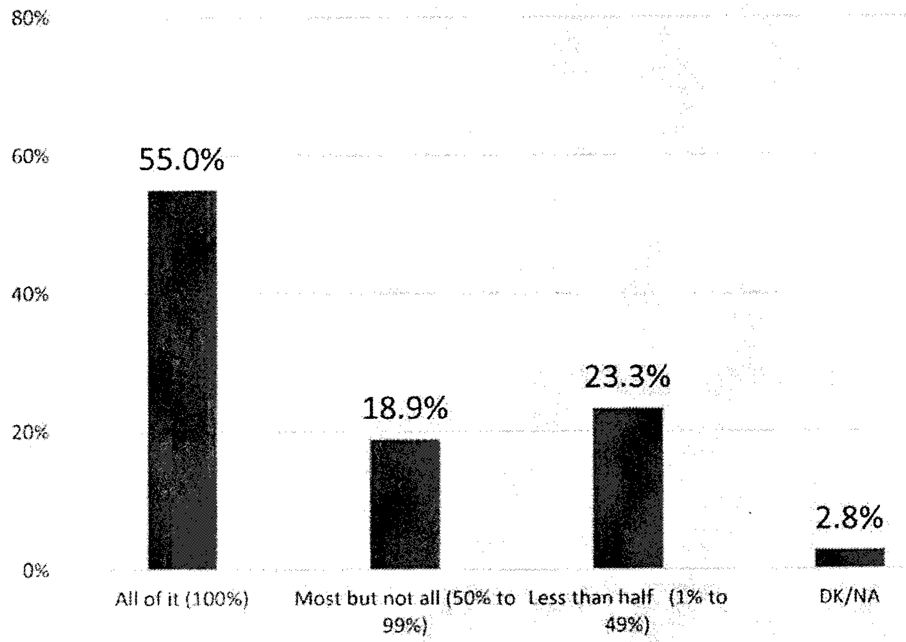
59 Id.

60 Id.

61 In 2014, employers reported that 74.3% of the installation workforce spends a majority of their time on installing systems, nearly double the amount reported in 2013 of 37.5%.

62 2012 was the first year that project developers were counted as a separate category.

Figure 16: Percentage of Establishments by Portion of Solar Revenue

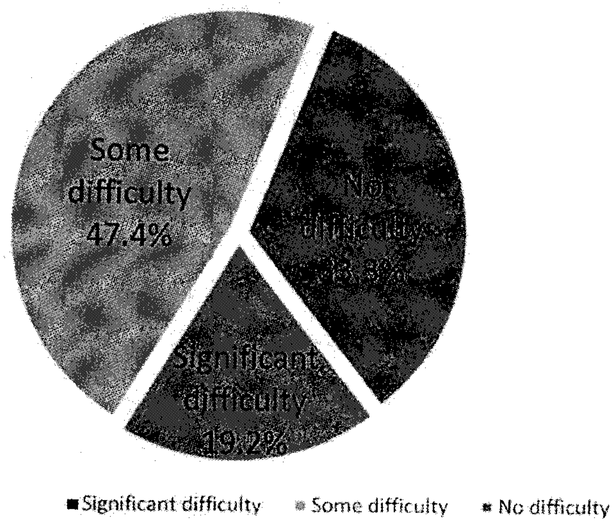


Nearly half of developers sought financing over the last year (48.3%), and over two-thirds (66.7%) had difficulty obtaining it, with one in five reporting significant difficulty.

Employers' stated difficulties in obtaining financing may be a reflection of the limited financing options available to solar developers, forcing them to continue to pursue existing finançing mechanisms with higher costs of capital than would be available with greater alternatives. Significant work has been done by numerous organizations on the prospect of financing alternatives to "traditional" tax equity partnerships, such as Master Limited Partnerships, Solar Real Estate Investment Trusts, and "yieldcos."[63] Nevertheless, broad adoption of any of these or other financing arrangements among developers and lenders does not yet appear to have occurred. Continued reliance on tax equity partnerships may result in unrealized development without an increase in the tax appetite of lenders, particularly as developers rush to begin projects before the expiration of the ITC.

63 See: "Master Limited Partnerships and Real Estate Investment Trusts: Opportunities and Potential Complications for Renewable Energy" from the National Renewable Energy Laboratory at http://www.nrel.gov/docs/fy14osti/60413.pdf and "Solar YieldCos: Proven Concept or Hype?" from GreenTech Media at http://www.greentechmedia.com/articles/read/solar-yieldcos-proven-concept-or-hype, among others.

Figure 17: Difficulty Trying to Obtain Financing over Past 12 Months



Not surprisingly, about half of the firms who sought financing looked for project finance, which is most typically a combination of debt and equity.

Nearly 60% of developers expect to lay off workers if the ITC is reduced as planned. Again, this significant reduction in employment is likely tied to the fact that project economics for utility-scale solar installations stand to be impacted the greatest by reductions in the ITC. With industry analysts projecting an 80% decline in these installations in 2017 (when the commercial ITC is scheduled to decrease to 10% and some major utilities are expected to have mostly fulfilled their renewable portfolio standard targets), it should come as no surprise that employment in this sector will also be affected dramatically.[64]

Project developers employ a large proportion of women and veterans, but solar workers are less racially and ethnically diverse in this sector than in other solar sectors.

64 SEIA/GTM Research Solar Market Insight Q3 2014

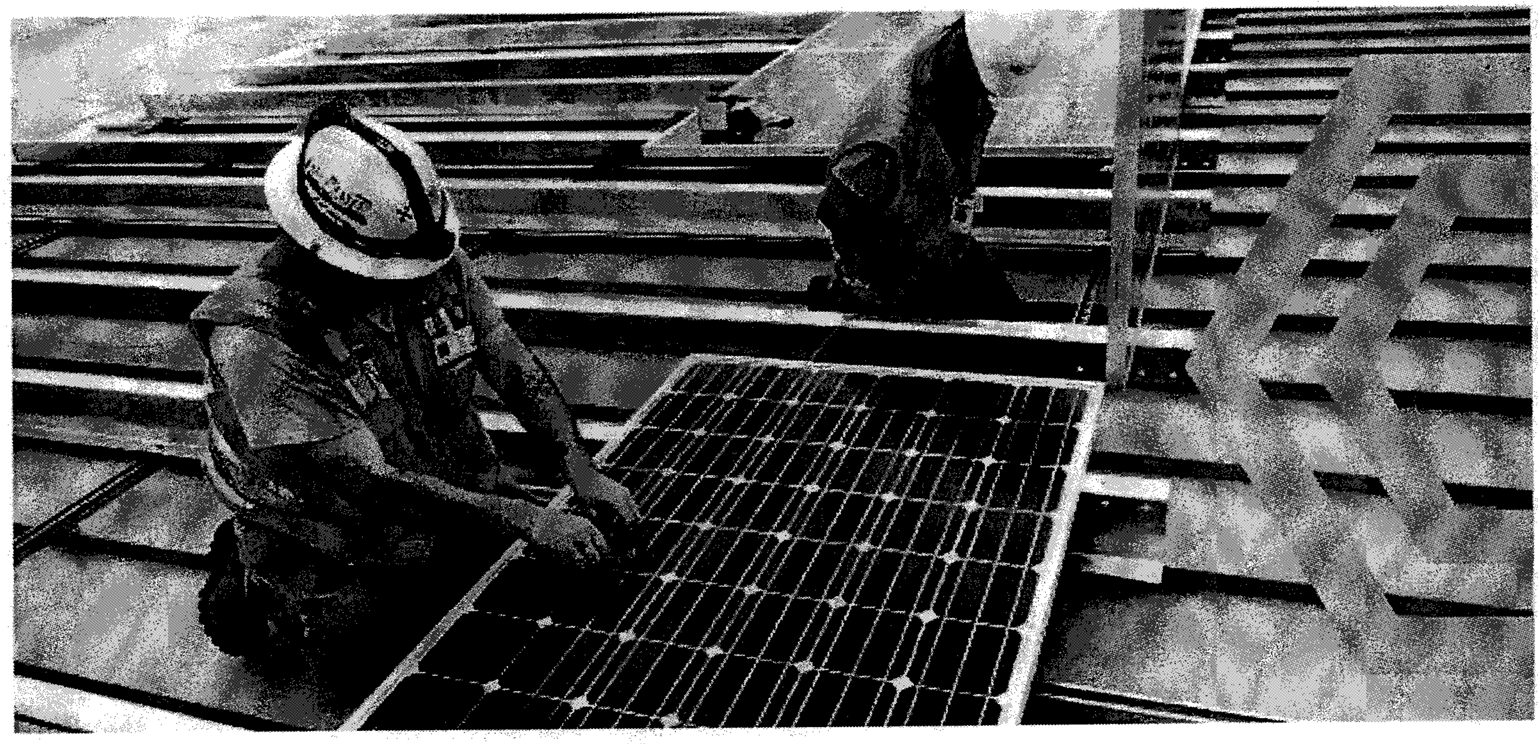


Table 12 shows the recent hires of project developers by demographic group.

Table 12: 2014 Project Developer Solar Worker Demographic Breakdown[65]

	Employment	% of Project Development Employment	% of U.S. Workforce	% of Utility System Construction Industry
Women	3,657	24.2%	49.6%	11.2%
Veterans of the U.S. Armed Forces	1,932	12.8%	7.0%	n/a
Latino or Hispanic	1,283	8.5%	13.0%	18.0%
Asian or Pacific Islanders	1,130	7.5%	5.2%	1.4%
African-American	699	4.6%	11.7%	5.8%

65 See EMSI Class of Worker 2014.3; The Employment Situation – November 2014, Bureau of Labor Statistics, available at: http://www.bls.gov/news.release/pdf/empsit.pdf.

George Ashton

Occupation: CFO
Company: Sol Systems
Years at Occupation: 6
Location: Washington, DC

As an executive at Sol Systems, Mr. Ashton performs business development and corporate strategies, operations, and colleague training. He co-founded Sol Systems in 2008 after receiving his MBA; Sol Systems is Mr. Ashton's first foray in the solar energy industry.

When asked about what he likes best about his job, he noted that solar is a "great industry, and there are great folks at the company. There is a common sense of purpose and a common drive to succeed in the right ways." Mr. Ashton's advice for others looking to enter the solar field is that they should seek out as many informational interviews as needed to "figure out where you want to be." He added that new entrants to the solar field "should be willing to think creatively and work hard"

Other

Entities such as research and development firms, nonprofits, government agencies, and academic research centers play a small but important role in the U.S. solar industry.

Big News in the "Other" Sector:

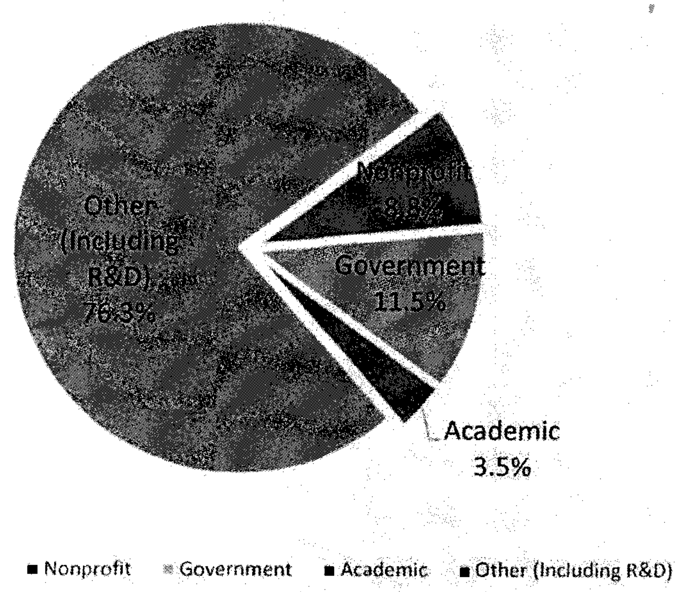
- **The U.S. solar industry has continued to expand its efforts to create and employ new forms of project financing.** 2014 saw the creation of a number of "yieldco" structures designed to provide investors with an attractive investment opportunity and companies with a means of financing new projects with cheaper capital. Based on the success of the half dozen or so yieldcos created to date, some analysts are predicting the creation of several more in the coming year.[66] The last year has seen companies take further steps toward large scale securitization[67] of solar assets and the first-ever registered offering of "solar bonds" to public investors.[68] In addition, more lending institutions – whether in partnership with solar companies or independently[69] – have been offering new financial products for solar or have increased the amount they are willing to finance through existing financing options (including home equity lines of credit, which have become an option for more homeowners since the housing market has improved).

- **Early-stage investment in pre-commercial firms rose sharply through 2011, but has since fallen to pre-2007 levels.** Private investment at the early stages (Seed, Series A, and Series B) has dropped most significantly.[70] While there are many potential reasons for this decline, such as high-profile bankruptcies and declines in traditional PV, the need for innovation in the long-term is unchanged.

About 5.2% of the solar workforce, or 8,989 workers, are engaged in other solar activities such as research and development, nonprofit advocacy, academic research, or government oversight.

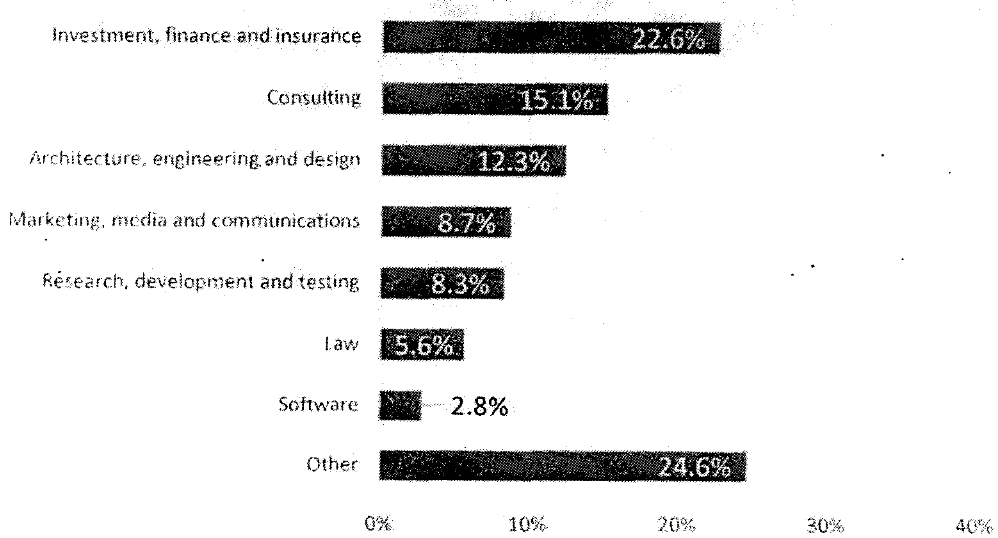
66 See "Deutsche Bank expects more publicly traded PV-based yield cos" from PVTech at http://www.pv-tech.org/news/deutsche_bank_expects_more_publicly_traded_pv_based_yield_cos
67 See "Debt Financing Tied to Solar Project Pools Will Spur Growth for Residential Developers" from GreenTech Media at http://www.greentechmedia.com/articles/read/Debt-Financing-Tied-to-Solar-Project-Pools-Will-Spur-Growth-For-Residential
68 See "SolarCity Starts Selling 'Solar Bonds' Online to Public Investors" from GreenTech Media at http://www.greentechmedia.com/articles/read/SolarCity-Innovates-Again-With-a-Public-Offering-of-Solar-Bonds
69 See "Admirals Bank and SunPower Partnership Announces $200 Million Loan Funding Program for Residential Solar Systems" from Admirals Bank at http://www.admiralsbank.com/news/press-releases/admirals-bank-and-sunpower-finance-home-solar-systems
70 Cleantech Group's i3 data.

Figure 18: Percentage Breakdown of "Other" Employment



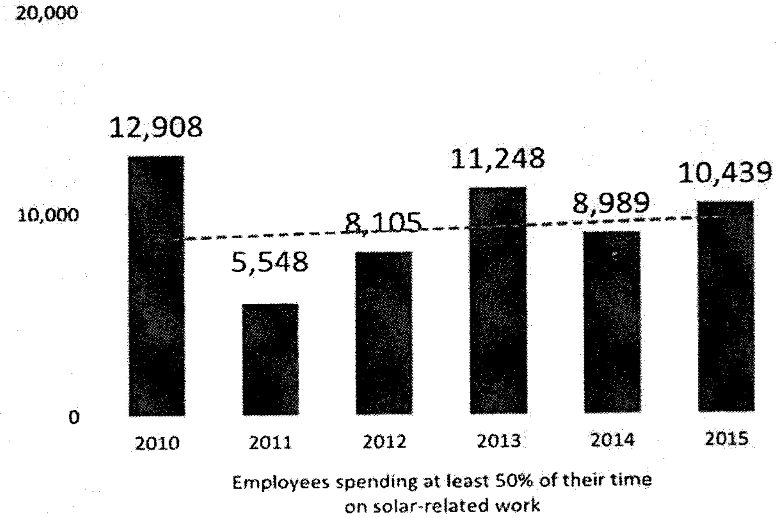
The "other" sector declined from November 2013 to November 2014 and has declined by more than 30% since September 2010.

Figure 19: Percentage Breakdown of "All Other" Establishments



*In the chart above, "other" includes any activities that had two or fewer responses in the survey.

Figure 20: "Other" Employment Growth from September 2010 to November 2015 (Projected)



Some of this contraction can be attributed to declines in research and development (evident from declining public and private research investments), while a large portion is due to the maturation of the industry. As more "pure play" solar firms proliferate, many of the ancillary support functions previously provided by "other" firms are now being brought in-house.

Two areas that seem to be growing are project and bank financing and international consulting. This may be fueling the sector's anticipated 16% growth over the coming year.

Women account for more than 40% of solar workers among these "other" solar firms. Veterans also make up a greater share of employment in the "other" category as compared to the overall industry, though Latino, Asian and Pacific Islander, and African-American employment is lower than average, as seen in Table 13 below.

Table 13: 2014 "Other" Solar Worker Demographic Breakdown[71]

	Employment	% of Other Employment	% of U.S. Workforce
Women	3,928	43.7%	49.6%
Veterans of the U.S. Armed Forces	966	10.7%	7.0%
Latino or Hispanic	848	9.4%	13.0%
Asian or Pacific Islanders	622	6.9%	5.2%
African-American	477	5.3%	11.7%

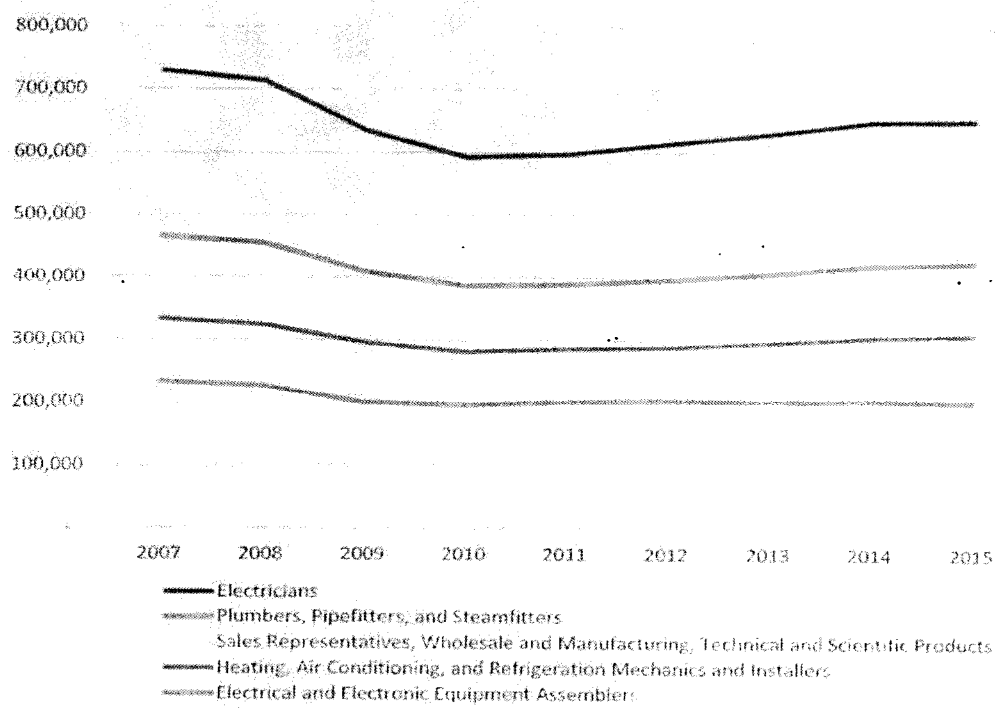
71 See EMSI Class of Worker 2014.3; The Employment Situation – November 2014, Bureau of Labor Statistics, available at: http://www.bls.gov/news.release/pdf/empsit.pdf.

Workforce Development

The solar industry has added tens of thousands of jobs over the past five years in a variety of occupational categories including engineering, sales, production, and, most abundantly, the construction trades. This growth has occurred during a time of slow economic recovery in the United States, as other industries have struggled to add jobs. With historically high unemployment rates – particularly in the trades – following the economic recession, solar employers had little difficulty finding qualified applicants with abundant related experience in their fields. In fact, 2010 (the year of the first *National Solar Jobs Census*) was the worst year for employment across five related, traditional occupations: electricians, plumbers, HVAC technicians, electrical equipment assemblers, and technical and scientific product sales representatives.

Electricians, which are particularly valuable to solar installation firms, were hit hard. Between 2007 and 2010, almost 19% of electricians (about 136,000) across the United States lost their jobs. Since 2010, about 40,000 of these jobs have been recovered, but there are still 93,000 fewer electrician jobs today than there were in 2007.

Figure 20: Comparison Occupational Employment 2007-2015



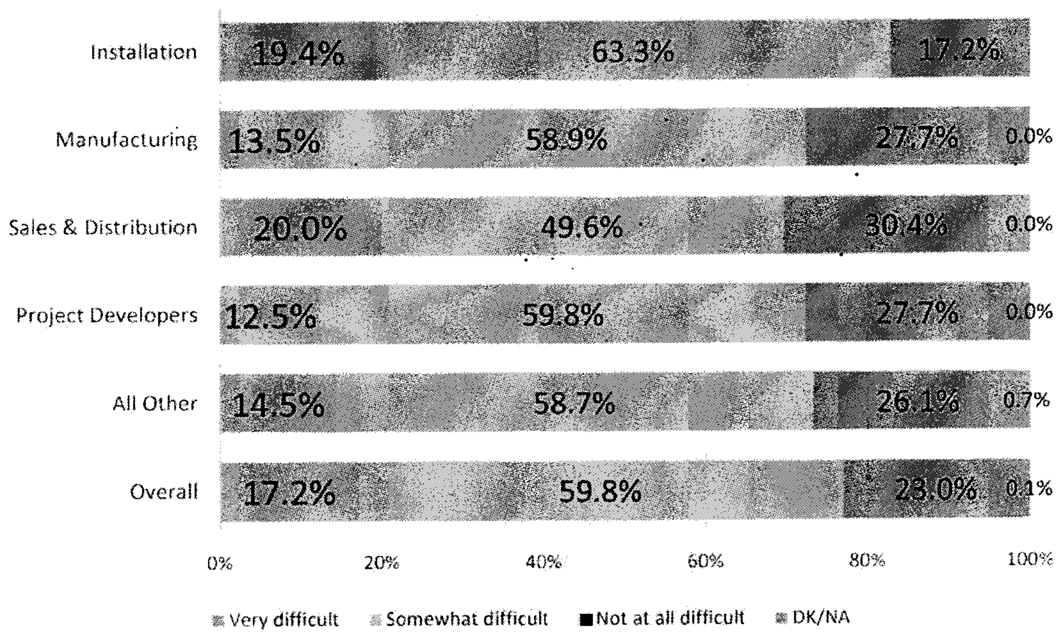
These statistics illustrate the key role that the solar industry has played in providing employment for many of the hardest hit occupations and a road to recovery for thousands who were out of work. At the same time, the surplus of experienced workers made for a very competitive solar labor market for some job seekers. Inexperienced trainees, for example, have faced very long odds when competing against applicants with licensure, experience, and a solid track record in related industries.

The tide is slowly turning and much of the slack of the construction-trade and broader solar labor market is being quickly absorbed. **As this trend accelerates, there will be fewer experienced candidates available, and employers will be more likely to turn to education and training (both on-the-job and with outside training providers) to meet their needs for a skilled workforce.** Two key metrics for understanding the supply and demand of the workforce are employers' reported difficulties in finding qualified workers and the wages paid to employees in different industry sectors, both of which are reviewed in detail in this section.

Difficulty Hiring

One of the most important metrics for understanding potential gaps and surpluses in the labor market is employers' reported difficulty in hiring. Overall, solar employers report increasing difficulty in finding qualified workers as compared to previous *Census* reports, though it is not yet to a critical level. Nearly one in four solar employers overall report that they have no difficulty finding the employees they need, and about one in six report that it is very difficult to find qualified employees.

Figure 21: Difficulty finding solar employees over the last 12 months



Difficulty finding qualified employees was highest among solar installation firms, with 83% of employers reporting at least some difficulty (63% somewhat difficult and 19% very difficult). Of the installation firms having difficulty, one-third reported that it is most difficult to find electricians with solar expertise (33%), solar installers (29%), finance staff (19%), and software engineers (18%). The most frequently cited reasons for the difficulty are lack of appropriate skills (24%), competition with other firms (21%), and general lack of qualifications in the workforce (21%).

Employers in the Pacific Region note the greatest difficulty finding workers, followed closely by the Northeast and Southeast.

Table 14: Difficulty finding solar employees by region.

	Overall	Northwest	Pacific	Southwest	Midwest	Southeast	Mid-Atlantic	Northeast
Very difficult	**17.2%**	20.5%	16.1%	14.7%	20.0%	29.4%	10.4%	15.1%
Somewhat difficult	**59.8%**	51.3%	64.2%	58.3%	50.5%	48.0%	65.2%	65.1%
Not at all difficult	**23.0%**	28.2%	19.7%	26.9%	29.5%	22.5%	24.3%	19.7%

Manufacturers and project developers note great difficulty finding engineers (non-electrical), while sales firms most frequently cite issues with hiring salespeople. Lack of relevant skills and experience are the most frequently cited reasons for these difficulties.

Wages

In addition to the trends for employer-reported hiring difficulties, changes in wages paid offer insight into supply and demand as wages rise in response to the scarcity of talent. Wages for installers have risen slightly since 2013, with the mean rising $0.38 per hour (a 1.6% increase). At the same time, wages for production/assembly workers fell $0.63, a decline of 3.5%.

For the first time, this year's *Census* survey asked firms about their average pay for solar designers and salespeople. Solar designers earn $30-40 per hour on average, while salespeople have a wider range of pay, from about $30 to more than $60 per hour. From a sector standpoint, developers and utilities pay the highest wages to sales staff, followed by manufacturers, sales firms, and installers.

Table 15: 2014 Average Hourly Wage by Solar Sector

	Installer	Salesperson[1]	Production/ Assembly	Designer
Overall	$24.01	$36.25	$17.60	$36.16
Installation	$24.01	$34.50	n/a	$32.25
Manufacturing	n/a	$44.05	$17.60	$31.63
Sales and Distribution	n/a	$36.15	n/a	$30.35
Developers/Utilities	n/a	$53.15	n/a	$40.78

The median wage for installers at utility-scale firms is approximately 20% higher than at firms working on commercial or residential scale projects. There are several other key differences, noted in the table below.

Table 16: 2014 Difficulty Hiring, Use of On-the-Job Training, and Views on the Importance of Credentials by Solar Installation Sectors

	Difficulty hiring %very/some/not	OJT %yes/no	Credentials %yes/no
Overall	19/63/17	89/11	75/25
Residential	18/68/14	90/10	81/19
Commercial	20/60/20	89/11	75/25
Utility-Scale	14/68/18	81/19	36/64

Workforce Profiles

Solar employers were asked to provide information regarding the background of their hires over the last 12 months in order to determine how many had previous experience related to the position or college degrees. More than two-thirds of all solar workers hired over the last 12 months had previous experience, but only 27.3% have at least an associate's degree. This is quite low when compared to other fast-growing industries.

Previous experience is most important for developers and installers, and less so for manufacturers and salespeople. These groups differ dramatically in terms of education requirements, however, as more than 70% of new hires at developer/utilities had a bachelor's degree, compared to only 10.9% of those hired by installers.

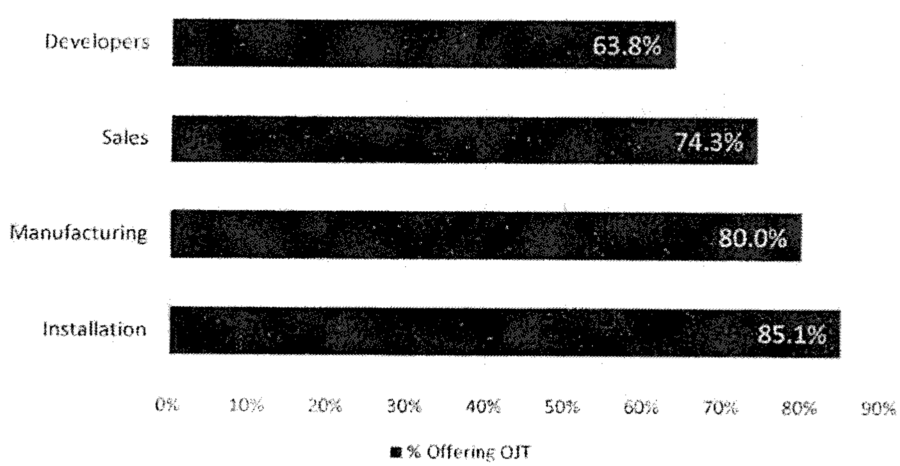
Table 17: 2014 New Solar Employees Experience and Education Requirements by Sector

Sector	% with Experience	% with Bachelor's or Higher	% with Associate's or credential but not BA
Overall	67.3	21.4	5.9
Installation	68.4	10.9	2.6
Manufacturing	59.9	40.7	17.3
Sales	45.5	43.9	20.4
Developers	85.5	70.3	12.9

Employers were also asked about the value they place on technical credentials, such as the North American Board of Certified Energy Practitioners (NABCEP) and Underwriters Laboratories (UL), as well as training program accreditation from the Interstate Renewable Energy Council (IREC). Credentials have more value to installers and developers, while manufacturers and sales firms place less importance on them during the hiring process. Some employers remain somewhat skeptical about the importance of such credentials, but over 50% of respondents indicated that they think credentials either "definitely" or "probably" help them find higher-quality employees. Both credentialing bodies and the industry should continue to work together to recognize and demonstrate the value of credentials in hiring practices and workforce training programs.

About three quarters of all solar firms offer formal on-the-job training to supplement the skills of their workers.

Figure 22: Use of On-the-Job Training by Solar Sector



The infographic (on the next page) illustrates the typical solar photovoltaic installer career pathway. The information is drawn from Monster Government Solutions and PayScale data and reviews the most frequently reported occupation, wage, education, and skill data for photovoltaic installers. The data also include the most prevalently held occupations prior to becoming a solar installer (within five years), as well as the most typical five year progressions.

A distinct career progression has yet to form for photovoltaic installers. A large number of PV installers worked previously in higher wage positions in the past five years. Given the high unemployment in the construction industry five years ago, it is likely that the solar industry has helped to reemploy laid-off tradespeople such as roofers, construction managers and foremen, and other laborers. The data clearly indicate that, at least in the short-term, experience in the construction industry is a must for solar installers.

PV Installer Career Pathway

Jobs 5 Years Later

Solar Panel Installer	Construction Manager	Construction Foreman	Roofer	Solar Energy/ Power Engineer
$41,300	$67,900	$45,200	$32,800	$72,600
Typical Degree High School Education	**Typical Degree** Bachelor's Degree	**Typical Degree** High School Education	**Typical Degree** Less than High School	**Typical Degree** Bachelor's Degree
Certificates - NABCEP Entry Level Certificate of Knowledge - NABCEP Solar PV Installer Certification	**Certificates** - OSHA 30 Hour - OSHA 10 Hour - LEED Accredited Professional (LEED AP) - Project Management Certificate - Occupational Safety & Health Administration - Project Management Professional (PMP)	**Certificates** - Occupational Safety and Health Administration (OSHA) - OSHA Forklift Operator Certification - OSHA 30 Hour - Commercial Driver License (CDL) - Class A	**Certificates** - OSHA Forklift Operator Certification - OSHA 10 Hour - Commercial Driver License (CDL) - Class B	**Certificates** - NABCEP Solar PV Installer Certification - Certified Professional Engineer (PE)

Solar Panel Installer

$33,200

Typical Degree
High School Education

Certificates
NABCEP Entry Level Certificate of Knowledge
NABCEP Solar PV Installer Certification

Skills
Solar Energy/Solar Power
Electronic Troubleshooting

Jobs 5 Years Before

Solar Panel Installer	Construction Laborer	Electrician	Roofer	Construction Foreman	Construction Manager
$33,200	$27,000	$33,900	$28,400	$41,000	$51,600
Typical Degree High School Education	**Typical Degree** High School Education	**Typical Degree** Certificate	**Typical Degree** Less than High School	**Typical Degree** High School Education	**Typical Degree** Bachelor's Degree
Certificates - NABCEP Entry Level Certificate of Knowledge - NABCEP Solar PV Installer Certification	**Certificates** - OSHA 10 Hour - OSHA Forklift Operator Certification - Commercial Driver License (CDL)-Class A - Occupational Safety and Health Administration (OSHA)	**Certificates** - General Journeyman Electrician - Master Electrician - Apprentice Electrician - Journeyman's Certificate in Non-Destructive testing	**Certificates** - OSHA Forklift Operator Certification - OSHA 10 Hour - Commercial Driver License (CDL) - Class B	**Certificates** - Occupational Safety and Health Administration (OSHA) - OSHA Forklift Operator Certification - OSHA 30 hour - Commercial Driver License (CDL) - Class A	**Certificates** - OSHA 30 hour - OSHA 10 Hour - LEED Accredited Professional (LEED AP) - Project Management Certificate - Occupational Safety & Health Administration - Project Management Professional (PMP)

Conclusions & Recommendations

The U.S. solar industry continues on its well-documented positive growth trajectory, posting 22% employment growth from November 2013 to November 2014, and 86% job growth since September 2010. Firms across the entire value chain of solar goods and services have noted significant employment gains, though none more so than the installation sector, driven by the historic increases in installed solar capacity across the country. Given the relationship between installed capacity and employment growth, the next couple of years – when annual installed capacity is expected to be 18% (2015) and 69% (2016) greater than that coming on-line in 2014 – will surely see this upward growth trend continue in the short term.

Though employers remain optimistic about near-term growth – anticipating 20.9% job growth when employment in the national economy is expected to increase by only 1% - results and trends from the Census series reveal challenges and opportunities for future growth.

The greatest looming threat for continued employment growth is the expiration of the 30% federal Investment Tax Credit (ITC) at the end of 2016. With this policy in place, approximately half of all employers have reported job growth in each of the last several years, with only a few (typically 2-3% of all firms) experiencing declines in employment. In Census 2014, only less than 40% of solar employers stated reductions in the ITC would not impact their workforce. Installation and project development firms – which together employ nearly two-thirds of the entire solar workforce – stand to be affected the greatest, with 62% of installation firms and 60% of project developers expecting to shed workers once the current ITC expires.

Even as employment continues to grow in the next two years, improvements in labor efficiency (the amount of capacity installed by each worker) may start reducing the rate at which new solar workers are added. In 2012, the U.S. solar industry required about 19.5 workers per installed megawatt. This number dropped sharply in 2013 to 16 jobs per megawatt, and continued to decline by about a half of a worker to 15.5.

On the bright side, solar jobs are becoming increasingly available to workers of differing backgrounds. Overall, the solar industry places greater emphasis on previous related experience (which two-thirds of new hires in 2014 possessed) than on education (with only 21% of new workers holding a bachelor's degree or higher and less than 6% having an associate's degree or credential). Though certain sectors are more likely to require employees with higher education (such as project development), firms in every sector still place greater weight on experience over education. In the installation sector, nearly 70% of new hires had some form of previous experience, whereas less than 14% had some form of higher education, suggesting these jobs – which constitute the bulk of total solar employment – may be filled by workers with little or no formal higher education.

The industry is also becoming increasingly diverse in terms of worker gender, racial/ethnic background, and veteran status. In 2014, each of these demographics represented a larger proportion of the solar workforce than in the previous year, indicating more members of these groups are seeking employment in the solar industry, and that these jobs are becoming more available to them.

Analysis of industry trends across the entire Census series indicates that the observed solar employment growth has not come without some growing pains. As the national employment situation continues to improve and electricians, roofers, and workers in other trades related to solar find work in their respective industries, this pool of qualified workers will become less available to the solar industry. This phenomenon may already be impacting industry growth. Over three-quarters of solar employers experience at least some difficulty in finding the employees they seek, with about one in six reporting it has been very difficult to find qualified workers.

An increase in demand for qualified workers relative to supply can be expected to compel employers to offer higher wages in order to attract the talent they seek, as seen in the 1.6% increase in average wages for installers (the sector reporting the greatest difficulty in finding new workers) over the previous year. While welcome news for solar workers, rising wages could also drive up labor installation costs, which constitute the single largest category of solar soft costs.

One obvious way to limit the impact of rising wages is by increasing the supply of qualified workers through education, training, and apprenticeship. Given the stark differences among employers in their reporting regarding the use of on-the-job training, third-party training, and credentials, it is becoming clearer that the solar industry is one that is searching for a consistent framework for training and evaluating talent. This may become a problem quickly as the growth of the industry accelerates.

Based on these conclusions, we make the following recommendations:

Promote stability in federal policy. The U.S. solar industry continues to demonstrate its strength across most of the value chain. Although this may change as labor efficiencies improve, there is currently a very strong link between solar adoption and job creation. As has been the case with every domestic energy industry in our nation's history, the solar industry continues to benefit from policies and incentives that accelerate growth and help bring the industry to scale, particularly those policies with the multiyear certainty needed to leverage project financing. In Census 2012, employers cited federal tax incentives for solar investment as one of the top three drivers of industry and employment growth. Similarly in Census 2014, three out four employers reported that the ITC had helped their business. Given the importance of such policies to the deployment of solar technology, it is not unreasonable to expect that the continuation of demand-side incentives will continue to have a strong, positive impact on job creation and competitiveness. Given the incredi ble history of job creation by the solar industry over the last several years, there seems little reason to change the status quo at the federal level.

Increase access to financing. Approximately two-thirds of firms in each of the installation, manufacturing, sales and distribution, and project development sectors experienced difficulty in obtaining financing. These difficulties are likely a reflection of the limited financing options available to solar companies, forcing them to continue to pursue existing financing mechanisms with higher costs of capital than would be available with some alternatives. For installation and project development firms, an increased ability to leverage promising financing arrangements such as Master Limited Partnerships, Solar Real Estate Investment Trusts, yieldcos, and securitization of solar assets may help alleviate this problem.

While access to capital is important for solar companies, it is also key for consumers. Increasing the number and availability of solar financing options for home and business owners will help further drive solar adoption, in turn leading to increased solar employment. Though the solar industry has continually proven its ability to develop and offer innovative financing solutions, there remain many key un(der)addressed markets. As one example, consider that the solar boom has not spread uniformly across the spectrum of household incomes because, unlike many more affluent families, lower-income households face a number of inherent barriers to going solar. These barriers include being less likely to own their roof, having limited access to affordable financing, being more likely to live in buildings with deferred maintenance, and being unable to realize the financial benefits of fuel-free electricity because their utility bills are partially or fully subsidized. Finding ways to serve the low-income markets is essential for the solar industry to expand beyond its current market of relatively affluent early technology adopters. At the same time, many of the more affluent households in the U.S. are aging, and less likely to remain in their homes for the number of years that may be required for full-payback of their systems. Programs that allow loans to follow the home rather than the owner (such as property assessed clean energy, or PACE) could unlock this untapped potential.

Continue to develop bridge programs for veterans. Veterans of the U.S. Armed Forces continue to represent a larger proportion of the solar workforce as compared to the overall economy. This strong representation may be driven in part by a high degree of skill transferability between military occupations and solar jobs, which has been supported by interviews with select solar employers conducted for the 2014 report Veterans in Solar: Securing America's Energy Future, co-authored by The Solar Foundation and the Truman National Security Project. Despite this potential skills overlap, some groups of veterans – especially those in the 18 to 24 age group – continue to grapple with high unemployment. A deeper understanding of the skills developed in military occupations – especially non-technical workplace skills that are in high demand in the solar industry – can help these former service members transition into jobs in the solar industry. Workforce training providers are aware of this opportunity but need greater support to further develop the solar industry as a strong employer of military veterans.

In addition, workforce training providers and solar employers should become more familiar with the Post-9/11 GI Bill and the education and training opportunities it provides.

Online portals such as the "Veteran's Employment Center" (https://www.ebenefits.va.gov/ebenefits/jobs), provided by the Department of Veterans Affairs and the Department of Defense, as well as "America's Job Centers" run by the Department of Labor (http://www.servicelocator.org/onestopcenters.asp), can help employers identify and connect with veterans seeking employment. Finally, The Solar Foundation encourages industry to participate in the White House's Joining Forces initiative and publically commit to hiring increasing numbers of veterans.

Support worker evaluation efforts and the development of comprehensive assessment tools. As the supply and demand balance for qualified workers continues to shift, the industry will have a growing need for workers able to meet their technical, educational, and soft skill requirements. As documented in this report, solar employers most frequently focus on a candidate's experience when determining whether they would make a good fit. An overreliance on experience can cause companies to overlook otherwise qualified – though inexperienced – candidates, and may cause them to face even greater difficulty in recruiting talent in the face of contracting pools of experienced workers. The development of a comprehensive set of assessment tools that evaluate all aspects of a candidate's suitability for employment (not just technical skills) can be of great value in overcoming or avoiding these issues.

Support early stage R&D. Due in part to continued declines in the price of traditional solar goods, investment in early-stage research and development is down sharply. Technical innovation is critical for the long-term competitiveness of the industry, yet both public and private dollars to support it are significantly lower. Given the low returns on R&D investments expected in the private sector, the gap in research funding from private sources will likely persist, suggesting an increased need for public sector support of early stage research on new and more efficient solar technologies and applications.

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APPENDIX: Census Methodology and Data Sources

The *National Solar Jobs Census* methodology is the most closely aligned with the Bureau of Labor Statistics' methodology for its Quarterly Census of Employment and Wages (QCEW) and Current Employment Statistics (CES). Like BLS, this study uses survey questionnaires and employer- reported data, though ours are administered by phone and email, as opposed to mail.

Also like BLS, we develop a hierarchy of various categories that represent solar value chain activities (within their broader NAICS framework), develop representative sample frames, and use statistical analysis and extrapolation in a very similar manner to BLS. We also constrain our universe of establishments by relying on the most recent data from the BLS or the state departments of labor, depending on which is collected most recently. We believe that the categories that we have developed could be readily adopted by BLS should it choose to begin to quantify solar employment in its QCEW and CES series.

The results from the Census are based on rigorous survey efforts that include 66,986 telephone calls and over 25,655 emails to known and potential solar establishments across the United States, resulting in a margin of error +/- 2.03% at a 95% confidence interval. Unlike economic impact models that generate employment estimates based on economic data or jobs-per-megawatt (or jobs-per-dollar) assumptions, the National Solar Jobs Census series provides statistically valid and current data gathered from actual employers.

The survey was administered to a known universe of solar employers that includes 15,552 establishments and is derived from SEIA's National Solar Database as well as other public and private sources. Of these establishments, 2,839 provided information about their solar activities (or lack thereof), and 1,634 completed full or substantially completed surveys. The margin of error for the known universe is than +/-2.26%.

The survey was also administered to a stratified, clustered, random sampling from various industries that are potentially solar-related (unknown universe) that include a total of 260,824 establishments nationwide. After an extensive cleaning and de-duplication process, a sampling plan was developed that gathered information on the level of solar activity (including none) from 6,230 establishments. Of these, 435 establishments qualified for and completed full surveys. The margin of error for the unknown universe is 1.1%.

The indirect and induced job figures were gathered using averaged figures from EMSI's input output model (see Data Sources, above). The industries selected for installation were electrical contractors and power and communication line construction; for manufacturers, semiconductor equipment manufacturing and other electronic and electrical assembly; for sales and distribution, wholesale trade of electronic appliances and wholesale trade of heating and hot water apparatus; and for project development, heavy civil construction and engineering and power and communication line construction.

The following three-phased methodology describes the survey process used to gather employer information from both self-identified or known solar employers, those establishments that are connected to solar industry associations and can be found on solar employer databases, and unknown solar employers that are found in industry classifications that are more likely to have solar employers. This methodology describes the process that was followed for all of the solar employer surveys except for those completed by utilities in earlier editions of the *Census.*

Phase 1: Develop, classify and analyze a database of self-identified or known solar employer

The first phase created a comprehensive database of all known or self-identified solar employers across the country. This database was developed by SEIA and its partners. The comprehensive database was developed from all of the partners' contact information of employers. Duplicates were identified and removed following a stringent evaluation of firm phone numbers, locations, and firm names.

The database of employers did not include variables that consistently identified which sector (manufacturing, installation, sales and distribution, project development, and other) each employer was involved in, the size of the employer, or whether the employer had a single location or represented multiple locations.

Phase 2: Survey of self-identified or known solar employers.

The second phase of the survey research was a census, using online and telephone surveys of all solar employers from the database developed in phase one. Employers were asked which sector they were involved in (installation, manufacturing, wholesale trade, research & development and other) and based on their response they were forwarded to the appropriate survey instrument. All employers in the database with email information were sent multiple online invitations and for those that did not complete an online survey, they were called up to three times. The employers without email information were called up to five times and asked to participate in the survey by completing a brief phone survey. These results represent the solar employer community that is connected to regional and national solar trade associations.

It is important to note that surveys were completed for each employment location and not necessarily for each firm. So if a solar employer was asked to participate in a survey, s/he would be asked about the employment profile of a given location and not of the entire firm.

Phase 3: A random sampling of employers in industry classifications that are most likely to have unknown solar employers.

The final phase of the survey research was a sampling of employers in specific industries within wholesale trade, manufacturing, and the construction (installation) industries. The survey was completed over the phone and the sample was stratified by industry, region, and firm size (4 or fewer employees or 5 or more employees). These results represent the solar employers that make up the wholesale trade, manufacturing, and construction industry employers within the industry classifications noted below.

It is important to note that the percentage of overlap between the known and unknown universe of solar employers was calculated based on a thorough search of the known firm database to the unknown universe file or establishments that indicated they had already completed a similar survey. The resulting calculation of overlapping establishments was taken out of the total estimate of establishments in the unknown universe of solar employers.

Data for the "other" category does not capture all jobs or establishments in the category. Although some "other" establishments are included in the known universe (see section accounting, legal, finance, and other ancillary establishments spend only a very small portion of their time on solar activities. Thus, full inclusion would lead to inflated employment counts.

This report cites comparison data from the Bureau of Labor Statistics Current Employment Statistics and Economic Modeling Specialists International Class of Worker data for 2014. EMSI is typically selected for instances where self-employed and covered total employment comparisons (such as past and future growth rates) are required. BLS data are used for monthly absolute jobs figures.

EMSI Data Sources and Calculations

Industry Data

In order to capture a complete picture of industry employment, EMSI basically combines covered employment data from Quarterly Census of Employment and Wages (QCEW) produced by the Department of Labor with total employment data in Regional Economic Information System (REIS) published by the Bureau of Economic Analysis (BEA), augmented with County Business Patterns (CBP) and Nonemployer Statistics (NES) published by the U.S. Census Bureau. Projections are based on the latest available EMSI industry data, 15-year past local trends in each industry, growth rates in statewide and (where available) sub-state area industry projections published by individual state agencies, and (in part) growth rates in national projections from the Bureau of Labor Statistics.

This report uses state data from the following agencies: Alabama Department of Industrial Relations; Alaska Department of Labor and Workforce Development; Arizona Department of Commerce, Research Administration; Arkansas Department of Workforce Services; California Labor Market Information Department; Colorado Department of Labor and Employment; Connecticut did not provide us with a data source; Delaware Office of Occupational and Labor Market Information, Delaware Wages 2004; District of Columbia did not provide us with a data source; Florida Agency for Workforce Innovation; Georgia Department of Labor, Workforce Information and Analysis, Occupational Information Services Unit; Hawaii Department of Labor and Industrial Relations, Research and Statistics Office; Idaho Department of Labor; Illinois Department of Employment Security, Employment Projections; Indiana Department of Workforce Development; Iowa Workforce Development; Kansas Department of Labor, Labor Market Information Services, Kansas Wage Survey; Kentucky Office of Employment and Training; Louisiana Department of Labor; Maine did not provide us with a data source; Maryland Department of Labor, Licensing and Regulation, Office of Labor Market Analysis and Information; Massachusetts did not provide us with a data source; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Minnesota Department of Employment and Economic Development; Mississippi Department of Employment Security; Missouri Department of Economic Development; Montana Department of Labor and Industry, Research and Analysis Bureau; Nebraska Workforce Development; Nevada Department of Employment, Training and Rehabilitation, Information Development and Processing Division, Research and Analysis Bureau; New Hampshire Department of Employment Security; New Jersey Department of Labor and Workforce Development; New Mexico Department of Labor, Bureau of Economic Research and Analysis; New York Department of Labor, Division of Research and Statistics; North Carolina Employment Security Commission, Labor Market Information Division; North Dakota Job Service, Labor Market Information Center; Ohio Department of Job and Family.

State Data Sources

Services, Labor Market Information Division; Oklahoma Employment Security Commission; Oregon Employment Department, Oregon Labor Market Information System; Pennsylvania Department of Labor and Industry, Center for Workforce Information and Analysis; Rhode Island did not provide us with a data source; South Carolina Employment Security Commission, Labor Market Information Department; South Dakota Department of Labor, Labor Market Information Division; Tennessee Department of Labor and Workforce Development, Research and Statistics Division; Texas Workforce Commission; Utah Department of Workforce Services; Vermont did not provide us with a data source; Virginia Employment Commission, Economic Information Services; Washington State Employment Security Department, Labor Market and Economic Analysis Branch; West Virginia Bureau of Employment Programs, Research Information & Analysis Division; Wisconsin Department of Workforce Development, Bureau of Workforce Information; Wyoming Department of Employment, Research and Planning.

Input-Output Data

The input-output model in this report is EMSI's gravitational flows multi-regional social account matrix model (MR-SAM). It is based on data from the Census Bureau's Current Population Survey and American Community Survey; as well as the Bureau of Economic Analysis' National Income and Product Accounts, Input-Output Make and Use Tables, and Gross State Product data. In addition, several EMSI in-house data sets are used, as well as data from Oak Ridge National Labs on the cost of transportation between counties.

This report uses data release EMSI Complete Employment 2014.3

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For questions about this report or to explore options for an in-depth solar jobs study for your state/region, please contact Andrea Luecke at The Solar Foundation, aluecke@solarfound.org.

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CHAIRMAN

BOB STUMP
COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **THE ALLIANCE OF SOLAR CHOICE'S NOTICE OF FILING SURREBUTTAL TESTIMONY OF MARK FULMER**

The Alliance for Solar Choice hereby provides notice of filing the Surrebuttal Testimony of Mark Fulmer in the above-referenced matter.

Respectfully submitted this 23rd day of February, 2016.

Arizona Corporation Commission
DOCKETED
FEB 23 2016
DOCKETED BY

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **THE ALLIANCE OF SOLAR CHOICE'S NOTICE OF FILING SURREBUTTAL TESTIMONY OF MARK FULMER**

The Alliance for Solar Choice hereby provides notice of filing the Surrebuttal Testimony of Mark Fulmer in the above-referenced matter.

Respectfully submitted this 23rd day of February, 2016.

Court S. Rich
Rose Law Group pc
Attorney for TASC

Original and 13 copies filed on
this 12nd day of February, 2016 with:

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Before the

Arizona Corporation Commission

In the Matter of the Application of	)	
UNS Electric, Inc. for the	)	
Establishment of Just and Reasonable	)	
Rates and Charges Designed to	)	
Realize a Reasonable Rate of Return	)	**Docket No. E-04204A-15-0142**
On the Fair Value of the Properties	)	
Of UNS Electric, Inc. Devoted to It's	)	
Operations Throughout the State of	)	
Arizona and for Related Approvals	)	

Testimony of

Mark Fulmer
For The Alliance for Solar Choice

February 23, 2016

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I. Introduction and Summary

Q: Please state your name.

A: I am Mark Fulmer.

Q: Did you provide direct testimonies in this proceeding on November 6, 2015 and December 9, 2016 on behalf of The Alliance for Solar Choice (TASC)?

A: Yes.

Q: What is the purpose of this surrebuttal testimony?

A: I respond to a number of issues raised by witnesses for Staff, Arizona Public Service (APS) and RUCO in their December 9 testimonies, as well as UNSE witnesses Tilghman, Dukes, and Overcast. My silence on any particular issue should not be construed as agreement or assent.

Q: Did UNSE make a major change in its proposal with respect to residential rates?

A: Yes. It is now proposing that a three-part rate with time-of-use (TOU) periods be applied to all residential and small commercial customers.[1] This differs from its initial proposal of requiring three-part rates only for residential and small commercial customers with new distributed generation (DG) systems, and no mandatory TOU.

Q: Please summarize your conclusions.

A: My main conclusion is that the UNSE proposed rates and policies would not provide an

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[1] Rebuttal Testimony of David G. Hutchens at 2.

opportunity for residential customers to make cost-effective investments in solar DG. For purchased systems, the payback periods would be measured in decades rather than years, and for systems that are leased, positive cash flow would not occur.

My other conclusions are:

1. There is no foundation for UNSE to impose a mandatory three-part TOU rate on residential customers. There has been only a smattering of opt-in pilot programs testing residential customer understanding of and response to demand charges and to my knowledge no utility has yet implemented mandatory residential TOU. More first-hand knowledge is needed.
2. UNSE and Staff greatly understate the difficulty customers will have understanding and responding to demand charges. Even the educational materials of the only utility with a mandatory residential demand charge identified in the proceeding offered suggestions on how to respond to the demand charges that were so generic so as to be equally applicable to any time-of-use tariff.
3. A number of partics rely heavily on the ratemaking principles of James Bonbright. As aptly stated by APS witness Dr. Faruqui, "each of Professor Bonbright's principles should be read in conjunction with the others." However, UNSE and Staff have not heeded this advice, and as such, the Commission must be cautious when considering these arguments in the context of setting a residential rate.
4. The recent examples of utility regulators' rulings on DG in other states raised by UNSE are not applicable here, and in the case of Nevada, actually provide

a cautionary tale of how not to reform net energy metering.

5. I calculate that the impact of UNSE's and RUCO's proposals will be as detrimental to existing and new solar DG customers as the final rates approved in Nevada.
6. Using data from UNSE's 2014 Integrated Resource Plan (IRP), I calculate the levelized value of solar DG to UNSE to be on the order of 10¢-14¢/kWh. This is relatively close to UNSE's average residential rate, indicating that in the long run, full-service customers would be held neutral and, in fact, could even receive a net benefit by continuing current net metering policies.

II. A Three-Part TOU Rate Is Not Ready for Prime Time

Q: What does this portion of your testimony address?

A: In this section I discuss the reasons why it inappropriate to for UNSE to introduce a mandatory three-part rate, particularly one with TOU energy charges. In doing so, I rebut other parties' witnesses who argue otherwise.

Q: Throughout your testimonies in this proceeding you have been very skeptical of demand charges for residential customers, be they full-service or those using DG. Are you alone in this skepticism?

A: No. I note that the Regulatory Assistance Project recently issued a paper urging "great caution" in designing residential demand charges.[2] The paper confirms many of the concerns that I raise, as well as others such as impact on apartment dwellers, disregard of

[2] Lazar, Jim, November 2015. "Use Great Caution in Design of Residential Demand Charges," Montpelier: Regulatory Assistance Project. Included as Attachment A. The Regulatory Assistance Project is a nonprofit that "advises public officials on regulatory and competitive utility policies."

diversity patterns and mis-allocation of costs into demand charges.[3]

A. There Is Little To No Experience With Residential Demand Charges On This Scale, Let Alone With Mandatory TOU

Q: All the examples of utilities with residential three-part rates provided in Mr. Tilghman's opening testimony were voluntary: the customer had to choose to be on the rate. Have any witnesses addressed the prevalence—or even presence—of residential tariffs with mandatory demand charges?

A: UNSE witness Dr. Overcast was able to provide one single example of a utility with mandatory residential demand charges: Butler Rural Electric Cooperative (Butler REC) in El Dorado, Kansas.[4]

Q: Do any other witnesses provide examples of mandatory or default three-part residential rates?

A: No. Arizona Public Service (APS) witness Dr. Faruqui provides testimony suggesting that residential customers could respond to demand charges. He states:

> More than 40 pilot studies and full-scale rate deployments involving over 200 rate offerings over roughly the past dozen years have found that customers respond to new price signals by changing their energy consumption pattern.[5]

However, <u>none</u> of the over 40 pilot studies or 200 rate offerings included rates with demand charges. They were solely time of use rates, peak time rebates, and critical peak pricing rates.

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[3] *Ibid.*
[4] Overcast at 35.
[5] Faruqui at 14.

Q: Did Dr. Faruqui cite any academic studies explicitly exploring residential demand charges?

A: Yes. However, with the exception of one study from 2009, all of the studies were at least 30 years old.[6] The one more recent study is for an opt-in program in a town in Norway. Given that the participants in the Norwegian study were self-selected, coupled with the cultural and climatic differences between Norway and Arizona, I cannot recommend the Arizona Corporation Commission (ACC) rely upon this study as a justification for a three-part rate for UNSE.

Q: Do any other witnesses provide examples of mandatory TOU residential rates?

A. No. To my knowledge there are no utilities in the U.S. that currently employ mandatory TOU rates for all residential customers. California is set to move all residential customers to *default* TOU rates starting in 2019, but *default* TOU is very different than *mandatory* TOU. Default TOU rates allow all residential customers to maintain the flexibility to choose a rate design that is right for them, while mandatory TOU rates leave customers with no options if they find that they are unable to adapt. While the California Public Utilities Commission did recently vote to move only all new DG customers onto mandatory TOU rates starting likely in 2017, this decision was in response to a much higher penetration of DG customers than exists in UNSE's territory. Mandatory TOU for DG customers remains an uncommon rate design that is typically only explored in areas with very high DG penetration.

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[6] Faruqui at 15.

Q: What considerations are being made by California utilities in the transition to default residential TOU?

A. The transition to residential default TOU is not being taken lightly. The California PUC has ordered the utilities to implement extensive piloting to determine how ratepayers will respond to TOU rates and to ensure that such a transition is not unduly harmful, particularly to vulnerable rate classes such as elderly or low-income. To ensure successful implementation, these pilots will collect data on several differ rate TOU rate designs over the course of 15 months from more than 50,000 participants.[7]

Q: Has UNSE proposed any pilot programs to explore the impact of mandatory TOU rates or demand charges?

A. No. UNSE has not proposed to do any piloting for these extreme rate designs either before or after implementation. In my opinion, adoption of these rates without thorough testing is simply experimenting on ratepayers unnecessarily. With such untested rate design, the outcomes could be severe. Furthermore, both Staff and UNSE suggest that demand charges be implemented after providing the customer with only three months of historical usage data.[8] Given the highly varied seasonal climates in Arizona, this is clearly insufficient. Usage data from March, April, and May are not sufficient for a customer to understand or manage their demand and TOU energy consumption during the following summer and winter months. If UNSE is authorized to implement such drastically different rate design, it should provide customers with at least a full year of usage data prior to implementation.

[7] Statewide TOU Pilot Design Final Report, p. 99.
[8] Solganick at 31; Dukes at 9.

B. A Three-Part Rate Cannot Currently Encourage Innovation

Q: A number of witnesses suggest that a three-part residential rate would encourage innovation, prompting customers to react to the demand charge.[9] In his rebuttal testimony, Mr. Tilghman provides the examples of battery storage and fuel cells.[10] Are these innovations costly?

A: Yes. While demand charges would in theory create a market for demand-reducing technologies, these technologies are not nearly as simple as installing a new thermostat, light bulb, or windows. For example, the TESLA Powerwall battery with 7 kWh of storage costs $3,000, plus the cost of installation by a qualified electrician, and if used without solar PV, the cost of an inverter.[11] With respect to the other technology mentioned by Mr. Tilghlman, fuel cells, the non-profit Upgrade Energy California says a residential fuel cell can cost over $50,000 in addition to installation costs.[12]

These are serious investments for households at virtually any income level. Given that the average income in Mohave and Santa Cruz Counties are 26% and 29% lower, respectively, than the national average; that over 26% of the population of Santa Cruz County is below the federal poverty line; and that over ¼ of Mohave County residents are senior citizens, investments of this magnitude should not be expected to be widespread.[13] And while innovative entrepreneurs may develop business models to deliver these technologies (and others) in a way that lower-income citizens can afford, they currently

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[9] E.g., Faruqui at 14, Tilghman at 5, Broderick at 8.
[10] Tilghman at 5. All citations to Tilghman refer to his January 19, 2016 Rebuttal Testimony.
[11] https://www.teslamotors.com/powerwall Accessed 2/13/16.
[12] http://www.energyupgradeca.org/en/save-energy/home/make-your-power/make-your-power-with-fuel-cells Accessed 2/13/15
[13] Statistics from U.S. Census Bureau: State and County QuickFacts. http://quickfacts.census.gov/qfd/states/04000.html. Accessed 2/13/16

do not exist.

C. It Has Not Been Demonstrated That Residential Customers Will Understand and be Able to Respond to Demand Charges

Q: Staff witnesses Broderick testifies, "residential customers can be quickly educated" on how to respond to a demand charge;[14] that "Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before;"[15] and "Staff does not presume that any group is so vulnerable as to be unable to understand and tolerate a demand kW charge."[16] Has Mr. Broderick provided any evidence to support these opinions?

A: No. They are simply assertions with no discussion or evidence to support them. Furthermore, educating the customers in Santa Cruz County will present an extra challenge, as over ¾ of the population speaks a language other than English at home.[17] Given that the only pilot programs for residential demand charges cited so far in this proceeding were opt-in,[18] I believe that data from a pilot program with randomly assigned participants is needed in order to conclude that "customers can be quickly educated" and meaningfully respond to demand charges.

Mr. Broderick also testifies that "Solar DG customers will, therefore, need to carefully consider their lifestyle decisions and additional related technology choices for those hours, for example, in the summer from when the sun starts to set and until 8

[14] Broderick at 8.
[15] Broderick at 7.
[16] Broderick at 9.
[17] Statistics from U.S. Census Bureau: State and County QuickFacts. http://quickfacts.census.gov/qfd/states/04000.html. Accessed 2/13/16
[18] Butler REC was not a pilot and is discussed later.

p.m."[19] Since Staff and UNSE also propose having full service customers on demand charges, they too will have to "carefully consider their lifestyle decisions." I am skeptical that a rate design, which requires customers to carefully consider their lifestyles in order to adjust their electric bill, is rational or fair.

Q: UNSE witness Dr. Overcast points out that one rural electric cooperative in Kansas, Butler REC, has residential demand charges, and included as an attachment to his testimony the educational material that Butler REC provides for its customers. Did you review this attachment?

A: Yes. The Butler REC educational material emphasizes "FREE demand" (emphasis original), in that customers don't pay demand charges a majority of the time. The "tips" for how to reduce demand include only one that is specific to reducing demand charges: running large appliances outside of the peak demand periods.[20] The other nine suggestions are equally applicable to general energy efficiency. The Butler REC message to its demand-charge customers is no different than what a utility would provide concerning a time-of-use rate, except that the ramifications of using power in the peak hours are much greater. Nowhere does the Butler REC educational material state that the customer has to reduce demand <u>every</u> weekday evening between 5:00 and 8:00—with no exceptions—in order to reduce the demand charge portion of their bill. If a Butler REC customer has to run one load of laundry in the evening, or cook one meal using an electric range, they're paying a hefty the demand charge for that month. I cannot conclude from either Dr. Overcast's testimony or the Butler REC education materials that

[19] Broderick at 8.
[20] HEO-5, page 4.

he provided that the Butler REC customers in general fully understand demand charges and are reacting in a knowledgeable way.

Q: **Witnesses for UNSE have pointed to the mandatory three-part rate instituted by Salt River Project (SRP) for customers with solar DG. Has SRP management been consistently positive about residential demand charges?**

A: No. At a SRP Special Board Meeting on February 12, 2015, SRP General Manager Mark Bonsall was perhaps a bit more candid than he intended, when he flatly stated that it would be difficult for him to put his grandmother on a three-part rate, and that she'd likely be paying more than she needs to:

> MR. BONSALL:I guess the bottom line on that is I think it would be very difficult, were she still with us, to put my grandma ma on a demand charge. I mean, we're gonna have people that just don't want to do that or it's too complicated for them to understand and/or they don't care about it. I think we need to be sensitive to some of those issues as well.
>
> MR. HOOPES: I hope you're not suggesting that I want your grandmother to pay more than she needs to, but --
>
> MR. BONSALL: Actually, President Hoopes, I was assuming that.[21]

Q: **Have there been societal repercussions from SRP's rate design?**

A: According to the Solar Jobs Census, Arizona lost 2,282 of its 9,204 solar jobs last year.[22] While solar employment in Arizona is expected to grow 8.4% in 2016, this figure will be much lower and possibly negative if UNSE's mandatory 3-part TOU rate design is approved, particularly if other Arizona utilities follow suit.

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[21] Salt River Project Special Board Meeting Continuation Special Board Meeting On Proposed Changes To Standard Electric Price Plans And Terms And Conditions Of Competition. February 12, 2015. Transcript at 46. Attachment B

[22] The Solar Foundation, 2015. *State Solar Jobs Census Compendium* at 119.

Q: Please summarize your testimony concerning customer understanding and reaction to demand charges.

A: Neither UNSE or any other party has provided studies or evidence that residential customers generally understand demand charges and will be able be able to react to the "price signals" they send. Additionally, movement of residential customers to mandatory TOU rates, especially in the absence of extensive piloting, would be unprecedented and inappropriate. As such, it would be putting the cart way in front of the horse to institute a three-part TOU residential rate throughout the service area. Additional controlled studies are needed to ascertain how much customers would actually understand about demand charges and TOU. Furthermore, additional affordable tools need to be in place for customers to meaningfully react to demand charges and TOU before the ACC contemplates implementing such a rate.

III. Rate Design Principals

Q: A number of witnesses in the proceeding have referred to fundamental ratemaking principals as formulated by James C. Bonbright and presented in *Principles of Public Utility Rates.*[23] Can you summarize who has referred to Bonbright in testimony, and what they have said?

A: Yes. First, in his December 9^{th} testimony APS witness Dr. Faruqui summarizes Bonbright's ten "attributers of a sound rate structure," grouping them into five general categories: economic efficiency, equity, revenue adequacy and stability, bill stability, and

[23] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, 1988. *Principles of Public Utility Rates (Second Addition).* Arlington VA: Public Utility Reports, Inc.

customer satisfaction.[24] He then focuses on "cost causation," arguing that while not explicitly listed in Bonbright's list, is clearly implied by it (particularly on economic efficiency and equity). [25] To his credit, he also testifies, "cost causation may need to be balanced against the other core principles," and "Each of Professor Bonbright's principles should be read in conjunction with the others."[26]

UNSE rebuttal witness Dr. Overcast frames his testimony around three principles: fairness, efficiency, and gradualism, stating that, "These principles are consistent with rate principles developed by Bonbright and discussed widely by others."[27] He further includes quotes attributed to Bonbright throughout his testimony, however specific citations are not provided.

Other witnesses also refer to Bonbright, although not in the detail that Drs. Faruqui and Overcast do. RUCO witness Huber testifies that his recommendations are based on Bonbright's principals, as summarized in a NARUC document.[28] SWEEP witness Schlegel and VoteSolar Witness Kobor both cite to Bonbright when discussing very specific cost and rate issues.[29] Lastly, I responded in my December 9th testimony to how UNSE witness Dukes used Bonbright's text, pointing out that he focused on only two of the foundational principals, revenue stability and rates that yield total revenue requirements, at the expense of others, such as simplicity, understandability, public acceptability, avoidance of undue discrimination, and wastefulness.[30]

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[24] Faruqui at 5-8.
[25] Faruqui at 8.
[26] Faruqi at 9.
[27] Overcast at 40.
[28] Huber at 5.
[29] Schegel at 7; Kobor at 57.
[30] Fulmer at 10.

Q: Can these rate making principles sometimes conflict?

A: Yes, and as such, regulators must strike a balance: too much emphasis on any one principle can lead to undermining the others.

Q: Please provide an example of how some of these ratemaking principles are in conflict.

A. A prime example of this is the tension between revenue adequacy and economic efficiency. Revenue adequacy requires that the utility can recover all of its costs. Utility revenues are typically determined using embedded or marginal short-term costs. Economic efficiency requires that customers be provided with price signals that will allow them to make economically efficient decisions with regard to their electricity consumption levels. In other words, customers must be given the proper price signals to invest in energy efficiency measures, invest in distributed generation resources, or simply consume less energy in order to save on electric bills.

As I have noted in my prior testimonies in this docket, there can be significant differences between short-term costs used for determining revenue adequacy and long-term costs used for sending economically efficient price signals. In the short-term, fixed costs can include capacity costs associated with generation, transmission and distribution; while over the long-term, none of these costs are truly fixed. Setting rates based on short-run price signals will not be efficient in the long run.

Q: Do you have any concerns with the way other witnesses are using Bonbright's principles?

A: Yes. First, I note that near the beginning of his chapter on Cost of Service, Bonbright states, "In the first place, the principle [the cost standard of ratemaking] is followed far more closely as a measure of general rate levels than a measure of individual rate schedules."[31] However, much, if not all, of the cost-of-service discussions raised by Drs. Faruqui and Overcast focus solely on "individual rate schedules." As such, the Commission must be cautious when considering these arguments in the context of setting a residential rate.

IV. Mischaracterizations of TASC Testimony

Q: What do you address in this section of your testimony?

A: I will point out some of the mischaracterizations of, and misleading statements about, my testimony made by UNSE witnesses.

Q: Mr. Tilghman testifies, "The Company will credit every kWh of energy produced from the DG system that the customer uses at the full retail rate."[32] Is this correct?

A: First, characterizing the savings of reduced customer use at the electric meter, for whatever reason, as a "credit" bestowed by the utility is disingenuous. It isn't a credit; it is simply the value of not paying for power that is not purchased. This is true whether the customer is not a home, has installed energy efficient equipment or self-provides a portion of their electricity usage. Second, federal law requires that utilities allow customers to self-provide power behind the meter.[33] UNSE is not crediting the customer;

[31] Bonbright at 110.
[32] Tilghman at 6.
[33] *See* 18 C.F.R. 292.303(c)(e)

it is following the law.

Q: In response to your testimony on the differing environmental impacts between solar DG and central solar, Mr. Tilghman states, "Even without the Company's site selection criteria to minimize these impacts, it is irrational to argue that any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities."[34] How do you respond?

A: In this sentence from his rebuttal, Mr. Tilghman is responding to an argument that I did not make. Nowhere in my Direct Testimony do I say that the differences in the environmental impact between central solar and DG solar alone justify any purported cost difference between the two technologies. I would not make such a statement. Instead, I point out that there are differences in the environmental impacts of DG and central solar, and that those differences should be noted and accounted for. Never do I argue that "any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities."

Q: How do the UNSE witnesses mischaracterize solar DG's contribution to peak hours?

A: First, Mr. Tilghman states: "[Mr. Fulmer testifies that] 'solar provides power during times of high system load when power is more valuable,' once again highlighting his lack of actual operational experience in grid management and relying on an often repeated, yet incorrect, statement that applies to only a few months during the year."[35] While I have

[34] Tilghman at 13.
[35] Tilghman at 13.

not participated in grid management, I have prepared and critiqued integrated resource plans (IRPs) and testified in state utility commission proceedings on electric resource planning. As I will discuss below, utilities plan their supply capacity portfolio based on the anticipated demand occurring on a few highest days—if not hours—of the year.

Second, Mr. Tilghman says,

> "The Company has previously shown that at no time during the year does the system peak when solar peaks. In fact, during the winter months when the system peaks before the sun rises and after the sun sets, solar has absolutely zero value during the times of greatest need and when prices are the highest."[36]

Dr. Overcast also makes analogous statements.[37]

Q: How do you respond?

A: First, nowhere do I state that solar PV's output coincides with UNSE's system peak. Simply because the PV panels' maximum output does not occur at the exact same time as the utility's maximum load does not mean that it does not contribute to reducing system peak. In fact, in the value of solar analysis presented later in this testimony, I explicitly take this fact into account using UNSE's own solar "coincidence factor." The coincidence factor is a number that reflects what fraction of power solar PV's capacity contributes to system peak demand.

Second, I do not understand why Mr. Tilghman and Dr. Overcast suggest that the fact that the UNSE system peaks during winter months is applicable to the capacity value of solar. As noted in UNSE's 2014 Integrated Resource Plan, UNSE is a summer-peaking utility.[38] As shown in the Charts 12 and 13 from its IRP (repeated below), UNSE's

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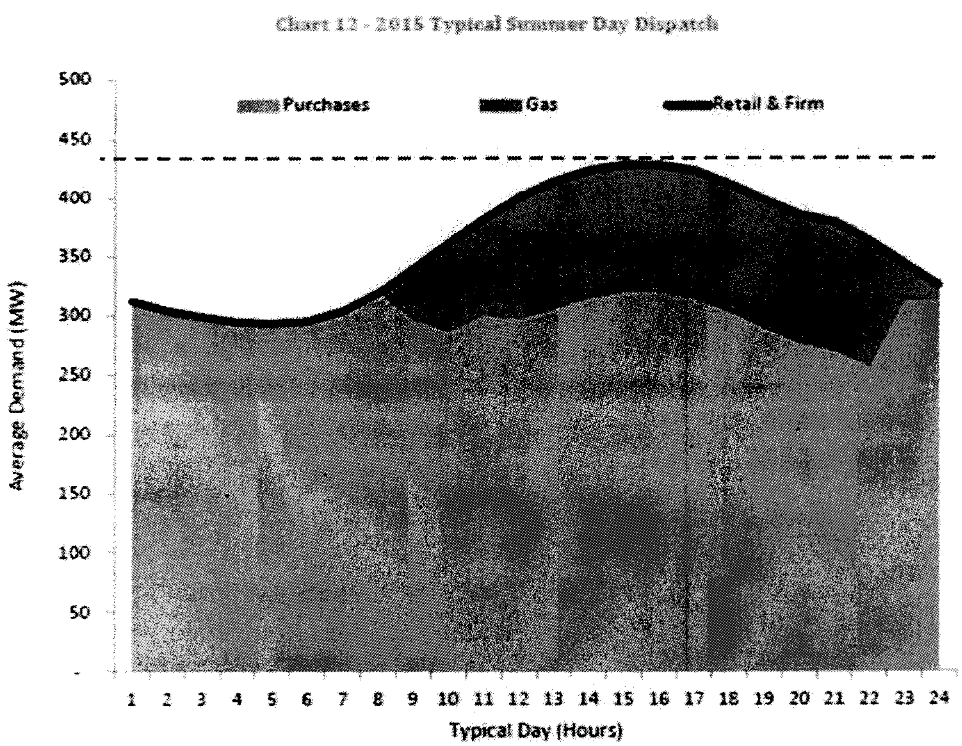
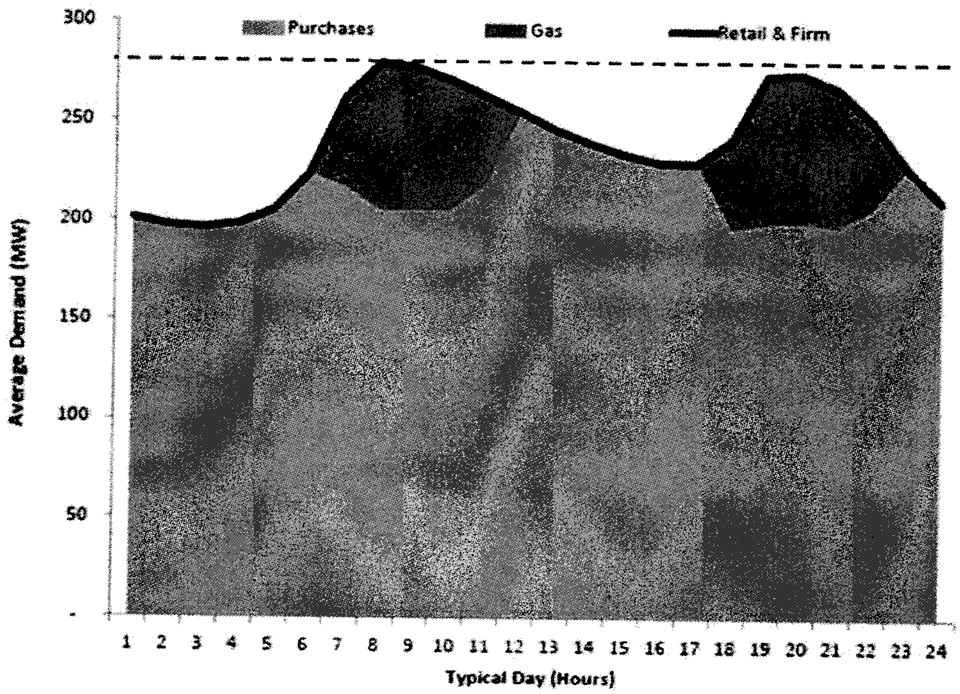
[36] Tilghman at 13.
[37] Overcast at 12-13.
[38] UDR 1.006: Unisource Energy 2014 Integrated Resource Plan (IRP), April 1, 2014 at 44. This is also shown in

typical peak summer load is ~160 MW more than its typical winter peak load. Furthermore, the two figures show that the typical <u>peak</u> winter load is less than the <u>average</u> summer load.. Given that generation capacity is planned around the system's peak load, the fact that solar PV does not generate power during early winter mornings is not relevant when considering PV contribution to a utility's generating capacity.



RUCO witness Huber's testimony at 20.

Chart 13 - 2015 Typical Winter Day Dispatch



Q: What does Dr. Overcast testify concerning rate options to address DG?

A: Dr. Overcast states,

> All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three- part rate."[39]

This statement is a classic example of a false dichotomy. Setting aside whether or not net metering with banking is just and reasonable or not, he simply asserts that the "only possible alternative" is the one he supports: DG as a separate rate class with a three-part rate. Obviously, this isn't the only possible alternative. RUCO has proffered alternatives. Staff has suggested alternatives. Even UNSE's own recommendation to move all

[39] Overcast at 19.

residential customers onto the three-part TOU rate, and not just DG uses, contradicts Dr. Ovcercast's statement. There are many ways to address solar DG besides the two stated by Dr. Overcast. To assert that his is the only answer is disingenuous and misleading.

In fact, I recommend that Staff and UNSE work together to examine alternatives to both the simple two-part rate and a three-part rate with TOU. Some options that I believe should be considered include default time of use, minimum bill provisions, and critical peak pricing (i.e., very high rates a few hours a year during system peaks).

V. Miscellaneous Issues

A. RUCO Rate Proposals

Q: Please Summarize RUCO witness Huber's proposals concerning residential customers with DG.

A: Mr. Huber suggests three alternatives to UNSE's proposal.

1. A "non-export" policy, whereby customers with DG system are not allowed to export power to the grid, or if the Commission is not agreeable, to allow exports to be valued at wholesale rates. [40]
2. A "DG TOU rate," with "energy and TOU demand intended to recover fixed costs from customers with DG.[41]
3. A "simple fixed credit mechanism," whereby the customer with DG simply pays the tariffed rate for all if his or her actual consumption while being credited for all of the output of the customer's DG system. I would classify

[40] Huber at 13.
[41] Huber at 14.

this as a "buy-all-sell-all" or a feed-in tariff.

Q: Do you find Mr. Huber's first suggestion—non-export policy—to be reasonable?

A: No. Although Huber would grandfather existing DG customer into their current DG compensation mechanism, forbidding grid export or crediting exports is poor policy. First, it would remove much of the economic value of solar DG, which I believe would reduce new solar DG adoptions to a trickle. This violates the Commission's REST goals (as later discussed by Huber).[42] In addition, the non-compensation or minimal compensation (short-run wholesale power market prices) would grossly understate the value that DG systems are providing to UNSE and its customers. This is discussed in depth later in Section VII of my testimony.

Q: Do you find Mr. Huber's second suggestion—the three-part TOU DG rate—to be reasonable?

A: No. As discussed in Section VI and shown in Table 1 of my testimony, Mr. Huber's proposed flat energy rate with a seasonal TOU demand charge would not offer a viable economic opportunity for customers desiring solar DG.

Q: What about his feed-in-tariff proposal?

A: While a feed-it-tariff can be a piece of the solar DG puzzle, it isn't a replacement for net metering. First, it is equally as difficult to set an appropriate FIT rate as it is to determine how or if costs shifting with net energy metering. Second, there are significant tax implications, such as loss of certain tax benefits that accrue to residential solar that serves

[42] Huber at 21.

onsite load as well as the sales to the utility of power being seen as income.

B. Intermittency And Geographic Diversity

Q: Mr.Tighlman also states "Mr. Fulmer's and Ms. Kobor's claims that there is a benefit of intermittency smoothing that lacks any credible, real-world evidence."[43] Is this accurate?

A. No. Pages 13 through 15 of my November 6 Direct Testimony list many credible studies based on real-world evidence that geographically dispersed DG provides a "smoother" more reliable solar power source than a central solar station. For example:

- A study that analyzed the power fluctuations of seven PV plants scattered throughout Spain concluded "[t]he geographical dispersion of the PV plants is a highly effective way of smoothing the power fluctuations, even for ten minute sampling intervals. It is sufficient to locate two PV plants at a distance of 6 km, one from the other, to ensure that the fluctuations over 10 minute intervals are independent of each other and are smoothed out when combined."[44]
- A similar study conducted in Colorado arrived at the same conclusions: "[o]verall, a significant smoothing effect was observed when the averaged solar irradiance at four solar sites across Colorado is compared to the individual sites."[45]
- Lave et al. concluded in their study that "[w]hile the variability of PV powerplants can be a concern, geographic diversity within the plant will lead to a reduction in

[43] Tilghman at p 12
[44] Marcos, J., L. Marroyo, E. Lorenzo, and M. García. "Power Output Fluctuations in Large PV Plants." In *International Conf. on Renewable Energies and Power Quality*, 2012. http://www.icrepq.com/icrepq'12/676-marcos.pdf.
[45] Lave, Matthew, and Jan Kleissl. "Solar Variability of Four Sites across the State of Colorado." *Renewable Energy* 35, no. 12 (December 2010): 2867–73. doi:10.1016/j.renene.2010.05.013.

variability versus a single point. By examining a 2.1MW residential rooftop PV plant in Ota City, Japan and a 19MW central PV plant in Alamosa, Colorado, the relative variability as a function of capacity was found to decay exponentially for both plants."[46]

- A Lawrence Berkeley National Laboratory study "conclude[d] that the costs of managing the short-term variability of PV are dramatically reduced by geographic diversity and are not substantially different from the costs for managing the short-term variability of similarly sited wind in [the Southern Great Plains]."[47]
- Finally, a report by the National Renewable Energy Laboratory, citing studies in Japan,[48,49] and Germany,[50] concluded "[i]t is well studied that aggregation of sites produces a smoother output of power on a per capacity basis. These studies primarily address smoothing through geographic dispersion, and attempts have been made to mathematically model this phenomenon."[51]

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[46] Lave, Matthew, Joshua S. Stein, and Abraham Ellis. "Analyzing and Simulating the Reduction in PV Powerplant Variability due to Geographic Smoothing in Ota City, Japan and Alamosa, CO." In *Photovoltaic Specialists Conference (PVSC), Volume 2, 2012 IEEE 38th*, 1–6. IEEE, 2012. http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6656719.
[47] Mills, Andrew. "Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power." *Lawrence Berkeley National Laboratory*, 2010. http://escholarship.org/uc/item/9mz3w055.pdf.
[48] Murata, Akinobu, and Kenji Otani. "An Analysis of Time-Dependent Spatial Distribution of Output Power from Very Many PV Power Systems Installed on a Nation-Wide Scale in Japan." *Solar Energy Materials and Solar Cells* 47, no. 1 (1997): 197–202.
[49] Otani, Kenji, Jyunya Minowa, and Kosuke Kurokawa. "Study on Areal Solar Irradiance for Analyzing Areally-Totalized PV Systems." *Solar Energy Materials and Solar Cells* 47, no. 1 (1997): 281–88.
[50] Wiemken, E., H. G. Beyer, W. Heydenreich, and K. Kiefer. "Power Characteristics of PV Ensembles: Experiences from the Combined Power Production of 100 Grid Connected PV Systems Distributed over the Area of Germany." *Solar Energy* 70, no. 6 (2001): 513–18.
[51] Urquhart, Bryan, Manajit Sengupta, and Jamie Keller. "Optimizing Geographic Allotment of Photovoltaic Capacity in a Distributed Generation Setting." *Progress in Photovoltaics: Research and Applications* 21, no. 6 (2013): 1276–85.

C. Recent Development Examples

Q: Mr. Tilghman also provides examples of states where actions have recently been taken to change their met metering policies. What examples did he provide?

A: He pointed to three states: Hawaii, Utah and Nevada. However, he did not include a major one—California, where the commission chose to continue net energy metering with compensation based on retail rates and month-to-month banking.[52] Furthermore, I found none of the policy recommendations in the three states to be compelling or applicable to Arizona.

- Hawaii: First and foremost, Hawaii Electric is at a much higher DG penetration level that UNSE, making the technical and economic issues associated with net metered solar ripe for discussion. Also, retail rates in Hawaii are significantly higher that UNSE's rates, with residential and small commercial rates ranging from a low of 22¢/kWh up to 35¢/KWh.[53] Additionally, the current buyback rate offered by Hawaiian utilities is no less than 15.07¢/kWh and ranges as high as 27.88¢/kWh.[54] Even their new pricing, which is many times higher than that proposed by UNSE, is higher than UNSE's retail rates.
- Utah: Mr. Tilghman provides a number of "fallacies" from a recent Utah Public Service Commission order addressing solar DG issues. However, none of the issues enumerated in the Utah decision cited by Mr. Tilghman are new, and in fact most are addressed organically by the dispersed nature of small solar DG. In fact, all six issues

[52] California Public Utilities Commission Decision 16-01-044.
[53] Hawaiian Electric Effective Rate Summaries, January 29, 2016.
https://www.hawaiianelectric.com/Documents/my_account/rates/effective_rate_summary/efs_2016_02.pdf
[54] Customer Grid Supply prices. https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-grid-supply-and-self-supply-programs. accessed 2/18/16.

listed by Mr. Tilghman focus on the fact that the utility does not have control over customer-side solar DG systems. This is true, but reflects the utility's (and frankly, the Utah Commission's) discomfort with elements outside of its control, while not considering the actual impacts. Yes, customers decide if and how much solar to install (Issues 1, 2, 4 and 6); how to maintain it (Issues 3 and 5). But this does not account for the fact that these decisions are made by thousands of independent actors (customers) as well as the fact that actors' best interests are generally aligned with the utility's. It is in the best interest of both the utility and the solar PV user (or if different, the PV owner) to keep the system well-maintained and operational. Furthermore, a diversity of actors (i.e., decisions concerning each system are made independently) mitigates most of the remaining concerns. People will not abandon their solar PV at the same time, creating the system problems implied by the six listed issues. Electric utilities need to be able to predict the load that they must serve; not control it.

- Nevada: The Nevada decision cited by Mr. Tilghman has caused widespread economic and political reverberations throughout the state. Major solar PV providers have pulled out of Nevada, laying off thousands of workers.[55] Solar customers have filed a class-action lawsuit.[56] If Arizona wants to avoid these problems, looking to Nevada for guidance would be poor advice.

[55] http://www.pv-magazine.com/news/details/beitrag/solarcity-pulls-out-of-nevada_100022579/#axzz40IJTiCx5 Accessed 2/15/16

[56] http://lasvegassun.com/news/2016/jan/15/lawsuit-filed-over-new-rooftop-solar-utility-rates/ accessed 2/15/16.

VI. Impact of Proposed Rates on Prospective Solar DG Customers

Q: Have you reviewed the impact that UNSE's proposed rates would have on solar customers' electric bills and how that would likely impact the business of solar?

A: Yes I have.

Q: Please explain the economics of solar to the utility customer and what you found in your analysis.

A: It appears most electric customers implement solar because it is a sound investment and a good use of their money. Before going solar, a utility customer has one bill for all his power. This bill comes from the utility, in this case, UNSE. In order to acquire solar, the customer either purchases or leases solar equipment to generate solar power for his use. After the customer purchases his solar equipment, and it is up and running, the customer pays the utility a reduced amount on a monthly basis, reflecting his reduced reliance on the utility for much of his electricity. The reduced monthly payments to the utility act as the return on the solar investment, ultimately paying the customer back for his sizable investment over a period of time. This period of time is also called the "payback period" in the solar business. The old adage, "the shorter the payback period, the better the investment," clearly applies here. If the payback period gets too long, then a customer could make wiser investments elsewhere, potentially eliminating the financial incentive to purchase a solar system entirely.

In the lease situation, the customer ends up with two bills related to his consumption of energy. The customer continues to receive a bill from the utility, reflecting his reduced reliance on the utility for his power needs; but also receives a monthly bill from the solar leasing company for the lease payments on the solar equipment. When these two monthly bills are added together, they should be less than what the customer would otherwise pay to the utility if the customer was still relying on the utility for 100% of his electric needs. If the two bills added together are more than the customer would otherwise pay a utility for 100% of his power needs, then the customer's investment in solar will not be a profitable one and, like other poor investments, will be avoided.

I examined UNSE's proposed tariffs using the spreadsheet tool first circulated by Staff (per Staff data request to TASC, SFT-BG 2.1), as modified to accurately account for appropriate assumptions and to model specific rate plans at issue in this case as described below, to determine what impact they would have on the payback period for a purchased solar system and the impact they would have on a solar leasing customer's ability to save money by leasing solar panels. As I summarize below in Table 1, the proposed UNSE tariffs leave the payback period much too long to justify the purchase of solar equipment and eliminates the opportunity for a customer to save money with a solar lease.

I examined each proposed UNSE tariff, under both status quo net metering and proposed net billing scenarios, using public load and generation profiles appropriate for the geographic territories that UNSE serves. I focused primarily on northern Arizona, using NREL Las Vegas billing determinants and load shape.

Under the proposed UNSE transition rates and final rates and a net billing mechanism, solar customers would pay significantly more per year than full-service customers (Table 1). Using the NREL billing determinants,[57] solar lease customers under the proposed 2-part non-TOU net billing transition rate would pay roughly $188 more per year for solar, or $16 per month. With the same rates, but under the current net metering billing mechanism, solar customers would save roughly $207 per year, or $17 per month. For customers that purchased their system outright, under the 2-part net billing transition rates it will take roughly 46 years to recoup the investment of their system, far exceeding the expected system life of roughly 35 years, and compared with roughly 23 years under the two-part transitional rate with net metering. Under the proposed final TOU demand charge rates, solar customers would lose under both net metering and net billing. Under net metering, customers would pay $347 more per year for solar ($29 per month), and $409 per year ($34/month) under net billing. With the proposed demand charges, solar customers who buy their systems outright would likely never be able to recoup the upfront cost of their investment, with the payback under both net metering at 58 years, and the payback under net billing exceeding 100 years.

[57] Assumes NREL Las Vegas high load estimate, most indicative as solar customers typically have higher than average load. Further assumes average monthly consumption at roughly ~1,500 kWh per year, with a system sized at 8.5kW offsetting 80% of load.

Table 1. Economics of Solar DG Under Proposed Rates

	Proposed 2-part transition non-TOU rate (net metering)	Proposed 2-part transition non-TOU rate (net billing)	Proposed final 3-part TOU rate (net metering)	Proposed final 3-part TOU rate (net billing)	Nevada Final Rates (net billing)	RUCO Advanced DG TOU rate (net billing)
Pre-Solar Utility Bill	$2,030	$2,030	$1,816	$1,816	$2,220	$1,985
Post-Solar Utility Bill	$513	$907	$853	$914	$1,533	$1,009
Utility Bill Savings	$1,517	$1,123	$963	$901	$687	$976
Total Lease Cost*	$1,311	$1,311	$1,311	$1,311	$1,311	$1,311
Total Solar Bill	$1,823	$2,217	$2,163	$2,225	$2,844	$2,319
Annual Bill Savings	$207	($188)	($347)	($409)	($623)	($334)
Breakeven Lease Rate	$0.10	$0.08	$0.07	$0.06	$0.05	$0.07
Discounted payback**	22.8 Years	45.5 Years	57.6 Years	100+ Years	100+ Years	100+ Years

*As reported in Greentech Media, the LCOE for solar leases in Arizona is 11.1 cents per kWh. Year 1 lease rate of $0.08946/kWh converted from LCOE by assuming 2.9% escalation, 7.2% discount rate, and 0.5% annual degradation.

**Assumes system cost of $3.60/watt (DC),[58] 2.9% escalation, 7.2% discount rate, and 0.5% annual degradation.

Q: How does this compare to the tariff's recently implemented in Nevada?

A: The impact of the rates that will be implemented over a transition of several years in Nevada, which have led to the near shutdown of the solar DG industry in the entire state, is similar to the impact of UNSE's proposed final 3-part rate. To determine the Nevada results, I simply input into my UNSE impact model the final approved Nevada fixed charge, energy, and export rates under a net billing scenario, consistent with Nevada's new rates. As shown in the table above, the Nevada rates result in customers paying roughly $623 more per year for solar, which, from a customer's perspective is not significantly different than the anticipated $347 per year increase under UNSE's proposed 3-part net metering rate, or the $409 per year increase resulting from UNSE's

[58] Lawrence Berkeley National Laboratory, Tracking the Sun VIII, August 2016, p. 32.

proposed 3-part net billing rate. Under UNSE's proposed 3-part net billing rate, customers would need to obtain a solar lease rate of no more than $0.06 per kWh in order to not lose any money going solar. Under a 3-part net metering rate this breakeven is slightly higher at $0.07 per kWh. Compare these rates to the breakeven rate at $0.05 per kWh under the Nevada scenario. Any rate design resulting in a breakeven rate well below the estimated $0.08946/kWh currently available to Arizona customers is unreasonable.

Q: Have you evaluated the rate proposals of other parties in this proceeding?

A: Yes. I also calculated the impact of RUCO's "Advanced DG TOU Option," which is a 3-part DG-only net billing rate design with three components: 1) a minimum bill of $12.25 per month; 2) a base energy rate equal to $0.085/kWh; and 3) and a summer only demand charge of $19.50/kW, assessed over peak hours (2-8 p.m.).[59] The proposed export rate under RUCO's Advanced DG TOU Option is $0.085/kWh. I compared the solar bill savings under this DG-only rate to pre-solar costs assuming that a customer would otherwise take service on the Residential Service rate schedule. Revenue neutral rates for this rate schedule were provided by RUCO in Exhibit 2 of Huber's testimony.

Q: Please explain your findings from your RUCO analysis.

A: The impact of RUCO's proposed 3-part rate is included in Table 1. RUCO's Advanced DG TOU Option would be extremely detrimental to solar customers, with impacts very similar to UNSE's proposed rates and the Nevada rates. Under RUCO's proposed rate, customers would spend roughly $334 more per year ($28 per month) for solar, requiring

[59] Huber Direct Testimony, p. 14.

a solar lease rate of $0.07/kWh to bring this loss to $0.

Q: So what does this suggest about what would happen to the solar industry in UNSE service territory if the proposed rates are implemented?

A: It is clear that UNSE's and RUCO's proposed tariffs would render investing in rooftop solar through purchase or lease a poor economic choice for consumers. In other words, the economics of the solar investment would make adopting solar actually more expensive than simply continuing to purchase all power from the utility. In other instances where this has occurred, like SRP territory and Nevada, the market for rooftop solar has essentially grounded to a halt. Given my analysis, that is what I would expect to happen in UNSE territory if these tariffs are adopted. I expect UNSE's proposed tariffs to essentially stop the implementation of DG solar in UNSE's service territory.

VII. Value of Solar Analysis

Q: What is the purpose of this section of your testimony?

A: UNSE witness Dallas Dukes noted that TASC and Vote Solar simply opposed all rate design changes without proposing any substantive alternatives.[60] This is because TASC believes that net metering continues to be an appropriate policy for residential and small commercial solar DG. To support this assertion, I present a value of solar analysis, which shows that the long-term value of solar DG is comparable to the forgone rates that the solar offsets.

[60] Dukes at 3.

A. Method and Assumptions

Q: How did you conduct this value of solar analysis?

A: In general, I followed the structure outlined in the report "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (Crossborder Report).[61] The report was prepared on behalf of solar interests in response to a January 23, 2013 ACC order for APS to conduct a multi-session technical conference to evaluate the costs and benefits of renewable DG and net energy metering (NEM). This report identified a number of key utility areas where solar DG can, in the long run, avoid costs to the utility costs, thus providing value to the utility.

Q: Please describe your analysis.

A: To calculate the value of DG solar, I estimated values for seven areas where DG solar can avoid or cause utility costs. I looked at each of these elements over the long run, projecting the levelized value of each element over the 20 year life of a typical solar DG system. I used the UNSE weighted average cost of capital from its 2014 Integrated Resource Plan (IRP)[62] for the discount rate.

The seven elements considered are:

1. Avoided energy: Avoided energy is the variable cost of power plants that is avoided due to the effective load reductions provided by solar DG. They can be calculated assuming a specific proxy power plant (e.g., a combustion turbine) or using wholesale market prices.

[61] Beach, R. Thomas and Patrick G. McGuire, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," Crossborder Energy, May 8, 2013.
[62] IRP Table 27 at 214

2. Avoided generation capacity: Avoided generation capacity cost is value of the forgone or deferred power plants caused by the load reduction provided by solar DG.
3. Avoided transmission costs: Avoided transmission cost is value of the forgone, deferred or downsized transmission investments caused by the load reduction provided by solar DG.
4. Avoided distribution costs: Avoided distribution cost is value of the forgone, deferred or downsized distribution investments caused by the load reduction provided by solar DG.
5. Avoided greenhouse gas (GHG) emissions costs: Avoided GHG emissions costs are the emissions associated with the reduced output of the marginal power plants which set the avoided energy cost. These emissions are multiplied by an assumed carbon dioxide (CO_2) cost ($/metric ton) to arrive at the avoided greenhouse gas cost. Separately, in the avoided environmental externality component, I account for the full social cost of greenhouse gas emissions.
6. Incremental integration costs: Even with geographic diversity, there is a cost to integrate solar DG into the UNSE system. Based the UNSE IRP, these integration costs cover the incremental ancillary services to support the added solar generation.
7. Avoided environmental externalities. Like with avoided greenhouse gas emissions costs, solar DG can reduce criteria air pollutant (NO_x, SO_x and fine particulate matter) emissions associated with the reduced output of the marginal power plants which set the avoided energy cost. These emissions are multiplied by an assumed

emissions cost to arrive at the criteria air pollutant cost. Because there is currently no market value for these pollutants in Arizona, and one is not anticipated, these costs are best described as externalities.

I also included the estimated marginal cost of water. Given the arid climate of Arizona and the increasing demand for water in the Southwest, including the marginal cost of water (i.e., the cost of water reclamation or desalinization) is appropriate.

Q: What data do you use?

A: I consider two cases. In one, I rely upon data from UNSE's 2014 IRP to the fullest extent possible. This is labeled throughout as "IRP Case." I also show a case using some alternative data, which differs from the IRP Case in that it assumes a west-facing PV array (so as to maximize on-peak production) and uses data from the Crossborder Report for distribution avoided costs and integration costs. In each section below, where I explain my calculations, I note what data I use and their source.

I must be clear that simply because I choose to label the second case "Alternative" does not mean that the results in the IRP are truer or more reliable. Rather, the purpose of the IRP case is to show that using UNSE's own data, solar DG can have much greater value than has been asserted in this proceeding

B. Results

Q: What did you find?

A: Overall, I found that the levelized benefits of solar DG are on the order of 10¢-14¢/kWh ($100-$140/MWh). This analysis is detailed in Table 2. The value of each component listed above for each of my cases is shown, along with subtotals at key intervals: only the avoided costs; the avoided costs net the integration costs; and the avoided and integration costs plus a value for air emission externalities. When avoided costs alone are considered, the value of solar is ~$100/MWh (using IRP data and $142/MWh with a west-facing array and alternative assumptions). Accounting for integration costs reduces these amounts by about $4.50/MWh. Including air emissions externalities brings the totals back to $136/MWh and $180/MWh for the IRP and Alternate cases, respectively.

Table 2. Value of Solar (Levelized $/MWh)

	IRP Case	Alternate
Energy	$50.44	$50.44
Gen. Capacity	$40.16	$77.62
Transmission	$2.78	$5.15
Distribution	$0.00	$2.00
GHG	$6.76	$6.76
Avoided Costs	$100.13	$141.97
Integration costs	($4.55)	($2.00)
With Integration costs	**$95.58**	**$139.97**
Eniv. Externalities	$40.28	$40.28
With Emissions costs	$135.86	$180.25

Q: What do these values mean for this proceeding?

A: Other solar advocates and I have been arguing in this proceeding that net metering can provide value to UNSE in ways that are not captured in the narrow, short-term cost of service perspective that UNSE and others have taken. Because the avoided cost value of solar DG is approximately equal to UNSE's residential rate, net metered solar DG should not impact and may even benefit full-service customers in the long run. Solar DG should be held to similar cost-benefit standards as other behind-the-meter activities such as energy efficiency; a high bar singling out solar DG is inappropriate.

C. Avoided Energy

Q: How did you calculate avoided energy costs?

A: I calculated avoided energy costs as the price of natural gas multiplied by a market heat rate and added in a loss factor (Table 3). A market heat rate is the implied relationship between the market price of natural gas and the market price of power. Inherent in this, is the assumption that natural gas generation is predominantly on the margin in power markets, which indeed is the case throughout the Western US. The natural gas price used here is calculated from the current Henry Hub futures prices, a basis swap to the Permian Basin, and transportation to a gas plant in UNSE territory (UNSE schedule T-1). The Henry Hub futures prices and basis swap values are from *Platt's Gas Daily*, while the market heat rate is taken from the 2014 IRP.[63] I then included a factor of 10% to account for the transmission and distribution losses from a transmission-connected power plant to the customer meter.[64] This calculation results in a levelized cost of energy of $50.44/MWh.

[63] IRP at 219, Chart 42, rounded mean value.
[64] Tilghman at 11.

Table 3. Derivation of Avoided Energy Cost

year	Gas Price $/mmbtu	Market Heat Rate mmbtu/MWh	Power Price $/MWh	loss factor	Price $/MWh
2017	$3.92	8	$31.37	10%	$34.51
2018	$4.06	8	$32.51	10%	$35.76
2019	$4.20	8	$33.58	10%	$36.93
2020	$4.35	8	$34.77	10%	$38.25
2021	$4.49	8	$35.95	10%	$39.55
2022	$4.65	8	$37.18	10%	$40.90
2023	$4.80	9.5	$45.63	10%	$50.19
2024	$4.96	9.5	$47.08	10%	$51.79
2025	$5.11	9.5	$48.58	10%	$53.43
2026	$5.27	10	$52.70	10%	$57.98
2027	$5.43	10	$54.30	10%	$59.73
2028	$5.58	10	$55.83	10%	$61.41
2029	$5.71	10	$57.12	10%	$62.83
2030	$5.80	10	$57.97	10%	$63.77
2031	$6.08	10	$60.81	10%	$66.89
2032	$6.34	10	$63.40	10%	$69.74
2033	$6.60	10	$66.05	10%	$72.65
2034	$6.88	10	$68.76	10%	$75.64
2035	$7.13	10	$71.29	10%	$78.42
2036	$7.40	10	$73.99	10%	$81.39
				Levelized	**$50.44**

D. Avoided Capacity

Q: Why is it reasonable to include an avoided generation capacity cost in your calculation?

A: Including avoided generation capacity in my calculation is consistent with the IRP. In the Sensitivity section of the IRP, UNSE considered the case where it achieved only 50% of its energy efficiency and distributed generation targets. The case stated that this reduction would cause UNSE to install additional combustion turbines in 2019 and 2024.[65] This

[65] IRP at 244.

means that energy efficiency and DG are offsetting the need for additional generation resources, and as such should take credit for those capital savings when considering their cost-effectiveness.

The combustion turbines cited in the IRP were 21 MW LM2500s. As the IRP did not contain cost data for this model, I used the closest one for which explicit data were provided, the LM6000. The Figures on pages 79 and 83 of the IRP suggest that this is a reasonable assumption.

Q: How did you calculate avoided generation capacity cost?

A: The calculation is shown below in Table 4. As is common practice (e.g., see RUCO witness Huber's December 9 testimony), I assumed that avoided generation capacity cost can be represented by the cost of a new combustion turbine (CT). This is because CTs tend to be the least-cost source of new utility-scale capacity, as well as the explicit type of resource identified as offset by DG and energy efficiency in the IRP.

I took the total construction cost of the LM6000 CT from the IRP, adjusted the value to 2017 dollars and applied a carrying charge. A carrying charge effectively translates an investment amount over the life of the asset. The value used here, 11.17%, is from the value of solar DG study commissioned by APS in 2013 and performed by SAIC (as cited in the Crossborder Report).[66] I then added the fixed operating and maintenance (O&M) cost and gas transportation reservation costs from the IRP.[67] This sum was then scaled up to account for reserve margin savings (i.e., a 10% reduction in peak load results

[66] Crossborder ReportCrossborder Report at 10.

[67] Unless it was explicitly stated otherwise, I assumed that all costs in the UNSE IRP were in 2014 dollars, and were adjusted to 2017 using deflators from the Department of Energy Information Administration in this analysis.

in an 11.5% reduction in capacity needs) and losses from the avoided CT to the meter.

I then applied a coincident factor from the 2014 IRP.[68] The coincident factor reflects the output of the solar system at time of system peak. For the Alternative case, I scaled the coincident factor up by the ratio of PV output during peak hours between a standard south-facing PV array and a west-facing array (using data from the NREL model, PVWatts). A west-facing array is instructional to consider: while it generates less overall electricity than a south-facing one, it generates more during the summer late afternoon and early evening hours, coinciding with UNSE system peaks. I then applied the capacity factor for solar PV to arrive at the levelized dollar per megawatt-hour value.

Table 4. Derivation of Avoided Generating Capacity Cost

IRP Case	Alternate	
$1,123	$1,123	per kW total construction cost
11.17%	11.78%	Carrying Charge
$125.39	$132.23	per KW-year
$16.68	$16.68	fixed O & M
$18.04	$18.04	gas transp $/kW-yr
$160.10	$166.95	per KW-year
15%	15%	Reserve Margin
$184.12	$191.99	per KW-year
10%	10%	losses
$202.53	$211.19	per KW-year
33%	52%	coincidence factor
$66.83	$109.82	per KW-year
19%	16%	Capacity Factor
$40.16	$77.62	per MWh

E. Avoided Transmission and Distribution

Q: How did you calculate avoided transmission cost?

A: The only quantitative data provided in the IRP for marginal transmission costs was for

[68] IRP at 70.

connecting a new generator to the UNSE grid.[69] These costs included a mile of transmission line plus the substation interconnection. Consistent with the avoided generation calculation, I used the interconnection cost assumptions associated with a LM6000. I then used a process similar calculating the avoided generation capacity; the only difference is that I used a slightly different carrying charge, per the Crossborder Report.[70] This calculation is shown in Table 5.

Table 5. Derivation of Avoided Transmission Cost
(based on marginal generator interconnection)

IRP Case	Alternate	
$4.866	$4.866	million per installation
45	45	MW per installation
108.13	108.13	per kW
12%	12%	Carrying Charge
$12.74	$12.74	per KW-year
10%	10%	losses
$14.01	$14.01	per KW-year with losses
33%	52%	coincidence factor
$4.62	$7.29	per KW-year of solar
19%	16%	Capacity Factor solar
$2.78	$5.15	per MWh solar

Q: **Shouldn't an avoided transmission cost calculation consider deferred or avoided investment in transmission assets?**

A: Yes. However, there was insufficient data in the IRP to make such a calculation. Thus, the values I show below should be considered conservative.

Q: **What did you assume for avoided distribution cost?**

---

[69] IRP at 101.

[70] Crossborder Report at 11 (Table 6)

A: The IRP afforded no data that would allow me to estimate an avoided distribution cost. In the name of conservatism, I did not assume any avoided distribution costs for my IRP case. This is not because I do not believe that avoided distribution does not exist. Rather, that for this analysis, I could not quantify it based on the IRP. For the Alternative case, I used the value calculated in the Crossborder Report: $3/MWh.[71]

F. Avoided Greenhouse Gas

Q: How did you calculate a value for avoided greenhouse gas costs?

A: For the initial years 2017 through 2022, shown below in Table 6, I assumed the avoided cost of CO_2 to be zero. In 2023, I assumed a value of $17.26/metric ton, which I then escalated at 6% per year. This matches the carbon cost assumptions in the Emissions Prices section of the IRP.[72]

I then multiplied the emissions cost by the carbon content of natural gas (117 lb per MMbtu) and by the mean market heat rate (rounded) from the IRP.[73] As shown below, the levelized cost of carbon emissions offset by solar DG is $7.43/MWh.

[71] Crossborder Report at 12.
[72] IRP at 213.
[73] IRP at 219.

Table 6. Derivation of Avoided Greenhouse Gas Cost

year	$/ton	lbs/tonne	lbs/mmbtu	mmbtu/MWh	$/MWh	With 10% Losses
2017	$0.00	2200	117	8	$0.00	$0.00
2018	$0.00	2200	117	8	$0.00	$0.00
2019	$0.00	2200	117	8	$0.00	$0.00
2020	$0.00	2200	117	8	$0.00	$0.00
2021	$0.00	2200	117	8	$0.00	$0.00
2022	$0.00	2200	117	8	$0.00	$0.00
2023	**$17.26**	2200	117	9.5	$8.72	$9.59
2024	$18.30	2200	117	9.5	$9.24	$10.17
2025	$19.39	2200	117	9.5	$9.80	$10.78
2026	$20.56	2200	117	10	$10.93	$12.03
2027	$21.79	2200	117	10	$11.59	$12.75
2028	$23.10	2200	117	10	$12.28	$13.51
2029	$24.48	2200	117	10	$13.02	$14.32
2030	$25.95	2200	117	10	$13.80	$15.18
2031	$27.51	2200	117	10	$14.63	$16.09
2032	$29.16	2200	117	10	$15.51	$17.06
2033	$30.91	2200	117	10	$16.44	$18.08
2034	$32.76	2200	117	10	$17.42	$19.17
2035	$34.73	2200	117	10	$18.47	$20.32
2036	$36.81	2200	117	10	$19.58	$21.54
				Levelized:	**$6.76**	**$7.43**

G. Integration Costs

Q: How did you calculate a cost of integrating the solar DG into the utility system?

A: I followed the method laid out in the Renewable Resources Integration Costs section of the IRP.[74] There, Table 21 showed the integration cost for three renewable types, including solar PV, with each cost's sensitivity to renewable capacity and gas price. The base integration cost from the IRP for solar PV was $7.60/MWh, based on 25 MW of solar and Permian Basin gas prices of $6.00/mmbtu. However, this $6/mmbtu assumption is not consistent with my analysis. Given the gas futures price analysis described earlier,

[74] IRP at 170.

the levelized cost of Permian gas in my analysis is $3.40/mmbtu. With the integration cost sensitivity shown in the IRP ($1.40/MWh change in integration cost for every $1 change in Permian gas prices) this results in an integration cost of $4.14/MWh, or $4.55/MWh with losses. This calculation is shown in Table 7.

Table 7. Derivation IRP Interconnection Cost

Per IRP	$7.60	/MWh
Adjustments for lower gas prices		
Assumed Gas	$6.00	/mmbtu
Used gas	$3.53	/mmbtu
Difference	$2.47	/mmbtu
Change in gas price	$1.40	mmbtu/MWh
Change in integration cost	$3.46	/MWh
integration cost	$4.14	/MWh
losses	10%	
With losses	**$4.55**	**/MWh**

H. Environmental Externality Savings

Q: How did you calculate the cost of avoided air emissions?

A: First, I took the emissions rates for sulfur oxides (SO_x), nitrogen oxides (NO_x), and fine particulate matter (PM10) for a combustion turbine (CT) and a natural gas combined cycle (CC) from the IRP.[75] Because the market heat rate tended to fall between that of a combustion turbine and combined cycle, I used a simple average of the two emissions rates. I then multiplied these emission rates by the emissions cost from the Crossborder Report and summed the costs to arrive at the final air emissions cost.[76] This process is illustrated in Table 8.

[75] IRP at 73, 74.
[76] Crossborder Report at 13.

Table 8. Derivation of Air Emission Externality Cost

	Emissions rate, lb/MWh			Cost			Total	With10%
	CT	CC	Ave.	$/tonne	lb/tonne	$/lb	$/MWh	Losses
SOx	0.006	0.004	0.005	$11,144	2,200	$5.07	$0.03	$0.03
NOx	0.323	1.094	0.7085	$6,926	2,200	$3.15	$2.23	$2.45
PM10	0.73	0.054	0.392	$1,642	2,200	$0.75	$0.29	$0.32
								$2.80

Q: Did you calculate the marginal cost of water consumption?

A: Yes. I used the same basic method for estimating the marginal cost of water as I used for estimating the emissions costs. I used the simple average of the water use for a CT and a CC from the IRP[77] and then multiplied these water consumption amounts by the marginal water cost from the Crossborder Report to arrive at a marginal avoided cost of water of $1.88/MWh.[78]

Q: Did you consider greenhouse gas emission costs above the market values you included earlier?

A: Yes. For an incremental externality cost for GHG, I made two adjustments. First, I accounted for methane leakage during transport from the wellhead to the marginal power plant. The US EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" places methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant at 1.1% of production.[79] But because methane is a much more potent greenhouse gas than carbon dioxide, I multiplied the natural gas leakage emissions by methane's

[77] IRP at 73, 74.
[78] Crossborder Report at 13.
[79] EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013," US Environ. Prot. Agency, pp. ES1–ES26, 2014.

global warming potential, 25.[80] Second, I used the EPS's societal cost of carbon rather than the market value per the UNSE IRP.[81]

Table 9 Greenhouse Gas Externaltiy Cost, $/MWh

Powerplant Emissions	$33.75
Natural Gas System Methane Losses	$9.28
Net Market Cost	($7.43)
	$35.60

I. Other, Not Easily Quantifiable Benefits

Q: You included eight elements in your value of solar analysis. Are there additional elements that might be included in such an analysis?

A: Yes. There are a number of other benefits that distributed solar can provide that are much more difficult to quantify. In this section of my testimony, I address a few of these and note values that other parties have placed on the benefits. I have chosen not to include them in my quantitative analysis as they require more analysis than time allowed for in this proceeding.

Q: Can solar DG provide reliability benefits and reduce a utility's reserve margin requirement?

A: Yes. For example a 2005 article by Duke, Williams and Payne in the *Energy Policy* journal notes that PV deployment makes it possible to reduce the reserve margins needed to ensure power system reliability.[82] Duke *et al* point out that electric grids with large

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[80] *Ibid.*

[81] https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. 3% discount rate. Accessed 2/19/16.

[82] "Accelerating residential PV expansion: demand analysis for competitive electricity markets" Duke et al., *Energy Policy* 33, 2005 (Duke 2005) p. 1922

generation facilities require a higher reserve margin since an unanticipated loss of output from even a single generating facility could affect service continuity. In contrast, a power system with a large number of distributed PV systems alleviates reserve requirements because individual systems are far smaller than central-station plants, and the risk of unexpected technical failure is uncorrelated across different PV systems.

This is echoed a 2011 report prepared for the New York State Energy Research and Development Authority (NYSERDA), which noted that, in general, distributed generation can increase system reliability by increasing the number and variety of generating technologies; reducing the size of generators and the distance between generators and load; and by reducing loading on distribution and transmission lines.[83]

The reserve margin benefit issue is illustrated by an example cited in the NYSERDA study:

> During the last wave of nuclear plant construction, single units were built as large as 1100 MW in capacity. Seabrook I is an example. At the time Seabrook I came into service, its loss became the single largest risk to the reliability of the New England grid and substantially increased the risk of system outages. To remedy this situation, the New England Power Pool had to increase the required reserve margin for every utility in New England by several percentage points. A two percentage point increase in the region's required capability would amount to something on the order of 500 MW. The cost savings implicit in reducing the size of plants and dispersing them can be appreciated from that observation.[84]

Q: Beyond providing reliability benefits by lowering reserve margin requirements, can solar DG provide other grid support or ancillary services?

A: Yes. According to a 2013 meta-study by the Rocky Mountain Institute, grid support

[83] "Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies." Prepared for NYSERDA by Pace Energy and Climate Center and Synapse Energy Economics 2011 (NYSERDA 2011) p.17
[84] NYSERDA 2011, p. 17

> services provided by solar DG can include reactive supply and voltage control, frequency regulation and response, making up for energy imbalances, providing operating reserves, and scheduling and forecasting benefits to ensure operational safety.[85] The study notes that differing standards and rules based on different systems could affect the valuation of solar DG grid support services,[86] however it is likely that with changes in technology, the net value proposition of solar DG as grid support will increase.[87]

This fundamental conclusion that solar DG can provide grid support is corroborated by reports and studies prepared for the National Renewable Energy Laboratory,[88] and NYSERDA.[89] These studies assign values as high as 1.5 cents/kWh to the ancillary services provided by distributed generation.[90] Further evidence of benefits with respect to power quality, conservation voltage regulation, equipment life extension, and reliability and resiliency benefits have been quantified in the recently published SolarCity paper "A Pathway to the Distributed Grid." (Attachment C) While I do not attempt to replicate SolarCity's analysis for UNSE due to a lack of available data, I note that the estimates of the value of solar in this analysis are conservative given the limited data available to estimate these difficult-to-quantify values.

Q: Can solar DG provide a hedge against volatile fuel prices?

A: Yes. A 2013 paper by the Interstate Renewable Energy Council notes that solar DG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are

[85] "A Review Of Solar PV Benefit & Cost Studies", Rocky Mountain Institute 2013 (RMI 2013) p. 15
[86] RMI 2013 p. 33
[87] RMI 2013 p. 34
[88] "Photovoltaics Value Analysis," Prepared for National Renewable Energy Laboratory by Navigant Consulting 2008 (NREL 2008) p. 13
[89] NYSERDA 2011 p. 18
[90] NREL 2008, p. 13

susceptible to shortages and market price volatility.[91] It further notes that solar DG provides a hedge against uncertainty regarding future regulation of GHG and other emissions, which also impact fuel prices. Solar DG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices, effectively blending price stability into the total utility portfolio.

Q: What is the value of this fuel price hedge?

A: A number of studies have placed values on this benefit. These include Duke 2005 (0.7¢/kWh in California for natural gas price risk);[92] NREL 2008 (up to 0.9¢/kwh);[93] NYSERDA 2011 (0.4-0.9¢/kWh, quoting Americans for Solar Power 2005);[94] and Xcel Energy 2013 (0.66¢/kWh).[95]

Q: Does this conclude your surrebuttal testimony?

A: Yes.

[91] "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," Interstate Renewable Energy Council 2013 (IREC 2013) p. 30
[92] Duke 2005 p. 8
[93] NREL 2008 p. 5
[94] NYSERDA 2011 p. 25
[95] "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System" Prepared by Xcel Energy Services 2013 (Xcel 2013) Table 16, p. 43

ATTACHMENT A

Use Great Caution in Design of Residential Demand Charges

Jim Lazar

For decades, electricity prices for larger commercial and industrial customers have included demand charges, which recover a portion of the revenue requirement based on the customer's highest usage during the month. Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. The caution applied should address the following key issues in most demand-charge rate designs:

- *Diversity:* Different customers use capacity at different times of the day, and these customers should share the cost of this capacity.
- *Impact on Low-Use Customers:* Most demand-charge rate designs have the effect of increasing bills to low-use customers, including the vast majority of low-income customers.
- *Multifamily Dwellings:* The utility never serves individual customer demands in apartment buildings, only the combined demand of many customers at the transformer bank.
- *Time Variation:* If demand charges are not focused on the key peak hours of system usage, they send the wrong price signal to customers.

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In the recent Regulatory Assistance Project (RAP) publication *Smart Rate Design for a Smart Future,*[1] we looked at many attributes of rate design for residential and small commercial consumers. We identified three key principles for rate design:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Customers should pay for power supply and grid services based on how much these customers use and when they use it.
- Customers supplying power to the grid should receive full and fair compensation—no more and no less.

Applying these principles results in an illustrative rate design that constructively applies costing principles in a manner that consumers can understand and respond to. **Exhibit 1** shows the illustrative rate design, including a customer charge for customer-specific billing costs and a demand charge for customer-specific transformer capacity costs. The exhibit also includes a time-varying energy price to recover distribution

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Exhibit 1. Illustrative Rate Design

Illustrative Residential Rate Design

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

Source: Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.

system capacity costs and power supply costs designed to align prices with long-run marginal costs.

Customers can and will respond to rate design. We need to make sure that their actions actually serve to maximize their value and minimize long-run electric system costs. The illustrative rate is clearly directed toward these ends.

DEMAND CHARGES HAVE ALWAYS BEEN ONLY AN APPROXIMATION

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month. Demand charges are sometimes coupled with a "ratchet" provision that charges the customer on the basis of the highest measured demand over the previous 12-month period or other multi-billing-period span of time.

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month.

Exhibit 2 is a typical medium commercial rate design. It includes a demand component.

Utilities often justified demand charges on the basis of two arguments. First, they were

Exhibit 2. Illustrative Demand Charge Rate

Basic Tariff For Large Commercial Customer

Rate Element	Price
Customer Charge $/month	$20.00
Demand Charge $/kW/month	$10.00
Energy Charge $/kWh	$0.08

Key Terms for Demand Charges

CP: coincident peak demand: the customer's usage at the time of the system peak demand.

NCP: non-coincident peak demand: the customer's highest usage during the month, whenever it occurs.

Diversity: the difference between the sum of customer NCP and the system CP demands.

asserted as a "fairness" rate that assured that all customers paid some share of the utilities' system capacity costs. Second, especially when coupled with ratchets, they had the effect of stabilizing revenues.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.

But demand charges are a shortcut, measuring each customer's individual highest usage during a month, regardless of whether the usage was coincident with the system peak. The customer's individual peak was used as a proxy for that customer's contribution to system capacity costs. Demand charges were implemented in this way even though customers' individual demands did not coincide with the peak system demand, or more accurately, with the coincident peak for the individual components of the system involved, each of which may have peaks different from the system peak. This was always a "second-best" approach. It is roughly accurate for large commercial customers, because their highest usage *usually* (but not always) coincided with the system peak.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak. The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential consumers. But coincident-peak (CP) demand charges have other shortcomings, leaving some customers with more than their share of costs and others with none at all, as shown in **Exhibit 3.**

With data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour of usage.

Today, with data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

 DOI 10.1002/gas /

of usage. This more precise usage data makes demand charges a largely antiquated approach for all customer classes—and particularly inappropriate for residential consumers.

DIVERSE USER PATTERNS VARY GREATLY

Residential customers use system capacity at different times of the day and year. Some people are early-risers, and others stay up late at night. Some shower in the morning, and some in the evening. Some have electric heat, and others have air conditioning.

This variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs. Demand charges are not very useful for this purpose.

A half-century ago, Garfield and Lovejoy discussed how system capacity costs should be reflected in rates.[2] Their observations, summarized in Exhibit 3, are as relevant today as when they were published. We compare the performance of three rate-design approaches to these criteria.

Variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs.

Following this guidance, capacity costs need to be recovered in every hour, with a concentration of these charges in system peak hours. The illustrative rate design in Exhibit 1 does this effectively. The typical commercial rate design in Exhibit 2, loading system capacity costs to an NCP demand charge, does not, because it recognizes only one hour of customer-specific demand.

Churches and stadiums illustrate this problem with demand charges. Churches have peak demands on days of worship—most often Wednesday nights and Sunday mornings, and stadium lights are used only a few hours per month, in the evening hours in the fall and winter. None of this usage is during typical peak periods.

Applying demand charges to recover system capacity costs based on non-coincident peak demand to churches and stadiums has long been recognized as inappropriate. Such charges have the effect of imposing system capacity costs on customers whose usage patterns contribute little, if anything, to the capacity design criteria of an electric utility system at the same rate as customers using that capacity during peak periods. The same problem applies for residential consumers.

On a typical distribution system, multiple residential consumers share a line transformer, and hundreds or thousands share a distribution feeder. The individual non-coincident demands of individual customers are not a basis for the sizing of the distribution feeder; only the combined demands influence this cost. Even at the transformer level, some level of diversity is assumed in determining whether to install a 25-kilovolt-amp or 50-kilovolt-amp transformer to serve a localized group of perhaps a dozen customers.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.

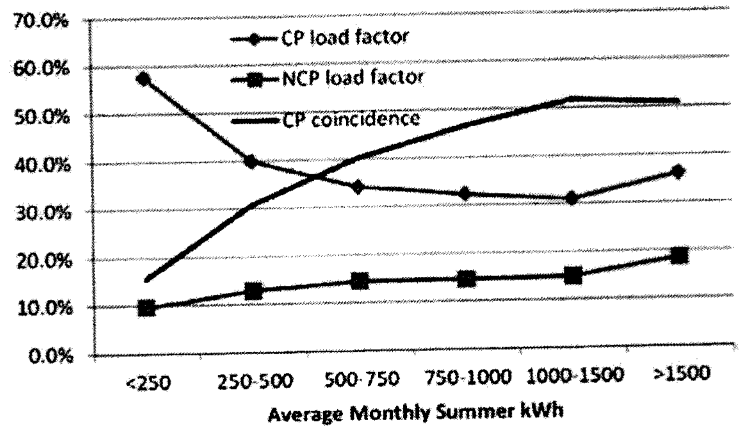
Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month. Some customers (think of a doughnut shop and nightclub) use capacity only in the morning or evening, and can share capacity, while others (think of a 24-hour mini-mart) use capacity continuously and preempt this capacity from use by others. Modern rate design needs to distinguish between different characteristics in the usage of capacity and ensure all customers make an appropriate contribution to system capacity costs.

Time-varying rates do this very well, while simple CP and NCP demand charges do not.

IMPACT ON LOW-USE CUSTOMERS

Individual residences have very low individual customer load factors but quite average collective usage patterns.

Exhibit 4. Load Factors



Source: Marcus, B. (2015, June). Presentation at Western Conference of Public Service Commissioners, Phoenix, AZ.

Exhibit 4 shows data from Southern California Edison Company. As is evident, while the individual customer load factors of small-use residential customers are only about 10 percent, their group coincident peak load factor is more like 60 percent, quite close to an overall system load factor. A demand charge based on NCP demand greatly overcharges these customers. Meanwhile, the high-use residential customers, who have more peak-oriented loads, would be undercharged with a simple NCP demand charge based on overall residential usage.

The evidence is that the effect is to shift costs to smaller-use customers.

Rate analysts have examined the impact of demand-charge rate designs on residential customers. The evidence is that the effect is to shift costs to smaller-use customers, with about 70 percent of small-use residential customers experiencing bill increases, and about 70 percent of large-use residential customers experiencing bill decreases, even before any shifting of load.[3]

APARTMENT DIVERSITY

About 30 percent of American households live in some sort of multifamily dwelling. Apartments generally have the lowest cost of service of any residential customer group, because the utility provides service to many customers at a single point of delivery through a transformer bank sized to their combined loads. Because the sum of individual customer NCP demand greatly exceeds the combined group demand the utility serves, and by a greater margin than for other customer subclasses, NCP demand charges shift costs inappropriately to these multifamily customers.

About 30 percent of American households live in some sort of multifamily dwelling.

Low-income consumers are more likely to reside in apartments, and nationally, low-income household usage is about 70 percent of average household usage.[4] Therefore, imposing NCP demand charges on residential consumers, without separate treatment of apartments, would have a serious adverse impact on these customers, many of whom are

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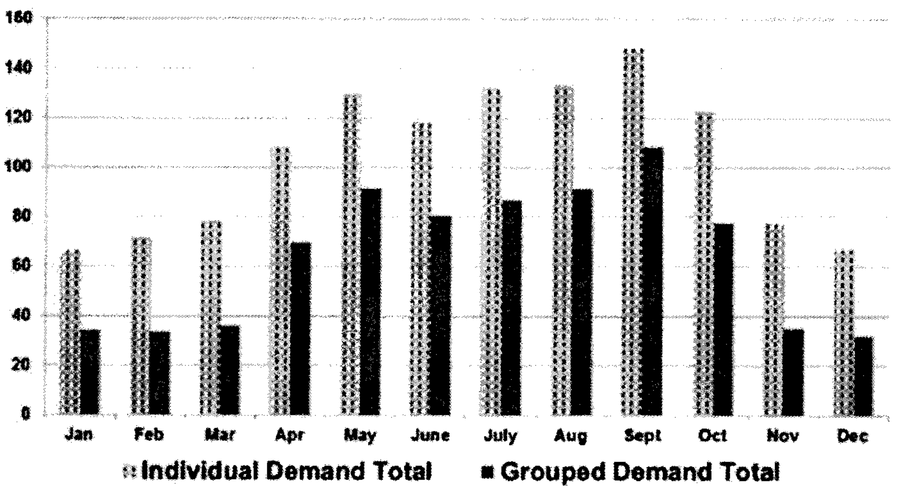
Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building



Source: Author, from data supplied by Los Angeles–area municipal utility.

low-income households and often strain to pay their electric bills.

Exhibit 5 shows the sum of individual customer monthly non-coincident peaks for a 26-unit apartment complex in the Los Angeles area, and the monthly group peaks of these customers actually seen by the utility at the transformer bank serving the complex. The exhibit shows that billing customers on the basis of non-coincident peak demand would dramatically overstate the group responsibility for system capacity costs.

TIME-VARYING COST RECOVERY

As expressed by Garfield and Lovejoy, the optimal way to recover system capacity costs is through a time-varying rate design. This can be as simple as a higher charge for usage during on-peak hours than off-peak hours, or it can be a fully dynamic hourly time-varying energy rate. What is clear is that a single demand charge, applied to a single one-hour NCP or CP measure of demand, is unfair to those customers whose usage patterns allow the shared use of system capacity.

Some utilities have implemented time-varying demand charges. California investor-owned utilities impose NCP demand charges for distribution costs, and CP demand charges for generation and transmission capacity on larger commercial consumers. More recently, some utilities have imposed demand charges on smaller customers based on summer on-peak-hour demands only. All of these reflect gradual movement toward equitable recovery of system capacity costs, but full time-of-use (TOU) energy pricing is more effective, more cost-based, more equitable, and more understandable.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month. Usage during peak periods can be assigned the costs of peaking power supply resources and seldom-used distribution system capacity costs installed for peak hours. Usage during other hours can be assigned the cost of baseload resources and the basic distribution infrastructure needed to deliver that power.

The pricing can be as granular as the analyst chooses and the regulator approves—but a key element of rate design is simplicity. For that reason, most analysts shy away from rate design with more than three time periods and a few rate elements.

The illustrative rate design in Exhibit 1 shows a three-period TOU plus critical peak price for both power supply and distribution capacity cost recovery, a customer charge for billing costs, and a demand charge to recover the cost of the final line transformer. It may be as complex a rate design as most residential consumers will reliably understand.

TRANSITIONING TO A TOU RATE DESIGN

Many customer groups are apprehensive about time-varying utility rates, because some consumers will receive higher bills and may not be able easily to change their usage patterns. This same concern would apply to implementation of a demand-charge rate design, but because that produces a less desirable result, we do not consider it a meaningful option. There are the following tools that can be used for a transition:

- *Shadow billing:* Provide consumers with *both* the current rate design and the proposed TOU rate design calculated on the bill prior to rollout.
- *Load control:* Prior to implementing a TOU rate, assist customers to install controls on their major appliances to ensure against inadvertent usage during on-peak periods.
- *Customer-selected TOU periods:* The Salt River Project in Arizona has had excellent success allowing customers to choose a three-hour "on-peak" period out of a four-hour system peak period.[5]

COMMON ERRORS IN DEMAND-CHARGE DESIGN

Common errors include the following:

- *Upstream Distribution Costs:* Any capacity costs upstream of the point of customer connection can be accurately assigned to usage and recovered in time-varying prices.
- *Using NCP Demand:* NCP demand is not relevant to any system design or investment criteria above the final line transformer, and only there if the transformer serves just a single customer.
- *Accounting for Diversity:* Diversity is greatest among small-use customers and needs to be fully accounted for.
- *Apartments:* Apartments have the lowest cost of service of any residential customer group, the highest diversity, and suffer the most when a single rate design is applied to all residential customers.

GUIDANCE FOR COST-BASED DEMAND CHARGES

The following guidelines can be used;

- Limit any demand charges to customer-specific capacity.
- Fully recognize customer load diversity in rate design.
- Demand charges upstream of the customer connection, if any, should apply only to the customer's contribution to system coincident peak demand.
- Compute any demand charges on a multi-hour basis to avoid bill volatility.

Modern metering and data systems make it possible to increase greatly the accuracy, and therefore the fairness, of cost allocation among a diverse customer base. Legacy concepts, such as demand charges, especially those based on NCP demand, prevent the implementation of these improvements and should be eliminated. Time-varying cost assignment is preferred, so that these new technologies can deliver their full value to customers and utilities alike.

NOTES

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ATTACHMENT B

SALT RIVER PROJECT

SPECIAL BOARD MEETING

CONTINUATION SPECIAL BOARD)
MEETING ON PROPOSED CHANGES TO)
STANDARD ELECTRIC PRICE PLANS)
AND TERMS AND CONDITIONS OF)
COMPETITION)
)

February 12, 2015
9:40 a.m.
SRP PERA CLUB
East Continental Drive
Tempe, Arizona

Prepared By:

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continue to look at that possibility because if we're going to be all about price signals producing appropriate results, then I think we need to be fair and consistent in how we look at that.

MR. LOWE: Understood. Thank you.

MR. BONSALL: If I could kind of amplify a little bit on some of those answers. You know, we already have demand charges in our industrial customers, our commercial class. As you know, you're on EZ-3, EZ-3 is getting closer to a demand kind -- it's a demand related version of an energy charge. If you took EZ-3 and you compressed it down to an instantaneous number, you basically got a demand charge. You got Time-Of-Use customers. Between EZ-3 and Time-Of-Use, we've got a quarter of a million residential customers, plus or minus currently, correct me if I'm wrong, on time differentiated pricing which is a reflection of demand cost. You've got seasonal differentiation as well in the wintertime, summertime, summer peak seasons.

So we've got a number of versions that are kind of along those lines economically and it's the customer's choice, frankly, which price plan they select. I mean, ultimately in this discussion, you will get to the point where you're weighing the benefits of customer choice or customer preference versus how (unintelligible) you want to be on sending an economic signal and Rob economically established it would be the purest economic thing to do to send a demand signal.

On the other hand, when people buy a commodity, they are not just buying a commodity. They're buying a lot of things that go around the commodity, including information, including convenience, including just their level of interest in the commodity purchase itself. It's not just explicitly through the commodity.

I guess the bottom line on that is I think it would be very difficult, were she still with us, to put my grandma ma on a demand charge. I mean, we're gonna have people that just don't want to do that or it's too complicated for them to understand and/or they don't care about it. I think we need to be sensitive to some of those issues as well.

MR. HOOPES: I hope you're not suggesting that I want your grandmother to pay more than she needs to, but --

MR. BONSALL: Actually, President Hoopes, I was assuming that. Knowing you, I thought, "He makes some sense."

MR. HOOPES: You can deal with those things with a more transparent subsidy of the core or price plan, poor people, people who don't have the capabilities of making a rational choice, but I would suggest to some degree that's throwing the baby out with the bath water. It's all about the numbers, how many would benefit from it and how it would be applied.

But I guess also to carry on with one of Wendy's comment is, is we're doing it for the solar people and I understand it's -- those are new customers. They can make a choice as to whether or not they want to play at all, but we make much of the price signal for them and I think -- I'm not suggesting it makes sense now or it will make sense three years from now, but I think it's not fair and is inappropriate to just categorically exclude the possibility that it might make sense over time to move to more of a tiered demand for more customers and distributed generation customers.

MR. BONSALL: I wasn't suggesting that we would not do that. I just think there's a no trade off involved there that we all consistently need to keep in mind. You know, one option that we could consider here is the possibility, frankly, of opening up E-27 on a pilot basis to other customers and see what they think.

MR. HOOPES: Yeah.

MR. BONSALL: Just try it out and see what they think.

MR. WHITE: Mark.

ATTACHMENT C

A Pathway to the Distributed Grid

Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value

White Paper

SolarCity

Grid Engineering

Executive Summary

Designing the electric grid for the 21st century is one of today's most important and exciting societal challenges. Regulators, legislators, utilities, and private industry are evaluating ways to both modernize the aging grid and decarbonize our electricity supply, while also enabling customer choice, increasing resiliency and reliability, and improving public safety, all at an affordable cost.

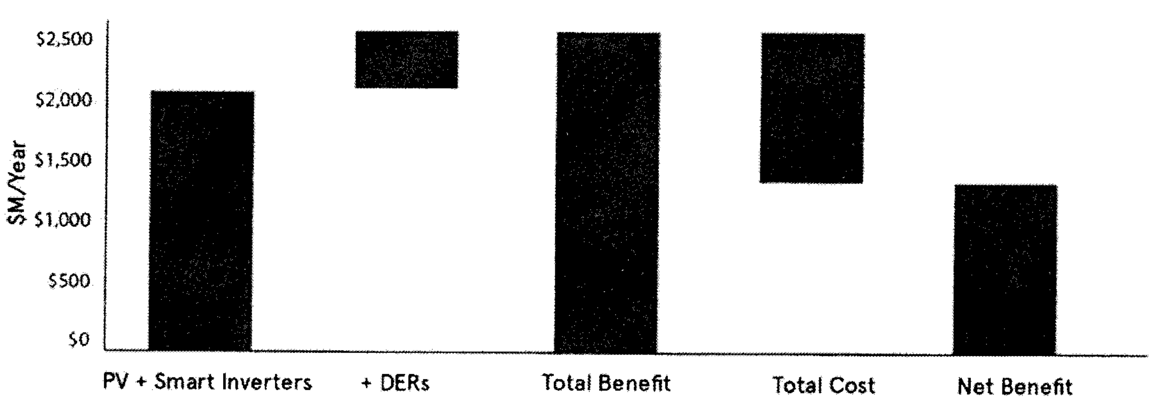
However, modernizing an aging grid will require significant investments over and above those seen in any recent period – potentially exceeding $1.5 trillion in the U.S. between 2010-2030.[1] Given the large sums of ratepayer funds at stake and the long-term impact of today's decisions, it is imperative that such investment is deployed wisely, cost-effectively, and in ways that leverage the best technology and take advantage of customers' desire to manage their own energy.

In this report, we explore the capability of distributed energy resources (DERs) to maximize ratepayer benefits while modernizing the grid. First, we quantify the net societal benefits from proactively leveraging DERs deployed in the next five years, which we calculate to be worth over $1.4 billion a year in California alone by 2020. Then, we apply this methodology to the most recently available Investor Owned Utility (IOU) General Rate Case (GRC) filing – Pacific Gas and Electric's 2017 GRC – in order to evaluate whether DERs can cost effectively replace real-world planned distribution capacity projects. Finally, we evaluate the impediments to capturing these benefits in practice. These structural impediments undermine the deployment of optimal solutions and pose economic risk to consumers, who ultimately bear the burden of an expensive grid. Accordingly, we suggest several ways to overcome these impediments by improving the prevailing utility regulatory and planning models.

Distributed Energy Resources Offer a Better Alternative

This report presents an economic analysis of building and operating a 21st century power grid – a grid that harnesses the full potential of distributed energy resources such as rooftop solar, smart inverters, energy storage, energy efficiency, and controllable loads. We find that an electric grid leveraging DERs offers an economically better alternative to the centralized design of today. DERs bring greater total economic benefits at lower cost, enable more affordability and consumer choice, and improve flexibility in grid planning and operations, all while facilitating the de-carbonization of our electricity supply.

Over $1.4 Billion per Year in Net Societal Benefits from DERs by 2020



February 2016

To evaluate the potential benefits, we build on existing industry methodologies to quantify the net societal benefits of DERs. Specifically, we borrow the *Net Societal Costs/Benefits* framework from the Electric Power Research Institute (EPRI),[2] incorporating commonly recognized benefit and cost categories, while also proposing methodologies for several hard-to-quantify benefit categories that are often excluded from traditional analyses. Next, we incorporate costs related to the deployment and utilization of DERs, including integration costs at the bulk system and distribution levels, DER equipment costs, and utility program management costs. Using this structure, we quantify Net Societal Benefits of more than $1.4 billion a year by 2020 for California alone from DER assets deployed in the 2016-2020 timeframe, as depicted in the previous figure.

In addition to evaluating net societal benefits at the system level, we consider the benefits of DER solutions for specific distribution projects in order to evaluate whether DERs can actually defer or replace planned utility investments in practice. Specifically, we apply the relevant set of cost and benefit categories to the actual distribution investment plans from California's most recently available GRC filing, which is PG&E's 2017 General Rate Case Phase I filing. This real-world case study assesses a commonly voiced critique of utilizing DERs in place of traditional utility infrastructure investments: that not all avoided cost categories are applicable for every distribution project, or that DERs only provide a subset of their potential benefits in any specific project. Therefore, we consider only a subset of utility-applicable avoided cost categories when assessing the set of distribution infrastructure projects in PG&E's 2017 GRC filing; we also utilize PG&E's own avoided cost values rather than our own assumptions. Even using PG&E's conservative assumptions on this subset of benefits, we quantify a net benefit for DER solutions used to replace the distribution capacity investments in PG&E's 2017 GRC

Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

While our analysis shows net societal benefits from DERs, both at the societal and distribution project levels, under the prevailing utility regulatory model DER benefits cannot be fully captured. Instead, utilities have a fundamental financial incentive of "build more to profit more", which conflicts with the public interest of building and maintaining an affordable grid. Under today's regulatory paradigm, utilities see a negative financial impact from utilizing resources for distribution services that they do not own – which includes the vast majority of distributed energy resources – even if those assets would deliver higher benefits at lower cost to ratepayers. This financial incentive model is a vestige of how utilities have always been regulated, a model originally constructed to encourage the expansion of electricity access. However, in this age of customers managing their energy via DERs, this regulatory model is outdated. This report offers a pathway to removing this structural obstacle, calling for a regulatory model that neutralizes the conflict of incentives facing utilities. While separating the role of grid planning and sourcing from the role of grid asset owner – such as through the creation of an independent distribution system operator (IDSO) – would achieve this objective, some states may choose not to implement an IDSO model at this time. In these instances, this paper proposes the creation of a new utility sourcing model, which we call *Infrastructure-as-a-Service*, that allows utility shareholders to derive income, or a rate of return, from competitively sourced third-party services. This updated model would help reduce the financial disincentive that currently biases utility decision-making against DERs, encouraging utilities to deploy grid investments that maximize ratepayer benefits regardless of their ownership.

Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Combined with the "build more to profit more" financial incentive challenge, current grid planning can encourage 'gold-plating', or overinvestment, in grid infrastructure. Furthermore, outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential integration challenges rather than proactively harnessing these flexible assets. This report offers a pathway to modernizing grid planning, calling for the utilization of an *Integrated Distribution Planning* approach that encourages incorporating DERs into every aspect of planning, rather than merely accommodating DER interconnection. Additionally, transparency into grid needs and planned investments is fundamental to realizing benefits. As such, this report recommends a data transparency approach that invites broad stakeholder engagement and increases industry competition in providing grid solutions.

Key Takeaways

1. Distributed energy resources offer *net economic benefits to society* worth more than $1.4 billion per year in California alone by 2020, including benefits related to voltage and power quality, conservation voltage reduction, grid reliability and resiliency, equipment life extension, and reduced energy prices.

2. To realize these benefits, the *utility regulatory incentive model* must change to take advantage of customer choices to manage their own energy. Utility incentives should promote best-fit, least-cost investment decisions regardless of service supplier – eliminating the current bias toward utility-owned investments.
3. Utility planning approaches must also be modernized to capture these benefits. Utilization of an *integrated distribution planning* framework will unlock the economic promise of distributed energy resources, while widely sharing utility grid data in standard data formats will invite broader stakeholder engagement and competition.

Recommendations and Next Steps

Our ultimate goal is to help provide concrete evidence and recommendations needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to transition to a cleaner, more affordable and resilient grid. While the details of implementing these recommendations would vary from state to state, we see the following as promising steps forward for all industry stakeholders in modernizing our grid:

1. Future regulatory proceedings and policy venues related to capturing the benefits of DERs should *incorporate the expanded benefit and cost categories* identified in this paper.
2. Regulators should look for near-term opportunities to *modernize the utility incentive model*, either for all utility earnings or at a minimum for demonstration projects, to eliminate the bias toward utility-owned investments.
3. Regulators should require utilities to *modernize their planning processes* to integrate and leverage distributed energy resources, utilizing the integrated distribution planning process identified in this paper.
4. Regulators should require utilities to *categorize all planned distribution investments* in terms of the underlying grid need. Utilities should make data available electronically to industry, ideally in a machine-readable format.

Call for Input

We offer this paper as an effort to support the utilization of grid modernization to maximize ratepayer benefits. The cost/benefit analysis we develop here is an effort meant to expand the industry's ability to quantify the holistic contribution that DERs offer to the grid and its customers, extending the familiar cost/benefit framework beyond PV-only analyses and into full smart inverter and DER portfolios. Furthermore, we recognize that important regulatory proceedings – such as the CPUC Distribution Resource Plans (DRP) and CPUC Integrated Distributed Energy Resources (IDER) – will play an important role in giving stakeholders the tools to calculate the value of DERs, and offer this paper a as resource in those efforts.

No single report could adequately address all the issues – engineering, economic, regulatory – that naturally arise during such a transformative time in the industry. By compiling the major issues in one place, we attempt to advance the discussion and suggest that this paper includes a "table of contents" of critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

There are many details of this paper that can be refined, including utilizing more complete data sets to inform the cost/benefit analysis. We welcome ongoing dialogues with utilities and other stakeholders to improve the assumptions or calculations herein, including sharing data and revising methodologies to arrive at more representative figures. In fact, most of the authors of this paper are former utility engineers, economists, technologists, and policy analysts, and would value the opportunity to collaborate. We welcome a constructive dialogue, and can be reached at gridx@solarcity.com.

Acknowledgements

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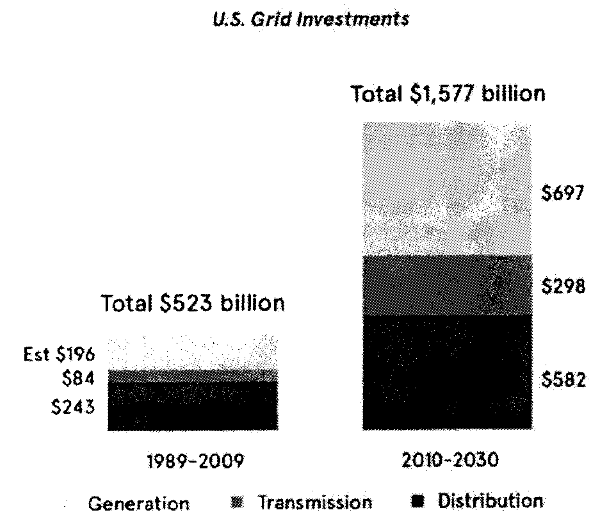
I. Introduction

Grid Investments are Increasing

Grid infrastructure planners are responsible for some of the most significant infrastructure investments in the United States. As of 2011, U.S. utilities had almost half a trillion dollars of undepreciated transmission, distribution and generation assets on their balance sheets, growing at a rate of 6 to 8% per year.[3] As depicted in the adjacent figure, the Edison Electric Institute forecasts that another $879 billion dollars in distribution and transmission investments alone will occur in the twenty year period of 2010 through 2030 – about $44 billion dollars per year – significantly larger than investments seen in the previous 20 year period.[4] Grid investments have a significant and increasing impact on the total electricity costs faced by U.S. consumers.



In light of this huge level of grid investment occurring over the next few decades, an imperative exists to ensure that these investments are deployed to maximize ratepayer benefits. There has been relatively little focus to date on how to effectively focus and reduce these infrastructure costs, particularly in the areas of transmission and distribution planning, despite the fact that they often make up half of the average residential customer's bill. This level of investment calls for a reexamination of the technological solutions available to meet the grid's needs and an overhaul of the planning process that deploys these solutions. States like California and New York have begun this process, primarily spurred by a focus on how distribution planning and operations may evolve in a future with high penetration of distributed resources.[5] While these nascent discussions and rulemakings are positive first steps, the planning framework for grid modernization must change considerably to avoid costing ratepayers billions in unnecessary, underutilized investments.

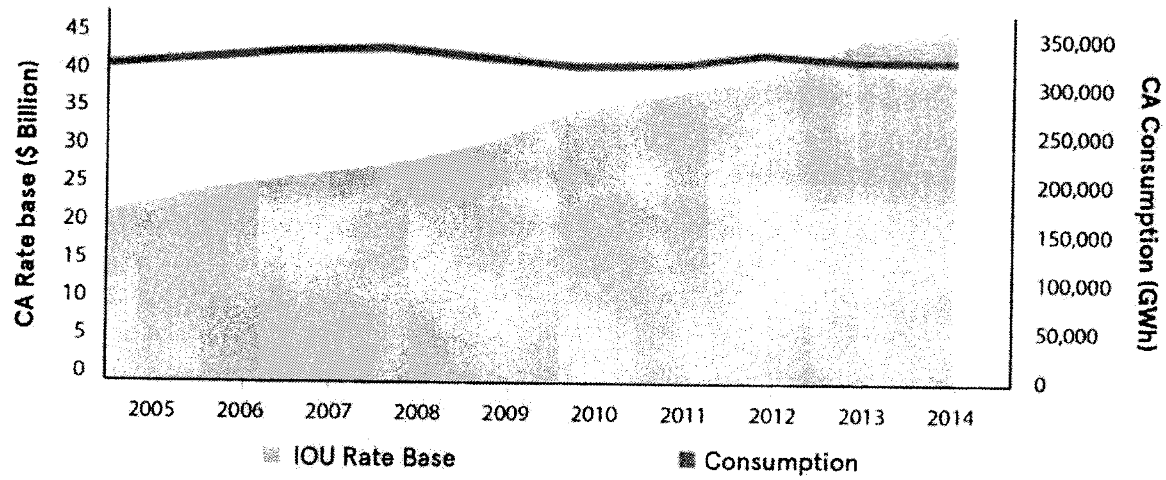
Current Utility Regulatory Model Incents a *Build More to Profit More* Approach

The current utility regulatory model, which was designed around a monopoly utility managing all aspects of grid design and operation, is outdated and unsuited for today's reality of consumers installing DERs that can benefit the grid. Therefore, industry fundamentals need to be reexamined, and the utility incentive model is a key place to start.

Electric utilities are generally regulated under a "cost plus" model, which compensates utilities with an authorized rate of return on prudent capital investments made to provide electricity services. While this model makes sense when faced with a regulated firm operating in a natural monopoly, it is well known to result in a number of economic inefficiencies, as perhaps best analyzed by Jean Tirole in his Nobel Prize winning work on market power and regulation.[6]

One fundamental problem resulting from the "cost plus" utility regulatory model is that utilities are generally discouraged from utilizing infrastructure resources that are not owned by the utility, even if competitive alternatives could deliver improved levels of service at a lower cost to ratepayers. Beyond regulatory oversight, this model contains no inherent downward economic pressure on the size of the utility rate base, or the cumulative amount of assets upon which the utility earns a rate of return. As such, utility rate bases have consistently and steadily grown over time. For example, the following chart depicts the size and recent growth of the electricity rate base for California investor-owned utilities, which continues to significantly grow even in the presence of flat electricity consumption. In short, the fundamental incentive utilities have to build more utility-owned infrastructure in order to profit more conflicts with the public interest as the grid becomes more customer-centric and distributed.

Trends in Rate Base for California Investor-Owned Utilities[7,8]



Traditional Grid Planning Focuses on Traditional Assets

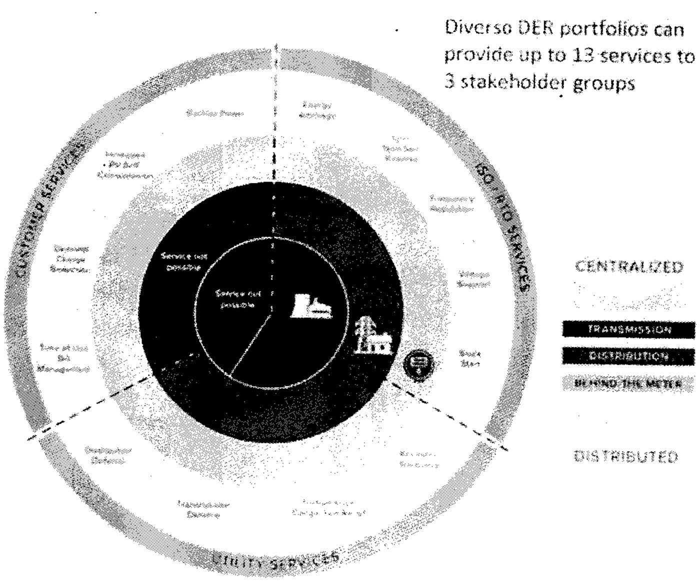
Grid planning for infrastructure investments has historically focused on installing expensive, large assets that provide service over a wide geographic region. This structure naturally evolved from the technology and market characteristics of the original electricity industry, including a natural monopoly, centralized generation, long infrastructure lead times, high capital costs with significant economies of scale, and a concentration of technical know-how within the utility.

Many of these barriers have been eliminated with the technological advancement in physical infrastructure options – such as DER portfolios that can meet grid needs – and increased sophistication of grid design and operational tools. However, grid planning remains focused on utilizing traditional infrastructure to the detriment of harnessing the increasing availability of DERs. Utilizing DER solutions will require a shift in grid planning approaches, as well as increased access to the underlying planning and operational data needed to enable DERs to operate most effectively in concert with the grid.

Distributed Energy Resources Offer Increased Grid Flexibility

Distributed energy resources include assets such as rooftop PV, smart inverters, controllable loads, permanent load shifting, combined heat and power generators, electric vehicles, and energy efficiency resources. These resources provide a host of benefits to the customer, utility, and transmission operator as identified by numerous research organizations including EPRI and the Rocky Mountain Institute (RMI). As depicted in the RMI figure to the right, diverse portfolios of DERs offer a wide range of grid services at the distribution, transmission, and customer levels.[9]

Distributed energy resources can offer deferral and avoidance of planned grid investments, improved grid resiliency, and increased customer choice. DERs, if deployed effectively and placed on equal footing in the planning process with traditional grid investments, can ultimately lead to increased net benefits for ratepayers.



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II. Distributed Energy Resources Offer a Better Alternative

Motivated by the challenge faced in designing a grid appropriate to the 21st century, this report first focuses on determining the quantifiable net economic benefits that DERs can offer to society. The approach taken builds on existing avoided cost methodologies – which have already been applied to DERs by industry leaders – while introducing updated methods to hard-to-quantify DER benefit categories that are excluded from traditional analyses. While the final net benefit calculation derived in this report is specific to California, the overall methodological advancements developed here are applicable across the U.S. Moreover, the ultimate conclusion from this analysis – that DERs offer a better alternative to many traditional infrastructure solutions in advancing the 21st century grid – should also hold true across the U.S., although the exact net benefits of DERs will vary across regions.

A. Methodology

The methodology utilized in this paper is built upon well-established frameworks for valuing policies, programs and resources – frameworks that are grounded in the quantification of the costs and benefits of distributed energy resources. Specifically, the methodology employed here:

1. Begins with the Electric Power Research Institute's 2015 Integrated Grid/Cost Benefit Framework in order to quantify total net societal costs and benefits in a framework that applies nationally.[10]
2. Quantifies the benefits for the state of California, where the modeling of individual cost and benefit categories is possible using the California Public Utilities Commission 2015 Net Energy Metering Successor Public Tool.[11] Within the context of California, this report's DER avoided cost methodology is expanded beyond EPRI's base methodology to incorporate commonly recognized (although not always quantified) categories of benefits and costs, while also proposing methodologies for several hard-to-quantify categories using the Public Tool.
3. Incorporates the full costs of DER integration, including DER integration cost data as identified by California utilities in their 2015 Distribution Resource Plans[12] to determine the net benefits of achieving 2020 penetration levels.
4. Repeats the methodology in a concrete case study by applying it to the planned distribution capacity projects from the most recent Phase I General Rate Case in California.

Enhancing Traditional Cost/Benefit Analysis and Describing Benefits as Avoided Cost

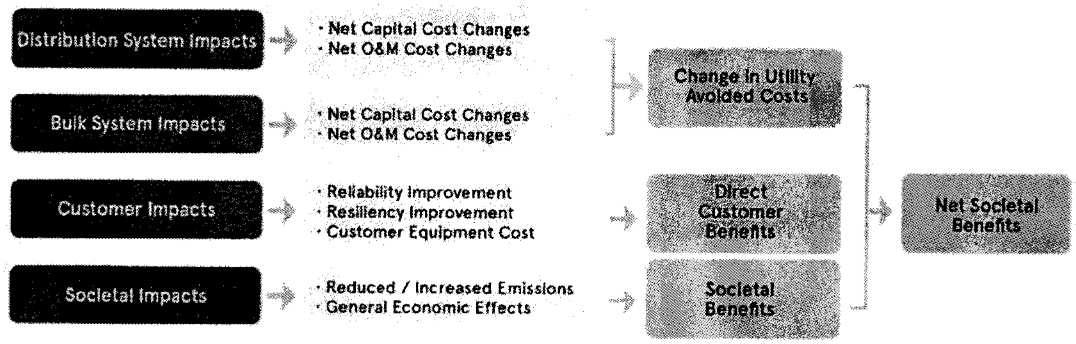
Cost/benefit analyses have been conducted for many decades to evaluate everything from utility-owned generation to utility-administered customer programs such as energy efficiency rebates and demand response program funding. This paper replicates established methodologies wherever possible, and offers new or enhanced methodologies where appropriate to consider new benefit categories that are novel to customer-driven adoption of DERs, and therefore often excluded from traditional analyses.

A key component of cost/benefit analysis commonly used for valuing the benefits of DER is the avoided cost concept, which considers the benefits of a policy pathway by quantifying the reduction in costs that would otherwise be incurred in a business-as-usual trajectory. While avoided cost calculations can be performed with varying scopes,[13] there is some degree of consensus on what the appropriate value categories are in a comprehensive avoided cost study. Groups like IREC,[14] RMI[15] and EPRI[16] have attempted to take these standard valuation frameworks even further, describing general methods for valuing some of the benefit categories that are often excluded from traditional analyses.

Each step taken by researchers to enhance previously used avoided cost methodologies advances the industry beyond outdated historical paradigms. DER-specific methodological updates include the consideration of new types of avoided costs that could be provided by distributed resources, or a revision of the assumption that resources adopted by customers are uncontrollable, passive deliverers of value to the grid and that proactive planning and policies cannot or will not be implemented to maximize the value of these grid-interactive resources.

This report continues the discussion using EPRI's 2015 Integrated Grid/Cost Benefit Framework as a springboard. EPRI's framework, depicted in the following image) was chosen as it is the most recently published comprehensive cost/benefit analysis framework for DERs. This report assumes a basic familiarity with EPRI's methodology – or avoided cost methodologies in general – on the part of the reader, although explanations of each cost or benefit category are included in the following section.

EPRI Cost/Benefit Framework[17]



The Value of DERs within California

While the overall methodology enhanced within this report is applicable nationwide, the focus of this report's economic valuation of DERs in the cost/benefit analysis is limited to the state of California. For California's NEM 2.0 proceeding, the energy consulting firm Energy+Environmental Economics (E3) created a sophisticated model that parties used to determine the impact of various rate design proposals. A major component of this model was the ability to assess DER avoided costs under different input assumptions. The more traditional avoided cost values in this paper are derived from the inputs used in the NEM 2.0 proposal filing of The Alliance of Solar Choice (TASC) for the E3 model, which is available publicly online.[18]

Additionally, benefit and cost categories for DERs – along with accompanying data and quantification methods – are being developed in the CPUC Distribution Resource Plans (DRP) proceeding. This update of the DER valuation framework in the DRP proceeding, however, is not present in the existing methodologies being used to quantify the benefits of rooftop solar in California as part of the NEM 2.0 proceeding due to the concurrent timing of the two proceedings. This report bridges these two connected proceedings in its economic analysis of the value of DERs within California.

While evaluating net societal benefits at the system level in California is a key step in understanding the total potential value of DERs, there remains much discussion within the industry regarding whether calculated net benefits can actually be realized from changes in transmission and distribution investment planning. To this end, this analysis applies the developed California DER valuation framework to a real-world case study utilizing the latest GRC filed in California, PG&E's 2017 General Rate Case Phase I filing. By utilizing this third dataset, in addition to the NEM 2.0 and DRP proceedings, this analysis delivers a comprehensive and up-to-date consideration of the potential value DERs can provide to the grid.

Analysis Scope, Assumed Scenario, and End State

This report evaluates the benefits of customer DER adoption, the associated costs, and the resulting net benefit/cost.

DESCRIPTION OF SCOPE	
Net Societal Benefit = Societal Benefits – Societal Costs	
Societal Benefits	The benefits that would be generated if California achieved high-penetration of distributed energy resources.
Societal Costs	The investment cost that would be necessary to enable California to achieve high-penetration of distributed energy resources.
Net Societal Benefits	The value to society of achieving a high-penetration California defined as the benefits of the outcome less the costs of achieving the outcome.

The benefits and costs of DER are highly dependent on penetration levels. Therefore, this analysis utilizes a set of common assumptions for expected DER penetration, and specifies a market end state scenario upon which benefits and costs are quantified. The end-state assumed in this report utilizes scenarios in Southern California Edison's (SCE) July 1, 2015 Distribution Resource Plan, which includes DER adoption levels and integration cost estimates for the 2016-2020 period. These integration costs inform DER penetration assumptions, which are applied consistently across the benefits calculations to ensure that the costs of low penetration are not attributed to the benefits of high penetration, and vice-versa.

Incremental DER Adoption Scenario for 2016-2020

TECHNOLOGY	QUANTITY
Solar	4.5 GW
With Storage	900 MWh (10% Adoption)
With Load Control	150 MW (20% Adoption)

To simplify the discussion, solar deployment is focused on the years 2016-2020, adopting the penetration levels and costs associated with the TASC reference case as filed in the CPUC NEM 2.0 proposal filing, which corresponds approximately to SCE's Distribution Resource Plan Scenario 3. Of the approximately 900,000 new solar installations expected to be deployed during this period, SolarCity estimates 10% would adopt residential storage devices and 20% would adopt controllable loads (assumptions are based on customer engagement experience and customer surveys). These adoptions are central to the ability of customer DER deployments to defer and avoid traditional infrastructure investments as assessed in this paper.

The assumptions described above are used to complete the cost/benefit analysis of DERs for the whole of California. After evaluating net societal benefits at the system level, the methodology is then applied to a particular case study of actual distribution projects proposed under the latest GRC filed within California, PG&E's 2017 General Rate Case Phase I filing.

In the following sections, the deployment scenario is evaluated both qualitatively and quantitatively under a cost-benefit framework that is grounded in established methodologies, but enhanced to consider the impact of such a large change in the way the electric system is operated. The study consolidates a range of existing analyses, reports and methodologies on DERs into one place, supporting a holistic assessment of the energy policy pathways in front of policy-makers today.

B. Avoided Cost Categories

The avoided cost categories evaluated in this report are summarized in the following table. The first seven categories are included within traditional cost-benefit analyses, and as such are not substantially extended in this report (see Appendix for methodological overviews and TASC NEM Successor Tariff filing for comprehensive descriptions and rationale on assumptions[19]). The next five categories (in yellow highlight) represent new methodology enhancements to hard-to-quantify avoided cost categories (i.e. benefit categories) that are often excluded from traditional analyses. In this section, we detail the methodology and rationale for quantifying these five avoided cost categories.

AVOIDED COST	DESCRIPTION
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility
Voltage and Power Quality	The value of avoiding or reducing the cost required to maintain voltage and frequency within acceptable ranges for customer service
Conservation Voltage Reduction	The value of enabling conservation voltage reduction benefits by providing localized voltage support
Equipment Life Extension	The value of extending the useful life and improving the efficiency of distribution infrastructure by reducing load and thermal stress equipment
Reliability & Resiliency	The value of avoiding or reducing the impact outages have on customers
Market Price Suppression	The value of reducing the electric demand in the market, hence reducing market clearing prices for all consumers of electricity

Voltage, Reactive Power, and Power Quality Support

Solar PV and battery energy storage with 'smart' or advanced inverters are capable of providing reactive power and voltage support, both at the bulk power and local distribution levels. At the bulk power level, smart inverters can provide reactive power support for steady-state and transient events, services traditionally supplied by large capacitor banks, dynamic reactive power support, and synchronous condensers. For example, in Southern California the abrupt retirement of the San Onofre Nuclear Generation Station (SONGS) in 2013 created a local shortage of reactive power support, endangering stable grid operations for SCE in the Los Angeles Basin area. To meet this reactive power need, SCE sought approval to deploy traditional reactive power equipment at a cost of $200-$350 million, as outlined in the table below. DERs were not included in the procurement to meet this need. Had DERs with smart inverters been evaluated as part of the solution, significant reactive power capacity could have been obtained to avoid the deployment of expensive traditional equipment.

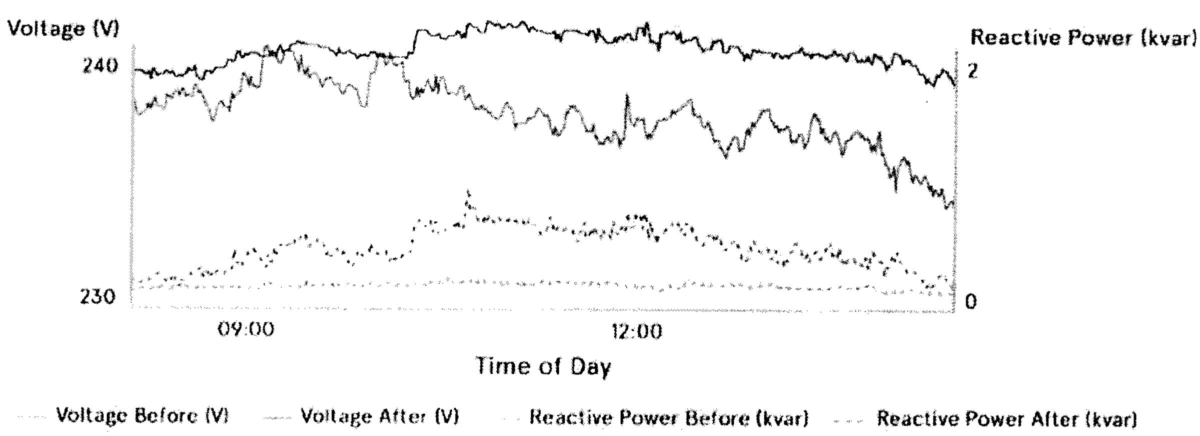
SONGS Reactive Power Replacement Projects

PROJECT	CAPACITY (MVAR)	IN-SERVICE	COST
Huntington Beach Synchronous Condensers	280	6/1/2013	$4.75M
Johanna and Santiago 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M $10-50M
Viejo 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M $10M $10-50M
Talega Area Dynamic Reactive Support	250	6/1/2015	$58-72M
South Orange County Dynamic Reactive Support	400	12/1/2017	$50-75M
Penasquitos 230 kV Synchronous Condenser	240	5/1/2017	$56-70M
Total	**1,400**		**$201-$352M**

Sources[20,21,22,23,24,25,26,27]

At the distribution level, smart inverters can provide voltage regulation and improve customer power quality, functions that are traditionally handled by distribution equipment such as capacitors, voltage regulators, and load tap changers. While the provision of reactive power may come at the expense of real power output (e.g. such as power otherwise produced by a PV system), inverter headroom either exists or can readily be incorporated into new installations to provide this service without impacting real power output. The capability of DER smart inverters to provide voltage and power quality support is currently being demonstrated in several field demonstration projects across the country. For instance, a demonstration project in partnership with an investor-owned utility is currently demonstrating the voltage support from a portfolio of roughly 150 smart inverters controlling 700kW worth of residential PV systems. The chart below depicts the dynamic reactive power delivered to support local voltage. In this instance, smart inverter support resulted in a 30% flatter voltage profile.[28]

Reactive power and voltage support from a smart inverter



Projects such as the SONGS reactive power procurement project provide recent examples where utility investment was made for reactive power capacity. These projects were used to quantify the economic benefit of DERs providing reactive power support. To do so, a corresponding $/kVAR-year value was applied to the inverter capacity assumed in the deployment scenarios to determine the value of the services offered by the DER portfolio. Note, also, that markets including NYISO, PJM, ISO-NE, MISO, and CAISO already compensate generators for capability to provide and provision of reactive power.[29]

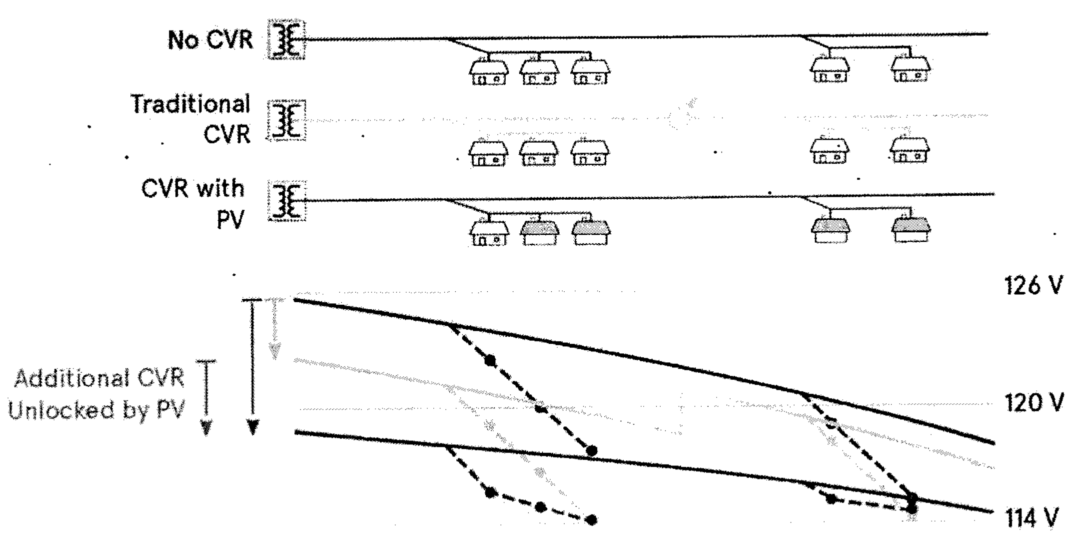
Conservation Voltage Reduction

Smart inverters can enable greater savings from utility conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that reduces customer service voltages in order to achieve a corresponding reduction in energy consumption. CVR programs are often implemented system-wide or on large portions of a utility's distribution grid in order to conserve energy, save customers on their energy bills, and reduce greenhouse gas emissions. CVR programs typically save up to 4% of energy consumption on any distribution circuit.[30] The utilization of smart inverters is estimated to yield another 1-3% of incremental energy consumption savings and greenhouse gas emissions reductions.

From an engineering perspective, CVR schemes aim to reduce customer voltages to the lowest allowable limit as allowed by American National Standards Institute (ANSI) standards. However, CVR programs typically only control utility-owned distribution voltage regulating equipment, changes to which affect all customers downstream of any specific device. As such, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit), since dropping the voltage any further would violate ANSI standards for that customer.

Since smart inverters can increase or decrease the voltage at any individual location, DERs with smart inverters can be used to more granularly control customer voltages in CVR schemes. For example, if the lowest customer voltage in a utility voltage regulation zone were to be increased by, say, 1 Volt by controlling a local smart inverter, the entire voltage regulation zone could then be subsequently lowered another Volt, delivering substantially increased CVR benefits. Such an example is depicted in the image below, where the green line represents a circuit voltage profile where smart inverters support CVR. Granular control of customer voltages through smart inverters can dramatically increase CVR benefits.

DERs control voltage locally and enable CVR

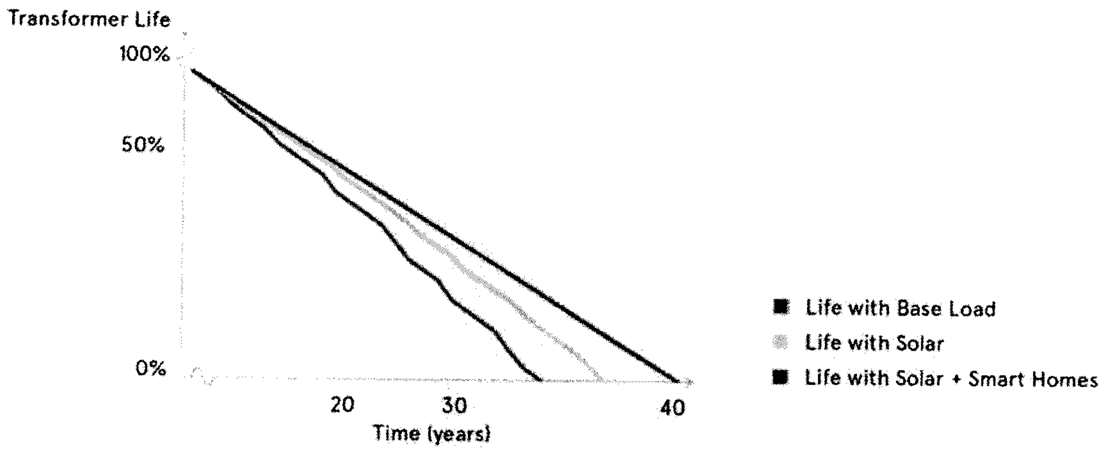


Equipment Life Extension

Either through local generation, load shifting, and/or energy efficiency, DERs reduce the net load at individual customer premises. A portfolio of optimized DERs dispersed across a distribution circuit in turn reduces the net load for all equipment along that distribution circuit. Distribution equipment, such as substation transformers, operating at reduced loading will benefit from increased equipment life and higher operational efficiency.

Distribution equipment may operate at very high loading during periods of peak demand, abnormal configuration, or emergency operation. When the nominal rating of equipment is exceeded, or overloaded, the equipment suffers from degradation and reduction in operational life. The more frequently that equipment is overloaded, the more that such degradation occurs. Furthermore, the efficiency of transformers and other grid equipment falls as they perform under increased load. The higher the overload, the larger the efficiency losses. Utilities have significant portions of their grid equipment that regularly operate in overloaded fashion. DERs' ability to reduce peak and average load on distribution equipment therefore leads to a reduction in the detrimental operation of the equipment and an increase in useful life, as shown in the following figure. The larger the peak load reduction, the larger the life extension and efficiency benefits.

Distributed Energy Resources Extend Transformer Life



To quantify these benefits, medium to large liquid-filled transformers were modeled with typical load and DER generation profiles. The magnitude of the reduced losses and resulting equipment degradation avoidance were calculated using IEEE C57.12.00-2000 standard per unit life calculation methodology.[31,32] DERs such as energy storage are able to achieve an even greater avoided cost than solar alone, as storage dispatch can more closely match the distribution peak. Quantified benefits contributing to net societal benefits calculation include the deferred equipment investment due to extended equipment life and reduced energy losses through increased efficiency.

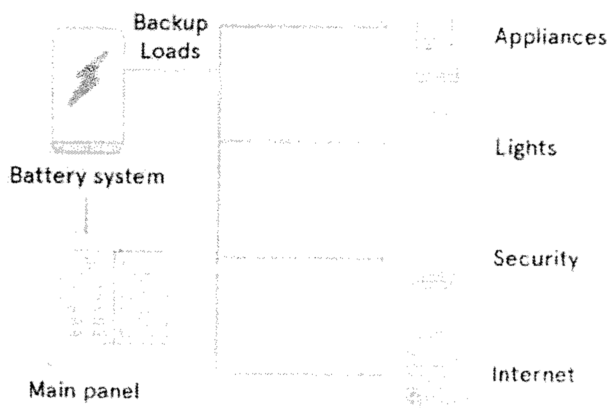
Note that non-optimized DERs can be cited as having negative impact on equipment life. While highly variable generation and load can negatively impact equipment life – such as driving increased operations of line regulators – optimized and coordinated smart inverters mitigate this potential volatility impact on equipment life.

Resiliency and Reliability

DERs such as energy storage can provide backup power to critical loads, improving customer reliability during routine outages and resiliency during major outages. The rapidly growing penetration of batteries combined with PV deployments will reduce the frequency and duration of customer outages and provide sustained power for critical devices, as depicted in the adjacent figure.

Improved reliability and resiliency has been the goal of significant utility investments, including feeder reconductoring and distribution automation programs such as fault location, isolation, and service restoration (FLISR). Battery deployments throughout the distribution system can eventually reduce utility reliability and resiliency investments. However, this analysis utilizes a conservative approach, only considering average customer savings from reduced outages and excludes avoided utility investments.

Distributed Energy Resources Improve Customer Resiliency and Reliability

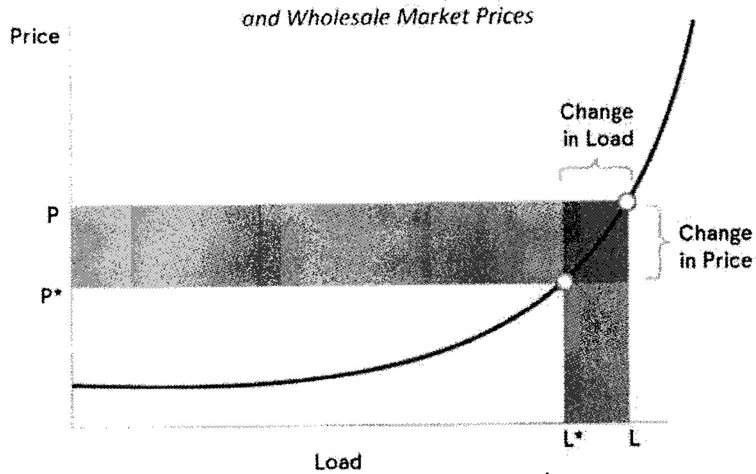


To quantify near-term reliability and resiliency benefits, the value of lost load as calculated by Lawrence Berkeley National Lab[33] was applied to the energy that could be supplied during outages. Outages were based on 2014 CPUC SAIFI statistics.

Market Price Suppression Effect

Wholesale electricity markets provide a competitive framework for electric supply to meet demand. In general, as electric demand increases market prices increase. DERs can provide value by reducing the electric demand in the market, leading to a reduction in the market clearing price for all consumers of electricity. This effect was recently validated in the U.S. Supreme Court's decision to uphold FERC Order 745, noting that operators accept demand response bids if and only if they bring down the wholesale rate by displacing higher-priced generation. Notably, the court emphasized that "when this occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges."[34] As a behind-the-meter resource, rooftop solar impacts wholesale markets in a similar way to demand response, effectively reducing demand and thus clearing prices for all resources during solar production hours. While the CPUC Public Tool attempts to consider the avoided cost of wholesale energy prices, it does not consider the benefits of reducing wholesale market clearing prices from what they would have been in the absence of solar.

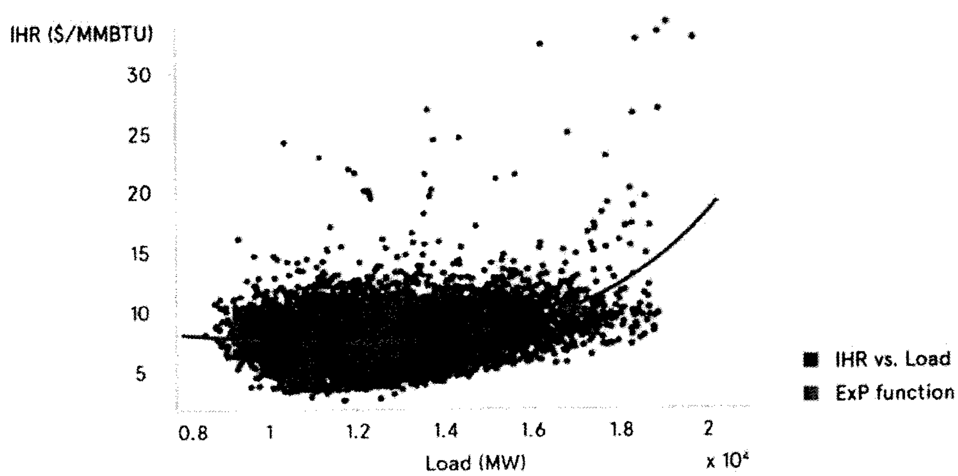
Relationship between Electric Demand and Wholesale Market Prices



This effect is illustrated in the adjacent figure. In the presence of DERs, energy prices are at the lower "P*" price which otherwise would have been at the higher "P" price absent the DERs. Market price suppression could then be quantified as the difference between prices multiplied by load, or $(P - P^*) * L^*$.

To quantify the magnitude of cost reductions due to market price suppression, this report estimates the relationship between load and market prices based on historical data. It is important to isolate other driving factors to only capture the effect of load change on prices. One of these driving factors is natural gas prices, which directly impacts electric prices because the marginal supply resource in California is often a natural gas-fired power plant. This can be isolated by normalizing market prices over gas prices, known as Implied Heat Rate (IHR), and estimating the relationship between IHR and load, which is shown in figure below for PG&E DLAP prices and load.

Relationship between electric demand and Implied Heat Rate for PG&E



Smart energy homes equipped with energy storage are able to achieve an even greater avoided cost than distributed solar alone. Storage devices that discharge in peak demand hours with high market clearing prices can take advantage of the stronger relationship between load and price at high loads.

Results

After establishing the 2016-2020 penetration scenario and defining the methodologies for each category of avoided cost, the CPUC Public Tool was utilized to estimate the benefits of achieving the 2020 penetration scenario. For avoided cost categories the CPUC Public Tool was not able to incorporate, calculations were completed externally using common penetration and operational assumptions for each technology type. In order to be consistent with the CPUC Public Tool outputs, levelized values are expressed in annual terms in 2015 dollars below.

Annual Benefits of 2016-2020 DER Deployments

AVOIDED COST CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	[illegible]	[illegible]	
Energy + Losses	$637	$74	$710
Generation Capacity	$91	$99	$190
Transmission Capacity	$333	$42	$375
Distribution Capacity	$187	$54	$241
Ancillary Services	$6	$1	$7
Renewable Energy Compliance	$199	$23	$221
Societal Benefits	$371	$43	$414
Voltage and Power Quality	$91	$7	$99
Conservation Voltage Reduction	$34	$4	$38
Equipment Life Extension	$31	$4	$36
Reliability & Resiliency	$0	$8	$8
Market Price Suppression	$163	$19	$182
Total Benefits	**$2,143**	**$378**	**$2,521**

Previous assessments of high penetration DERs have replicated existing methodologies that have often been applied to passive assets like energy efficiency; however, these approaches fail to recognize the potential value of advanced DERs that will be deployed during the 2016-2020 timeframe. When a more comprehensive suite of benefits that could be generated by DERs today is considered, total benefits of the 2016-2020 DER portfolio in California exceeds $2.5 billion per year.

C. The Costs of Distributed Energy Resources

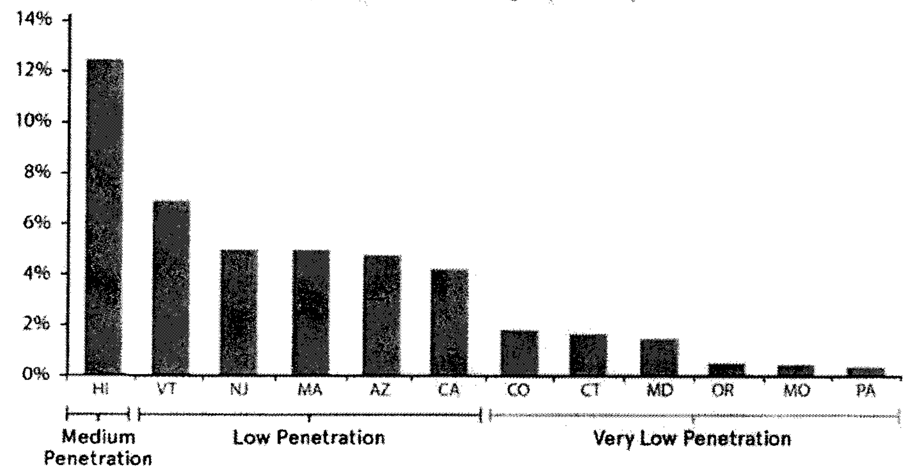
As presented above, distributed resources offer significant ratepayer benefits; however, these benefits are not available without incurring incremental costs to enable their deployment. In order to quantify the net societal benefit of DERs, these costs must be subtracted from the benefits. Costs for distributed energy resources include integration at the distribution and bulk system levels, utility program management, and customer equipment.

Distribution Integration Costs

DERs are a critical new asset class being deployed on the distribution grid which must be proactively planned for and integrated with existing assets. This integration process will sometimes require unavoidable additional investments. However, it is essential to separate incremental DER integration costs from *business as usual* utility investments. Recent utility funding requests for DER integration have included costs above those needed to successfully integrate DERs. This subsection will explore typical DER integration costs and evaluate the validity of each type.

While new DER integration rules of thumb and planning guidelines are emerging,[25] no established approach exists for identifying DER integration investments or estimating their cost. It is clear, however, that integration efforts and costs vary by DER penetration level. Generally, lower DER penetration requires fewer integration investments, while higher penetration may lead to increased investment. As depicted in the following chart, NEM PV penetration levels vary across the U.S.[36] Most states have *very low* (<5%) penetrations, while only Hawaii experiences *medium* (10-20%) penetration. California exhibits *low* (5-10%) penetration overall, although individual circuits may experience much higher penetration.

NEM Solar Capacity as a Percentage of Total System Peak



For this analysis, DER integration costs were developed from estimates submitted by California utilities to the CPUC as part of their Distribution Resource Planning (DRP) filings. This analysis incorporates the specific cost categories and figures from Southern California Edison's filing, since this filing alone included specific cost estimates. In assessing these costs, each proposed investment was reviewed to determine whether it was a required incremental cost resulting from the integration of DERs. If so, it should indeed be included in the cost/benefit calculation. If the investment (or a portion thereof) was determined to be a component of utility *busines as usual* operations, such investment was not included in the analysis.

In order to determine whether a proposed utility investment is required, the following *threshold question* was asked:

- *Would these costs be incurred even in the absence of DER adoption?*

If the costs would be incurred regardless of DER adoption, or if the utility had previously requested regulatory approval for the investment but justified the investment via a program unrelated to DER adoption, then the costs should not be classified as DER integration costs. For example, if a utility had previously requested approval to upgrade (i.e. cutover) 4kV circuits to a higher voltage in order to increase capacity and reliability before DERs were prevalent, yet now associates the upgrade costs to DERs, then the investment should not be attributed to DER integration. This threshold analysis eliminates from consideration or reduces some of the proposed utility integration costs.

Of the remaining costs, each was further assessed by asking the following set of *screening questions*:

- Do more cost effective mitigation measures exist for the proposed investment? Can advanced DER functionalities (e.g. volt/VAR support) mitigate or eliminate the need for the investment?
- Are costs relevant for the forecasted DER penetration levels, or only for much higher penetrations?
- Do stated costs reflect realistic cost figures, or do they reflect inflated estimates?

Several utility integration investments are proposed to mitigate an integration challenge where more cost effective solutions exist. For example, voltage-related concerns due to PV variability are often used to justify replacement of capacitor banks on distribution feeders. However, the use of embedded voltage and reactive power capabilities in smart inverters make the deployment of new capacitor banks redundant and overly expensive in most instances. Furthermore, while some proposed costs may be relevant for high penetrations of DERs – such as bi-directional relays to deal with reverse power flows – these investments may not be necessary at low penetration levels.

The following table presents the DER integration investment categories as identified in SCE's DRP filing according to its Scenario 3 forecast for DER growth in California. SCE's integration costs were scaled up in order to estimate total distribution integration costs for all California utilities; therefore, the table represents total California distribution integration costs over 2016-2020. For each investment, applicability to DER integration is assessed using the threshold and screening questions discussed above, resulting in a quantification of costs that are directly "Applicable to DERs". An overview of the assessment of each high-level integration category is provided in the table, with more detailed technical discussion of each investment type and assessment rationale offered in the Appendix. This cost quantification is necessarily high-level due to the lack of details available for each investment type. As such, more specific assessment is necessary in order to evaluate integration investment plans. This exercise identifies 25% of SCE's DER integration costs, or $1,450 million (or levelized to $189 million annually[37]), as truly applicable to DER integration, which is the number utilized in the cost/benefit analysis in this paper.

CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERs (%)
Distribution Automation	Automated switches w/enhanced telemetry, remote fault indicators	$710	0%
Substation Automation	Substation automation, modern protection relays	$691	30%
Communication Systems	Field area network, fiber optic network	$888	0%
Grid Reinforcement	Conductor upgrades to a larger size, conversion of circuits to higher voltage	$1,070	50%
Technology Platforms and Applications	Grid analytics platform/applications, long term planning tool set, distribution circuit modeling tool, interconnection application processing, DRP data sharing portal, grid/DER management system, system architecture and cyber security, distribution Volt/VAR optimization	$2,337	30%
Total Distribution Integration Costs		**$5,697**	**25% (1,450)**

Bulk System Integration Costs

Integration of variable resources with the bulk power grid is expected to result in an increase in variable operating costs associated with the way the generation fleet is used to accommodate the variability. To quantify this cost, $/MWh values quantifying this cost for a 33% renewable portfolio standard were scaled per calculations adopted by the California PUC.[38]

Utility Program Management Costs

To estimate the incremental utility program costs associated with DER adoption, the default inputs within the Public Tool were used, which include upfront installation and metering costs, as well as incremental billing costs. All told, these costs amounted to $26 million per year based on the level of adoption in the TASC base case scenario.

Customer Equipment Costs

The costs of DERs themselves must be considered, including the cost of equipment, labor, and financing. For solar, CPUC Energy Division staff's reference case solar price forecast is used to determine the cost of deployed equipment in the 2016-2020 timeframe, factoring in the December 2015 extension of the Federal Investment Tax Credit. For storage, the price forecast was based on Navigant Research's projections;[39] for controllable thermostats, current vendor prices were used.

Based on these forecasts, deployments forecasted for the 2016-2020 timeframe yielded a blended average adoption cost of the installed base of $3.86/W for the 2016-2020 timeframe, or $2.70/W after reflecting the 30% Federal Investment Tax Credit (ITC). In absolute terms, the total cost of adoption to Californians translates to $12.1 billion (nominal) for 4.5GW of rooftop solar. For co-located storage and load control, total investment to meet adoption forecasts totals $259 million.

Results

Societal net benefits calculations require a comprehensive consideration of costs that society bears as a result of attaining the specified 2020 penetration levels, including the costs of administering customer programs, grid integration costs needed to accommodate new assets, and the cost of the assets themselves, which are borne by customers. In the table below, each category is quantified, totalling $1.1 billion per year.

CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	4.5 GW	90,000 homes	
Utility Program Management Costs	$24	$3	$26
Integration Costs (Distribution + Bulk)	$170	$20	$189
Customer Equipment Costs	$770	$119	$889
Total Costs	**$964**	**$141**	**$1,105**

D. *Quantifying Net Benefits*

In this section, we complete EPRI's Cost/Benefit analysis by comparing benefits and costs of DERs during the 2016-2020 deployment timeframe. For consistent comparisons, levelized costs and benefits are based on the year 2020, with all benefits and costs values translated to 2015 dollars.[40]

Establishing a common DER penetration scenario and converting all benefits and costs to net present value terms allows simple summation of each category to provide indicative societal net benefit, suggesting a significant societal value for widespread DER adoption. In total, the benefits of the analyzed scenario are $2.5 billion per year, compared to costs of $1.1 billion per year, resulting in a net societal benefit to Californians of $1.4 billion per year by 2020.

Results of EPRI Societal Net Benefit Test

	CATEGORY	PV+SMART INVERTER ($M/YEAR)	+DERS ($M/YEAR)	TOTAL ($M/YEAR)
Benefits	Energy + Losses	$637	$74	$710
	Generation Capacity	$91	$99	$190
	Distribution Capacity	$333	$42	$375
	Transmission Capacity	$187	$54	$241
	Ancillary Services	$6	$1	$7
	Renewable Energy Compliance	$199	$23	$221
	Voltage and Power Quality	$91	$7	$99
	Conservation Voltage Reduction	$34	$4	$38
	Equipment Life Extension	$31	$4	$36
	Reliability & Resiliency	$0	$8	$8
	Market Price Suppression	$163	$19	$182
	Societal Benefits	$371	$43	$414
	Total Benefits	**$2,143**	**$378**	**$2,521**
Costs	Program Costs	$24	$3	$26
	Integration Costs	$170	$20	$189
	Equipment Costs	$770	$119	$889
	Total Costs	**$964**	**$141**	**$1,105**
	Total Net Benefits			**$1,416**

E. *Case Study: PG&E's Planned Distribution Projects in 2017 General Rate Case*

In the previous section, categories of avoided costs were described and the corresponding values were quantified for the state of California. In this section, the same methodology is applied to PG&E's planned distribution projects from its most recent PG&E 2017 General Rate Case filing from September 2015.

Every three years, California utilities seek approval to recover expenses and investments, including a target profit level, that are deemed necessary for the prudent provision of utility services. For perspective, half of customer's utility payments were driven by the "wires" component of the electric grid in 2014[41] and California's investor owned utilities are expected to add $143 billion of new capital investment into their distribution rate bases through 2050.[42]

Despite the significant size of this avoided cost category, DERs have historically been considered passive assets having little potential on the "wires" side of the business. While not all distribution investment can be avoided by DERs, some of the currently-planned projects are being implemented to accommodate demand growth and replacement of aging assets; these projects could instead be deferred or avoided by DERs. While the CPUC Public Tool uses a generalized treatment of distribution capacity avoided costs to estimate the potential value of deferrals across utilities, more specific values are used in this section sourced from publicly available documents.

The table below summarizes the large capacity-related distribution projects detailed in PG&E's General Rate Case. PG&E seeks approval of $353 million for these distribution system investments.[43] When this $353 million PG&E capital investment is adjusted to factor in the ratepayer perspective – which includes the lifetime cost of the utility's target profit level and recovery of costs related to operations and maintenance, depreciation, interest and taxes from ratepayers – the net present societal cost to PG&E ratepayers of these distribution capacity projects is approximately $586 million.[44] This $586 million cost to ratepayers adds over 1GW of conventional distribution capacity but addresses only 256 MW of near-term capacity deficiencies on PG&E's distribution system when deployed.

Summary of PG&E Electric Distribution Capacity Request – 2017 GRC[45]

Net Present Ratepayer Cost of Capital Investment ($M)[46]	**$586**
Near-term GRC Forecast Deficiency Addressed (MW)	**256**

Based on this societal cost, we consider the net benefits of an alternative, DER-centric solution, which relies on solar with smart inverters, energy storage and controllable thermostats. Due to lack of sufficient detail from PG&E's General Rate Case regarding the operational profiles of the electric distribution capacity projects in question, a simplifying assumption of 75% is used for the DER portfolio's distribution load carrying capacity ratio, which is based on the CPUC's Public Tool default peak capacity allocation factors (PCAF) for PG&E's distribution planning areas. This load carrying capacity ratio reflects capabilities based on customer adoptions with a storage sizing ratio of 2 kWh of energy storage for every 1 kW of PV capacity, or approximately 10 kWh of energy storage for a customer with 5kW of solar installed, as well as a controllable thermostat.

In order to accurately compare the DER solution, the full lifetime cost of the DER solution is considered, which includes the costs of additional DERs that would be needed to accommodate load growth over the lifetime of the conventional solution – assumed to be 25 years. This DER solution deployment schedule, which continuously addresses incremental capacity needs on the grid, contrasts with the traditional, bulky solution deployment schedule, which requires a large upfront investment for capacity to address a small, incremental near-term need. While a DER solution delivers sufficient capacity in each year to provide comparable levels of grid services, deployments occur steadily over time rather than in one upfront investment.

This approach highlights one of the key potential benefits of utilizing a DER solution over a traditional, bulky grid asset: DERs can be flexibly deployed in small bundles over time, a benefit that is further explored in Section IV on the benefits of transitioning to more integrated distribution planning.

Using these assumptions, the previous state-wide methodology is applied to DERs avoiding PG&E's planned distribution capacity projects, but two conservative assumptions are made. First, the scope of benefits is limited to a subset of avoided cost categories that would be directly considered by utility planners today for these types of projects. Whereas conventional equipment used to meet distribution capacity projects are generally unidimensional resources providing a single source of value – distribution capacity – DERs provide multiple sources of value. Second, we base our calculations on PG&E's lower avoided cost values,[46] rather than our own, to demonstrate that there are net benefits even under a conservative scenario.

In addition to avoiding the ratepayer cost of $586 million for planned distribution capacity projects, the DERs deployed to avoid PG&E's distribution capacity projects also avoid $946 million in energy purchases and $79 million and $99 million in generation capacity and avoided renewable energy credit purchases, respectively, totaling $1,709 million in benefits. On the cost side, program costs, integration costs and equipment costs for the associated DERs total to $1,605 million, resulting in a net present value to PG&E ratepayers of $104 million. This net benefit result is particularly notable given the limited scope of benefits considered in this case study and the reliance on PG&E's lower avoided cost values.

Net Benefit of DER Solutions to PG&E Electric Distribution Capacity Request – 2017 GRC
(Calculations Based on PG&E Cost and Benefit Assumptions)

TYPE	CATEGORY	SOURCE	NPV (2015 $M)
	Energy + Losses	PG&E NEM Successor Filing [58]	$946
	Generation Capacity[59]	PG&E NEM Successor Filing	$79
	Distribution Capacity	PG&E 2017 General Rate Case	$586
	Transmission Capacity	Not Included	-
	Ancillary Services	Not Included	-
	Renewable Energy Compliance	PG&E NEM Successor Filing	$99
Benefits	Voltage and Power Quality	Not Included	-
	Conservation Voltage Reduction	Not Included	-
	Equipment Life Extension	Not Included	-
	Reliability & Resiliency	Not Included	-
	Market Price Suppression	Not Included	-
	Societal Benefits	Not Included	-
	Total Benefits		**$1,709**
	Program Costs	PG&E Nem Successor Filing	$55
Costs	Integration Costs	SCE DRP with SolarCity Revisions	$363
	Equipment Costs	PG&E NEM Successor Filing	$1,188
	Total Costs		**$1,605**
	Total Net Benefits		**$104**

In this section, the data available to third-parties around distribution capacity projects from the most recent California Phase I General Rate Case (PG&E's 2017 GRC filing) was used to explore the potential benefits of leveraging DERs to avoid conventional distribution capacity-related investments. Calculations were performed based on PG&E's own avoided cost assumptions from NEM Successor Tariff filings and General Rate Case filings. Results indicate that deploying DER solutions in lieu of PG&E's planned distribution capacity expansion projects in its 2017 GRC could yield net benefits, even looking only at the energy, capacity, and renewable energy compliance values of the DER solutions. While not preferred, simplified assumptions were used to fill missing sources of information and data (e.g. distribution peak capacity allocation factors and forecasted load growth) where necessary. That such simplifying assumptions are necessary highlights the need for additional data sharing on specific infrastructure projects in order to assess the potential of DERs to offset these investments.

III. Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

Section II demonstrated how California could realize an additional $1.4 billion per year by 2020 in net benefits from the deployment of new DERs during the 2016-2020 timeframe. This state-wide methodology was then applied to the planned distribution capacity projects for California's most recent GRC request, showing how the deployment of DERs in lieu of planned distribution capacity expansion projects in PG&E's next rate case could save customers over $100 million.

Despite this potential value from embracing a distribution-centric grid, utilities face institutional barriers to realizing these benefits. Reducing the size of a utility's ratebase – its wires-related investments – cuts directly into shareholder profits. Expecting utilities to proactively integrate DERs into grid planning, when doing so has the potential to adversely impact shareholder earnings, is a structurally flawed approach. It will be impossible to completely capture the potential benefits of DERs until the grid planner's financial conflict with the deployment of DERs is neutralized.

Incentive Barriers

Realigning the incentives of the grid planner to solely focus on delivering a safe, reliable and affordable grid, regardless of the ownership and service models that materialize in the market, is a necessary first step to realize the potential of DERs. There are two fundamental paths forward to address this conflict of interest.

The first path towards realizing this objective would be to separate the role of distribution planning, sourcing, and operations from the role of distribution asset owner, similar to the evolution of Independent System Operators (ISOs) and Regional Transmission Operators (RTO) at the bulk system level. FERC's decree to create independent operators in Order 2000 was driven by the observation that the lack of independent operation of the bulk power system enabled transmission owners to continue discriminatory operation of their systems to favor their own affiliates and further their own interests.[47]

However, while an independent distribution system operator (IDSO) is an appealing governance model, some state regulators may choose a second path for addressing the utility conflict of incentives: maintaining the utilities' traditional role in planning and operating the distribution grid, while neutralizing the misalignment by changing utility incentives. Given the near-term focus in many states on retaining the utility's current role in grid planning and operation, this paper chooses to focus on this path and proposes a model that ensures the utility incentive against non-utility owned assets is neutralized.

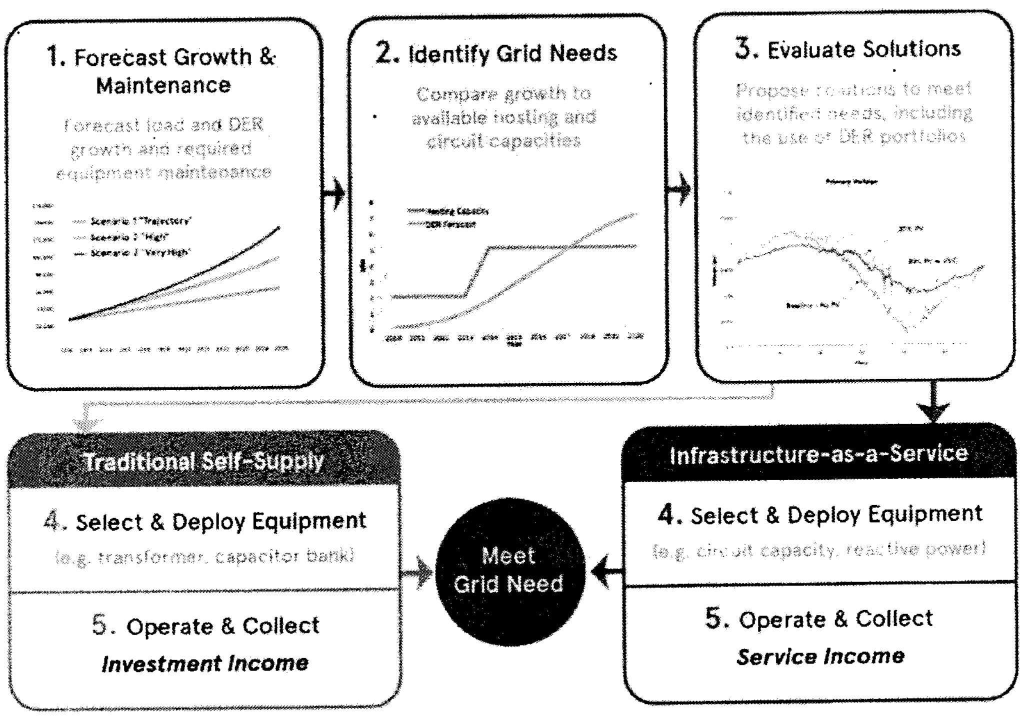
Proposed Solution

In order to ensure least cost/best fit distribution investments in states without an IDSO, this paper proposes the creation of a new utility incentive model, *Infrastructure-as-a-Service,* which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers.

Infrastructure-as-a-Service

Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect).[48]

Utility Planning and Sourcing Utilizing Infrastructure-as-a-Service Model



Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need *if* more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York.[49] While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Distribution Loading Order

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order[50] would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs. The table below depicts the types of resources that would be prioritized over traditional investments in such a policy.

Distribution Loading Order: Sourcing Solutions

PRIORITY	RESOURCE TYPE	RESOURCE EXAMPLES
1	Distributed Energy Resources	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2	Conventional Distribution Infrastructure	Transformers, reconducturing, capacitors, voltage regulators, sectionalizers

In concert with a mechanism like *Infrastructure-as-a-Service*, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

Benefits of Infrastructure as a Service

Creating a pathway for DERs to offer grid services in lieu of utility infrastructure investment would be beneficial for utility ratepayers for a variety of reasons.

1. Saves ratepayers money: Allowing full and fair consideration of DER solutions equips grid planners with a broader suite of tools to meet grid needs, resulting in higher infrastructure utilization and lower customer electricity bills.
2. Promotes competition: Expanding the set of suppliers that are eligible to offer distribution solutions unleashes the power of markets to benefit ratepayers. Well-designed competitive markets can deliver superior solutions that are more affordable than those resulting from a self-supply "cost plus" planning model.
3. Increased flexibility and sources the best solution: Sourcing mechanisms that can deliver resources with new desirable characteristics (e.g. granular sizing, fast lead-times, flexible operational traits) into the distribution planners' toolbox creates no-regrets flexibility. And by rendering a utility neutral to the choice of ownership structure, the planner can focus on the singular objective of delivering the least-cost, best-fit solution.
4. Encourages innovation: Providing clear market opportunities for third-party solutions promotes product and service innovation, putting the collective innovation capabilities of all market participants and customers to work.

5. Engages customers: Utilizing DERs to provide grid services increases the capability and willingness of individual customers to actively manage their energy profiles. Ultimately, a neutral decision model like Infrastructure-as-a-Service will help foster the transition from passive ratepayers to proactive customers.

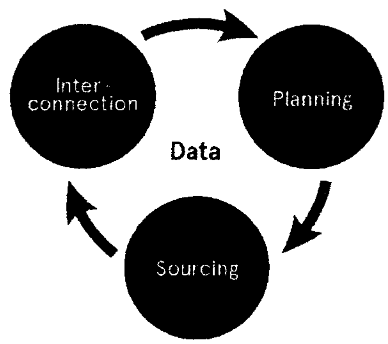
The CPUC recently enhanced the 2016 scope for its Distribution Resource Plan proceeding to formally consider the utility role, business models, and financial interest with respect to DER deployment.[51] Infrastructure-as-a-service is one mechanism to consider that would reduce the conflict of interest towards third-party services inherent in the utility incentive model today. Alternative efforts, such as creating greater functional independence between ownership and operations, as in an IDSO model, should also be explored. Irrespective of the mechanism, an effort to neutralize the utility decision model is needed to ensure that DERs are fully utilized and valued for grid services.

IV. Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to fully realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential DER integration challenges, rather than proactively harnessing these flexible assets.

A. Adopt Integrated Distribution Planning

Grid planning can be modernized by utilizing an approach to meeting grid needs while at the same time expanding customer choice to utilize DERs to manage their own energy. We call this holistic process *Integrated Distribution Planning*.



Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework, as depicted in the adjacent figure, expedites DER *interconnections*, integrates DERs into grid *planning*, *sources* DER portfolios to meet grid needs, and ensures *data* transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement.

If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. For more details on integrated distribution planning, see the "Integrated Distribution Planning" white paper overviewing the framework at www.solarcity.com/gridx.

B. Grid Planning Data Must be Transparent and Accessible

The first step in grid planning is to identify the underlying grid needs. As discussed throughout this paper, the use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition.

Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. The table below is an initial set of minimally-required data to foster adequate stakeholder engagement in regards to specific, utility-identified grid needs.

Data to Foster Engagement in Grid Needs and Planned Investments

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/non-spinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios (e.g. 20% margin above expected deficiency embedded within equipment ratings to ensure available capacity during contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. The following data should be made available and kept current by utilities in order to encourage broad engagement in grid design.

Data to Foster Engagement in General Grid Design and Optimization

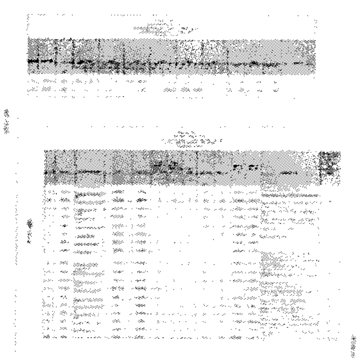
DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Share Standardized, Machine-Readable Data Sets

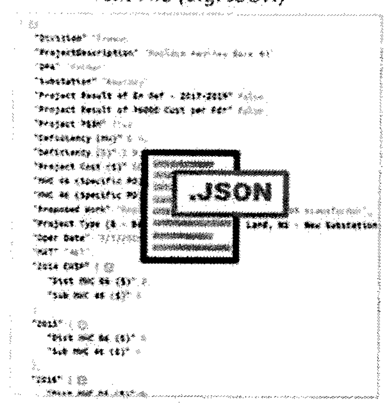
Data that *is* made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.

The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. To illustrate a potential path forward, below is an example of traditional grid capacity needs and corresponding capacity investments as communicated via PG&E's 2017 GRC Phase 1 filing; the image of the text file on the right shows how those same grid needs and planned investments could be translated into a machine-readable format.

General Rate Case Worksheet PDF



Standard Format Text File (e.g. JSON)



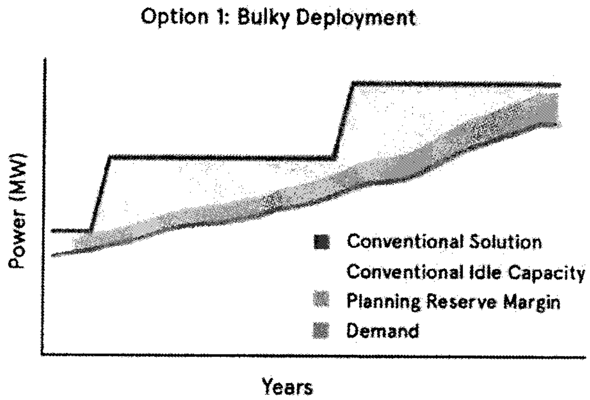
C. *Benefits of Integrated Distribution Planning*

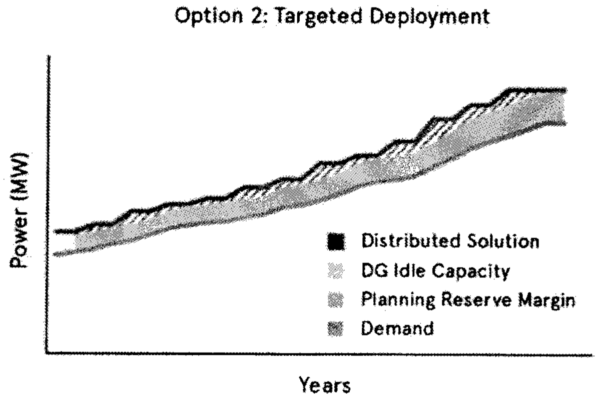
Opening the door to DER solutions in grid planning provides the obvious benefit of a new suite of technological options for grid planners. In some cases, DERs may simply be lower cost on a $/kW basis or more effective at meeting the identified grid need than the conventional solution, making them an obvious choice. DERs, however, also offer an advantage over conventional options due to their targeted and flexible nature, which fundamentally changes the paradigm of grid planning.

Status quo grid planning relies on deploying bulky, traditional infrastructure solutions to address forecasts of incremental, near-term grid needs. In many cases, conventional solutions are 15X larger than the near-term grid need that is driving the actual deployment of the infrastructure.[52] This fundamental reality of grid planning creates two major opportunities for DERs to deliver better value to ratepayers than conventional solutions: 1) utilizing small and targeted solutions, and 2) utilizing the flexibility of DER portfolios.

Value of Small & Targeted Solutions in Modern Distribution Planning

The first source of value is the result of more incremental and targeted investment, which captures the benefit of time value of money. Bulky utility solutions with long equipment lifetimes present a lumpiness challenge for planners. Needs for new resources are driven at the margin, but the available solutions are only cost-effecive when sized to match their long lifetimes, often resulting in low lifetime utilization rates. The significantly smaller building blocks that modern DERs offer planners effectively overcome this historical problem. The figures below compare the deployment timeline of a traditional bulky solution installed to meet demand growth long in the future, relative to a targeted DER solution deployed in small batches to meet continuous demand growth, and the corresponding expectation of idle capacity over time.[53]





Option 1 meets every year's capacity requirement by deploying large solutions infrequently, whereas Option 2 meets annual needs through smaller and more continuous deployments. While the infrastructure deployed with Option 1 will continue to meet the required planning reserve margins decades into the future, it requires a significant upfront investment. Option 2 targets the near-term required planning reserve margins on a continuous basis. Both options ensure that the planning reserve margin for reliability purposes is met, but Option 1 results in higher idle capacity rates over the lifetime of the infrastructure in aggregate when compared to Option 2.

Extending the basic financial idea of the time value of money, paying for capacity today is more expensive than paying for capacity tomorrow – even before considering any cost decreases resulting from technological advancements. DER solutions that can preserve reliability, while delaying capital investments for new capacity until future periods, are inherently valuable to ratepayers. This value driver means that solutions that may look more expensive on a per unit of nameplate capacity basis are actually more cost effective on a net present value basis.

Value of Increased Flexibility in Modern Distribution Planning

The second source of value to be realized from modernizing planning stems from a related but separate challenge that grid planners face: the risk of suboptimal decisions arising from forecast error. This risk is primarily driven by two dynamics:

1. Long lead times are necessary to deploy traditional infrastructure.
2. Long depreciation lifetimes are allowed by regulators for those assets.

As a result, grid planners commonly make investment decisions many years into the uncertain future, and then charge customers for the maintenance, depreciation, profit and taxes associated with those assets over 20 to 30 years or more. Investment under uncertainty imposes risks, which, if not managed properly, create unforeseen ratepayer costs. Among other sources of uncertainty, grid planning and expansion using traditional bulky infrastructure is subject to demand growth uncertainty and technology uncertainty. Both of these forecast errors can be large and expensive.

Over-forecasting demand can result in an overbuilt system for which ratepayers must bear the full burden, even if the infrastructure was not needed. Under-forecasting demand can require the installation of suboptimal, expensive patchwork solutions, or threaten reliability if solutions cannot be provided in time. Similarly, on the technology side, inaccurately forecasting the future costs and capabilities of technologies may result in premature obsolescence as technological advancement dramatically reduces equipment costs or increases equipment efficiency. While private firms typically bear these investment risks in other industries, utility ratepayers bear 100% of these forecast error risks in the electric industry unless the utility regulator acts to disallow cost recovery.

Due to these risks, DERs with shorter lead times can offer real-option value (ROV) by delaying deployment until forecast uncertainty is smaller, effectively buying time for planners and reducing the probability of a mistake. While the value of real options can be significant, it is difficult to quantify without the requisite data, including historical loading data, historical forecasts, and current long-term project forecasts. These data needs are further elaborated on in the subsequent section.

Policy Considerations

The additional sources of value, including time value of money and real option value, associated with a transition towards integrated distribution planning that fully leverages DER deployments were explored above, but are not explicitly quantified due to the limited data publically available. Ongoing proceedings in California, such as the Distribution Resource Plan (DRPs) and Integrated Distributed Energy Resources (IDER), create important vehicles to share information between parties in order to explore these important but less conventional sources of value that are not yet well quantified.

V. Conclusion

In this report, we explored the capability of distributed energy resources to maximize ratepayer benefits while modernizing the grid. The opportunity associated with proactively leveraging DERs deployed over the next five years is significant, creating $1.4 billion a year by 2020 in net societal benefits across the state of California. Applying the state-wide methodology to a subset of real distribution capacity projects identified in California's most recent utility General Rate Case yielded similar results, suggesting DERs can cost effectively replace real-world planned distribution capacity projects today.

The impediments to capturing these benefits in practice remain significant. Utility incentives must be realigned to ensure that the full potential of DERs can be realized. Shifting the utility's core financial incentive from its current focus of "build more to profit more" towards a future state where the utility is financially indifferent between sourcing utility-owned and customer-driven solutions would neutralize bias in the utility decision making process. However, modernizing grid planning is also necessary. Grid planning must be updated to incorporate DERs into every aspect of grid planning, and the process itself must become radically more transparent with greater access to and standardization of data.

The benefits of achieving these changes would be real – and large. While initially complex to consider, the greater flexibility DERs can provide to grid planners and operators leads to greater reliability and resiliency. Similarly, the more targeted and incremental deployments of DERs can enable more efficient and affordable grids. Most importantly, utilities that can successfully modify planning processes would be able to fully take advantage of the assets their customers chose to adopt.

While no single report will adequately address all the issues – engineering, economic, regulatory – that naturally come with a transformative time in the industry, we hope that compiling these issues in one place, even with a high-level focus, advances the discussion and provides an overview of the critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

About Grid Engineering Solutions

Our Grid Engineering Solutions team is leading efforts to make the 21st century's distributed grid a reality. At SolarCity, grid engineering is more than understanding how the current power system works and how to interconnect distributed energy resources. It encompasses a cross-functional approach to evaluating engineering, technology, economic, and policy considerations side-by-side. We apply our expertise in power systems engineering, energy economics, and advanced grid technology to unlock innovative solutions that enable the grid of the future.

The majority of the Grid Engineering Solutions team members, including the authors of this paper, are former utility engineers, economists, technologists, and policy analysts. We treat the design and operation of the electric grid as a major opportunity to partner across the energy industry, with the aim of driving innovation to benefit consumers and our environment. Collaboration across utilities, grid operators, regulators, national laboratories, philanthropists, environmentalists, distributed energy resource providers, energy service providers, and customers is paramount to meeting the challenge of modernizing our grid. We welcome any dialogue that helps foster the next generation of grid design and operations. For more information, please visit us at www.solarcity.com/gridx or contact us at gridx@solarcity.com.

Appendix 1: Overview of Traditional Avoided Cost Categories and Methodologies

The traditional avoided cost categories evaluated in this report are detailed in the following table. Descriptions of the avoided cost, overview of the CPUC Public Tool's treatment of these avoided costs, and TASC's adjusted methodologies are provided. The adjusted TASC methodologies are used to quantify the traditional avoided cost values used in this paper. See TASC NEM Successor Tariff filing for more details on quantification approach.[54]

AVOIDED COST	DESCRIPTION	CPUC PUBLIC TOOL METHODOLOGY	TASC INPUT
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value.	The Public Tool creates a forecast of future energy prices using a simplified dispatch model and applies those prices to the DER generation in each hour. The model also allows a locational multiplier to be applied to capture the additional value of DER generation that occurs in specific locations.	TASC used the default assumptions for calculating energy value, but utilized the locational multiplier with a value of 4.8%, which was the premium derived from the empirical correlation between DER locations and CAISO locational marginal prices (LMPs).
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements.	The Public Tool calculates the long-run cost of capacity by determining the Cost of New Entry (CONE) for a combustion turbine, and nets that cost against the energy and ancillary services revenues that a plant would be expected to earn.	TASC used the default assumptions for net CONE, and assumed that the long-run marginal cost that net CONE represents is the value of capacity starting in 2017, also known as the Resource Balance Year (RBY).
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads.	The Public Tool allows the user to input a $/kW-year value for avoided transmission capacity. The model takes this input and assesses the avoided cost by taking into account the level of coincidence of DER generation with the coincident peak that drives transmission expansion.	TASC assumed the avoided cost was the marginal cost of transmission capacity, which was estimated to be $87/kW-year based on regression analysis of historical transmission costs and their correlation with load growth.
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads.	The avoided cost attributable to DERs takes into account the level of coincidence of DER generation with the drivers of these marginal costs, which are allocated to specific time periods by Peak Capacity Allocation Factors (PCAFs).	TASC assumed the avoided cost was the marginal cost of distribution capacity, which was sourced from each IOU's most recent CPUC general rate case.
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs.	The Public Tool defines the cost for ancillary services as a 1% of wholesale energy costs, and allocates the value based on hourly load.	TASC did not modify any assumptions with respect to how avoided ancillary services are calculated.
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based.	The Public Tool bases this value on the above market costs of RPS generation. Under a 33% RPS, each kWh of DER generation reduces the need for RPS generation by 0.33 kwh.	TASC assumed a 33% RPS by 2020 and did not modify any assumptions with respect to how avoided RPS costs are calculated.
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility.	The Public Tool model provided the flexibility to insert assumptions for societal benefits based on $/tonne of emissions or $/kWh benefits.	TASC included the Environmental Protection Agency's value for the social cost of carbon, as well as estimates for NOx, PM10, land use, and water use benefits.

Appendix 2: Utility-Proposed Distribution Integration Investments in CA DRP

The following table presents the DER integration investment categories as identified in SCE's DRP filing. SCE's costs were scaled up to estimate total integration costs for all California utilities over 2016-2020. SCE cost estimates were stated at the category level, and were uniformly spread across the underlying investments. For each investment, applicability to DER integration is assessed using the threshold and screening questions identified in this paper. This quantification is necessarily high-level due to the lack of details provided, and additional details are necessary in order to fully evaluate investment plans.

INVESTMENT CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERS (%)	RATIONALE
Distribution Automation	Automated switches w/enhanced telemetry	$355	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Remote fault indicators	$355	0%	Business as usual: fault indicators are reliability driven and not necessary for DER integration.
Substation Automation	Substation automation	$346	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Modern protection relays	$346	60%	Investment in protective relay upgrades can be valid at high penetration of DERs, although setting changes can frequently eliminate need for relay replacements.
Communication Systems	Field area network	$444	0%	Business as usual: supports preexisting utility efforts to extend SCADA visibility throughout distribution system.
	Fiber optic network	$444	0%	
Technology Platforms and Applications	Grid analytics platform	$119	33%	Investments in identification and communication of grid needs are valid for high DER penetrations. However, only some of these costs are applicable to DERs as these tools broadly support grid modernization and will be used to process data from smart meters and utilityi grid devices.
	Grid analytics applications	$119	33%	
	Long-term planning tool set	$119	50%	Long-term planning and distribution circuilt modeling tools are used to forecast all grid needs and scenarios, including reliability, loads, and DERs; therefore, only a portion of these costs are driven by DER integration.
	Distribution circuit modeling tool	$119	50%	
	Interconnection application processing	$119	100%	Investments that support DER interconnection are directly related to DER integration.
	DRP data sharing portal	$119	100%	
	Grid and DER management system	$119	50%	Grid and DER management systems are used to manage all grid assets, including utility equipment and DERs; only a portion of these costs are driven by DER integration.
	System architecture and cyber security	$119	25%	As the grid becomes more reliant on more granular visibility and control, system architecture and cybersecurity investments are needed irrespective of DERs. Therefore, only a portion of these costs are driven by DER integration.
	Distribution Volt/VAR optimization	$119	25%	Business as usual: Volt/VAR Optimization programs preexisted DER deployments; while DERs increase Volt/VAR benefits, only a portion of these costs are driven by DERs.
Grid Reinforcement	Conductor upgrades to a larger size	$1,168	50%	Capacity and conductor upgrades driven primarily by safety, reliability and resiliency needs. However, capacity investments for high DER penetrations resulting in thermal limit violations are valid.
	Conversion of circuits to higher voltage	$1,168	10%	Business as usual: Supports preexisting utility efforts to convert circuits to higher voltage. Incremental costs associated with accelerated replacement could be driven by DER integration in some cases.
	Total	**$5,697**	**25% ($1,450)**	

Endnotes

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Note: SolarCity views the CPUC Public Tool as a useful resource to perform cost/benefit analyses, such as the analysis presented in this paper, in a transparent and publically repeatable manner. However, SolarCity cautions that there are structural flaws and limitations to the Public Tool that result in overstatement of PV and DER adoption and understatement of avoided cost benefits. Therefore, SolarCity does not support the use of the Public Tool in its current form to be the basis of ratemaking or tariff decisions.
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[43] Pacific Gas and Electric only provides project-level information for distribution capacity projects exceeding $3 million. Investment in smaller distribution capacity projects is incorporated into the broader distribution budget, but is not broken out in any detail.
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ORIGINAL

EXHIBIT

TASC-22

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
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DOUG LITTLE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **DIRECT TESTIMONY OF J. RANDALL WOOLRIDGE**

The Alliance for Solar Choice hereby provides notice of filing the Direct Testimony of J. Randall Woolridge in the above-referenced matter. This filing contains confidential information. Therefore, we are filing this redacted version and will be providing copies of the un-redacted copy directly to Brian Smith, Judge Jane L. Rodda and Thomas Broderick under separate seal.

Respectfully submitted this 6th day of November, 2015.

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~~Rose Law Group~~ pc
Attorney for TASC

Arizona Corporation Commission
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NOV 06 2015

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Before the

Arizona Corporation Commission

IN THE MATTER OF THE	)	DOCKET NO. E-04204A-15-0142
APPLICATION OF UNS ELECTRIC,	)	
INC. FOR THE ESTABLISHMENT	)	
OF JUST AND REASONABLE	)	
RATES AND CHARGES DESIGNED	)	
TO REALIZE A REASONABLE	)	DIRECT TESTIMONY OF
RATE OF RETURN ON THE FAIR	)	J. RANDALL WOOLRIDGE
VALUE OF THE PROPERTIES OF	)	
UNS ELECTRIC, INC. DEVOTED TO	)	
ITS OPERATIONS THROUGHOUT	)	
THE STATE OF ARIZONA, AND	)	
FOR RELATED APPROVALS.	)	

Testimony and Exhibits of

J. Randall Woolridge, Ph. D.
For The Alliance for Solar Choice

November 6, 2015

UNS Electric, Inc.
Docket No. E-04204A-15-0142

Direct Testimony of
Dr. J. Randall Woolridge, Ph.D.

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LIST OF EXHIBITS

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of Pennsylvania State University. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by The Alliance for Solar Choice ("TASC") to provide an opinion on the overall fair rate of return or cost of capital for UNSE Electric, Inc. ("UNSE" or "Company") and to evaluate UNSE's rate of return testimony in this proceeding.

Q. WHAT COMPRISES A UTILITY'S "RATE OF RETURN"?

A. A company's overall rate of return consists of three main categories: (1) capital structure (i.e., ratios of short-term debt, long-term debt, preferred stock and common equity); (2) cost rates for short-term debt, long-term debt, and preferred stock; and (3) common equity cost, otherwise known as Return on Equity ("ROE").

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. A ROE is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products/services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and/or products. For a regulated monopoly, the regulator determines the level of profit available to the utility. The United States Supreme Court established the guiding principles for establishing an appropriate level of profitability for regulated public utilities in two cases: (1) *Bluefield* and (2) *Hope*.[1] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Thus, determining an appropriate ROE requires determining the market-based cost of capital for the regulated firm. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate the percentage rate of return equity investors require for a given risk-class of firms in order to set an appropriate ROE for a regulated firm. This analysis requires using market data of similar-risk firms.

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[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*") and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review my cost of capital recommendation for UNSE and summarize the primary areas of contention between UNSE's rate of return position and my rate of return position. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss my proxy group of electric utility companies for estimating the cost of capital for UNSE. Fourth, I present my recommendations for the Company's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for UNSE. Finally, I critique the Company's rate of return analysis and testimony.

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

A. The Company has proposed a capital structure of 47.17% long-term debt and 52.83% common equity. The Company has recommended a long-term debt cost rate of 4.66%. UNSE witness Ms. Ann E. Bulkley has recommended a common equity cost rate of 10.35%. UNSE's overall proposed rate of return is 7.67%.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR UNSE?

A. I have reviewed the Company's proposed capital structure and senior capital cost rates. I have adjusted the capital structure to be more in line with the capitalizations of electric utility companies and UNSE's parent organizations. I have employed the Company's recommended long-term debt cost rate. I show that interest rates and capital costs remain at historically low levels. As such, I believe UNSE's common equity cost estimate of 10.35% is significantly overstated.

To estimate a more appropriate equity cost rate for UNSE, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to my proxy group of electric utilities ("Electric Proxy Group") as well as the proxy group developed by UNSE's rate of return witness Ms. Bulkley ("Bulkley Proxy Group"). My recommendation is that the appropriate ROE for UNSE is 8.75%. Combined with my recommended capitalization ratios and senior capital cost rate, my overall rate of return or cost of capital for UNSE is 6.71% as summarized in Exhibit JRW-1.

Q. **PLEASE SUMMARIZE THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.**

A. I show that the Company's proposed capital structure, with a common equity ratio of 52.83%, has more equity than the capitalizations of electric utilities. I have adjusted the proposed capitalization ratios and used a capital structure with 50% debt and 50% common equity. Other than the Company's proposed capital structure, the primary dispute is with respect to the appropriate ROE for UNSE. Ms. Bulkley has recommended an ROE of 10.35%, whereas my analysis indicates that an equity cost rate of 8.75% is appropriate for UNSE. Both Ms. Bulkley and I have applied the DCF and the CAPM approaches to groups of publicly-held electric utility companies. Ms. Bulkley has also used Risk Premium ("RP") approach to estimate an equity cost rate for UNSE.

Q. WHAT ARE THE PRIMARY ISSUES REGARDING THE ANALYSES USED TO DETERMINE THE EQUITY COST RATE OR ROE?

A. As I discuss in detail later in my testimony, my equity cost rate recommendation is consistent with the current economic environment. Long-term interest rates and capital costs are still at historically low levels. Ms. Bulkley has employed constant-growth and multi-stage growth versions of the DCF model. There are two primary errors in Ms. Bulkley's DCF analysis. First, she has given little weight to her DCF results. Second, she has used a projected Gross Domestic Product ("GDP") growth rate of 5.51% in her multi-stage DCF model which is excessive, is not reflective of prospective economic growth in the U.S., and is about 100 basis points above projections of GDP growth. In developing a DCF growth rate, I have reviewed thirteen growth rate measures, including historic and projected growth rate measures. I have also evaluated growth in dividends, book value, and earnings per share.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. The major area of disagreement involves the measurement and magnitude of the market or equity risk premium. In short, Ms. Bulkley's market risk premium is excessive and does not reflect current market fundamentals. As I highlight in my testimony, there are three procedures for estimating a market or equity risk premium – historic returns, surveys, and expected return models. Ms. Bulkley uses a projected market risk premium of 10.67%. Ms. Bulkley's projected equity risk premium uses analysts' long-term earnings per share ("EPS") growth rate projections to compute an expected market return and market risk premium. These EPS growth rate projections and the resulting expected market returns and risk premiums include unrealistic assumptions regarding future economic and earnings growth and stock returns. I have used an equity risk premium of 5.5%, which: (1) factors in all three approaches to estimating an equity premium; and (2) employs the results of many studies of the equity risk premium. As noted in my testimony, my assumed market risk premium reflects the market risk premiums that are: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

Ms. Bulkley also estimates an equity cost rate using the RP model. Her risk premium is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. She uses three estimates of the thirty-year bond yield: (1) the current yield of 2.50%; (2) a near-term forecast of 3.20%; and (3) a long-term forecast of 4.90%. She computes the risk premium based on quarterly authorized ROEs for electric utilities. There are several issues with her RP approach. First and foremost, this approach is a gauge of commission behavior and not investor behavior. Capital costs are determined in the market place through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also take into account other utility- and rate case-specific information in setting

ROEs. As such, Ms. Bulkley's RP approach and results reflect other factors used by utility commissions in authorizing ROEs in addition to capital costs. Second, Ms. Bulkley's RP methodology produces an inflated measure of the risk premium because she uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Finally, the risk premium is inflated as a measure of investor's required risk premium since electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

Q. HOW DO MS. BULKLEY'S RP ESTIMATES COMPARE TO THE ACTUAL STATE-LEVEL AUTHORIZED ROES FOR ELECTRIC UTILITY COMPANIES NATIONWIDE?

A. Ms. Bulkley's RP equity cost rate estimates for electric utility companies range from 9.70% to 10.72%. These figures are above the actual average state-level authorized ROEs. The authorized ROEs for electric utility companies have decreased in recent years such that the <u>trend</u> and the <u>norm</u> for authorized ROEs is below 10%.

Q. PLEASE SUMMARIZE THE PRIMARY DIFFERENCES IN POSITIONS REGARDING THE COMPANY'S COST OF CAPITAL.

A. In the end, the most significant areas of disagreement in measuring UNSE's cost of capital are: (1) the Company's proposed capital structure that includes a common equity ratio of 52.83%; (2) Ms. Bulkley's DCF equity cost rate estimates, and in particular, (a) the lack of weight she gives to her growth DCF results, and (b) the unrealistic projected GDP growth rate of 5.51% in her multi-stage DCF model; (3) the projected interest rates and market or equity risk premiums in her RP and CAPM approaches; and (4) whether or not an equity cost rate consideration is needed to account for the size of UNSE.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE OUTLOOK FOR INTEREST RATES AND CAPITAL COSTS?

A. Appendix B provides a more detailed assessment of the current market conditions. These are my summary observations:

First, the economy has been growing for five years, and, despite some weakness in the global economy, the Federal Reserve continues to see growing strength in the U.S. economy and is now expected to increase the Federal Funds rate in December. The labor market has improved better than expected, with unemployment now down to 5.1%.

Second, interest rates remain at historically low levels and are likely to remain low. There are two factors driving the continued lower interest rates: (1) as noted by the Federal Open Market Committee ("FOMC"), inflationary expectations in the U.S. remain very low and are below the FOMC's target of 2.0%; and (2) global economic growth – including Europe and Asia – remains stagnant. As a result, while the yields on ten-year U.S. Treasury bonds are low by historic standards, these yields are well above the government bond yields in Germany, Japan, and the United Kingdom. Thus, U.S. Treasuries offer an attractive yield relative to those of other major governments around the world, thereby attracting capital to the U.S. and keeping U.S. interest rates down.

Third, reflective of the improving economic conditions and earnings growth and low interest rates, the stock market is near an all-time high.

Fourth, with the end on the Federal Reserves' monetary stimulus program and with the prospect of the Federal Reserve raising the Federal Funds rate, there have been ongoing forecasts of higher interest rates for some time, and these forecasts have continued to be wrong.[2] These forecasts have consistently been wrong. Whereas the Federal Reserve can affect short-term rates, long-term interest rates are driven by economic growth and inflation.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE STATE OF THE MARKETS AND CAPITAL COSTS.

A. Overall, the economy and capital markets have recovered and are looking to the future, and, with low interest rates and high stock prices, capital costs continue to be at historically low levels. Because an appropriate ROE should reflect the current cost of capital, and capital costs are historically low, ROEs should concomitantly be lower.

[2] Ben Eisen, *Yes, 100% of economists were dead wrong about yields*, MARKET WATCH, October 22, 2014. Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," BLOOMBERG.COM (June 2, 2014), http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR UNSE.

A. To develop a fair rate of return recommendation for the Company, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies ("Electric Proxy Group"). Given the operations of UNSE, I have employed a proxy group of electric utility companies as well as the group of utilities developed by Ms. Bulkley ("Bulkley Proxy Group").

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF ELECTRIC COMPANIES.

A. The selection criteria for the Electric Proxy Group includes the following:

1. At least 50% of revenues from regulated electric operations as reported by *AUS Utilities Report*;
2. Listed as an Electric Utility by *Value Line Investment Survey* and listed as an Electric Utility or Combination Electric & Gas Utility in *AUS Utilities Report*;
3. An investment-grade corporate credit rating;
4. Has paid a cash dividend in the past six months, with no cuts or omissions;
5. Not involved in an acquisition of another utility, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and
6. Analysts' long-term earnings per share ("EPS") growth rate forecasts available from Yahoo, Reuters, and/or Zacks.

Q. PLEASE PROVIDE SUMMARY FINANCIAL STATISTICS FOR YOUR PROXY GROUP OF ELECTRIC COMPANIES.

A. The Electric Proxy Group includes twenty-nine companies. Summary financial statistics for the proxy group are listed in Panel A of page 1 of Exhibit JRW-4.[3] The median operating revenues and net plant among members of the Electric Proxy Group are $3,261.8 million and $9,173.5 million, respectively. The group receives 82% of its revenues from regulated electric operations, has BBB+ and Baa1 issuer credit ratings from S&P and Moody's respectively, a current common equity ratio of 47.7%, and an earned return on common equity of 9.2%.

Q. PLEASE DESCRIBE THE BULKLEY PROXY GROUP.

A. Ms. Bulkley's group is smaller and includes only twelve electric companies.[4] Although I believe that my group provides a more comprehensive sample to estimate an equity cost rate for the Company, I will also include the Bulkley Proxy Group in my analysis.

Summary financial statistics for Ms. Bulkley's proxy group are provided in Panel B of page 1 of Exhibit JRW-4. The median operating revenues and net plant for the Bulkley Proxy Group are $2,199.9 million and $7,053.2 million, respectively. On average, the group receives 91% of its revenues from regulated electric operations, has BBB+/BBB and Baa1 issuer credit ratings from S&P and Moody's, a

[3] In my testimony, I present financial results using both mean and medians as measures of central tendency. However, due to outliers among means, I have used the median as a measure of central tendency.

[4] I have excluded Southern Company from the group since it has become involved significant merger and acquisition activity.

current common equity ratio of 49.3%, and a current earned return on common equity of 8.8%.

Q. HOW DOES UNSE COMPARE TO THE TWO PROXY GROUPS?

A. Summary financial statistics for UNSE are listed in Panel A of page 1 of Exhibit JRW-4. UNSE's operating revenues and net plant are [redacted] respectively. The Company receives [redacted] of its revenues from regulated electric operations respectively, has an and A3 issuer credit rating from Moody's, a current common equity ratio of [redacted] and a current earned return on common equity of [redacted]

Q. HOW DOES THE INVESTMENT RISK OF THE COMPANY COMPARE TO THAT OF THE TWO PROXY GROUPS?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. Exhibit JRW-4 also shows S&P and Moody's issuer credit ratings for UNSE and the companies in the two groups. UNSE has an A3 issuer credit rating from Moody's, but is not rated by S&P. UNSE's Moody's issuer rating was upgraded from Baa1 to A3 on March 2, 2015. The Company's A3 rating is one-notch above the average Moody's ratings of the Electric (Baa1) and Bulkley (Baa1) Proxy Groups. Therefore, I believe that UNSE is less risky than the two proxy groups.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE UNSE'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. The Company has proposed a capital structure of 47.17% long-term debt and 52.83% common equity. The Company has recommended a long-term debt cost rate of 4.66%. This is summarized on Panel A of Exhibit JRW-5.

Q. ARE YOU ADOPTING UNSE'S RECOMMENDED CAPITAL STRUCTURE?

A. No. The Company is proposing a capital structure that includes a higher common equity ratio than the averages of the two proxy groups as well as its parent organizations.

Q. PLEASE DESCRIBE YOUR RECOMMENDED CAPITAL STRUCTURE FOR UNSE.

A. The capital structure data for UNSE has a higher common equity ratio than the two proxy groups. To balance these capital structures, and to provide for a more reasonable capitalization, I use a capital structure with a common equity ratio of 50.0%. A capital structure with a 50% common equity ratio is still above the average common equity ratios of the proxy groups. The details of my proposed capital structure are provided in Appendix C.

In Panel C of Exhibit JRW-5, I have used a common equity ratio of 50.0% and I have adjusted UNSE's long-term debt upwards on a pro rata basis such that they account, collectively, for 50.0% of total capital. The resulting capital structure includes 50.0% long-term debt, and 50.0% common equity.

Q. ARE YOU ADOPTING UNSE's RECOMMENDED SENIOR CAPITAL COST RATES?

A. I am adopting UNSE's recommended long-term debt cost rate of 4.66%.

V. <u>THE COST OF COMMON EQUITY CAPITAL</u>

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services.. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors). A more detailed discussion of the cost of equity capital for utilities, and the approaches to estimate the cost of equity capital, are provided in Appendix D. In the sections below, I discuss the methodologies that I have applied to my proxy group of electric utilities, the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM"), to estimate a more appropriate equity cost rate for UNSE.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR UNSE?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my understanding that this Commission has traditionally relied on the DCF model. I have also performed a CAPM study; however, I give these results less weight because I believe that risk premium studies such as CAPM provide a less reliable indication of equity cost rates for public utilities.

B. DCF Analysis

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED FOR YOUR DCF ANALYSIS?

A. I have calculated the dividend yields for the companies in the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in Panel A of page 2 of Exhibit JRW-10. For the Electric Proxy Group, the median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 3.7% to 3.9%. I am using the average if the medians - 3.85% - as the dividend yield for the Electric Proxy Group. For the Bulkley Proxy Group, provided in Panel B of page 2 of Exhibit JRW-10, the median dividend yields range from 3.8% to 3.9% using the 30-day, 90-day, and 180-day average stock prices. I am using the average of the medians – 3.90% - for the Bulkley Proxy Group.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by

4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[5]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half of the expected growth to reflect growth over the coming year. This is the approach employed by the Federal Energy Regulatory Commission ("FERC").[6] The DCF equity cost rate ("K") is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

[5] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).
[6] Opinion No. 414-A, *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶61,084 (1998).

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS, AS PROVIDED BY *VALUE LINE*.

A. Page 3 of Exhibit JRW-10 provides the 5- and 10-year historical growth rates for EPS, DPS, and BVPS for the companies in the proxy groups, as published in the *Value Line Investment Survey*. The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 2.5% to 5.0%, with an average of 3.7%. For the Bulkley Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-10, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 0.8% to 4.5%, with an average of 3.0%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-10. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-10, the medians range from 4.0% to 5.0%, with an average of 4.3%. For the Bulkley Proxy Group, as shown in Panel B of page 4 of Exhibit JRW-10, the medians range from 4.0% to 5.5%, with an average of 4.6%.

Also provided on page 4 of Exhibit JRW-10 are the prospective sustainable growth rates for the companies in the two proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and Bulkley Proxy Groups, the median prospective sustainable growth rates are 4.2% and 3.5%, respectively.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' long-term EPS growth rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-10. I have reported both the mean and median growth rates for the groups. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the Electric and Bulkley Proxy Groups are 4.6%/4.8% and 5.1%/5.2%.[7]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-10 shows the summary DCF growth rate indicators for the proxy groups.

The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 3.7%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 4.3%, and *Value Line*'s projected sustainable growth rate is 4.2%. The high end of the range for the Electric Proxy Group are the projected EPS growth rates of Wall Street analysts, which are 4.6% and 4.8% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators (ignoring historical growth) is 4.2% to 4.8 %. Giving primary weight to the

[7] Given variation in the measures of central tendency of analysts' projected EPS growth rates proxy groups, I have considered both the means and medians figures in the growth rate analysis.

projected EPS growth rate of Wall Street analysis, I will use 4.75% as the DCF growth rate for the Electric Proxy Group. This growth rate figure is clearly in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

The historical growth rate indicators for the Bulkley Proxy Group indicate a growth rate of 3.0%. *Value Line*'s average projected EPS, DPS, and BVPS growth rate for the group is 4.6%, and *Value Line*'s projected sustainable growth rate is 3.5%. The mean/median projected EPS growth rates of Wall Street analysts for the group are 5.1%/5.2%. The range for the projected growth rate indicators is 3.5% to 5.2%. Giving primary weight to the projected EPS growth rate of Wall Street analysis, I believe that a growth rate of 5.0% is appropriate for the Bulkley Proxy Group. As is the case for the Electric Proxy Group, this growth rate figure is clearly in the upper end of the range of historic and projected growth rates for the Bulkley Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUPS?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-10 and in the table below.

Table 1: DCF-derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**3.85%**	**1.02375**	**4.75%**	**8.70%**
Bulkley Proxy Group	**3.90%**	**1.02500**	**5.00%**	**9.00%**

The result for my Electric Proxy Group is the 3.85% dividend yield, times the one and one-half growth adjustment of 1.02375, plus the DCF growth rate of 4.75%, which results in an equity cost rate of 8.70%. The result for the Bulkley Proxy Group includes a dividend yield of 3.90%, times the one and one-half growth adjustment of 1.02500, plus the DCF growth rate of 5.00%, which results in an equity cost rate of 9.0%.

C. CAPM ANALYSIS

Q. PLEASE DISCUSS THE CAPM APPROACH

A. According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

Q. PLEASE DISCUSS YOU INPUTS FOR THE CAPM APPROACH.

A. Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data. The inputs for the CAPM approach include the risk-free interest rate, Beta, and the market risk premium. Additional details on the CAPM methodology and support for my assumptions are discussed in detail in Appendix D.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-11, the yield on 30-year U.S. Treasury bonds has been in the 2.5% to 4.0% range over the 2013–2015 time period. The 30-year Treasury yield is currently in the middle of this range. Given the recent range of yields and the possibility of higher interest rates, I use 4.0% as the risk-free rate, or R_f, in my CAPM.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0.

Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median betas for the companies in the Electric and Bulkley Proxy Groups are 0.75 and 0.78, respectively.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM ("MRP").

A. The MRP is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the MRP is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. There are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for

$E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[8]

Q. WHAT MARKET RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. Much of the data indicates that the market risk premium is in the 4.0% to 6.0% range. Several recent studies (such as Damodaran, American Appraisers, and Duarte and Rosa have suggested an increase in the market risk premium. Therefore, I will use 5.50%, which is in the upper end of the range, as the market risk premium or MRP.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-11 and in the table below.

Table 2: CAPM-derived Equity Cost Rate/ROE

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	4.0%	0.75	5.5%	8.1%
Bulkley Proxy Group	4.0%	0.78	5.5%	8.3%

For the Electric Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.75 times the market risk premium of 5.5% results in an 8.1% equity cost rate. The CAPM equity cost rate for the Bulkley Proxy group is 8.3%, which includes a risk-free rate of 4.0%, a beta of 0.78, and a market risk premium of 5.5%.

[8] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, P. 3.

D. Equity Cost Rate Summary and Recommendations

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. My DCF analyses for the Electric and Bulkley Proxy Groups indicate equity cost rates of 8.70% and 9.00%, respectively. The CAPM equity cost rates for the Electric and Bulkley Proxy Groups are 8.1% and 8.3%, respectively.

Table 3: ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	**8.70%**	**8.10%**
Bulkley Proxy Group	**9.00%**	**8.30%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Bulkley Proxy Groups is in the 8.10% to 9.00% range. However, since I rely primarily on the DCF model, I am using the upper end of the range as the equity cost rate. Therefore, I conclude that the appropriate equity cost rate for the groups is 8.75%. This selection reflects the slightly lesser risk of UNSE relative to the proxy groups and the DCF results for the groups.

Q. ARE YOU RECOMMENDING 8.75% AS AN EQUITY COST RATE FOR UNSE?

A. Yes.

Q. PLEASE INDICATE WHY AN 8.75% RETURN ON EQUITY IS APPROPRIATE FOR THE COMPANY AT THIS TIME.

A. There are a number of reasons why an 8.75% return on equity is appropriate and fair for the Company in this case:

1. I have employed a capital structure with a common equity ratio of 50.0%. This common equity ratio is higher than: (1) the averages of the proxy groups; [redacted]

2. The investment risk of UNSE, as indicated by the Company's Moody's issuer credit ratings, is a little below the proxy groups;

3. As shown in Exhibit JRW-8, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. As such, the cost of equity capital for this industry is amongst the lowest in the U.S., according to the CAPM;

4. As shown in Exhibits JRW-2 and JRW-3, capital costs for utilities, as indicated by long-term bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time; and

Q. HOW DOES THE PROPOSED 8.75% ROE COMPARE WITH THE ROE'S FOR OTHER ELECTRIC UTILITIES?

A. Authorized ROEs for electric and gas utilities have gradually decreased in recent years. These authorized ROEs for electric utilities have declined from 10.01% in 2012, to 9.8% in 2013, 9.76% in 2014, and 9.55% in the first three quarters of 2015 according to Regulatory Research Associates.[9] In my opinion, these authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. This has been especially true in recent years as some state commissions have been reluctant to authorize ROEs below 10%. However, the trend has been towards lower ROEs, and the norm now is below ten percent. Hence, I believe that my recommended ROE reflects our present historically low capital cost rates, and these low capital cost rates are finally being recognized by state utility commissions.

Q. PLEASE DISCUSS YOUR RECOMMENDATION IN LIGHT OF A RECENT MOODY'S PUBLICATION.

A. Moody's recently published an article on utility ROEs and credit quality. In the article, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates. [10]

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.

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[9] *Regulatory Focus*, Regulatory Research Associates, July, 2015. The electric utility authorized ROEs exclude the authorized ROEs in Virginia which include generation adders.

[10] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, but this is not impairing their credit profiles and is not deterring them from raising record amounts of capital. With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower interest rates and cost recovery mechanisms.[11]

> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

In particular, UNSE's Lost Fixed Cost Recovery mechanism ("LFCR") is such a mechanism, and in this current application, UNSE has proposed an expansion of the LFCR to further insulate it from the impact of reduced sales.

Overall, this article establishes that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

Q. DO YOU BELIEVE THAT YOUR 8.75% MEETS *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's

[11] *Ibid.*, p. 2.

financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital. Despite earning an ROE of only 5.5% in 2014, the Company's Moody's issuer rating was upgraded to A3 on March 2, 2015 and the Company has raised over $100 million in capital this year. My recommendation reflects the downward trend in authorized and earned ROEs of electric and gas utility companies. This is highlighted in the Moody's publication cited above that states, despite authorized and earned ROEs below 10%, the credit quality of electric and gas companies has not been impaired and, in fact, has improved and utilities are raising about $50 billion per year in capital. Major positive factors in the improved credit quality of utilities are regulatory ratemaking mechanisms. Therefore, I do believe that my ROE recommendation meets the criteria established in the *Hope* and *Bluefield* decisions.

Q. DO UNSE'S CREDIT RATINGS SUGGEST IT HAS REGULATORY MECHANISMS IN PLACE TO PROMOTE CREDIT QUALITY?

A. Yes. In its summary rationale for upgrading UNSE's long-term rating to A3, Moody's made the following comments:[12]

> UNSE's A3 senior UNSE secured rating reflects a constructive Arizona regulatory environment, reduced regulatory lag associated with cost and investment recoveries and the expectation that projected financial metrics including CFO pre-W/C to debt remain in the mid 20% range, which is offset by the relatively small size of the utility.

VI. CRITIQUE OF UNSE'S RATE OF RETURN TESTIMONY

[12] UNSE response to UDR 1.005, Moody's Investors Service, Moody's 2015 03-02 UNSEE.

Q. PLEASE SUMMARIZE MS. BULKLEY'S RATE OF RETURN RECOMMENDATION FOR UNSE.

A. The Company's rate of return recommendation is summarized on page 1 of Exhibit JRW-12. The Company has proposed a capital structure of 47.17% long-term debt and 52.83% common equity. The Company has recommended a long-term debt cost rate of 4.66%. UNSE witness Ms. Bulkley has recommended a common equity cost rate of 10.35%. UNSE's overall proposed rate of return is 7.67%.

Q. PLEASE SUMMARIZE THE PRIMARY DIFFERENCES IN POSITIONS REGARDING THE COMPANY'S COST OF CAPITAL.

A. The most significant areas of disagreement in measuring UNSE's cost of capital are: (1) the Company's proposed capital structure that includes a common equity ratio of 52.83%; (2) Ms. Bulkley's DCF equity cost rate estimates, and in particular, (a) the lack of weight she gives to her DCF results, and (b) the unrealistic projected GDP growth rate in her multi-stage DCF model; (3) the projected interest rates and the risk premiums in her RP and CAPM approaches; and (4) whether or not an equity cost rate consideration is needed to account for the size of UNSE.

Q. PLEASE REVIEW MS. BULKLEY'S EQUITY COST RATE APPROACHES AND RESULTS.

A. Ms. Bulkley has developed a proxy group of electric utility companies and employs DCF, CAPM, and RP equity cost rate approaches. Ms. Bulkley's equity cost rate estimates for UNSE are summarized in Exhibit JRW-13. Based on these figures, she concludes that the appropriate equity cost rate for the Company is 10.35%.

A. DCF Approach

Q. PLEASE SUMMARIZE MS. BULKLEY'S DCF ESTIMATES.

A. At pages 30-34 of her testimony and in Exhibits AEB-1 - AEB-3, Ms. Bulkley develops an equity cost rate by applying the DCF model to the Bulkley Proxy Group. Ms. Bulkley's DCF results are summarized in Panel A of Exhibit JRW-13. She uses constant-growth and multistage growth DCF models. Ms. Bulkley uses three dividend yield measures (30, 90, and 180 days) in her DCF models. In her constant-growth DCF models, Ms. Bulkley has relied on the forecasted EPS growth rates of Zacks, Yahoo, and *Value Line*. Her multi-stage DCF model uses analysts' EPS growth rate forecasts as a short-term growth rate and a long-term GDP growth of 5.51% that is based on historical GDP growth.

Q. WHAT ARE THE ERRORS IN MS. BULKLEY'S DCF ANALYSES?

A. The primary issues in Ms. Bulkley's DCF analyses are: (1) the low weight she gives her constant-growth DCF results; and (2) the projected GDP growth rate of 5.51% used in the multi-stage DCF model is not reflective of economic growth in the U.S., and is about 100 basis points above projections of GDP growth.

1. The Low Weight Given to the DCF Results

Q. HOW MUCH WEIGHT HAS MS. BULKLEY GIVEN HER DCF RESULTS IN ARRIVING AT AN EQUITY COST RATE FOR UNSE?

A. Apparently, not too much. The average of her mean constant-growth DCF equity cost rates is 9.24% and the average of her multi-stage DCF equity cost rates using a projected GDP growth rate of 5.51% is 9.44%. These are about 100 basis points below her 10.35% ROE recommendation. In addition, as explained in detail below, her multi-stage results are overstated because of her use of historical GDP growth.

2. Multi-Stage DCF Analysis with Historical GDP Growth

Q. PLEASE DISCUSS MS. BULKLEY'S MULTI-STAGE DCF ANALYSIS.

A. Ms. Bulkley employs a multi-stage DCF model and uses a historic long-term nominal GDP growth rate of 5.51%. The 5.51% GDP growth rate is based on (1) a real GDP growth rate of 3.26% which is calculated over the 1929-2014 time period and (2) an inflation rate of 2.19%.

Q. WHAT ARE THE ERRORS WITH MS. BULKLEY'S MULTI-STAGE DCF ANALYSIS.

A. There are two major errors in her analysis. First, Ms. Bulkley has not provided any theoretical or empirical support that historic long-term GDP growth is a reasonable proxy for the expected growth rate of the companies in her proxy group. Five-year and ten-year historic measures of growth for earnings and dividends for electric utility companies, as shown on page 3 of Exhibit JRW-10, suggest growth that is more than

100 basis points below Ms. Bulkley's projected GDP growth rate. Ms. Bulkley has provided no evidence as to why investors would rely on her estimate of long-term GDP growth as the appropriate growth rate for electric utility companies.

The second error is the magnitude of Ms. Bulkley's long-term GDP growth rate estimate of 5.51%. On page 1 of Exhibit JRW-14 of my testimony, I provide an analysis of GDP growth since 1960. Since 1960, nominal GDP has grown at a compounded rate of 6.63%. The graphs on pages 2, 3, and 4 of Exhibit JRW-14 show the decline in nominal GDP as well as its components, real GDP and inflation, in recent decades. To gauge the magnitude of the decline in nominal GDP growth, Table 4 provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50-years. Whereas the 50-year compounded GDP growth rate is 6.63%, there has been a monotonic and significant decline in nominal GDP growth over subsequent 10-year intervals. These figures clearly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy. Ms. Bulkley's long-term GDP growth rate of 5.51% is clearly inflated.

Table 4: Historic GDP Growth Rates

10-Year Average - 2005-2014	**3.9%**
20-Year Average - 1995-2014	**4.6%**
30-Year Average - 1985-2014	**5.2%**
40-Year Average - 1975-2014	**6.4%**
50-Year Average - 1965-2014	**6.8%**

Q. ARE THE LOWER GDP GROWTH RATES OF RECENT DECADES

CONSISTENT WITH THE FORECASTS OF GDP GROWTH?

A. Yes. A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed on page 5 of Exhibit JRW-14. The mean 10-year nominal GDP growth forecast (as of February 2015) by economists in the recent *Survey of Professional Forecasters* is 4.7%. The Energy Information Administration ("EIA"), in its projections used in preparing the *Annual Energy Outlook,* forecasts long-term GDP growth of 4.2% for the period 2013-2040.[13] The Congressional Budget Office ("CBO"), in its forecasts for the period 2015 to 2040, projects a nominal GDP growth rate of 4.3%.[14] Finally, the Social Security Administration ("SSA"), in its Annual OASDI Report, provides a projection of nominal GDP from 2015-2090.[15] The projected nominal GDP growth rate over this period is 4.5%. Overall, these projections of nominal GDP growth over extended future time periods provide direct evidence that Ms. Bulkley's long-term GDP growth rate of 5.51% is overstated by almost 100 basis points.

Q. **WHAT IS IRONIC ABOUT MS. BULKLEY BASING A REAL GDP FORECAST ON HISTORIC DATA?**

A. In developing a DCF growth rate for her constant-growth DCF analysis, Ms. Bulkley has totally ignored historic EPS, DPS, and BVPS data and relied solely on the long-term

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[13] Energy Information Administration, *Annual Energy Outlook,* http://www.cbo.gov/publication/49973.

[14] Congressional Budget Office, The *2015 Long-term Budget Outlook,* July 2015. https://www.cbo.gov/publication/50250.

[15] Social Security Administration, 2015 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program. http://www.ssa.gov/oact/tr/2015/X1_trLOT.html

EPS growth rate projections of Wall Street analysts and *Value Line*. However, in developing a terminal DCF growth rate for her multi-stage growth DCF analysis, Ms. Bulkley employed a GDP growth rate based on historic data going back to 1929.

B. CAPM Approach

Q. PLEASE DISCUSS MS. BULKLEY'S CAPM.

A. On pages 34-38 of her testimony and in Exhibits AEB-4 – AEB-5, Ms. Bulkley estimates an equity cost rate by applying a CAPM model to her proxy group. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Ms. Bulkley uses three measures of the risk-free interest rate: (a) a current yield of 2.50%, (b) a near-term projected yield of 3.20%, and (c) a long-term projected yield of 4.90%. She employs two different Betas (an average Bloomberg Beta of 0.665 and an average *Value Line* Beta of 0.750). She estimates a projected market risk premium ("MRP") for each of her risk-free rates which is based on a projected stock market return of 13.17%. Ms. Bulkley's CAPM results are provided in Panel B of Exhibit JRW-13 and range from 9.59% to 11.10%.

Q. WHAT ARE THE ERRORS IN MS. BULKLEY'S CAPM ANALYSES?

A. The two issues are: (1) the long-term projected 30-Year Treasury yield of 4.90%; and (2) primarily, the excessive MRP.

1. Risk-Free Interest Rate

Q. WHAT IS THE ISSUE WITH THE PROJECTED LONG-TERM TREASURY RATE OF 4.90%?

A. This figure is about 200 basis points above the current 30-year Treasury rate. This figure is simply not reasonable. Thirty-year Treasury bonds are currently yielding about 3.00%. Institutional investors would not be buying bonds at this yield if they expected interest rates to increase so dramatically in the coming years. An increase in yields of 200 basis points on 30-year Treasury bonds within the next couple years would result in significant capital losses for investors buying bonds today at current market yields, suggesting that Ms. Bulkley's use of a 4.90% 30-year projected treasury rate is unreasonable.

2. MRP

Q. PLEASE ASSESS MS. BULKLEY'S MRP DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500.

A. For her CAPM, Ms. Bulkley computes a MRP for each of her three risk-free interest rates by: (1) calculating an expected market return by applying the DCF model to the S&P 500; and (2) subtracting each of her three measure of the 30-year Treasury bond yield (2.50%, 3.20%, and 4.90%). The bottom line is that Ms. Bulkley's estimated expected stock market return of 13.19% is not realistic. She uses (1) a dividend yield of 2.00% and an expected DCF growth rate of 11.06%. The primary error is that the expected DCF growth rate is the projected 5-year EPS growth rate from Wall Street analysts as reported by Bloomberg. As explained below, this produces an overstated expected market return and equity risk premium.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT MS. BULKLEY'S GROWTH RATES ARE ERRONEOUS?

A. Ms. Bulkley's expected long-term EPS growth rates of 11.06% represents the forecasted 5-year EPS growth rates of Wall Street analysts as compiled by Bloomberg. The error with this approach is that, as previously discussed, the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.

Q. IS AN EPS GROWTH RATE OF 11.06% CONSISTENT WITH THE HISTORIC AND PROJECTED GROWTH IN EARNINGS AND THE ECONOMY?

A. No. A long-term EPS growth rates of 11.06% is not consistent with historic or projected economic and earnings growth in the U.S for several reasons: (1) long-term growth in EPS is far below Ms. Bulkley's projected EPS growth rates; (2) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower long-term economic and earnings growth in the future; and (3) over time, EPS growth tends to lag behind GDP growth.

The long-term economic, earnings, and dividend growth rate in the U.S. has only been in the 5% to 7% range. I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960.

The results are provided on page 1 of Exhibit JRW-14, and a summary is provided in Table 5 below.

Table 5 - GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.63%**
S&P 500 Stock Price	**6.83%**
S&P 500 EPS	**6.92%**
S&P 500 DPS	**5.65%**
Average	**6.51%**

The results are presented graphically on page 6 of Exhibit JRW-14. In sum, the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 5% to 7% range.

Q. DO MORE RECENT DATA SUGGEST THAT U.S. ECONOMIC GROWTH IS FASTER OR SLOWER THAN THE LONG-TERM DATA?

A. As previously discussed and presented in Table 4, the more recent trend suggests lower future economic growth than the long-term historic GDP growth. The historic GDP growth rates for 10-, 20-, 30-, 40- and 50- years clearly suggest that nominal GDP growth in recent decades has slowed to the 4.0% to 5.0% area. By comparison, Ms. Bulkley's long-run EPS growth rate projection of 11.06% is vastly overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by almost 100% in the future; and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-half of her projected growth rates.

Q. WHAT LEVEL OF GDP GROWTH IS FORECASTED BY ECONOMISTS AND VARIOUS GOVERNMENT AGENCIES?

A. As previously discussed, there are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in page 5 of Exhibit JRW-14.

Q. WHY IS GDP GROWTH RELEVANT IN YOUR DISCUSSION OF MS. BULKLEY'S USE OF THE LONG-TERM EPS GROWTH RATES IN DEVELOPING A MARKET RISK PREMIUM FOR her CAPM?

A. Because, as indicated in recent research, the long-term earnings growth rates of companies are on average limited to the growth rate in GDP.

Q. PLEASE HIGHLIGHT THE RESEARCH ON THE LINK BETWEEN ECONOMIC AND EARNINGS GROWTH AND EQUITY RETURNS.

A: Brad Cornell of the California Institute of Technology recently published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. Professor Cornell concludes with the following observations:[16]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research

[16] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February, 2010), p. 63.

> in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

Given current inflation in the 2% to 3% range and real returns in the 4% to 5% range, the results imply nominal expected stock market returns in the 6% to 8% range. As such, Ms. Bulkley's projected earnings growth rates and implied expected stock market returns and equity risk premiums are not indicative of the realities of the U.S. economy and stock market. As such, her expected CAPM equity cost rate is significantly overstated.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF MS. BULKLEY'S PROJECTED EQUITY RISK PREMIUM DERIVED FROM EXPECTED MARKET RETURNS.

A. Ms. Bulkley's market risk premium derived from her DCF application to the S&P 500 is inflated due to errors and bias in her study. Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. On this issue, the opinions of CFOs and financial forecasters are especially relevant. CFOs deal with capital markets on an ongoing basis since they must continually assess and evaluate capital costs for their companies. They are well aware of the historical stock and bond return studies of Ibbotson. The CFOs in the September 2015 *CFO Magazine* – Duke University Survey of about 500 CFOs shows an expected return on the S&P 500 of 6.00% over the next ten years. In addition, the financial forecasters in the February 2015 Federal Reserve Bank of Philadelphia survey expect an annual nominal market return of 5.79% over the next ten years. As such, with a more realistic equity or market risk premium, the appropriate equity cost rate for a public utility should be in the 8.0% to 9.0% range and not in the 10.0% to 11.0% range.

C. Risk Premium Approach

Q. PLEASE REVIEW MS. BULKLEY'S RP ANALYSIS.

A. On pages 38-41 of her testimony and in Exhibits AEB-6, Ms. Bulkley estimates an equity cost rate using an RP model. She uses the quarterly authorized ROEs for all electric utilities from Q1 1992 until Q1 2015. Ms. Bulkley develops an equity cost rate by: (1) regressing the authorized returns on equity for electric utility companies on the thirty-year Treasury Yield; and then (2) adding the risk premium established in (1) to each of her three different thirty-year Treasury yields: (a) a current yield of 2.50%, (b) a near-term projected yield of 3.20%, and (c) a long-term projected yield of 4.90%. Ms. Bulkley's RP results are provided in Panel C of Exhibit JRW-13. She reports RP equity cost rates ranging from 9.70% to 10.72%.

Q. WHAT ARE THE ERRORS IN MS. BULKLEY'S RP ANALYSIS?

A. The two issues are: (1) the long-term projected 30-Year Treasury yield of 4.90%; and (2) primarily, the excessive risk premium. The 4.90% base yield was discussed above.

1. Risk Premium

Q. WHAT ARE THE ISSUES WITH MS. BULKLEY'S RISK PREMIUM IN THE RP ANALYSIS?

A. There are several problems with this approach for calculating risk premium. The methodology produces an inflated measure of the risk premium because it uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury Yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if done correctly, which would be to use projected Treasury yields in the analysis rather than historic Treasury yields.

In addition, Ms. Bulkley's RP approach is a gauge of *commission* behavior and not *investor* behavior. Capital costs are determined in the market place through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also take into account other utility- and rate case-specific information in setting ROEs. As such, Ms. Bulkley's approach and results reflect other factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This may especially be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated.

Q. HOW DOES MS. BULKLEY'S RP RESULTS COMPARE TO THE CURRENT AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. Ms. Bulkley's results range from 9.70% to 10.72%. The current average ROEs for electric utilities are below the bottom of her range – 9.60%. Hence, her RP results overstate the current averages.

D. Size Premium

Q. PLEASE DISCUSS MS. BULKLEY'S PROPOSED SIZE ADJUSTMENT.

A. On pages 44-46 of her testimony and in Exhibit AEB-8, Ms. Bulkley estimates a size premium of 4.82% for the Company. Her estimate is based on the historical stock and bond return studies published by Morningstar. Whereas she does not make a specific adjustment for UNSE, she indicates: "Rather, I have considered the small size of UNSE Electric in my assessment of business risks in order to determine where, within a reasonable range of returns, UNSE Electric's required ROE falls."

Q. IS A SIZE ADJUSTMENT APPROPRIATE FOR UNSE?

A. No. There are three reasons that there is no need for a size adjustment or premium for UNSE: (1) a company's credit rating reflects the risk associated with the size of the company: (2) the size premium is based on historical returns which are upwardly biased measures of expected risk premiums; and (3) empirical studies show that size premiums are not required for utilities.

First, a Company's Moody's issuer credit rating of A3 incorporates many different risk factors, including the size of the company. In the case of UNSE, the Moody's credit ratings suggest the Company is a little less risky than the proxy groups. Therefore, there is no valid reason to include a size premium in the equity cost rate.

Second, this size adjustment is based on the historical stock market returns studies as performed by Morningstar (formerly Ibbotson Associates). There are a number of issues with the historical return methodology. First, this approach produces differing results depending on several factors, including the measure of central tendency used, the time period evaluated, and the stock and bond market index employed. In addition, there are a myriad of empirical problems in the approach, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the "Peso Problem"), the company survivorship bias (only successful companies survive – poor companies do not survive), the measurement of central tendency (the arithmetic versus geometric mean), the historical time horizon used, the change in risk and required return over time, the downward bias in bond historical returns, and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing).[17] The bottom line is that there are a number of empirical problems with using historical stock and bond returns to measure a size premium.

[17]These issues are addressed in a number of studies, including: Aswath. Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2015 Edition" NYU Working Paper, 2015, pp. 32-5; See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983); Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002); Bradford Cornell, *The Equity Risk Premium* (New York, John Wiley & Sons),1999, pp. 36-78; and J. P. Morgan, "The Most Important Number in Finance," p. 6.

Third, Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[18] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions, and hence, their financial performance is monitored on an ongoing basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common financial transactions such as the sale of securities. Furthermore, unlike their industrial counterparts, accounting standards and reporting are fairly standardized for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclosure, utilities are much different than industrials, which could account for the lack of a size premium.

E. Summary of Rate of Return Issues

Q. PLEASE REVIEW THE RATE OF RETURN ISSUES IN THIS CASE.

A. The primary rate of return issues that I have addressed include: (1) the Company's proposed capital structure that includes a common equity ratio of 52.83%; (2) Ms. Bulkley's DCF equity cost rate estimates, and in particular, (a) the lack of weight she

[18]Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of the Midwest Finance Association*, pp. 95-101, (1993).

gives to her DCF results, and (b) the unrealistic projected GDP growth rate of 5.51% in her multi-stage DCF model; (3) the projected interest rates and the risk premiums in her RP and CAPM approaches; and (4) whether or not an equity cost rate consideration is needed to account for the size of UNSE.

Q. ARE YOU ALSO PROVIDING A RATE OF RETURN RECOMMENDATION ON THE FAIR VALUE OF UNSE'S RATE BASE?

A. No. In this case I am not making a separate recommendation on the Fair Rate of Return on Rate Base ("FVRB"). Instead, I will accept Staff's methodology and approach for FVRB, but my recommendation would include my capital structure and ROE inputs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call.*

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past twenty-five years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, and Washington, D.C. He has also testified before the Federal Energy Regulatory Commission.

APPENDIX B: CAPITAL COSTS IN TODAY'S MARKETS

This appendix provides a detailed assessment of current market conditions, and is intended to supplement Section II of my testimony. As discussed in my testimony, based on the information presented below, given low interest rates and high stock prices, capital costs continue to be at historically low levels. Because an appropriate ROE should reflect the current cost of capital, and capital costs are historically low, ROEs should concomitantly be lower.

Q. PLEASE DISCUSS CAPITAL COSTS IN U.S. MARKETS.

A. Long-term capital cost rates for U.S. corporations are a function of the required returns on risk-free securities plus a risk premium. The risk-free rate of interest is the yield on long-term U.S. Treasury bonds. The yields on 10-year U.S. Treasury bonds from 1953 to the present are provided on Panel A of Exhibit JRW-2. These yields peaked in the early 1980s and have generally declined since that time. These yields fell to below 3.0% in 2008 as a result of the financial crisis. From 2008 until 2011, these rates fluctuated between 2.5% and 3.5%. In 2012, the yields on 10-year Treasuries declined from 2.5% to 1.5% as the Federal Reserve initiated its Quantitative Easing III ("QEIII") program to support a low interest rate environment. These yields increased from mid-2012 to about 3.0% as of December of 2013 on speculation of a tapering of the Federal Reserve's QEIII policy. Since that time, the ten-year Treasury yield declined and bottomed out at 1.7% in January of 2015. These yields have increased in 2015, and now are above 2.0%.

Panel B on Exhibit JRW-2 shows the differences in yields between ten-year Treasuries and Moody's Baa-rated bonds since the year 2000. This differential primarily reflects the additional risk premium required by bond investors for the risk associated with investing in corporate bonds as opposed to obligations of the U.S. Treasury. The difference also reflects, to some degree, yield curve changes over time. The Baa rating is the lowest of the investment grade bond ratings for corporate bonds. The yield differential hovered in the 2.0% to 3.5% range until 2005, declined to 1.5% until late 2007, and then increased significantly in response to the financial crisis. This differential peaked at 6.0% at the height of the financial crisis in early 2009, due to tightening in credit markets. The adjustment in credit markets increased corporate bond yields, and the "flight to quality," which decreased Treasury yields. The differential subsequently declined, and has remained in the 2.5% range.

Q. WHAT IS THE RISK PREMIUM?

A. The risk premium is the return premium required by investors to purchase riskier securities. The risk premium required by investors to buy corporate bonds is observable based on yield differentials in the markets. The market risk premium is the return premium required to purchase stocks as opposed to bonds. The market or equity risk premium is not readily observable in the markets (like bond risk premiums) since expected stock market returns are not readily observable. As a result, equity risk premiums must be estimated using market data. There are alternative methodologies to estimate the equity risk premium which have produced results that are subject to much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has ranged from 5% to 7%.[1] However, studies by leading academics indicate that the forward-looking equity

[1] See Exhibit JRW-11, p. 5-6.

risk premium is actually in the range of 4.0% to 6.0%. These lower equity risk premium results are consistent with the findings of equity risk premium surveys of CFOs, academics, analysts, companies, and financial forecasters.

Q. PLEASE DISCUSS INTEREST RATES ON LONG-TERM UTILITY BONDS.

A. Panel A of Exhibit JRW-3 provides the yields on A-rated public utility bonds. These yields peaked in November 2008 at 7.75% and have since declined significantly. These yields declined to below 4.0% in mid-2013, and then increased with interest rates in general to the 4.85% range as of late 2013. These rates dropped significantly during 2014 due to economic growth concerns and were bottomed out below 4.0% in the first quarter of 2015. They have since increased with interest rates in general and are back above 4.0%.

Panel B of Exhibit JRW-3 provides the yield spreads between long-term A-rated public utility bonds relative to the yields on 20-year U.S. Treasury bonds. These yield spreads increased dramatically in the third quarter of 2008 during the peak of the financial crisis and have decreased significantly since that time. For example, the yield spreads between 20-year U.S. Treasury bonds and A-rated utility bonds peaked at 3.4% in November 2008, declined to about 1.5% in the summer of 2012, and have remained in that range.

Q. PLEASE PROVIDE MORE DETAILS ABOUT THE FEDERAL RESERVE'S QEIII POLICY AND INTEREST RATES.

A. On September 13, 2012, the Federal Reserve released its policy statement relating to QEIII. In its statement, the Federal Reserve announced that it intended to expand and extend its purchasing of long-term securities to about $85 billion per month.[2] The Federal Open Market Committee ("FOMC") also indicated that it intended to keep the target for the federal funds rate between 0 to 0.25% through at least mid-2015. In subsequent meetings over the next year, the Federal Reserve reiterated the continuation of its bond buying program and tied future monetary policy moves to unemployment rates and the level of interest rates.[3]

During 2013, the speculation in the markets was that the Federal Reserve's bond buying program would be tapered or scaled back. This speculation was fueled by more positive economic data on jobs and the economy. The speculation led to an increase in interest rates, with the ten-year Treasury yield increasing to about 3.0% as of December 2013. Due to continuing positive economic data, the Federal Reserve decided to reduce its purchases of mortgage-backed securities and Treasuries by $5 billion per month beginning in January of 2014.[4]

Q. PLEASE DISCUSS THE FEDERAL RESERVE'S ACTIONS IN 2014 AND 2015.

A. The January 29, 2014 FOMC meeting was historic as Janet Yellen took over from Ben Bernanke as Fed Chairman. In subsequent monthly meetings during 2014, the FOMC noted that it saw improvement in the economy and the housing and labor markets and it continued to taper its bond buying program. In its October 28-29, 2014 meeting, the FOMC put an end to its bond buying program primarily due to improving economic conditions and, in particular, the better employment market.[5] The announcement was

[2] Board of Governors of the Federal Reserve System, *Statement Regarding Transactions in Agency Mortgage-Backed Securities and Treasury Securities* (Sept. 13, 2012).
[3] Board of Governors of the Federal Reserve System, *FOMC Statement* (Dec. 12, 2012).
[4] *Ibid.*
[5] Board of Governors of the Federal Reserve System, *FOMC Statement* (Nov. 19, 2014).

expected, and speculation grew as to when the Federal Reserve would change course in its "highly accommodative" monetary policy and move to increase short-term interest rates. This speculation continued through the end of 2014 and into 2015 as the economy has continued to advance and the unemployment rate has declined to 5.1%. With the improvement in the economy and the labor and housing markets, the FOMC focused on the sluggish pace of inflation and when inflation would approach the Federal Reserve's target rate of 2.0%. Early in 2015, the markets focused on one key word regarding monetary policy– 'patient.' In its March 18 statement, the FOMC omitted the word 'patient' with respect to the normalization of monetary policy, and suggested that its target range for federal funds would only be increased once the outlook for the labor market and price increases improved.[6] Since that time, the market debate and speculation has turned to which monthly meeting would the Federal Reserve increase the Fed Funds rate. At the September 17th meeting, the FOMC once again opted to keep the rate unchanged, citing the low inflation rate, slow global economic growth, and recent stock market volatility.[7]

Q. HOW HAS THE YIELD ON TEN-YEAR TREASURY BONDS REACTED TO THE FEDERAL RESERVE'S MONETARY POLICY ACTIONS?

A. The yield on the ten-year Treasury note was 3.0% as of January 2, 2014. This yield trended down during 2014, and bottomed out at 1.7% in January of 2015. With speculation growing about an increase in the Federal Reserve's discount rate, the ten-year yield subsequently increased to almost 2.5% in July. However, global economic growth

[6] Board of Governors of the Federal Reserve System, *FOMC Statement* (March 18, 2015).

[7] Board of Governors of the Federal Reserve System, *FOMC Statement* (September 17, 2015).

concerns, particularly those regarding China, have led to a decline in the ten-year Treasury yield to about 2.2%.[8]

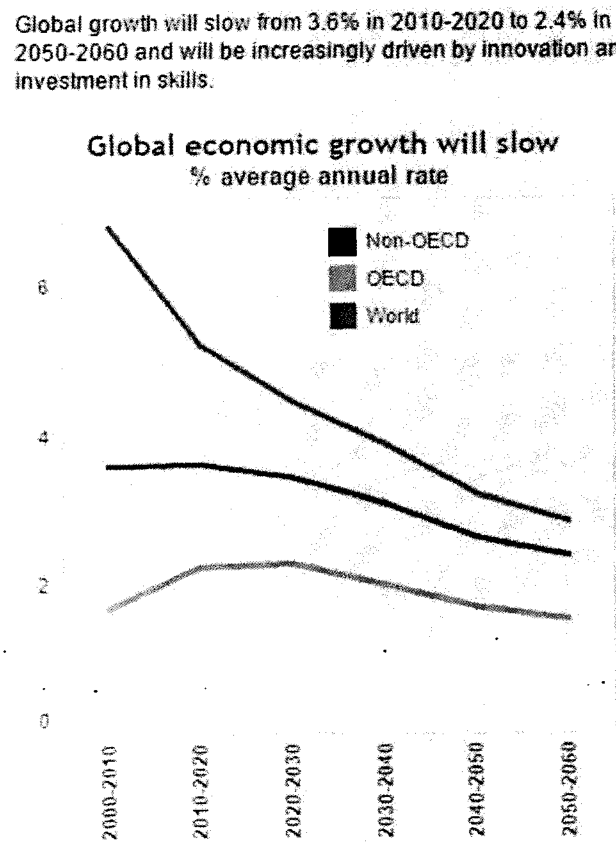
Q. YOU DISCUSS THE RECENT FEDERAL RESERVE POLICY AND CURRENT CONDITIONS IN THE ECONOMY AND THE FINANCIAL MARKETS. PLEASE PROVIDE A LONG-TERM PERSPECTIVE ON INTEREST RATES AND CAPITAL COSTS.

A. In the long run, the key drivers of economic growth measured in nominal dollars are population growth, the advancement and diffusion of science and technology, and currency inflation. Although the U.S. experienced rapid economic growth during the "post-war" period (the 63 years that separated the end of World War II and the 2008 financial crisis), the post-war period is not necessarily reflective of expected future growth. It was marked by a near-trebling of global population, from under 2.5 billion to approximately 6.7 billion. Over the succeeding 63 years, according to U.N. projections, the global population will grow considerably more slowly, reaching approximately 10.3 billion in 2070. With population growth slowing, life expectancies lengthening, and post-war "baby boomers" reaching retirement age, median ages in developed-economy nations have risen and continue to rise. The postwar period was also marked by rapid catch-up growth as Europe, Japan, and China recovered from successive devastations and as regions such as India and China deployed and leapfrogged technologies that had been developed over a much longer period in earlier-industrialized nations. That period of rapid catch-up growth is coming to an end. For example, although China remains one of the world's fastest-growing regions,

[8] http://research.stlouisfed.org/fred2/series/DGS10/downloaddata.

its growth is now widely expected to slow substantially. This convergence of projected growth in the former "second world" and "third world" towards the slower growth of the nations that have long been considered "first world" is illustrated in this "key findings" chart published by the Organization for Economic Co-operation and Development:[9]

Figure 1: Projected Global Growth



As to dollar inflation, it has declined to far below the level it reached in the 1970s. The Federal Reserve targets a 2% inflation rate, but (as noted above) has been unable to effect even that much inflation. Indeed, a recent Bloomberg article pointed out that "[t]he Fed's preferred measure of inflation has also fallen short of its 2 percent goal for 30

[9] See http://www.oecd.org/eco/outlook/lookingto2060.htm.

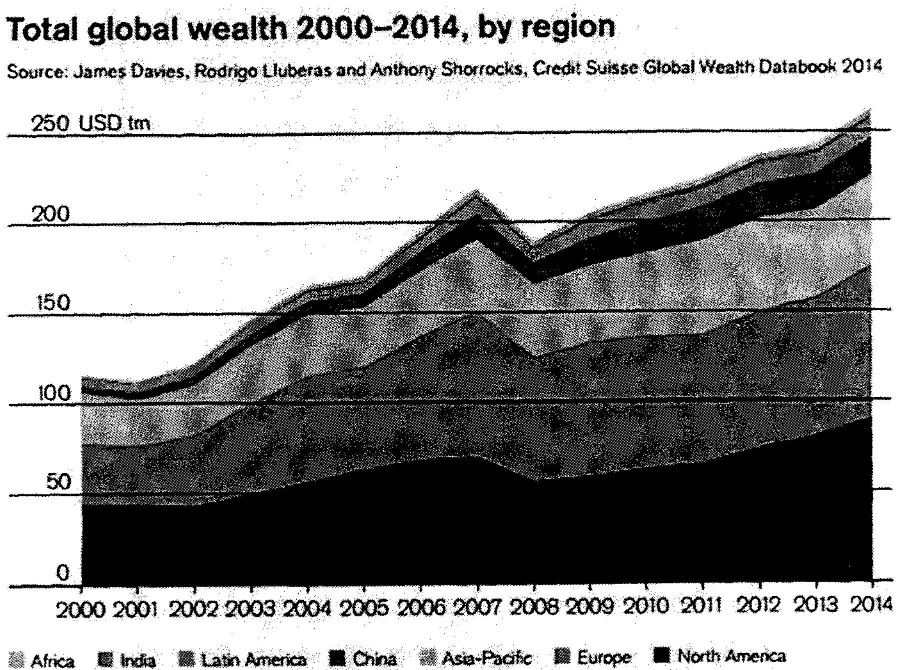
consecutive months, and he outlook for consumer-price increases over the next five years has fallen almost a percentage point since its high in June to a four-year low of 1.13 percent.[10] The U.S Energy Information Administration's (EIA) annual Energy Outlook includes in its nominal GDP growth projection a long-term inflation component, which is projected at only 1.8%.[11]

All of these factors signify slowed growth in annual economic production and income, even when measured in nominal rather than real dollars. Meanwhile, the stored wealth that is available to fund investments has continued to rise. As shown in the figure below, according to the most recent release of the Credit Suisse global wealth report, global wealth has more than doubled since the turn of this century, notwithstanding the temporary setback following the 2008 financial crisis.

[10] Susanne Walker, *Bond Investors Are Writing Off Inflation for Years, If Not Decades, to Come* (Dec 15, 2014), available at http://www.bloomberg.com/news/2014-12-15/wall-street-can-t-stop-stripping-bonds-as-inflation-deemed-dead.html.

[11] See EIA Annual Energy Outlook 2014, Table 20 (available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm).

<u>**Figure 2: Global Wealth – 2000-2014**</u>



These long-term trends mean that overall, and relative to what had been the post-war norm, the world now has more wealth chasing fewer opportunities for investment rewards. Ben Bernanke, the former Chairman of the Federal Reserve, called this phenomenon a "global savings glut."[12] Like any other liquid market, capital markets are subject to the law of supply and demand. With a large supply of capital available for investment and relatively scarce demand for investment capital, it should be no surprise to see the cost of investment capital decline.

[12] Ben S. Bernanke, *The Global Saving Glut and the U.S. Current Account Deficit* (Mar. 10, 2005), available at http://www.federalreserve.gov/boarddocs/speeches/2005/200503102/.

Q. RELATEDLY, PLEASE HIGHLIGHT MR. BERNANKE'S RECENT TAKE ON THE LOW INTEREST RATES IN THE U.S.

A. Mr. Bernanke addressed the issue of the continuing low interest rates recently on his weekly Brookings Blog. Bernanke indicated that the focus should be on real and not nominal interest rates and noted that, in the long term, these rates are not determined by the Federal Reserve:[13]

> If you asked the person in the street, "Why are interest rates so low?," he or she would likely answer that the Fed is keeping them low. That's true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed's policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The real interest rate is most relevant for capital investment decisions, for example. The Fed's ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for economic growth—not by the Fed.

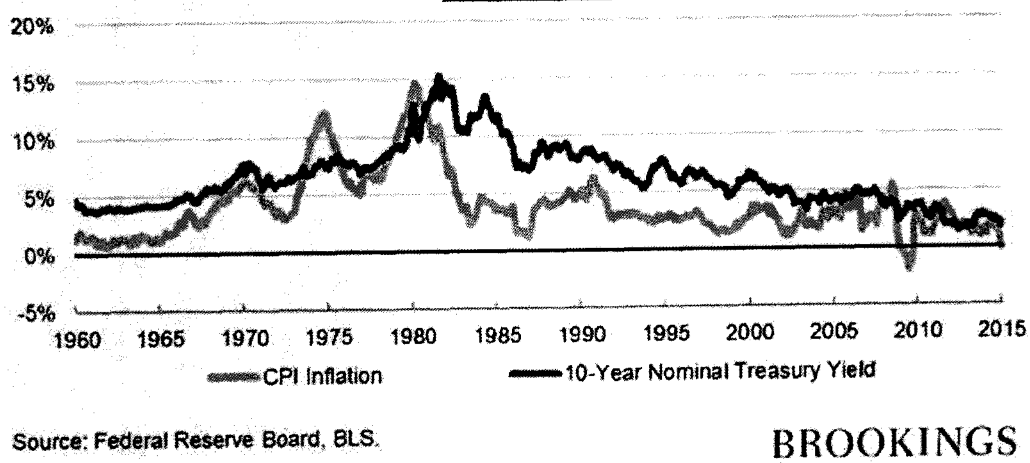
Bernanke also addressed the issue about whether low-interest rates are a short-term aberration or a long-term trend:[14]

> Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about minus 0.1

[13] Ben S. Bernanke, "Why are Interest Rates So Low," Weekly Blog, Brookings, March 30, 2015. http://www.brookings.edu/blogs/ben-bernanke/posts/2015/03/30-why-interest-rates-so-low.
[14] *Ibid.*

percent.

Figure 3:
Interest Rates and Inflation
1960-Present



Q. **WHAT ARE YOUR OBSERVATIONS REGARDING THE OUTLOOK FOR INTEREST RATES AND CAPITAL COSTS?**

A. I believe that there are several factors driving the markets.

First, the economy has been growing for five years, and, as noted above, despite some weakness in the global economy, the Federal Reserve continues to see growing strength in the U.S. economy. The labor market has improved better than expected, with unemployment now down to 5.1%.

Second, interest rates remain at historically low levels and are likely to remain low. There are two factors driving the continued lower interest rates: (1) as noted by the FOMC, inflationary expectations in the U.S. remain very low and are below the FOMC's target of 2.0%; and (2) global economic growth – including Europe and Asia – remains stagnant. As a result, while the yields on ten-year U.S. Treasury bonds are low by historic standards, these yields are well above the government bond yields in Germany, Japan, and the United Kingdom. Thus, U.S. Treasuries offer an attractive yield relative to those of other major governments around the world, thereby attracting capital to the U.S. and keeping U.S. interest rates down.

Third, reflective of the economic conditions and earnings growth and low interest rates, the stock market is near an all-time high.

Finally, with the end of the Fed's QEIII program, there were forecasts of higher interest rates for some time. However, these forecasts proved to be wrong. In fact, all the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and <u>100% of the economists were wrong</u>. According to the *Market Watch* article:[15]

> The survey of economists' yield projections is generally skewed toward rising rates — only a few times since early 2009 have a majority of respondents to the Bloomberg survey thought rates would fall. But the unanimity of the rising rate forecasts in the spring was a stark reminder of how one-sided market views can become. It also teaches us that economists can be universally wrong.

As a final note on this issue, these consensus forecasts of economists that interest rates are going higher seem to be continually wrong. In fact, in 2014, *Bloomberg* reported that the Federal Reserve Bank of New York has stopped using the interest rate estimates of professional forecasters in the Bank's interest rate model due to the unreliability of those forecasters' interest rate forecasts.[16]

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[15] Ben Eisen, *Yes, 100% of economists were dead wrong about yields*, MARKET WATCH, October 22, 2014.
[16] Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," BLOOMBERG.COM (June 2, 2014), http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE STATE OF THE MARKETS AND CAPITAL COSTS.

A. Overall, the economy and capital markets have recovered and are looking to the future, and, with low interest rates and high stock prices, capital costs continue to be at historically low levels. Because an appropriate ROE should reflect the current cost of capital, and capital costs are historically low, ROEs should concomitantly be lower.

APPENDIX C: CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

This appendix details my proposed capital structure, and is intended to supplement Section IV of my testimony. As stated in my testimony, based on the information below I recommend a capital structure for UNSE with 50% long-term debt, and 50% common equity.

Q. PLEASE DESCRIBE UNSE'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. The Company has proposed a capital structure of 47.17% long-term debt and 52.83% common equity. The Company has recommended a long-term debt cost rate of 4.66%. This is summarized on Panel A of Exhibit JRW-5.

Q. WHAT ARE THE COMMON EQUITY RATIOS IN THE CAPITALIZATIONS OF THE TWO PROXY GROUPS?

A. As shown in Exhibit JRW-4, the median common equity ratios of the Electric and Bulkley Proxy Groups are 47.7% and 49.3%, respectively. This indicates that the Company's proposed capitalization has a higher common equity ratio than the two proxy groups.

Q. HOW DOES THE COMPANY'S PROPOSED COMMON EQUITY RATIOS COMPARE TO COMMON EQUITY RATIOS OF UNSE'S PARENT COMPANY, UNS ENERGY, AND UTLIMATE PARENT COMPANY, FORTIS, INC?

A. As of year-end 2013 and 2014, UNS Energy had common equity ratios of [redacted], respectively.[1] In addition, as shown in Panel B of Exhibit JRW-5, Fortis' 2014 year-end capitalization included a common equity ratio of 43.6%. [redacted]

Q. ARE YOU ADOPTING UNSE'S RECOMMENDED CAPITAL STRUCTURE?

A. No. The Company is proposing a capital structure that includes a higher common equity ratio than the averages of the two proxy groups as well as its parent organizations.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN AN ELECTRIC UTILITY'S CAPITAL STRUCTURE.

A. An electric utility's decision regarding the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital with a given commitment of dollars than it could raise with just equity. Debt is, therefore, a

[1] UNSE Response to UDR1.004 Capital Structure Ratios – Confidential.

means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, its financial risk increases and the risk of the utility perceived by equity investors also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. **WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?**

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements the customers are called on to bear. Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management must pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. **HOW HAVE ELECTRIC UTILITIES TYPICALLY STRUCK THIS BALANCE?**

A. Due to regulation and the essential nature of its output, an electric utility is exposed to less business risk than other companies that are not regulated. This means that an electric utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. The utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements. Typically, one may see equity ratios for electric utilities range from 40% to 50%.

Q. GIVEN YOUR VIEW THAT UNSE'S EQUITY RATIO IS HIGHER THAN THAT OF THE PROXY GROUPS, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated electric utility's actual capital structure contains a high equity ratio, the options are: (1) to impute a more reasonable capital structure and reflect this capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a lower common equity cost rate.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between the lower risk and the appropriate authorized return should not be ignored.

Q. PLEASE DESCRIBE YOUR RECOMMENDED CAPITAL STRUCTURE FOR UNSE.

A. The capital structure data for UNSE has a higher common equity ratio than the two proxy groups. To balance these capital structures, and to provide for a more reasonable capitalization, I use a capital structure with a common equity ratio of 50.0%. A capital structure with a 50% common equity ratio is still above the average common equity ratios of the proxy groups.

In Panel C of Exhibit JRW-5, I have used a common equity ratio of 50.0% and I have adjusted UNSE's long-term debt upwards on a pro rata basis such that they account, collectively, for 50.0% of total capital. The resulting capital structure includes 50.0% long-term debt, and 50.0% common equity.

Q. ARE YOU ADOPTING UNSE'S RECOMMENDED SENIOR CAPITAL COST RATES?

A. I am adopting UNSE's recommended long-term debt cost rate of 4.66%.

APPENDIX D: THE COST OF COMMON EQUITY CAPITAL

This appendix provides a detailed discussion of the cost of equity capital for utilities, and my approach to estimate the cost of equity capital. This discussion is intended to supplement Section V of my testimony. As stated in my testimony and discussed below, I rely primarily on the Discounted Cash Flow Model ("DCF") model to estimate the cost of equity capital. While I have also performed a Capital Asset Pricing Model ("CAPM") study, I give these results less weight because I believe that risk premiums studies such as CAPM provide a less reliable indication of equity cost rates for public utilities.

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[1]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

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[1] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p.3.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[2]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using natural gas distribution, electric utility, and water utility companies. I used all companies in these three industries that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Panels A-C of Exhibit JRW-6. The average R-squares for the electric, gas, and water companies are 0.78, 0.63, and 0.49, respectively.[3] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

[2] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.
[3] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-7 provides indicators of public utility equity cost rates over the past decade.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. These yields spiked up to the 7.75% range with the onset of the financial crisis, and remained high and volatile until early 2009. These yields declined to below 4.0% in mid-2013, and then increased with interest rates in general to the 4.85% range as of late 2013. They subsequently declined to below 4.0% in the first quarter of 2015, but have increased with interest rates in general since that time.

Page 2 provides the dividend yields for electric utilities over the past decade. The dividend yields for this electric group declined from the year 2000 to 2007, increased to 5.2% in 2009, and dropped to 3.80% in 2014.

Average earned returns on common equity and market-to-book ratios for the electric group are on page 3 of Exhibit JRW-7. For the electric group, earned returns on common equity have declined gradually since the year 2000 and have been in the 9.50% range in recent years. The average market-to-book ratios for this group peaked at 1.68X in 2007, declined to 1.07X in 2009, and have increased since that time. As of 2014, the average market-to-book for the group was 1.50X. This means that, for at least the last decade, returns on common equity have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than they need to support an appropriate profit level for regulated utilities.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-8 provides an assessment of investment risk for 99 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey.* The study shows that the investment risk of utilities is very low. The average betas for electric, water, and gas utility companies are 0.74, 0.73, and 0.80, respectively. As such, the cost of equity for utilities is among the lowest of all industries in the U.S.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR UNSE?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my understanding that this Commission has traditionally relied on the DCF model. I have also performed a CAPM study; however, I give these results less weight because I believe that risk premium studies such as CAPM provide a less reliable indication of equity cost rates for public utilities.

B. DCF Analysis

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \dots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-9, Page 1 of 2. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model.

To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

C. DCF Growth Rate

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important element in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS

FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecast data free-of-charge on the internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as msn.money (http://money.msn.com).

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the EPS forecasts compiled by Reuters for Alliant Energy Corp. (stock symbol "LNT"). The figures are provided on page 2 of Exhibit JRW-9. The top line shows that one analyst has provided EPS estimates for the quarter ending December 31. The mean, high and low estimates are $0.53, $0.63, and $0.41, respectively. The second line shows the quarterly EPS estimates for the quarter ending March 31, 2016 of $0.94 (mean), $0.94 (high), and $0.94 (low). Lines three and four show the annual EPS estimates for the fiscal year ending December 2015 ($3.63 (mean), $3.68 (high), and $3.60 (low)) and for the fiscal year ending December 2016 ($3.83 (mean), $3.91 (high), and $3.75 (low)). The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. As in the LNT case shown here, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line shows the projected long-term EPS growth rate, which is expressed as a percentage. For LNT, two analysts have provided a long-term EPS growth rate forecast, with mean, high, and low growth rates of 5.75%, 6.00%, and 5.50%.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. WHY DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[4] Employing data over a twenty-year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[5] Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[6]

[4] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[5] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research (2000);* K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003); M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

[6] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth rate forecasts, and therefore stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Because stock prices reflect the bias, it would affect the dividend yield. In addition, the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias.

D. CAPM Analysis

Q. PLEASE DISCUSS THE CAPM APPROACH.

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-11.

A. Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-11, the yield on 30-year U.S. Treasury bonds has been in the 2.5% to 4.0% range over the 2013–2015 time period. The 30-year Treasury yield is currently in the middle of this range. Given the recent range of yields and the possibility of higher interest rates, I use 4.0% as the risk-free rate, or R_f, in my CAPM.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median betas for the companies in the Electric and Bulkley Proxy Groups are 0.75 and 0.78, respectively.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM ("MRP").

A. The MRP is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the MRP is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As is discussed below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[7]

[7] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, P. 3.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MRP.

A. Page 4 of Exhibit JRW-11 highlights the primary approaches to, and issues in, estimating the expected MRP. The traditional way to measure the MRP was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium range of 5% to 7% above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that ex post historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies. This is discussed in more detail later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[8]

In addition, there are a number of surveys of financial professionals regarding the MRP. There have also been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 500 CFOs participate in the survey.[9] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters.*[10] This survey of professional economists has been published for almost fifty years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[11]

Q. PLEASE PROVIDE A SUMMARY OF THE MRP STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the MRP.[12] Derrig and Orr's study evaluated the various approaches to estimating MRPs, as well as the issues with the

[8] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics,* 145 (1985).

[9] *See* DUKE/CFO MAGAZINE GLOBAL BUSINESS OUTLOOK SURVEY, www.cfosurvey.org (September, 2015).

[10] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters (Feb. 13, 2015).* The Survey of Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[11] Pablo Fernandez, Alberto Ortiz and Isabel Fernandez Acín, "Discount Rate (Risk-Free Rate and Market Risk Premium), used for 41 countries in 2015: a survey," April 23, 2015.

[12] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

alternative approaches and summarized the findings of the published research on the MRP. Fernandez examined four alternative measures of the MRP – historical, expected, required, and implied. He also reviewed the major studies of the MRP and presented the summary MRP results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the MRP.

Page 5 of Exhibit JRW-11 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the MRP. In developing page 5 of Exhibit JRW-11, I have categorized the studies as discussed on page 4 of Exhibit JRW-11. I have also included the results of studies of the "Building Blocks" approach to estimating the equity risk premium. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-11.

A. Page 5 of JRW-11 provides a summary of the results of the MRP studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium; (2) *ex ante* MRP studies; (3) MRP surveys of CFOs, financial forecasters, analysts, companies and academics; and (4) the Building Blocks approach to the MRP. There are results reported for over thirty studies, and the median MRP is 4.42%.

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-11 include every MRP study and survey I could identify that was published over the past decade and that provided an MRP estimate. Most of these studies were published prior to the financial crisis. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so were not estimating an MRP as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the MRP, I have reconstructed page 5 of Exhibit JRW-11 on page 6 of Exhibit JRW-11; however, I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 4.82%.

Q. GIVEN THESE RESULTS, WHAT MRP ARE YOU USING IN YOUR CAPM?

A. Much of the data indicates that the market risk premium is in the 4.0% to 6.0% range. Several recent studies (such as Damodaran, American Appraisers, and Duarte and Rosa have suggested an increase in the market risk premium. Therefore, I will use 5.50%, which is in the upper end of the range, as the market risk premium or MRP.

Q. IS YOUR *EX ANTE* MRP CONSERVATIVE COMPARED TO THE MRPS USED BY CFOS?

A. Yes. In the September, 2015 CFO survey conducted by *CFO Magazine* and Duke University, which included about 450 responses, the expected 10-year MRP was 3.8%.[13]

[13] *Id.* p. 66.

Q. **IS YOUR *EX ANTE* MRP CONSERVATIVE COMPARED TO THE MRPS OF PROFESSIONAL FORECASTERS?**

A. Yes. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey projected both stock and bond returns. In the February 2015 survey, the median long-term expected stock and bond returns were 5.79% and 3.91%, respectively. This provides an *ex ante* MRP of 1.88% (5.79%-3.91%).

Q. **IS YOUR *EX ANTE* MRP CONSISTENT WITH THE MRPS OF FINANCIAL ANALYSTS AND COMPANIES?**

A. Yes. Pablo Fernandez recently published the results of a 2015 survey of academics, financial analysts, and companies.[14] This survey included over 4,000 responses. The median MRP employed by U.S. analysts and companies was 5.5%.

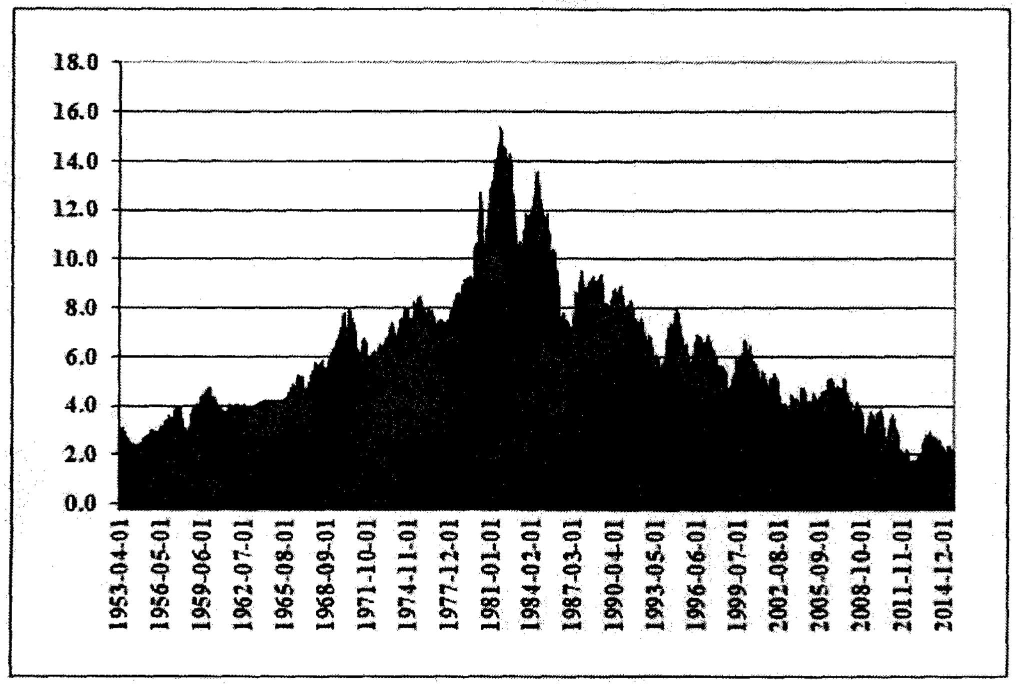
[14] *Ibid.* p. 3.

Exhibit JRW-1
UNS Electric, Inc.
Recommended Cost of Capital

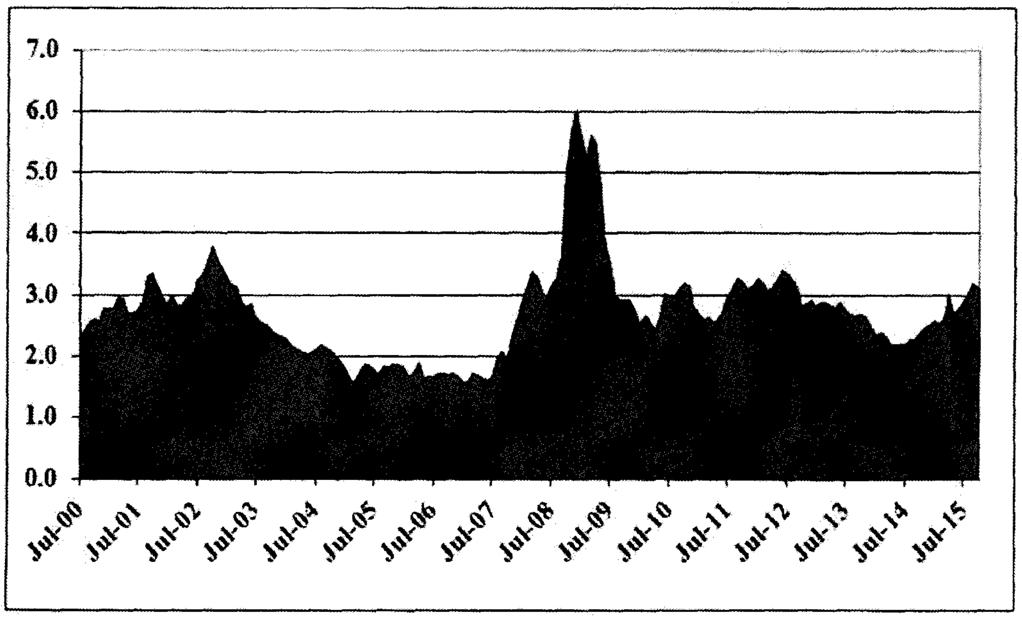
Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.66%	2.33%
Common Equity	50.00%	8.75%	4.38%
Total	100.00%		6.71%

Exhibit JRW-2

Panel A
Ten-Year Treasury Yields
1953-Present

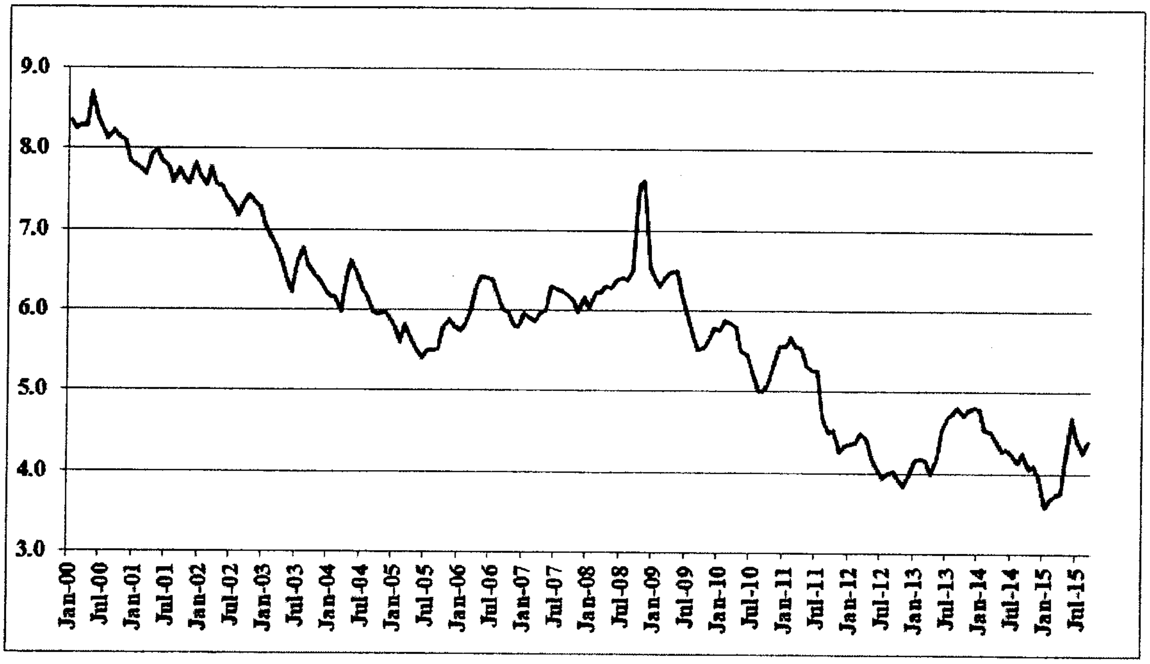


Panel B
Long-Term Moody's Baa Yields Minus Ten-Year Treasury Yields
2000-Present

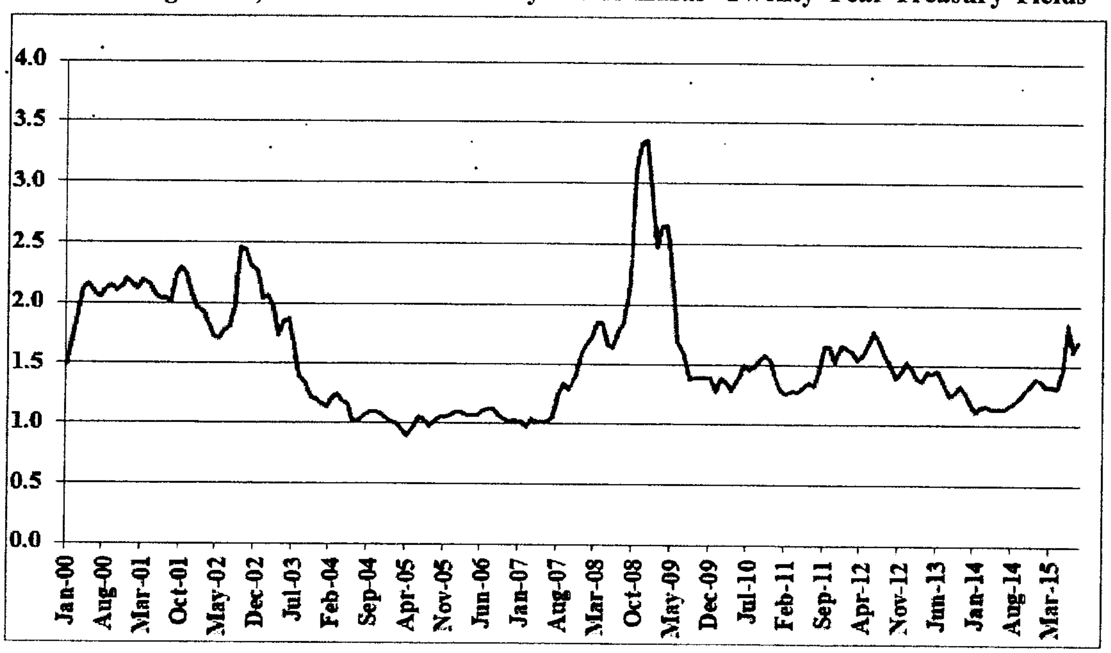


Source: Federal Reserve Bank of St. Louis, FRED Database.

Exhibit JRW-3
Panel A
Long-Term, A-Rated Public Utility Yields



Panel B
Long-Term, A-Rated Public Utility Yields minus -Twenty-Year Treasury Yields



Source: Mergent Bond Record, Federal Reserve Bank of St. Louis, FRED Database.

Exhibit JRW-4
UNS Electric, Inc.
Summary Financial Statistics for Proxy Groups

Panel A
Electric Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Percent Gas Revenue	Net Plant ($mil)	Market Cap ($mil)	S&P Issuer Credit Rating	Moody's Long Term Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	1,222.9	82		3,451.5	2.38	BBB+	A3	3.9	MN, WI	56.1	8.6	1.34
Alliant Energy Corporation (NYSE-LNT)	3,261.8	83	14	9,173.5	6.43	A-	A3	10.0	WI,IA,IL,MN	48.4	10.3	1.68
Ameren Corporation (NYSE-AEE)	6,015.0	82	18	17,700.0	9.90	BBB+	Baa1	4.0	IL,MO	47.7	9.1	1.48
American Electric Power Co. (NYSE-AEP)	16,978.0	81		45,013.0	26.99	BBB	Baa1	4.0	10 States	45.7	10.2	1.55
Avista Corporation (NYSE-AVA)	1,497.2	69	34	3,726.7	1.97	BBB	Baa1	3.4	WA,ID,AK	48.8	7.8	1.30
Black Hills Corporation (NYSE-BKH)	1,375.4	50	43	3,300.2	1.70	BBB	Baa1	3.9	CO,SD,WY,MT,NE,IA,KS	46.1	9.4	1.21
CMS Energy Corporation (NYSE-CMS)	6,649.0	63	32	13,775.0	9.34	BBB+	Baa2	2.8	MI	30.5	12.3	2.45
Consolidated Edison, Inc. (NYSE-ED)	12,622.0	71	14	30,448.0	19.19	A-	A3	3.8	NY,PA	48.4	8.8	1.50
Dominion Resources, Inc. (NYSE-D)	12,149.0	63	2	38,668.0	41.12	A-	Baa2	3.8	VA,NC,OH,WV	31.2	14.3	3.31
Duke Energy Corporation (NYSE-DUK)	23,608.0	90	2	71,759.0	47.53	A-	A3	3.4	NC,SC,FL,OH,KY	48.9	6.9	1.20
Edison International (NYSE-EIX)	12,891.0	100		33,594.0	19.90	BBB+	A3	5.2	CA	43.2	14.5	1.76
El Paso Electric Company (NYSE-EE)	895.8	100		2,541.6	1.43	BBB	Baa1	2.6	TX,NM	44.7	9.4	1.47
Empire District Electric Co. (NYSE-EDE)	637.2	91	7	1,945.9	0.95	BBB	Baa1	3.0	KS,MO,OK,AR	48.0	7.8	1.20
Entergy Corporation (NYSE-ETR)	12,206.2	79	1	28,808.0	11.41	BBB	Baa3	3.1	LA,AR,MS,TX	41.6	8.3	1.12
Eversource Energy (NYSE-ES)	8,104.1	87	13	19,079.2	15.14	A	Baa1	4.7	CT,NH,MA	50.7	9.2	1.49
FirstEnergy Corporation (ASE-FE)	14,764.0	67		36,117.0	12.86	BBB-	Baa3	1.6	OH,PA,NY,NJ,WV,MD	35.5	2.5	1.04
Great Plains Energy Incorporated (NYSE-GXP)	2,492.8	100		8,537.9	3.97	BBB+	Baa2	2.7	MO,KS	46.2	6.5	1.11
IDACORP, Inc. (NYSE-IDA)	1,287.7	100		3,934.2	3.10	BBB	Baa1	3.4	ID	53.0	10.9	1.55
MGE Energy, Inc. (NYSE-MGEE)	573.1	69	30	1,223.2	1.39	AA-	A1	6.5	WI	62.8	10.7	2.07
NorthWestern Corporation (NYSE-NWE)	1,181.4	71	24	3,843.2	2.60	BBB	A3	2.4	SD,MT,NE	43.6	11.6	1.71
OGE Energy Corp. (NYSE-OGE)	2,310.9	100		7,085.8	5.35	A-	A3	4.6	OK,AR	53.5	11.8	1.63
Otter Tail Corporation (NDQ-OTTR)	715.2	56		1,333.4	0.95	BBB	Baa2	3.5	MN,ND,SD	52.1	9.7	1.62
PG&E Corporation (NYSE-PCG)	17,363.0	80	20	45,010.0	25.04	BBB	Baa1	3.8	CA	48.8	8.9	1.56
Pinnacle West Capital Corp. (NYSE-PNW)	3,461.0	100		11,343.5	6.90	A-	Baa1	4.8	AZ	52.6	9.0	1.57
PNM Resources, Inc. (NYSE-PNM)	1,446.6	100		4,409.7	2.09	BBB	Baa3	2.4	NM,TX	43.0	7.0	1.20
Portland General Electric Company (NYSE-POR)	1,907.0	100		5,874.0	3.17	BBB	A3	2.3	OR	49.6	8.2	1.43
SCANA Corporation (NYSE-SCG)	4,692.0	55	19	12,591.0	7.54	BBB+	Baa3.	3.4	SC,NC,GA	45.9	14.7	1.41
Westar Energy, Inc. (NYSE-WR)	2,564.0	100		8,232.3	4.93	BBB+	Baa1	2.8	KS	47.3	9.2	1.49
Xcel Energy Inc. (NYSE-XEL)	11,275.8	83	17	29,350.4	17.29	A-	A3	3.3	MN,WI,ND,SD,MI	44.0	9.1	1.68
Mean	6,418.9	82	18	17,305.8	10.8	BBB+	Baa1	3.8		46.8	9.5	1.56
Median	3,261.8	82	18	9,173.5	6.4	BBB+	Baa1	3.4		47.7	9.2	1.49

Data Source: AUS Utility Reports, October, 2015; Pre-Tax Interest Coverage and Primary Service Territory are from Value Line Investment Survey, 2015.

UNS Electric, Inc.*	[redacted]				NM	na	A3	[redacted]	AZ	[redacted]		NM

*Source: Confidential - UDR 2.01 UNSE FS 2014- Confidential; and UDR 2.5 Authorized and Earned ROE - Confidential.

Panel B
Bulkey Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Percent Gas Revenue	Net Plant ($mil)	Market Cap ($mil)	S&P Issuer Credit Rating	Moody's Long Term Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	1,222.9	82		3,451.5	2.38	BBB+	A3	3.9	MN, WI	56.1	8.6	1.34
American Electric Power Co. (NYSE-AEP)	16,978.0	81		45,013.0	26.99	BBB	Baa1	4.0	10 States	45.7	10.2	1.55
Duke Energy Corporation (NYSE-DUK)	23,608.0	90	2	71,759.0	47.53	A-	A3	3.4	NC,SC,FL,OH,KY	48.9	6.9	1.20
Empire District Electric Co. (NYSE-EDE)	637.2	91	7	1,945.9	0.95	BBB	Baa1	3.0	KS,MO,OK,AR	48.0	7.8	1.20
Eversource Energy (NYSE-ES)	8,104.1	87	13	19,079.2	15.14	A	Baa1	4.7	CT,NH,MA	50.7	9.2	1.49
Great Plains Energy Incorporated (NYSE-GXP)	2,492.8	100		8,537.9	3.97	BBB+	Baa2	2.7	MO,KS	46.2	6.5	1.11
IDACORP, Inc. (NYSE-IDA)	1,287.7	100		3,934.2	3.10	BBB	Baa1	3.4	ID	53.0	10.9	1.55
Otter Tail Corporation (NDQ-OTTR)	715.2	56		1,333.4	0.95	BBB	Baa2	3.5	MN,ND,SD	52.1	9.7	1.62
Pinnacle West Capital Corp. (NYSE-PNW)	3,461.0	100		11,343.5	6.90	A-	Baa1	4.8	AZ	52.6	9.0	1.57
PNM Resources, Inc. (NYSE-PNM)	1,446.6	100		4,409.7	2.09	BBB	Baa3	2.4	NM,TX	43.0	7.0	1.20
Portland General Electric Company (NYSE-POR)	1,907.0	100		5,874.0	3.17	BBB	A3	2.3	OR	49.6	8.2	1.43
Westar Energy, Inc. (NYSE-WR)	2,564.0	100		8,232.3	4.93	BBB+	Baa1	2.8	KS	47.3	9.2	1.49
Mean	5,368.7	91	7	15,409.5	9.8	BBB+/BBB	Baa1	3.4		49.4	8.6	1.40
Median	2,199.9	96	7	7,053.2	3.6	BBB+/BBB	Baa1	3.4		49.3	8.8	1.46

Data Source: AUS Utility Reports, October, 2015; Pre-Tax Interest Coverage and Primary Service Territory are from Value Line Investment Survey, 2015.

Exhibit JRW-4

UNS Electric, Inc.

Value Line Risk Metrics

Panel A
Electric Proxy Group

Company	Beta	Financial Strength	Safety	Earnings Predictability	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.80	A	2	80	95
Alliant Energy Corporation (NYSE-LNT)	0.80	A	2	75	100
Ameren Corporation (NYSE-AEE)	0.75	A	2	85	95
American Electric Power Co. (NYSE-AEP)	0.70	A	2	90	100
Avista Corporation (NYSE-AVA)	0.80	A	2	80	95
Black Hills Corporation (NYSE-BKH)	0.95	B++	2	40	80
CMS Energy Corporation (NYSE-CMS)	0.70	B++	2	75	100
Consolidated Edison, Inc. (NYSE-ED)	0.60	A+	1	85	100
Dominion Resources, Inc. (NYSE-D)	0.70	B++	2	80	100
Duke Energy Corporation (NYSE-DUK)	0.60	A	2	80	100
Edison International (NYSE-EIX)	0.70	A	2	65	95
El Paso Electric Company (NYSE-EE)	0.75	B++	2	85	90
Empire District Electric Co. (NYSE-EDE)	0.70	B++	2	85	90
Entergy Corporation (NYSE-ETR)	0.65	B++	3	80	95
Eversource Energy (NYSE-ES)	0.75	A	1	85	100
FirstEnergy Corporation (ASE-FE)	0.65	B+	3	50	90
Great Plains Energy Incorporated (NYSE-GXP)	0.85	B+	3	70	95
IDACORP, Inc. (NYSE-IDA)	0.80	B++	2	95	95
MGE Energy, Inc. (NYSE-MGEE)	0.75	A	1	95	95
NorthWestern Corporation (NYSE-NWE)	0.70	B+	3	95	100
OGE Energy Corp. (NYSE-OGE)	0.90	A+	1	95	90
Otter Tail Corporation (NDQ-OTTR)	0.85	B+	3	50	85
PG&E Corporation (NYSE-PCG)	0.65	B+	3	60	95
Pinnacle West Capital Corp. (NYSE-PNW)	0.75	A+	1	70	100
PNM Resources, Inc. (NYSE-PNM)	0.85	B	3	30	85
Portland General Electric Company (NYSE-POI	0.80	B++	2	70	100
SCANA Corporation (NYSE-SCG)	0.75	B++	2	100	100
Westar Energy, Inc. (NYSE-WR)	0.75	B++	2	90	100
Xcel Energy Inc. (NYSE-XEL)	0.65	A	1	100	100
Mean	0.75	B++	2.0	77	95

Data Source: *Value Line Investment Survey*, 2015.

Panel B
Bulkey Proxy Group

Company	Beta	Financial Strength	Safety	Earnings Predictability	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.80	A	2	80	95
American Electric Power Co. (NYSE-AEP)	0.70	A	2	90	100
Duke Energy Corporation (NYSE-DUK)	0.60	A	2	80	100
Empire District Electric Co. (NYSE-EDE)	0.70	B++	2	85	90
Eversource Energy (NYSE-ES)	0.75	A	1	85	100
Great Plains Energy Incorporated (NYSE-GXP)	0.85	B+	3	70	95
IDACORP, Inc. (NYSE-IDA)	0.80	B++	2	95	95
Otter Tail Corporation (NDQ-OTTR)	0.85	B+	3	50	85
Pinnacle West Capital Corp. (NYSE-PNW)	0.75	A+	1	70	100
PNM Resources, Inc. (NYSE-PNM)	0.85	B	3	30	85
Portland General Electric Company (NYSE-POI	0.80	B++	2	70	100
Westar Energy, Inc. (NYSE-WR)	0.75	B++	2	90	100
Mean	0.77	B++	2.1	75	95

Exhibit JRW-5
UNS Electric, Inc.
Recommended Cost of Capital

Panel A - UNSE's Proposed Capitalization

Capital Source	Capitalization Ratio	Cost Rate
Short-Term Debt	0.00%	
Long-Term Debt	47.17%	4.66%
Common Equity	52.83%	
Total	100.00%	

Panel B - Fortis Inc. 2014 Capitalization

Capital Source	Capitalization Amount	Capitalization Ratio
Short-Term Debt	$ 713.0	3.6%
Long-Term Debt	$ 10,544.0	52.9%
Common Equity	$ 8,691.0	43.6%
Total	$ 19,948.0	100.00%

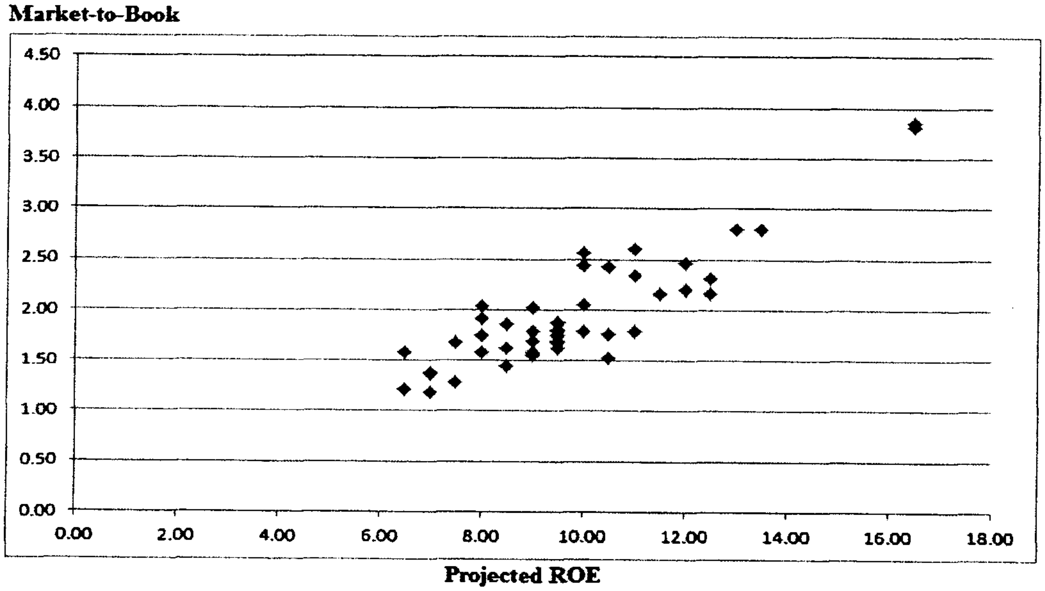
Source: Fortis Inc., *Value Line Investment Survey*, July 17, 2015.

Panel C - TASC's Proposed Capitalization - Capital Structure Ratios from Investor-Provided Capital

Capital Source	Adjustment Factor*	Capitalization Ratio	Cost Rate
Short-Term Debt	0.00%	0.00%	
Long-Term Debt	106.00%	50.00%	4.66%
Common Equity	94.64%	50.00%	
Total		100.00%	

* Adjustment is to short-term and long-term debt and common equity ratios to provide a 50% debt and 50% equity capital structure.

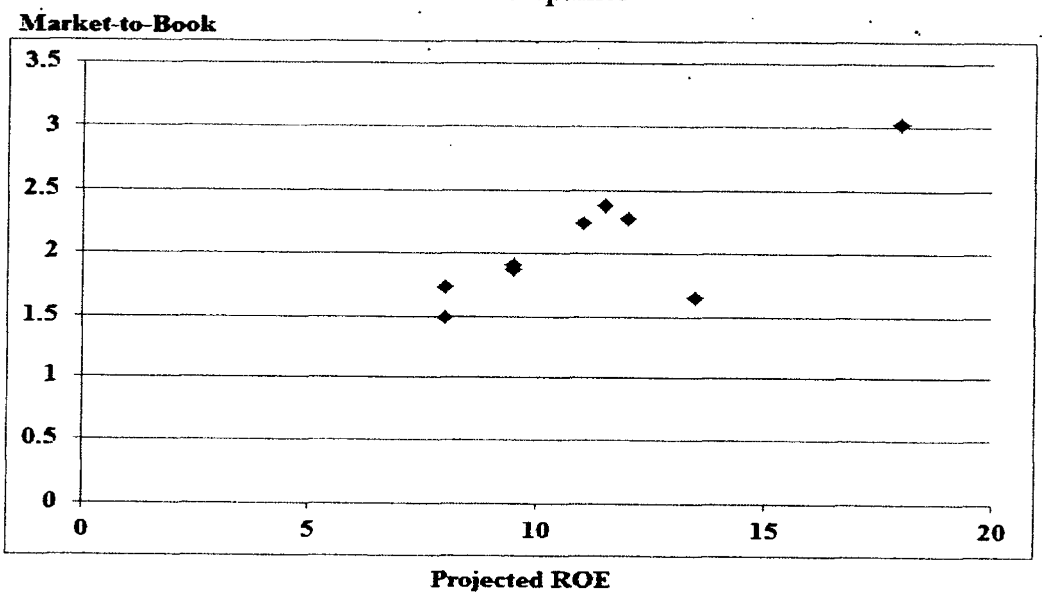
Exhibit JRW-6
Electric Utilities
Panel A



Value Line Investment Survey, 2015

R-Square = .78, N=46

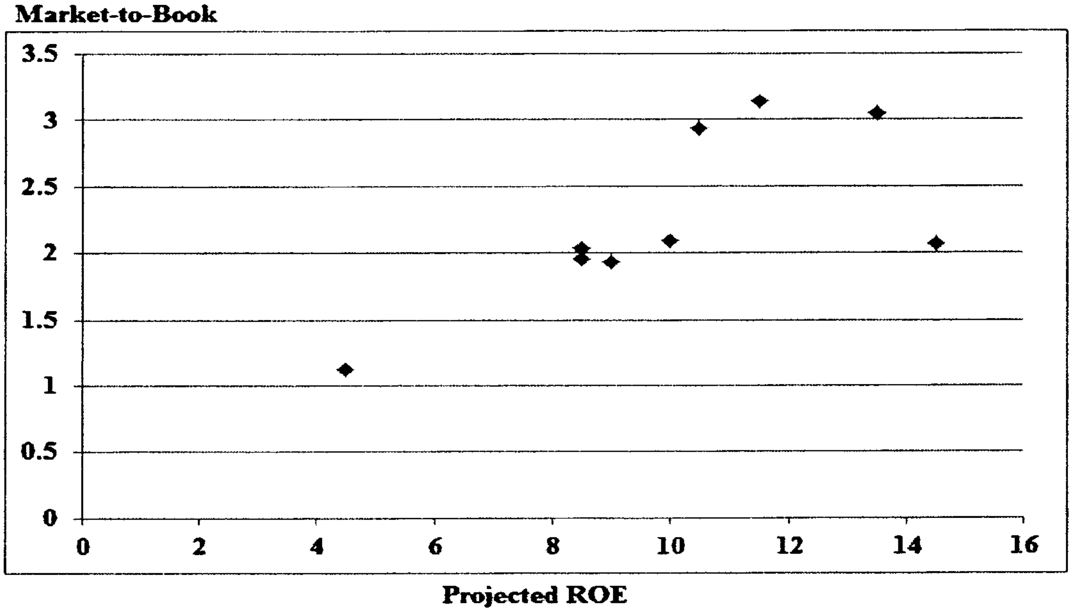
Panel B
Gas Companies



Value Line Investment Survey, 2015

R-Square = .63, N=9

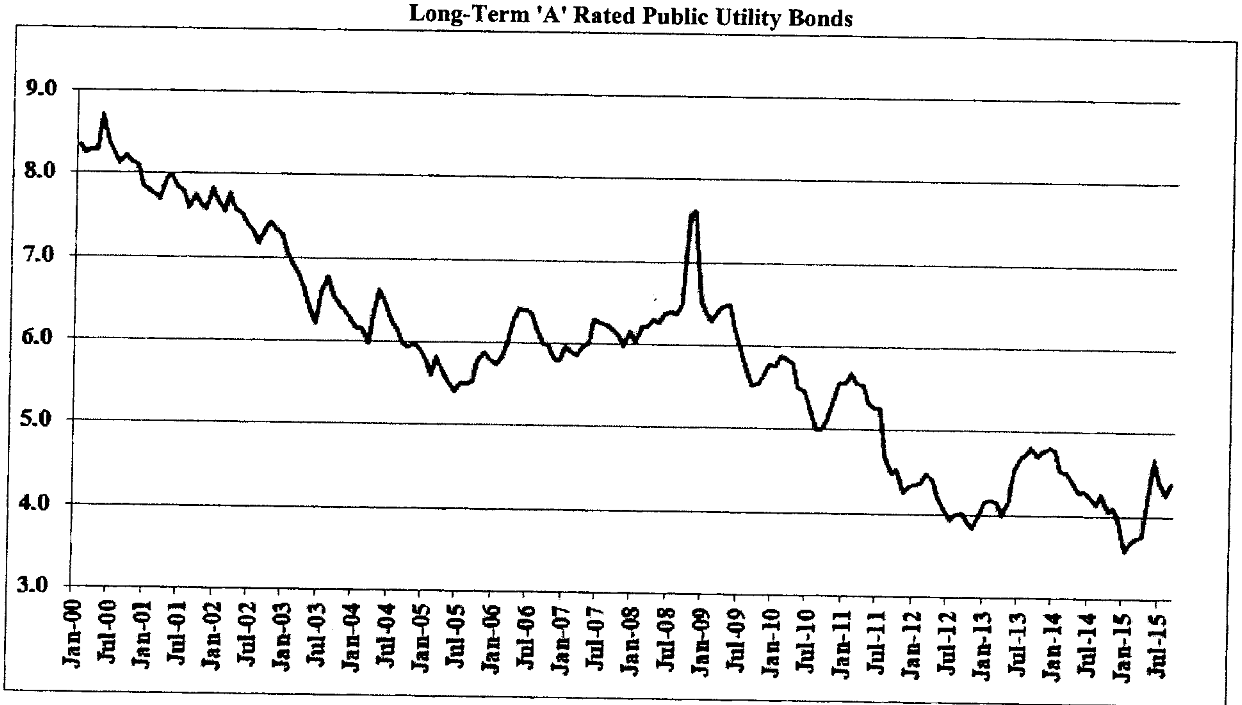
Exhibit JRW-6
Water Companies
Panel C



Value Line Investment Survey, 2015

R-Square = .49, N=9

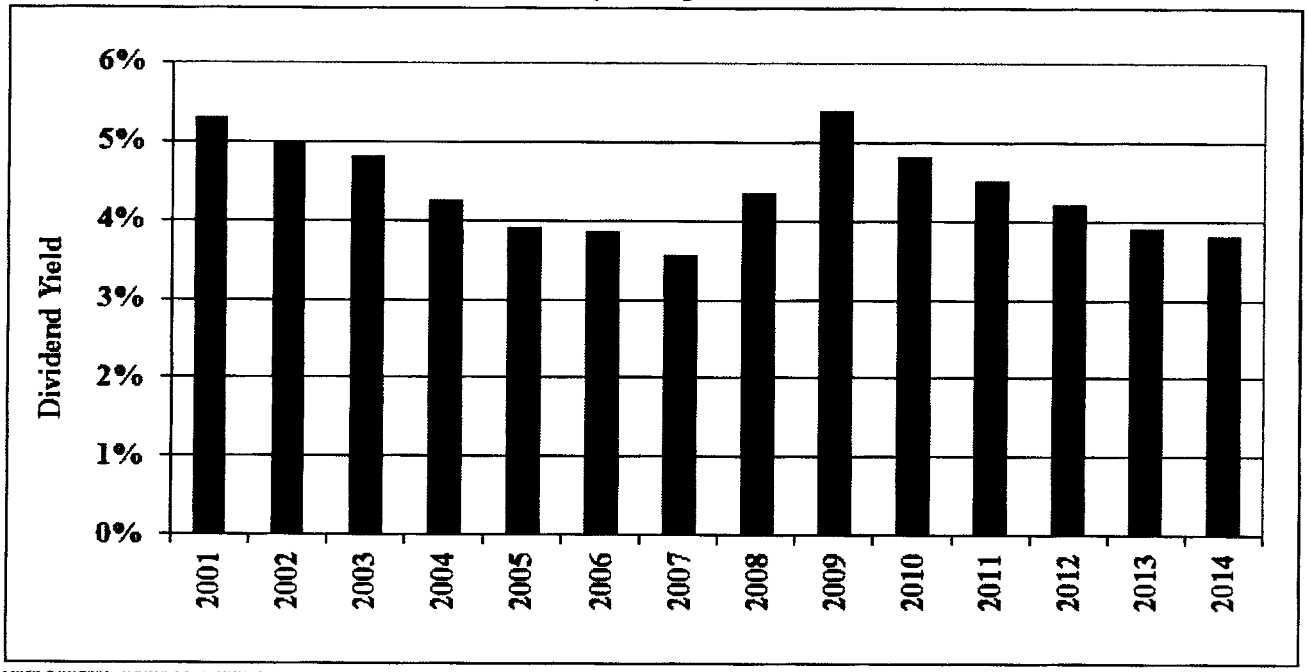
Exhibit JRW-7
Long-Term 'A' Rated Public Utility Bonds



Data Source: Mergent Bond Record

Exhibit JRW-7

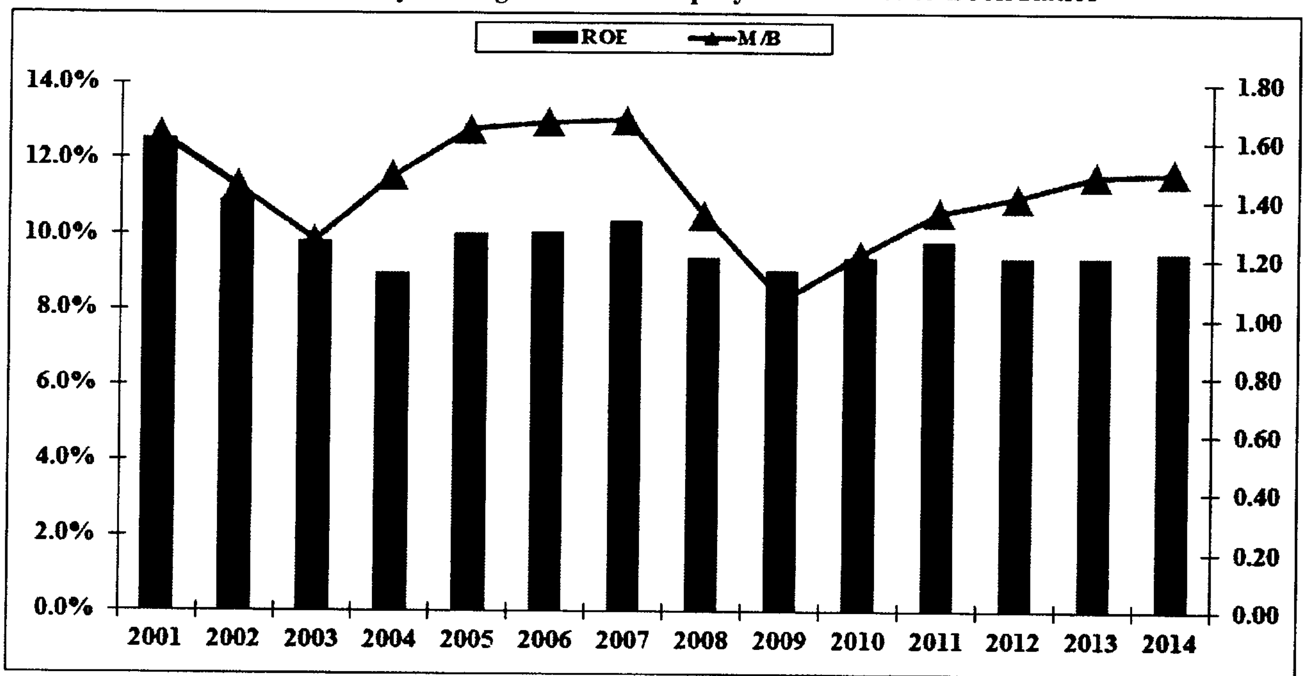
Electric Utility Average Dividend Yield



Data Source: *Value Line Investment Survey.*

Exhibit JRW-7

Electric Utility Average Return on Equity and Market-to-Book Ratios



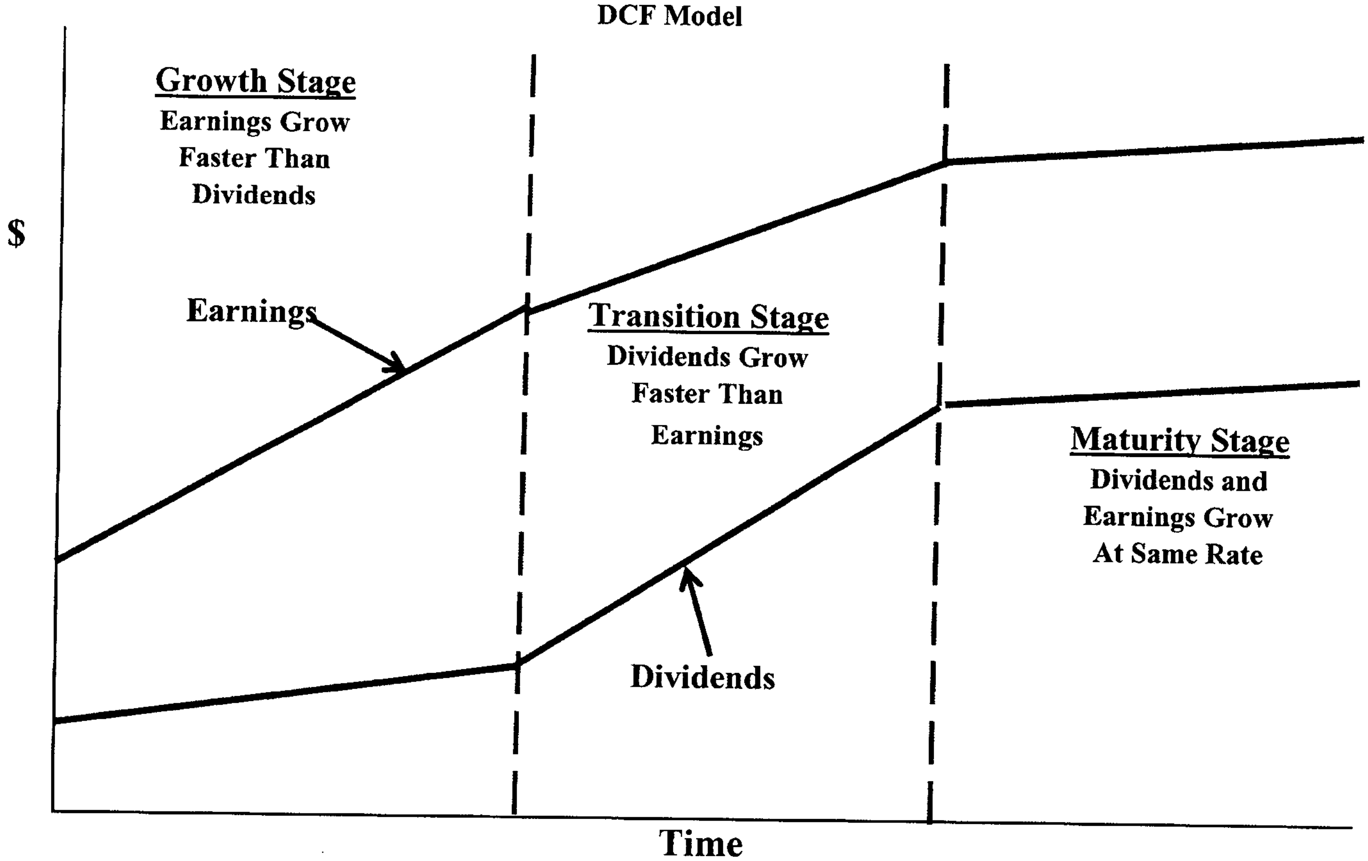
Data Source: *Value Line Investment Survey.*

Exhibit JRW-8

Industry Average Betas

Industry Name	Beta	Industry Name	Beta	Industry Name	Beta
Homebuilding	1.47	Chemical (Basic)	1.17	Retail Building Supply	1.01
Heavy Truck & Equip	1.44	Diversified Co.	1.16	Investment Co.(Foreign)	1.01
Metals & Mining (Div.)	1.43	Educational Services	1.16	Toiletries/Cosmetics	1.01
Petroleum (Producing)	1.38	Advertising	1.16	Med Supp Non-Invasive	1.00
Oilfield Svcs/Equip.	1.38	Automotive	1.16	Shoe	0.98
Steel	1.38	Computers/Peripherals	1.15	Retail Automotive	0.98
Metal Fabricating	1.37	Trucking	1.15	Retail (Softlines)	0.98
Auto Parts	1.37	Financial Svcs. (Div.)	1.15	Telecom. Utility	0.96
Building Materials	1.33	Entertainment Tech	1.14	R.E.I.T.	0.95
Maritime	1.33	Retail (Hardlines)	1.13	Information Services	0.95
Hotel/Gaming	1.30	Publishing	1.12	Med Supp Invasive	0.95
Electrical Equipment	1.29	Internet	1.12	Drug	0.94
Semiconductor Equip	1.28	Entertainment	1.12	Precious Metals	0.93
Semiconductor	1.28	Apparel	1.12	Environmental	0.93
Insurance (Life)	1.27	Newspaper	1.12	Restaurant	0.92
Public/Private Equity	1.27	Wireless Networking	1.10	Thrift	0.92
Engineering & Const	1.27	Industrial Services	1.09	Funeral Services	0.92
Railroad	1.27	Bank	1.09	Pharmacy Services	0.91
Human Resources	1.25	Computer Software	1.09	Retail Store	0.89
Natural Gas (Div.)	1.25	Recreation	1.09	Beverage	0.87
Chemical (Diversified)	1.24	Biotechnology	1.08	Reinsurance	0.86
Chemical (Specialty)	1.23	Paper/Forest Products	1.07	Pipeline MLPs	0.85
Power	1.23	Bank (Midwest)	1.06	Insurance (Prop/Cas.)	0.85
Petroleum (Integrated)	1.23	Oil/Gas Distribution	1.06	Household Products	0.84
Electronics	1.21	Medical Services	1.05	Food Processing	0.84
Machinery	1.21	Telecom. Services	1.05	Investment Co.	0.80
Precision Instrument	1.21	Healthcare Information	1.04	Natural Gas Utility	0.80
Coal	1.21	Air Transport	1.04	Retail/Wholesale Food	0.78
Telecom. Equipment	1.19	IT Services	1.04	Electric Utility (West)	0.77
Securities Brokerage	1.19	Foreign Electronics	1.02	Tobacco	0.77
Furn/Home Furnishings	1.19	Aerospace/Defense	1.02	Electric Util. (Central)	0.76
Office Equip/Supplies	1.19	Cable TV	1.02	Water Utility	0.73
E-Commerce	1.18	Packaging & Container	1.02	Electric Utility (East)	0.68

Exhibit JRW-9
DCF Model



Source: William F. Sharpe, Gordon J. Alexander, and Jeffrey V. Bailey, Investments (Prentice-Hall, 1995), pp. 590-91.

Exhibit JRW-9
DCF Model
Consensus Earnings Estimates
Alliant Energy Corp. (LNT)
www.reuters.com
10/1/2015

Line	Date	# of Estimates	Mean	High	Low
1	Quarter Ending Dec-15	4	0.53	0.63	0.41
2	Quarter Ending Mar-16	1	0.94	0.94	0.94
3	Year Ending Dec-15	10	3.63	3.68	3.60
4	Year Ending Dec-16	10	3.83	3.91	3.75
5	LT Growth Rate (%)	2	5.75	6.00	5.50

Exhibit JRW-10

UNS Electric, Inc.
Discounted Cash Flow Analysis

Panel A
Electric Proxy Group

Dividend Yield*	3.85%
Adjustment Factor	1.0238
Adjusted Dividend Yield	3.9%
Growth Rate**	4.75%
Equity Cost Rate	8.70%

* Page 2 of Exhibit JRW-10
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-10

Panel B
Bulkey Proxy Group

Dividend Yield*	3.90%
Adjustment Factor	1.0250
Adjusted Dividend Yield	4.00%
Growth Rate**	5.00%
Equity Cost Rate	9.00%

* Page 2 of Exhibit JRW-10
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-10

Exhibit JRW-10
UNS Electric, Inc.
Monthly Dividend Yields

Panel A
Electric Proxy Group

Company	Annual Dividend	Dividend Yield 30 Day	Dividend Yield 90 Day	Dividend Yield 180 Day
ALLETE, Inc. (NYSE-ALE)	$ 2.02	4.2%	4.2%	4.0%
Alliant Energy Corporation (NYSE-LNT)	$ 2.20	3.9%	3.8%	3.6%
Ameren Corporation (NYSE-AEE)	$ 1.64	4.1%	4.2%	4.1%
American Electric Power Co. (NYSE-AEP)	$ 2.12	3.9%	3.9%	3.8%
Avista Corporation (NYSE-AVA)	$ 1.32	4.2%	4.2%	4.1%
Black Hills Corporation (NYSE-BKH)	$ 1.62	4.1%	3.9%	3.6%
CMS Energy Corporation (NYSE-CMS)	$ 1.16	3.5%	3.5%	3.4%
Consolidated Edison, Inc. (NYSE-ED)	$ 2.60	4.1%	4.2%	4.2%
Dominion Resources, Inc. (NYSE-D)	$ 2.59	3.7%	3.7%	3.7%
Duke Energy Corporation (NYSE-DUK)	$ 3.30	4.7%	4.6%	4.4%
Edison International (NYSE-EIX)	$ 1.67	2.8%	2.9%	2.8%
El Paso Electric Company (NYSE-EE)	$ 1.18	3.3%	3.3%	3.3%
Empire District Electric Co. (NYSE-EDE)	$ 1.04	4.8%	4.7%	4.4%
Entergy Corporation (NYSE-ETR)	$ 3.32	5.2%	4.8%	4.5%
Eversource Energy (NYSE-ES)	$ 1.67	3.5%	3.5%	3.4%
FirstEnergy Corporation (ASE-FE)	$ 1.44	4.6%	4.4%	4.2%
Great Plains Energy Incorporated (NYSE-GXP)	$ 0.98	3.9%	3.9%	3.8%
IDACORP, Inc. (NYSE-IDA)	$ 1.88	3.1%	3.2%	3.1%
MGE Energy, Inc. (NYSE-MGEE)	$ 1.18	3.0%	3.0%	2.9%
Northwestern Corp. (NYSE-NWE)	$ 1.92	3.7%	3.8%	3.7%
OGE Energy Corp. (NYSE-OGE)	$ 1.10	4.0%	3.8%	3.6%
Otter Tail Corporation (NDQ-OTTR)	$ 1.23	4.8%	4.7%	4.3%
PG&E Corporation (NYSE-PCG)	$ 1.82	3.6%	3.6%	3.5%
Pinnacle West Capital Corp. (NYSE-PNW)	$ 2.38	3.9%	4.0%	3.9%
PNM Resources, Inc. (NYSE-PNM)	$ 0.80	3.1%	3.1%	3.0%
Portland General Electric Company (NYSE-POR)	$ 1.20	3.4%	3.5%	3.4%
SCANA Corporation (NYSE-SCG)	$ 2.18	4.1%	4.2%	4.1%
Westar Energy, Inc. (NYSE-WR)	$ 1.44	3.9%	4.0%	3.9%
Xcel Energy Inc. (NYSE-XEL)	$ 1.28	3.8%	3.8%	3.8%
Mean		3.9%	3.9%	3.7%
Median		3.9%	3.9%	3.8%

Data Sources: http://quote.yahoo.com, October, 2015.

Panel B
Bulkey Proxy Group

	Annual	Dividend Yield	Dividend Yield	Dividend Yield
ALLETE, Inc. (NYSE-ALE)	$ 2.02	4.2%	4.2%	4.0%
American Electric Power Co. (NYSE-AEP)	$ 2.12	3.9%	3.9%	3.8%
Duke Energy Corporation (NYSE-DUK)	$ 3.30	4.7%	4.6%	4.4%
Empire District Electric Co. (NYSE-EDE)	$ 1.04	4.8%	4.7%	4.4%
Eversource Energy (NYSE-ES)	$ 1.67	3.5%	3.5%	3.4%
Great Plains Energy Incorporated (NYSE-GXP)	$ 0.98	3.9%	3.9%	3.8%
IDACORP, Inc. (NYSE-IDA)	$ 1.88	3.1%	3.2%	3.1%
Otter Tail Corporation (NDQ-OTTR)	$ 1.23	4.8%	4.7%	4.3%
Pinnacle West Capital Corp. (NYSE-PNW)	$ 2.38	3.9%	4.0%	3.9%
PNM Resources, Inc. (NYSE-PNM)	$ 0.80	3.1%	3.1%	3.0%
Portland General Electric Company (NYSE-POR)	$ 1.20	3.4%	3.5%	3.4%
Westar Energy, Inc. (NYSE-WR)	$ 1.44	3.9%	4.0%	3.9%
Mean		3.9%	3.9%	3.8%
Median		3.9%	3.9%	3.8%

Data Sources: http://quote.yahoo.com, October, 2015.

Exhibit JRW-10

UNS Electric, Inc.
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Panel A
Electric Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	7.0	nmf	4.5	1.0	2.0	5.0
Alliant Energy Corporation (NYSE-LNT)	8.0	3.5	3.5	6.5	6.5	3.5
Ameren Corporation (NYSE-AEE)	-2.0	-4.5		-4.5	-6.0	-3.5
American Electric Power Co. (NYSE-AEP)	1.5	0.5	4.5	1.5	4.0	4.5
Avista Corporation (NYSE-AVA)	7.5	9.5	4.0	6.5	11.5	4.0
Black Hills Corporation (NYSE-BKH)	2.5	2.5	3.5	7.5	1.5	2.0
CMS Energy Corporation (NYSE-CMS)			3.0	12.0	23.5	4.0
Consolidated Edison, Inc. (NYSE-ED)	3.5	1.0	4.0	2.5	1.0	3.5
Dominion Resources, Inc. (NYSE-D)	3.0	5.5	1.5	2.5	7.0	2.0
Duke Energy Corporation (NYSE-DUK)				3.5	2.5	3.0
Edison International (NYSE-EIX)	10.0		6.5	4.5	2.5	2.0
El Paso Electric Company (NYSE-EE)	13.5		8.5	6.5		8.0
Empire District Electric Co. (NYSE-EDE)	2.5	-2.5	1.5	5.0	-4.5	2.0
Entergy Corporation (NYSE-ETR)	4.0	7.5	4.0	-1.5	3.0	4.5
Eversource Energy (NYSE-ES)	8.0	9.5	5.5	5.5	11.5	9.5
FirstEnergy Corporation (ASE-FE)	-1.5	0.5	2.0	-13.0	-4.0	1.5
Great Plains Energy Incorporated (NYSE-GXP)	-4.0	-6.0	4.5	2.5	-8.5	2.5
IDACORP, Inc. (NYSE-IDA)	9.0		5.0	10.0	5.5	6.0
MGE Energy, Inc. (NYSE-MGEE)	6.5	2.0	6.0	7.0	2.5	5.5
Northwestern Corp. (NYSE-NWE)			3.5	8.0	3.0	5.5
OGE Energy Corp. (NYSE-OGE)	8.5	2.5	8.5	8.0	4.5	9.0
Otter Tail Corporation (NDQ-OTTR)	-2.0	1.0	1.0	2.0		-4.5
PG&E Corporation (NYSE-PCG)	14.5		9.0	-5.0	3.0	4.0
Pinnacle West Capital Corp. (NYSE-PNW)	3.5	3.5	2.0	8.0	3.0	2.0
PNM Resources, Inc. (NYSE-PNM)	-2.5	0.5	1.5	8.0	-6.0	-1.0
Portland General Electric Company (NYSE-POR)				3.0	2.5	2.0
SCANA Corporation (NYSE-SCG)	3.0	4.0	5.0	4.0	2.0	5.0
Westar Energy, Inc. (NYSE-WR)	6.5	3.5	5.0	9.0	3.5	3.5
Xcel Energy Inc. (NYSE-XEL)	7.0	2.5	4.5	6.0	3.5	4.5
Mean	4.7	2.3	4.3	4.0	3.0	3.4
Median	4.0	2.5	4.3	5.0	3.0	3.5
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			3.7		

Panel B
Bulkey Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	7.0	nmf	4.5	1.0	2.0	5.0
American Electric Power Co. (NYSE-AEP)	1.5	0.5	4.5	1.5	4.0	4.5
Duke Energy Corporation (NYSE-DUK)				3.5	2.5	3.0
Empire District Electric Co. (NYSE-EDE)	2.5	-2.5	1.5	5.0	-4.5	2.0
Eversource Energy (NYSE-ES)	8.0	9.5	5.5	5.5	11.5	9.5
Great Plains Energy Incorporated (NYSE-GXP)	-4.0	-6.0	4.5	2.5	-8.5	2.5
IDACORP, Inc. (NYSE-IDA)	9.0		5.0	10.0	5.5	6.0
Otter Tail Corporation (NDQ-OTTR)	-2.0	1.0	1.0	2.0		-4.5
Pinnacle West Capital Corp. (NYSE-PNW)	3.5	3.5	2.0	8.0	3.0	2.0
PNM Resources, Inc. (NYSE-PNM)	-2.5	0.5	1.5	8.0	-6.0	-1.0
Portland General Electric Company (NYSE-POR)				3.0	2.5	2.0
Westar Energy, Inc. (NYSE-WR)	6.5	3.5	5.0	9.0	3.5	3.5
Mean	3.0	1.3	3.5	4.9	1.4	2.9
Median	3.0	0.8	4.5	4.3	2.5	2.8
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			3.0		

Exhibit JRW-10

UNS Electric, Inc.
DCF Equity Cost Growth Rate Measures
Value Line Projected Growth Rates

Panel A
Electric Proxy Group

Company	*Value Line* Projected Growth Est'd. '12-'14 to '18-'20 Earnings	Dividends	Book Value	*Value Line* Sustainable Growth Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	6.5	4.0	4.5	9.0%	39.0%	3.5%
Alliant Energy Corporation (NYSE-LNT)	6.0	4.5	4.0	11.5%	37.0%	4.3%
Ameren Corporation (NYSE-AEE)	7.0	3.5	3.5	10.5%	44.0%	4.6%
American Electric Power Co. (NYSE-AEP)	5.0	5.0	4.0	10.0%	34.0%	3.4%
Avista Corporation (NYSE-AVA)	5.0	4.0	3.5	8.5%	35.0%	3.0%
Black Hills Corporation (NYSE-BKH)	4.5	4.0	3.5	8.5%	40.0%	3.4%
CMS Energy Corporation (NYSE-CMS)	5.5	6.5	5.5	13.5%	38.0%	5.1%
Consolidated Edison, Inc. (NYSE-ED)	3.0	2.5	3.5	9.0%	36.0%	3.2%
Dominion Resources, Inc. (NYSE-D)	8.0	7.5	6.5	17.5%	28.0%	4.9%
Duke Energy Corporation (NYSE-DUK)	5.0	3.5	1.5	8.5%	30.0%	2.6%
Edison International (NYSE-EIX)	3.0	10.0	6.5	11.5%	48.0%	5.5%
El Paso Electric Company (NYSE-EE)	3.5	5.0	4.5	9.5%	50.0%	4.8%
Empire District Electric Co. (NYSE-EDE)	3.0	3.0	2.5	9.0%	33.0%	3.0%
Entergy Corporation (NYSE-ETR)	0.0	2.5	3.0	8.5%	31.0%	2.6%
Eversource Energy (NYSE-ES)	8.5	6.5	4.0	10.0%	44.0%	4.4%
FirstEnergy Corporation (ASE-FE)	7.0	-1.5	3.0	8.5%	48.0%	4.1%
Great Plains Energy Incorporated (NYSE-GXP)	5.0	6.0	3.0	7.5%	39.0%	2.9%
IDACORP, Inc. (NYSE-IDA)	1.0	6.0	4.0	8.5%	42.0%	3.6%
MGE Energy, Inc. (NYSE-MGEE)	7.0	4.0	6.0	13.0%	58.0%	7.5%
NorthWestern Corporation (NYSE-NWE)	6.5	6.5	5.5	10.0%	42.0%	4.2%
OGE Energy Corp. (NYSE-OGE)	3.0	10.0	5.0	11.5%	32.0%	3.7%
Otter Tail Corporation (NDQ-OTTR)	9.0	1.5	3.5	12.5%	41.0%	5.1%
PG&E Corporation (NYSE-PCG)	10.5	3.0	5.0	10.0%	49.0%	4.9%
Pinnacle West Capital Corp. (NYSE-PNW)	4.0	3.5	3.5	9.5%	36.0%	3.4%
PNM Resources, Inc. (NYSE-PNM)	9.0	10.0	3.5	9.5%	51.0%	4.8%
Portland General Electric Company (NYSE-POR)	6.0	5.5	4.5	9.5%	47.0%	4.5%
SCANA Corporation (NYSE-SCG)	4.5	3.5	5.5	9.5%	44.0%	4.2%
Westar Energy, Inc. (NYSE-WR)	6.0	3.0	5.0	9.5%	45.0%	4.3%
Xcel Energy Inc. (NYSE-XEL)	4.5	6.0	4.5	10.5%	38.0%	4.0%
Mean	5.4	4.8	4.2	10.2%	40.7%	4.1%
Median	5.0	4.0	4.0	9.5%	40.0%	4.2%
Average of Median Figures =		4.3			Median =	4.2%

Data Source: *Value Line Investment Survey.*

Panel B
Bulkey Proxy Group

Company	*Value Line* Projected Growth Est'd. '12-'14 to '18-'20 Earnings	Dividends	Book Value	*Value Line* Sustainable Growth Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	6.5	4.0	4.5	9.0%	39.0%	3.5%
American Electric Power Co. (NYSE-AEP)	5.0	5.0	4.0	10.0%	34.0%	3.4%
Duke Energy Corporation (NYSE-DUK)	5.0	3.5	1.5	8.5%	30.0%	2.6%
Empire District Electric Co. (NYSE-EDE)	3.0	3.0	2.5	9.0%	33.0%	3.0%
Eversource Energy (NYSE-ES)	8.5	6.5	4.0	10.0%	44.0%	4.4%
Great Plains Energy Incorporated (NYSE-GXP)	5.0	6.0	3.0	7.5%	39.0%	2.9%
IDACORP, Inc. (NYSE-IDA)	1.0	6.0	4.0	8.5%	42.0%	3.6%
Otter Tail Corporation (NDQ-OTTR)	9.0	1.5	3.5	12.5%	41.0%	5.1%
Pinnacle West Capital Corp. (NYSE-PNW)	4.0	3.5	3.5	9.5%	36.0%	3.4%
PNM Resources, Inc. (NYSE-PNM)	9.0	10.0	3.5	9.5%	51.0%	4.8%
Portland General Electric Company (NYSE-POR)	6.0	5.5	4.5	9.5%	47.0%	4.5%
Westar Energy, Inc. (NYSE-WR)	6.0	3.0	5.0	9.5%	45.0%	4.3%
Mean	5.7	4.8	3.6	9.4%	40.1%	3.8%
Median	5.5	4.5	3.8	9.5%	40.0%	3.5%
Average of Median Figures =		4.6			Median =	3.5%

Data Source: *Value Line Investment Survey.*

Exhibit JRW-10

UNS Electric, Inc.
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Panel A
Electric Proxy Group

Company	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	NA	NA	6.0%
Alliant Energy Corporation (NYSE-LNT)	5.8%	5.8%	5.3%	5.6%
Ameren Corporation (NYSE-AEE)	4.6%	4.6%	4.9%	4.7%
American Electric Power Co. (NYSE-AEP)	6.3%	6.3%	6.8%	6.4%
Avista Corporation (NYSE-AVA)	5.0%	NA	NA	5.0%
Black Hills Corporation (NYSE-BKH)	3.5%	NA	NA	3.5%
CMS Energy Corporation (NYSE-CMS)	6.8%	6.8%	6.2%	6.6%
Consolidated Edison, Inc. (NYSE-ED)	2.7%	2.7%	2.7%	2.7%
Dominion Resources, Inc. (NYSE-D)	5.4%	5.4%	6.3%	5.7%
Duke Energy Corporation (NYSE-DUK)	4.3%	4.3%	4.7%	4.5%
Edison International (NYSE-EIX)	2.4%	2.4%	4.7%	3.2%
El Paso Electric Company (NYSE-EE)	7.0%	NA	6.7%	6.9%
Empire District Electric Co. (NYSE-EDE)	3.0%	NA	5.0%	4.0%
Entergy Corporation (NYSE-ETR)	-2.1%	-2.1%	-4.6%	-3.0%
Eversource Energy (NYSE-ES)	6.3%	6.2%	6.8%	6.4%
FirstEnergy Corporation (ASE-FE)	0.9%	0.9%	NA	0.9%
Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.4%	6.1%	6.3%
IDACORP, Inc. (NYSE-IDA)	4.0%	4.0%	4.0%	4.0%
MGE Energy, Inc. (NYSE-MGEE)	4.0%	NA	NA	4.0%
NorthWestern Corporation (NYSE-NWE)	5.3%	5.3%	5.0%	5.2%
OGE Energy Corp. (NYSE-OGE)	3.3%	3.3%	5.0%	3.9%
Otter Tail Corporation (NDQ-OTTR)	6.0%	NA	NA	6.0%
PG&E Corporation (NYSE-PCG)	5.9%	5.9%	4.9%	5.5%
Pinnacle West Capital Corp. (NYSE-PNW)	5.4%	5.4%	5.2%	5.3%
PNM Resources, Inc. (NYSE-PNM)	8.6%	8.6%	8.0%	8.4%
Portland General Electric Company (NYSE-POR)	4.1%	4.1%	4.3%	4.1%
SCANA Corporation (NYSE-SCG)	4.3%	4.3%	4.2%	4.3%
Westar Energy, Inc. (NYSE-WR)	3.4%	3.4%	3.9%	3.6%
Xcel Energy Inc. (NYSE-XEL)	4.7%	4.7%	5.0%	4.8%
Mean	4.6%	4.5%	4.8%	4.6%
Median	4.7%	4.7%	5.0%	4.8%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, October, 2015.

Panel B
Bulkey Proxy Group

Company	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	NA	NA	6.0%
American Electric Power Co. (NYSE-AEP)	6.3%	6.3%	6.8%	6.4%
Avista Corporation (NYSE-AVA)	5.0%	NA	NA	5.0%
Duke Energy Corporation (NYSE-DUK)	4.3%	4.3%	4.7%	4.5%
Empire District Electric Co. (NYSE-EDE)	3.0%	NA	5.0%	4.0%
Eversource Energy (NYSE-ES)	6.3%	6.2%	6.8%	6.4%
Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.4%	6.1%	6.3%
IDACORP, Inc. (NYSE-IDA)	4.0%	4.0%	4.0%	4.0%
Otter Tail Corporation (NDQ-OTTR)	6.0%	NA	NA	6.0%
Pinnacle West Capital Corp. (NYSE-PNW)	5.4%	5.4%	5.2%	5.3%
Portland General Electric Company (NYSE-POR)	4.1%	4.1%	4.3%	4.1%
Westar Energy, Inc. (NYSE-WR)	3.4%	3.4%	3.9%	3.6%
Mean	5.0%	5.0%	5.2%	5.1%
Median	5.2%	4.9%	5.0%	5.2%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, October, 2015.

Exhibit JRW-10

UNS Electric, Inc.
DCF Growth Rate Indicators

Electric and Bulkey Proxy Groups

Growth Rate Indicator	Electric Proxy Group	Bulkey Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	3.7%	3.0%
Projected *Value Line* Growth in EPS, DPS, and BVPS	4.3%	4.6%
Sustainable Growth ROE * Retention Rate	4.2%	3.5%
Projected EPS Growth from Yahoo, Zacks, and Reuters - Mean/Median	4.6%/4.8%	5.1%/5.2%

Exhibit JRW-11

UNS Electric, Inc.
Capital Asset Pricing Model

Panel A
Electric Proxy Group

Risk-Free Interest Rate	4.00%
Beta*	0.75
Ex Ante Equity Risk Premium**	5.50%
CAPM Cost of Equity	8.1%

* See page 3 of Exhibit JRW-11

** See pages 5 and 6 of Exhibit JRW-11

Panel B
Bulkey Proxy Group

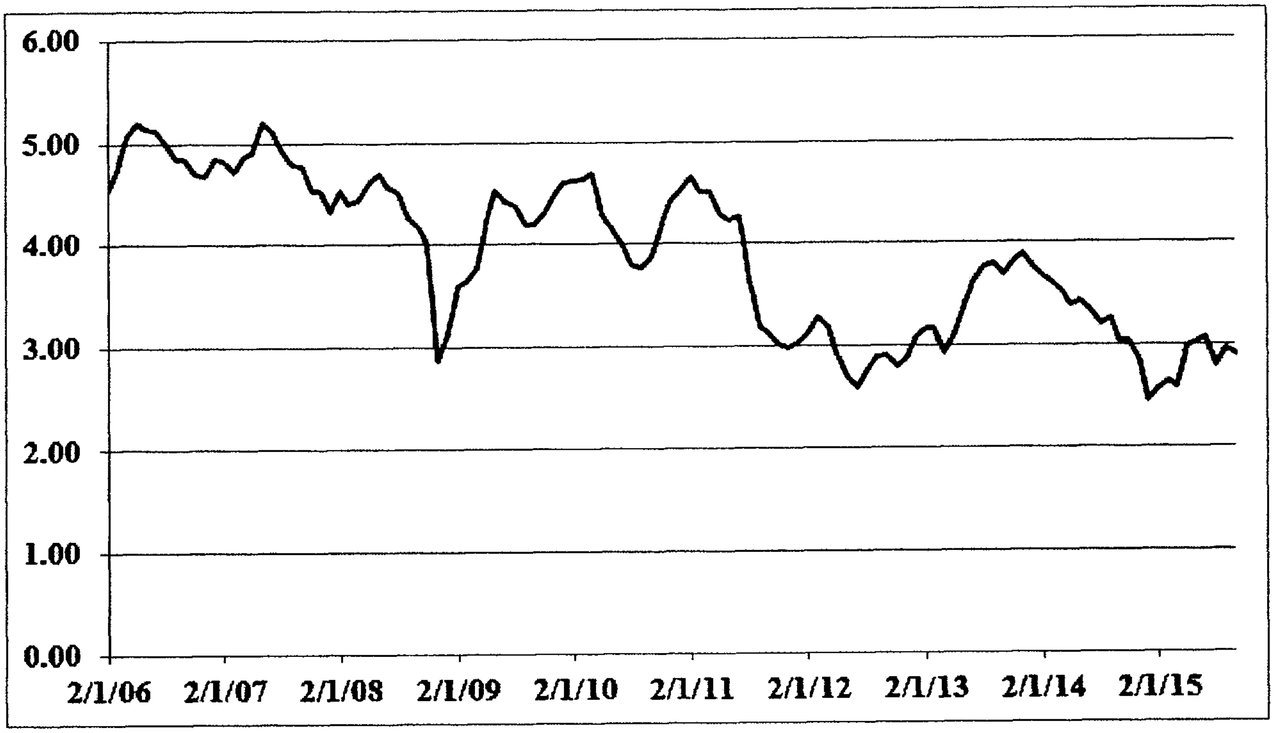
Risk-Free Interest Rate	4.00%
Beta*	0.78
Ex Ante Equity Risk Premium**	5.50%
CAPM Cost of Equity	8.3%

* See page 3 of Exhibit JRW-11

** See pages 5 and 6 of Exhibit JRW-11

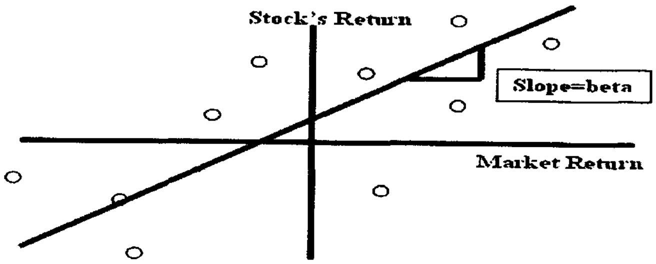
Exhibit JRW-11

Thirty-Year U.S. Treasury Yields
January 2006-Present



Source: Federal Reserve Bank of St. Louis, FRED Database.

Calculation of Beta



Panel A
Electric Proxy Group

Company Name	Beta
ALLETE, Inc. (NYSE-ALE)	0.80
Alliant Energy Corporation (NYSE-LNT)	0.80
Ameren Corporation (NYSE-AEE)	0.75
American Electric Power Co. (NYSE-AEP)	0.70
Avista Corporation (NYSE-AVA)	0.80
Black Hills Corporation (NYSE-BKH)	0.95
CMS Energy Corporation (NYSE-CMS)	0.70
Consolidated Edison, Inc. (NYSE-ED)	0.60
Dominion Resources, Inc. (NYSE-D)	0.70
Duke Energy Corporation (NYSE-DUK)	0.60
Edison International (NYSE-EIX)	0.70
El Paso Electric Company (NYSE-EE)	0.75
Empire District Electric Co. (NYSE-EDE)	0.70
Entergy Corporation (NYSE-ETR)	0.65
Eversource Energy (NYSE-ES)	0.75
FirstEnergy Corporation (ASE-FE)	0.65
Great Plains Energy Incorporated (NYSE-GXP)	0.85
IDACORP, Inc. (NYSE-IDA)	0.80
MGE Energy, Inc. (NYSE-MGEE)	0.75
NorthWestern Corporation (NYSE-NWE)	0.70
OGE Energy Corp. (NYSE-OGE)	0.90
Otter Tail Corporation (NDQ-OTTR)	0.85
PG&E Corporation (NYSE-PCG)	0.65
Pinnacle West Capital Corp. (NYSE-PNW)	0.75
PNM Resources, Inc. (NYSE-PNM)	0.85
Portland General Electric Company (NYSE-POR)	0.80
SCANA Corporation (NYSE-SCG)	0.75
Westar Energy, Inc. (NYSE-WR)	0.75
Xcel Energy Inc. (NYSE-XEL)	0.65
Mean	0.75
Median	0.75

Data Source: *Value Line Investment Survey*, 2015.

Panel B
Bulkey Proxy Group

ALLETE, Inc. (NYSE-ALE)	0.80
American Electric Power Co. (NYSE-AEP)	0.70
Duke Energy Corporation (NYSE-DUK)	0.60
Empire District Electric Co. (NYSE-EDE)	0.70
Eversource Energy (NYSE-ES)	0.75
Great Plains Energy Incorporated (NYSE-GXP)	0.85
IDACORP, Inc. (NYSE-IDA)	0.80
Otter Tail Corporation (NDQ-OTTR)	0.85
Pinnacle West Capital Corp. (NYSE-PNW)	0.75
PNM Resources, Inc. (NYSE-PNM)	0.85
Portland General Electric Company (NYSE-POR)	0.80
Westar Energy, Inc. (NYSE-WR)	0.75
Mean	0.77
Median	0.78

Data Source: *Value Line Investment Survey*, 2015.

Exhibit JRW-11
Risk Premium Approaches

	Historical Ex Post Returns	**Surveys**	**Expected Return Models and Market Data**
Means of Assessing The Market Risk Premium	Historical Average Stock Minus Bond Returns	Surveys of CFOs, Financial Forecasters, Companies, Analysts on Expected Returns and Market Risk Premiums	Use Market Prices and Market Fundamentals (such as Growth Rates) to Compute Expected Returns and Market Risk Premiums
Problems/Debated Issues	Time Variation in Required Returns, Measurement and Time Period Issues, and Biases such as Market and Company Survivorship Bias	Questions Regarding Survey Histories, Responses, and Representativeness Surveys may be Subject to Biases, such as Extrapolation	Assumptions Regarding Expectations, Especially Growth

Source: Adapted from Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

Exhibit JRW-8

UNS Electric, Inc.
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Median
Historical Risk Premium										
	Ibbotson	2015	1928-2014	Historical Stock Returns - Bond Returns	Arithmetic				6.00%	
					Geometric				4.40%	
	Damodaran	2015	1928-2014	Historical Stock Returns - Bond Returns	Arithmetic				6.25%	
					Geometric				4.60%	
	Dimson, Marsh, Staunton	2015	1900-2014	Historical Stock Returns - Bond Returns	Arithmetic					
					Geometric				4.40%	
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Staunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	Median									5.14%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	Best & Byrne	2001								
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns,, & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	Duarte & Rosa - NY Fed	2015	Projection	Projections from 29 Models					5.70%	
	Duff & Phelps	2015	Projection	Normalized with 4.0% Long-Term Treasury Yield					5.00%	
	Mschchowski - VL - 2014	2014	Projection	Fundamentals - Expected Return Minus 10-Year Treasury Rate					5.50%	
	American Appraisal Quarterly ERP	2015	Projection	Fundamental Economic and Market Factors					6.00%	
	Damodaran	2015	Projection	Fundamentals - Implied from FCF to Equity Model					6.25%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Years	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Years	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	Median									4.25%
Surveys										
	New York Fed	2013	Five-Year	Survey of Wall Street Firms					5.20%	
	Survey of Financial Forecasters	2015	10-Year Projection	About 20 Financial Forecastsers					1.88%	
	Duke - CFO Magazine Survey	2015	10-Year Projection	Approximately 500 CFOs					3.80%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%	5.37%	5.37%	
	Fernandez - Academics, Analysts, and Compan	2015	Long-Term	Survey of Academics, Analysts, and Companies					5.50%	
	Median									4.59%
Building Block										
	Ibbotson and Chen	2015	Projection	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.22%	5.21%	
					Geometric			4.20%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Woolridge		2015	Current Supply Model (D/P & Earnings Growth)					4.75%	
	Median									4.12%
Mean										4.52%
Median										4.42%

Exhibit JRW-8

UNS Electric, Inc.
Capital Asset Pricing Model
Equity Risk Premium

Summary of 2010-15 Equity Risk Premium Studies

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2015	1928-2014	Historical Stock Returns - Bond Returns	Arithmetic				6.00%	
					Geometric				4.40%	
	Damodaran	2015	1928-2014	Historical Stock Returns - Bond Returns	Arithmetic				6.25%	
					Geometric				4.60%	
	Dimson, Marsh, Staunton	2015	1900-2014	Historical Stock Returns - Bond Returns	Arithmetic					
					Geometric				4.40%	
	Median									5.13%
Ex Ante Models (Puzzle Research)										
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	Duarte & Rosa - NY Fed	2015	Projection	Projections from 29 Models					5.70%	
	Duff & Phelps	2015	Projection	Normalized with 4.0% Long-Term Treasury Yield					5.00%	
	Mschchowski - VL - 2014	2014	Projection	Fundamentals - Expected Return Minus 10-Year Treasury Rate					5.50%	
	American Appraisal Quarterly ERP	2015	Projection	Fundamental Economic and Market Factors					6.00%	
	Damodaran	2015	Projection	Fundamentals - Implied from FCF to Equity Model					6.25%	
	Median									5.60%
Surveys										
	New York Fed	2013	Five-Year	Survey of Wall Street Firms					5.20%	
	Survey of Financial Forecasters	2015	10-Year Projection	About 20 Financial Forecastsers					1.88%	
	Duke - CFO Magazine Survey	2015	10-Year Projection	Approximately 500 CFOs					3.80%	
	Fernandez - Academics, Analysts, and Companies	2015	Long-Term	Survey of Academics, Analysts, and Companies					5.50%	
	Median									4.50%
Building Block										
	Ibbotson and Chen	2015	Projection	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.22%	5.21%	
					Geometric			4.20%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Woolridge	2015	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				4.75%	
	Median									4.12%
Mean										**4.84%**
Median										**4.82%**

Exhibit JRW-12

UNS Electric, Inc.
Company's Proposed Cost of Capital

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	0.00%	2.07%	0.00%
Long-Term Debt	47.17%	4.66%	2.20%
Common Equity	52.83%	10.35%	5.47%

Summary of Ms. Bulkey's ROE Results

Panel A

Summary of Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-Day Average	8.19%	9.04%	10.05%
90-Day Average	8.28%	9.14%	10.14%
180-Day Average	8.49%	9.34%	10.35%

Summary of Multi-Stage Growth DCF Results

	Mean Low	Mean	Mean High
30-Day Average	9.08%	9.30%	9.58%
90-Day Average	9.17%	9.40%	9.69%
180-Day Average	9.39%	9.63%	9.92%

Panel B
Summary of CAPM Results

	Current 30-Year Treasury - 2.57%	2015-2016 Projected Risk-Free Rate - 3.20%	2016-2020 Projected Risk-Free Rate - 4.90%
Bloomberg Beta	9.59%	9.83%	10.40%
Value Line Beta	10.50%	10.68%	11.10%

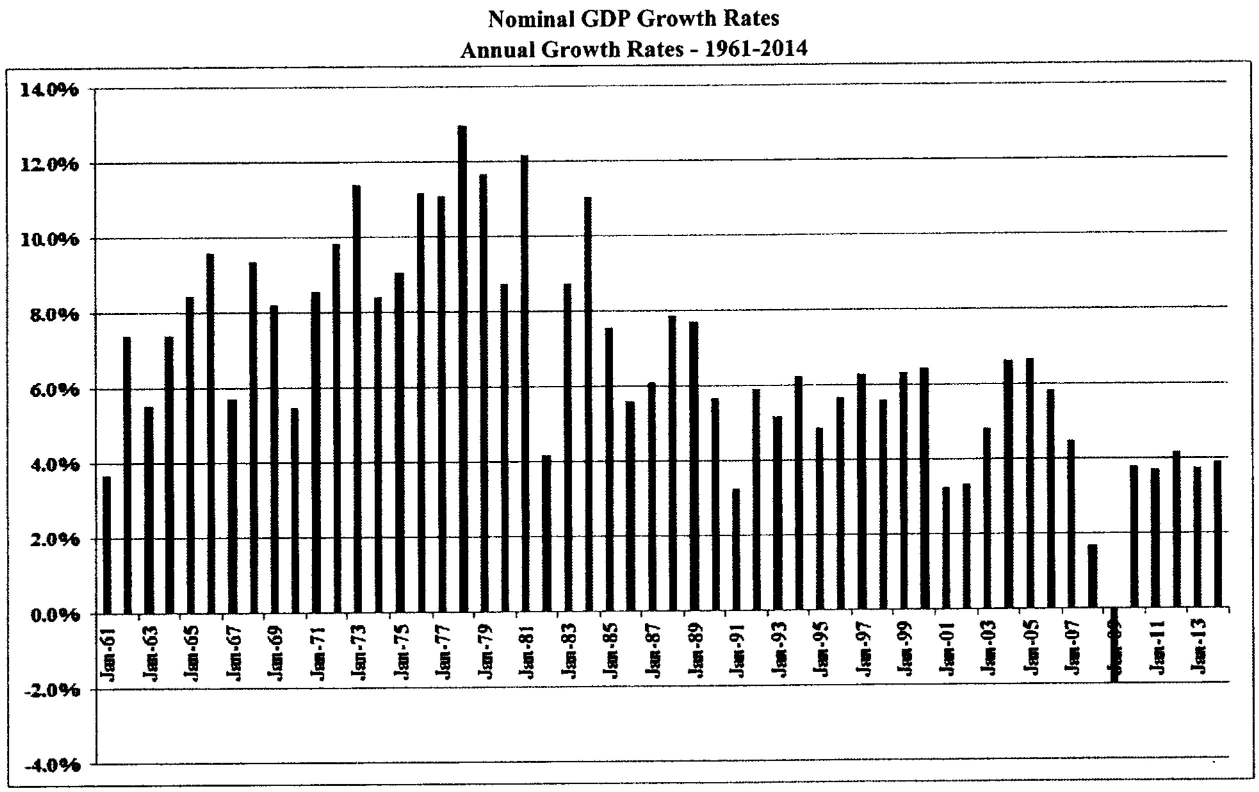
Panel C
Summary of RP Results

	Current 30-Year Treasury - 2.57%	2015-2016 Projected Risk-Free Rate - 3.20%	2016-2020 Projected Risk-Free Rate - 4.90%
Bond Yield Risk Premium	9.70%	10.00%	10.72%
Size Premium		4.82%	

Growth Rates
GDP, S&P 500 Price, EPS, and DPS

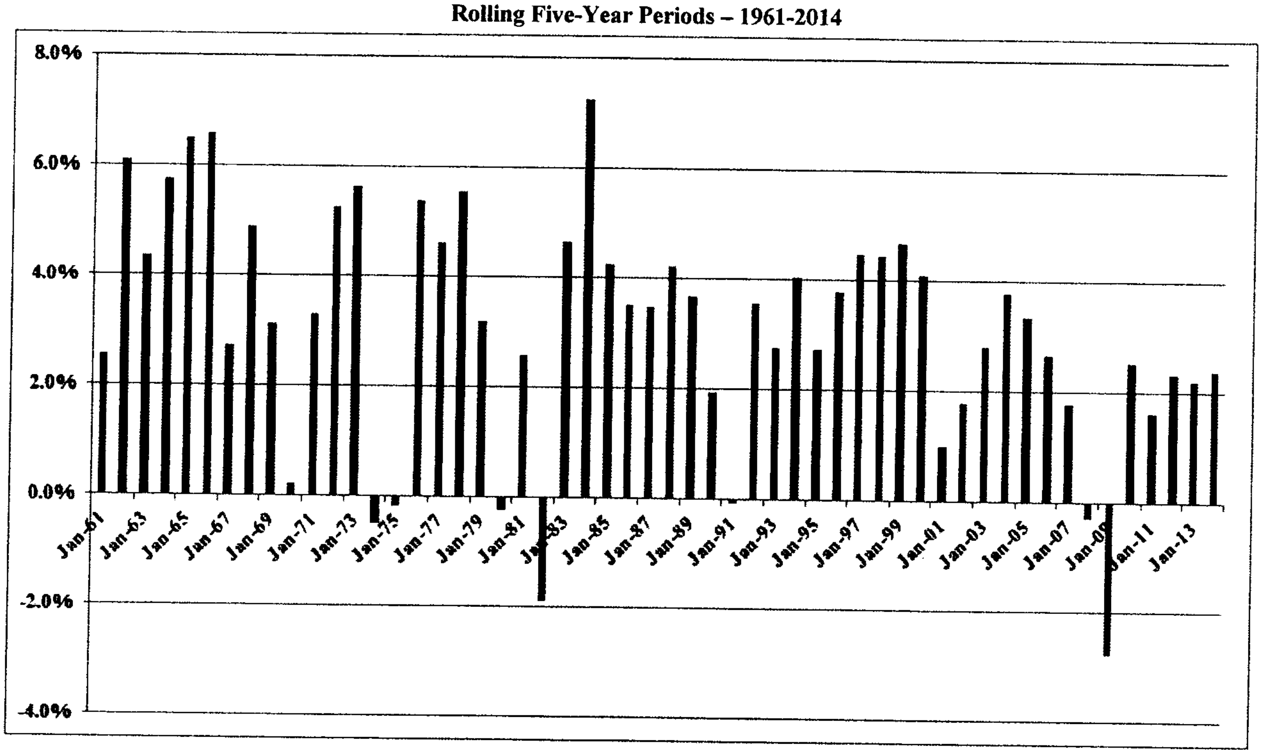
	GDP	S&P 500	Earnings	Dividends	
1960	543.3	58.11	3.10	1.98	
1961	563.3	71.55	3.37	2.04	
1962	605.1	63.10	3.67	2.15	
1963	638.6	75.02	4.13	2.35	
1964	685.8	84.75	4.76	2.58	
1965	743.7	92.43	5.30	2.83	
1966	815.1	80.33	5.41	2.88	
1967	861.7	96.47	5.46	2.98	
1968	942.5	103.86	5.72	3.04	
1969	1019.9	92.06	6.10	3.24	
1970	1075.9	92.15	5.51	3.19	
1971	1167.8	102.09	5.57	3.16	
1972	1282.4	118.05	6.17	3.19	
1973	1428.6	97.55	7.96	3.61	
1974	1548.8	68.56	9.35	3.72	
1975	1688.9	90.19	7.71	3.73	
1976	1877.6	107.46	9.75	4.22	
1977	2086.0	95.10	10.87	4.86	
1978	2356.6	96.11	11.64	5.18	
1979	2632.2	107.94	14.55	5.97	
1980	2862.5	135.76	14.99	6.44	
1981	3211.0	122.55	15.18	6.83	
1982	3345.0	140.64	13.82	6.93	
1983	3638.1	164.93	13.29	7.12	
1984	4040.7	167.24	16.84	7.83	
1985	4346.8	211.28	15.68	8.20	
1986	4590.1	242.17	14.43	8.19	
1987	4870.2	247.08	16.04	9.17	
1988	5252.6	277.72	24.12	10.22	
1989	5657.7	353.40	24.32	11.73	
1990	5979.6	330.22	22.65	12.35	
1991	6174.1	417.09	19.30	12.97	
1992	6539.3	435.71	20.87	12.64	
1993	6878.7	466.45	26.90	12.69	
1994	7308.8	459.27	31.75	13.36	
1995	7664.1	615.93	37.70	14.17	
1996	8100.2	740.74	40.63	14.89	
1997	8608.5	970.43	44.09	15.52	
1998	9089.2	1229.23	44.27	16.20	
1999	9660.6	1469.25	51.68	16.71	
2000	10284.8	1320.28	56.13	16.27	
2001	10621.8	1148.09	38.85	15.74	
2002	10977.5	879.82	46.04	16.08	
2003	11510.7	1111.91	54.69	17.88	
2004	12274.9	1211.92	67.68	19.41	
2005	13093.7	1248.29	76.45	22.38	
2006	13855.9	1418.30	87.72	25.05	
2007	14477.6	1468.36	82.54	27.73	
2008	14718.6	903.25	65.39	28.05	
2009	14418.7	1115.10	59.65	22.31	
2010	14964.4	1257.64	83.66	23.12	
2011	15517.9	1257.60	97.05	26.02	**Average**
2012	16163.2	1426.19	102.47	30.44	
2013	16768.1	1848.36	107.45	36.28	
2014	17420.7	2058.90	114.74	38.57	
Growth Rates	**6.63**	**6.83**	**6.92**	**5.65**	**6.51**

Data Sources: GDPA -http://research.stlouisfed.org/fred2/series/GDPA/downloaddat



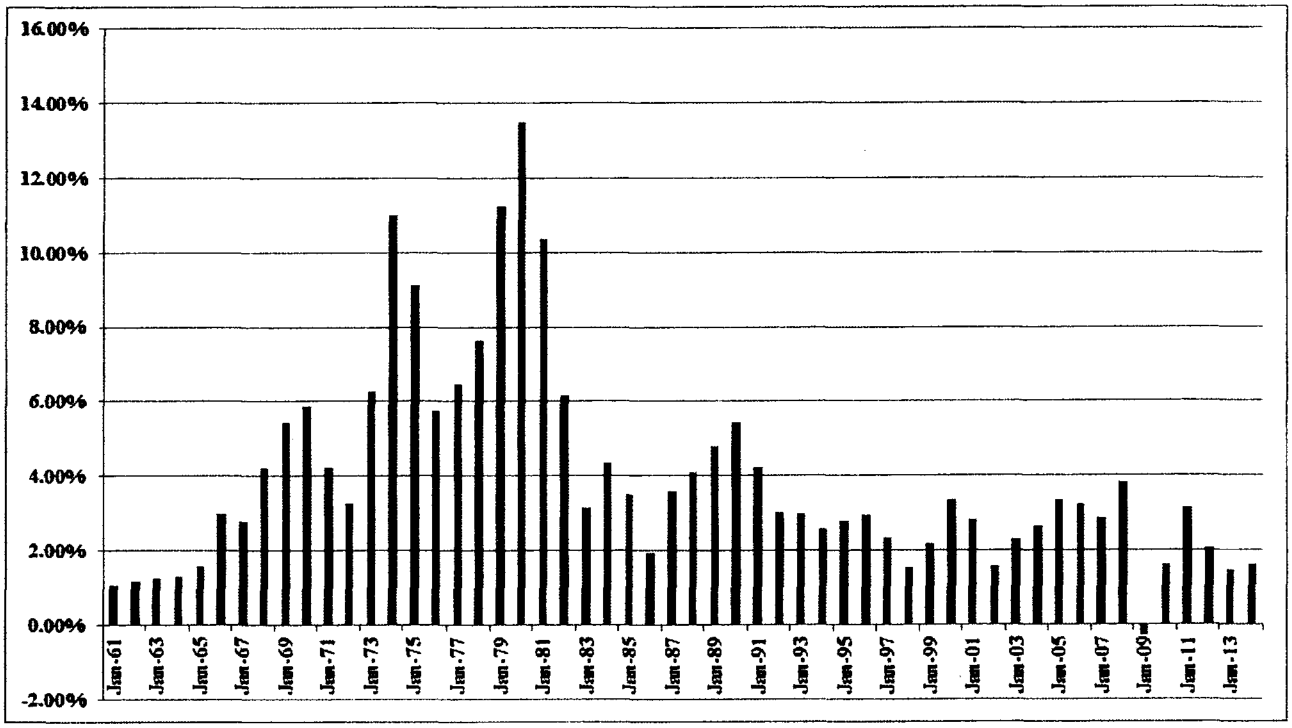
Data Sources: GDPA -http://research.stlouisfed.org/fred2/series/GDPA/downloaddata

Annual Real GDP Growth Rates
Rolling Five-Year Periods – 1961-2014



Data Sources: GDPC1 -http://research.stlouisfed.org/fred2/series/GDPC1/downloaddata

**Annual Inflation Rates
1961-2014**



Data Sources: CPIAUCSL -http://research.stlouisfed.org/fred2/series/CPIAUCSL/downloaddata

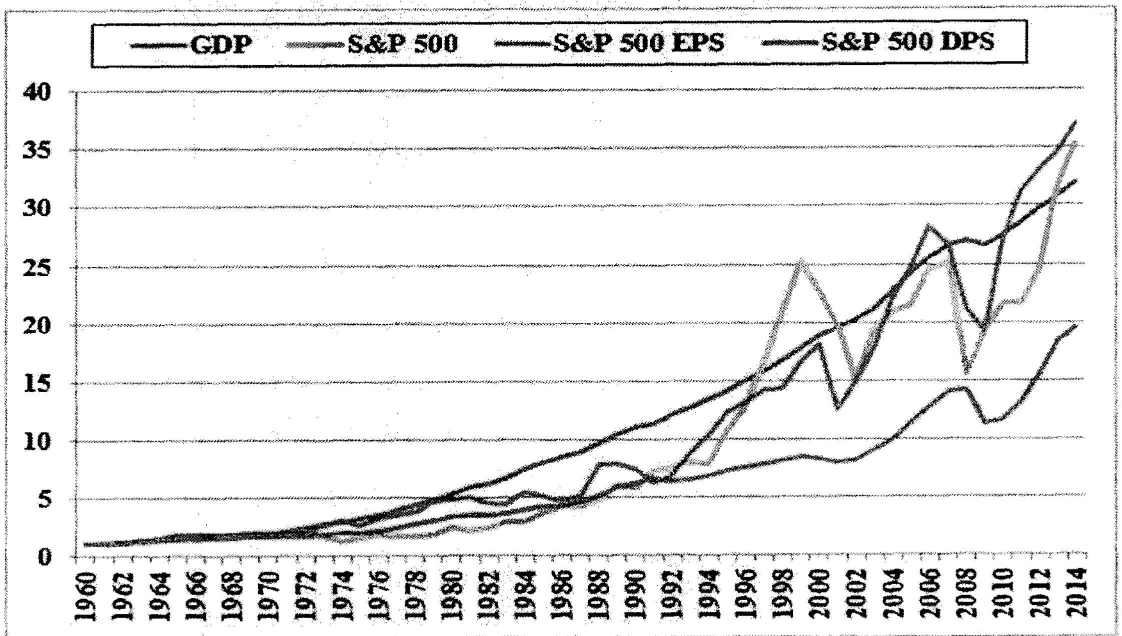
Projected GDP Growth Rates

	Time Frame	Projected Nominal GDP Growth Rate
Congressional Budget Office	2015-2040	4.3%
Survey of Financial Forecasters	Ten Year	4.7%
Social Security Administration	2015-2090	4.5%
Energy Information Administration	2013-2040	4.2%

Sources:

http://www.cbo.gov/topics/budget/budget-and-economic-outlook
http://www.eia.gov/forecasts/aeo/tables_ref.cfm Table 20
http://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2015/
http://www.ssa.gov/oact/tr/2015/X1_trLOT.html

Long-Term Growth of GDP, S&P 500, S&P 500 EPS, and S&P 500 DPS



	GDP	S&P 500	S&P 500 EPS	S&P 500 DPS
Growth Rates	6.63	6.83	6.92	5.65

Data Sources: GDPA -http://research.stlouisfed.org/fred2/series/GDPA/downloaddata
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
CHAIRMAN

BOB STUMP
COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	**DOCKET NO. E-04204A-15-0142** **THE ALLIANCE OF SOLAR CHOICE'S NOTICE OF FILING SURREBUTTAL TESTIMONY OF J. RANDALL WOOLRIDGE**

The Alliance for Solar Choice hereby provides notice of filing the Surrebuttal Testimony of J. Randall Woolridge in the above-referenced matter.

EXHIBIT
TASC-23
ADMITTED

Respectfully submitted this 23rd day of February, 2016.

Arizona Corporation Commission
DOCKETED
FEB 23 2016
DOCKETED BY

Court S. Rich
Rose Law Group pc
Attorney for TASC

Original and 13 copies filed on this 23rd day of February, 2016 with:

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Respectfully submitted this 23rd day of February, 2016.

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Attorney for TASC

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By: ____________________

Before the

Arizona Corporation Commission

In the Matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return On the Fair Value of the Properties Of UNS Electric, Inc. Devoted to It's Operations Throughout the State of Arizona and for Related Approvals	)))))))))	Docket No. E-04204A-15-0142

Testimony of

J. Randall Woolridge, Ph. D.
For The Alliance for Solar Choice

February 23, 2016

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801.

Q. HAVE YOU PREVIOUSLY PREPARED TESTIMONY IN THIS PROCEEDING?

A. Yes. I prepared testimony on behalf of The Alliance for Solar Choice ("TASC"). In that testimony I provided an opinion as to the overall fair rate of return or cost of capital for the regulated electric services of UNS Electric, Inc. ("UNSE" or "Company"). I also prepared an evaluation of UNSE's rate of return testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. In my surrebuttal testimony, I am initially evaluating the testimony of Staff witness Mr. Elijah Abinah and the merits of his ROE recommendation of 9.50%. I will then evaluate UNSE witness Ms. Ann E. Bulkley apparent acceptance of Staff's recommended ROE, and then I will provide a response to the rebuttal testimony of UNSE witness Ms. Ann E. Bulkley.

Q. PLEASE OUTLINE THE ISSUES YOU ARE ADDRESSING IN YOUR SURREBUTTAL TESTIMONY?

A. I am covering the following issues in my surrebuttal testimony:

A. Staff Witness Abinah's ROE Recommendation

B. Capital Market Conditions

C. Equity Cost Rate Issues

1. Proxy Group

2. Constant Growth Discounted Cash Flow ("DCF") Analysis

3. Multi-Stage DCF Analysis

4. Capital Asset Pricing Model ("CAPM") Approach

5. Bond Yield Plus Risk Premium Approach

Q. PLEASE DISCUSS STAFF WITNESS ABINAH'S ROE RECOMMENDATION.

A. Staff witness Mr. Abinah has recommended a ROE of 9.50% for UNSE. However, he has not performed any equity cost rate studies in arriving at this recommendation. Instead, Mr. Abinah recommends that UNSE be awarded the same ROE as the Commission granted in the Company's last rate case. This was Commission Decision No. 74235, issued on December 31, 2013. The 9.50% was the result of a settlement between the Company, Staff, and RUCO. While Mr. Abinah indicated that the basis of his 9.50% recommendation in this case was previous Commission decisions, he acknowledged that each case stands on its own merit. Mr. Abinah also cites the equity cost rate results of staff witness Mr. David C. Parcell in UNSE's two most recent rate cases - Docket Nos. E-04204A-09-0206 and E-04204A-12-0504. The ranges of Mr. Parcell's ROE studies were 7.6% to 10.5% in Docket No. E-04204A-09-0206 and 6.5% to 10.0% in Docket No E-04204A-12-0504. Without performing any equity cost rate studies, Mr. Abinah concludes that a cost of capital analysis in the current docket "would produce a similar, if not identical, range of 8.5 percent to 10.5 percent regardless of the methodologies employed by the various parties."

Q. WHAT ISSUES DO YOU HAVE WITH STAFF WITNESS ABINAH'S TESTIMONY AND ROE RECOMMENDATION?

A. There are a number of issue with his testimony. In general, he has justified his 9.50% ROE recommendation based on equity cost rate studies that are three to six years old. These are way out of date. In my thirty years of testifying in utility rate cases, I have never seen a Commission rely on such dated capital market data in arriving at a ROE authorization. Furthermore, he has relied on these studies without any empirical studies to support the contention that capital market conditions and cost rates are the same today as they were three to six years ago.

Q. HAVE CAPITAL MARKET CONDITIONS AND COST RATES CHANGED OVER THE PAST THREE TO SIX YEARS?

A. Yes. First and foremost, the economy has improved and the Federal Reserve has unwound its quantitative easing programs and has recently made the first upward adjustment to the federal funds rate. As these events have unfolded, interest rates have continued to decrease. These are depicted in Figure 1. As discussed later in this testimony, interest rates have continued to decline despite continual forecasts of higher interest rates. Therefore, interest rates and capital costs have declined over the past three to six years.

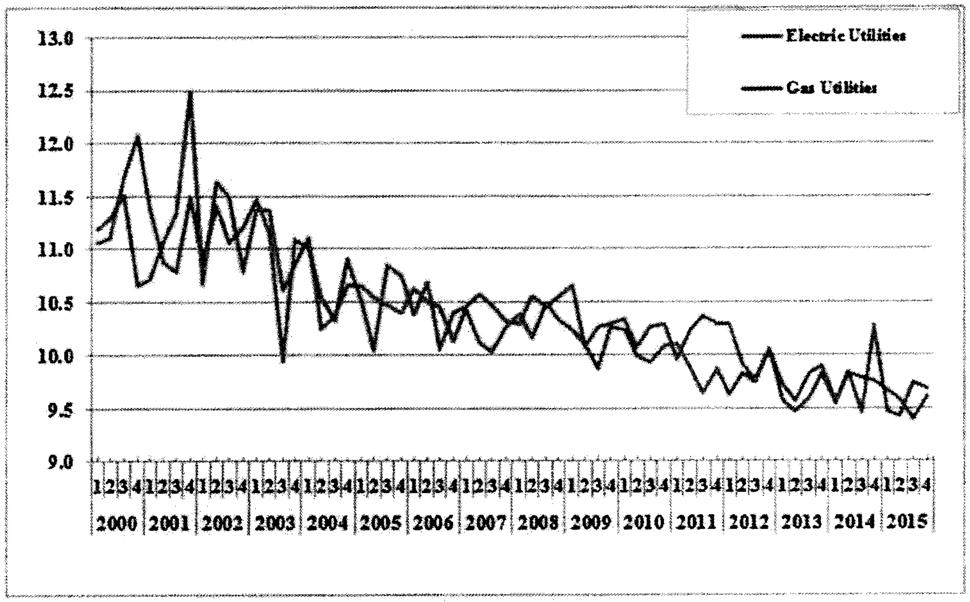
Figure 1
Thirty-Year U.S. Treasury Yields
2009-2016
Source: https://research.stlouisfed.org/fred2/series/DGS30

Q. HAVE THE LOWER INTEREST RATES AND CAPITAL COSTS IN THE PAST THREE TO SIX YEARS BEEN REFLECTED IN AUTHORIZED ROES FOR ELECTRIC UTILITIES AND GAS DISTRIBUTION COMPANIES?

A. Yes. The average quarterly authorized ROEs for electric utilities and gas distribution companies from 2000-2015 are shown in Figure 2. The downward trend is very apparent. The authorized ROEs for electric utilities have declined from 10.01% in 2012, to 9.8% in 2013, 9.76% in 2014,. and 9.58% in 2015 according to Regulatory Research Associates.[1] Nonetheless, in recent years I do believe that these authorized ROEs have lagged behind capital market cost rates because some state commissions have been reluctant to authorize ROEs below 10%.

Figure 2
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2015
Source: Regulatory Research Associates, 2016

[1] These figures exclude the Virginia cases that include ROE generation riders of up to 200 basis points.

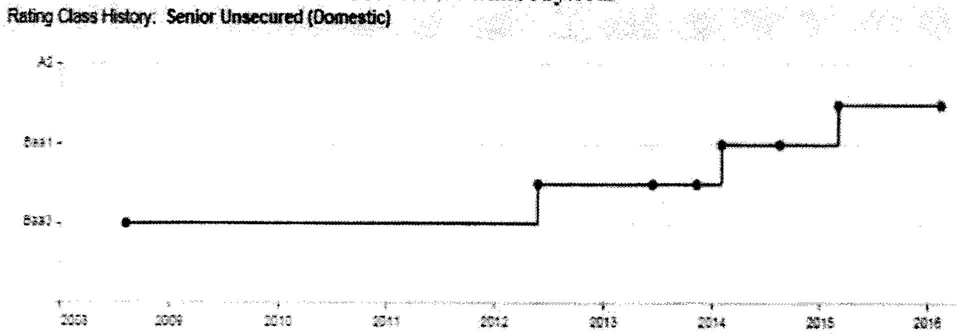


Q. ARE THESE ANY OTHER FACTORS THAT HAVE OCCURRED OVER THE PAST THREE TO SIX YEARS THAT STAFF WITNESS ABINAH IGNORED IN HIS TESTIMONY AND HIS RECOMMENDATION?

A. Yes. The investment risk of UNSE has declined. As shown in Figure 3, the Moody's issuer credit rating for UNSE has increased from Baa3 to A3 since 2012, an advance of three rating categories. This A3 rating is above the averages of the Electric and Bulkley Proxy Groups (See Exhibit JRW-4, page 1). The lower investment risk of UNSE as indicated by the Moody's ratings would indicate a lower ROE is warranted. Mr. Abinah has ignored the change in the investment risk of UNSE in his testimony and his ROE recommendation.

Figure 3
Moody's Issuer Ratings for UNSE
2000-2016

Source: www.moody.com



Q. DOES UNSE'S CREDIT RATINGS REFLECT THE RATE DESIGN PROVISIONS THAT THE COMPANY SEEKS IN THIS RATE CASE?

A. A. No. As noted above, UNSE's Moody's credit rating of A3 is better than the average credit ratings for the Electric and Moody's Proxy Groups. And, while the Company's Moody's credit report highlights its cost recovery mechanisms and indicates they are "credit supportive," the Company's credit ratings do not yet reflect its proposed mandatory demand charge for all residential customers. Such a charge, all else equal, would reduce the Company's risk by providing for higher level of fixed customer charges and mitigating risk associated with customers' ability to reduce energy usage to lower their utility bills. I am not aware of any other investor owned utility in the Country with such a mechanism.

Q. HOW DOES UNSE WITNESS MS. BULKLEY RESPOND TO MR. ABINAH'S ROE RECOMMENDATION OF 9.50%?

A. She indicates that UNSE would not oppose Staff REO recommendation as long as " … the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn that ROE." She goes on to say that " … current capital market conditions fully support a ROE well in excess of 9.5% percent, and that 9.5% is, at best, the bottom of the range at this time." She goes on to disagree that 8.5% is the bottom of the range of previous staff testimony.

Q. PLEASE RESPOND TO UNSE WITNESS MS. BULKLEY'S OBSERVATIONS?

A. She is wrong on both the range and capital market conditions. With respect to the range, as I noted above, the bottom of the range for Mr. Parcell's equity cost rate studies of his two prior testimonies is actually 6.5%. The range for his CAPM results from the Docket No E-04204A-12-0504 case was 6.5% to 6.8%. Second, as discussed below in detail, Ms. Bulkley is wrong on what ROE is supported by current capital market conditions. In particular, the economists' forecasts used by Ms. Bulkley, that always point to higher future interest rates, has continually been wrong for almost a decade. In addition, she claims that the actions of the Federal Reserve and the prospect of higher future interest rates have resulted in the underperformance of utility stocks. As shown below, this is simply incorrect.

Q. MS. BULKLEY ATTEMPTS TO DEFEND MR. ABINAH'S 9.5% ROE RESOMMENDATION BY COMPARING CERTAIN ECONOMIC INDICATORS IN 2009 AND 2013 TO THE PRESENT. PLEASE RESPOND.

A. On pages 23-24 of her testimony, Ms. Bulkley cites certain economic indicators in 2009 and 2013 to support Mr. Abinah's claim that the 9.5% ROE provided in the 2013 settlement is reflective of the current economic environment. Among the indicators that she highlight are real GDP growth, unemployment, and inflation. In Figures 4, 5, and 6 I have provided graphs of these indicators over the past ten years.

Figure 4
Quarterly Real GDP Growth
2006-2015
Source: http://www.tradingeconomics.com/united-states/gdp-growth

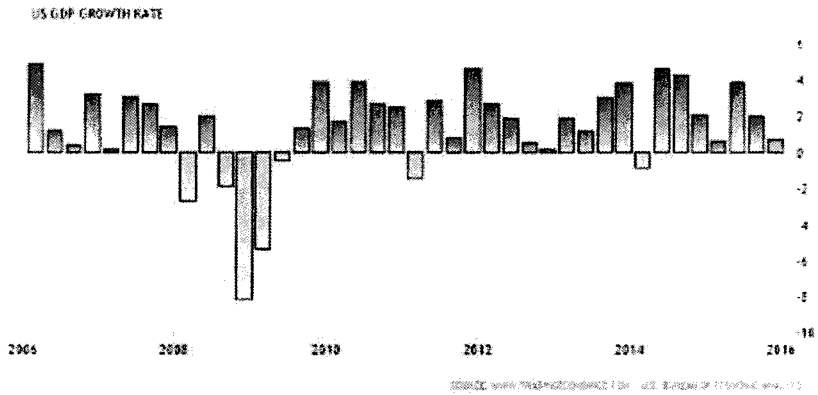


Figure 5
Unemployment Rate
2006-2015
Source: http://data.bls.gov/timeseries/LNS14000000

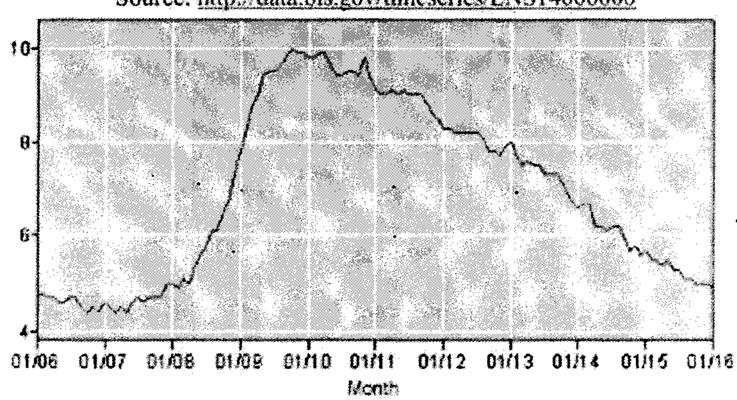
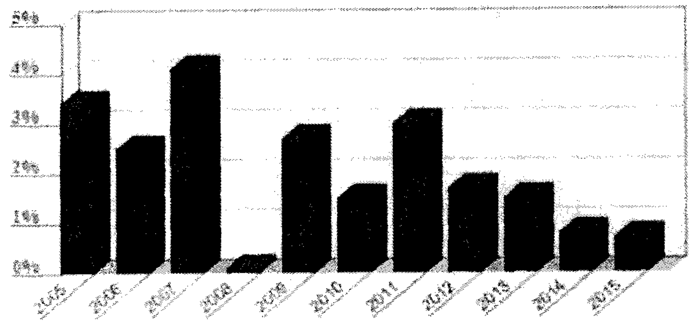


Figure 6
Annual Inflation Rate
2006-2015
Source: http://www.usinflationcalculator.com/inflation/current-inflation-rates/



Q. WHAT DO YOU BELIEVE THESE FIGURES SUGGEST ABOUT ECONOMIC CONDITIONS?

A. I believe that these figures show that the economy is continuing to grow, but at a slow pace, the labor market have improved significantly, and inflation reflects the slow economic growth and has declined over the past five years. Overall, these conditions, combined with the overall capital market conditions including lower interest rates, suggests that capital costs have declined. Furthermore, consistent with Mr. Abinah, Ms. Bulkley has ignored the fact the UNSE overall investment risk, as its credit ratings, is lower today as its Moody's rating has improved from Baa3 in 2012 to A3 currently.

A. Capital Market Conditions

Q. IN HER DIRECT AND REBUTTAL TESTIMONIES, MS. BULKLEY IMPLIES THAT INTEREST RATES AND CAPITAL COSTS ARE INCREASING IN MAGNITUDE. PLEASE RESPOND.

A. Between pages 15-21 of her rebuttal testimony, Ms. Bulkley argues that my 8.75% ROE recommendation is not justified by current and expected market conditions. In her discussion of capital market conditions, Ms. Bulkley implies that interest rates and capital costs are increasing. She cites economists' projections of interest rates and credit spreads to support the idea that the Company needs a higher ROE.

Q. PLEASE DISCUSS THE FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS.

A. Ms. Bulkley cites the interest rate forecasts provided by *Blue Chip Financial Forecasts*. In my direct testimony, I highlighted that the consensus forecasts of economists are that interest rates are going higher and these forecasts are continually wrong. I also noted that *Bloomberg* reported that the Federal Reserve Bank of New York has gone as far as stopping use of interest rate estimates of professional forecasters in its interest rate model.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE INTEREST RATE FORECASTS OF ECONOMISTS.

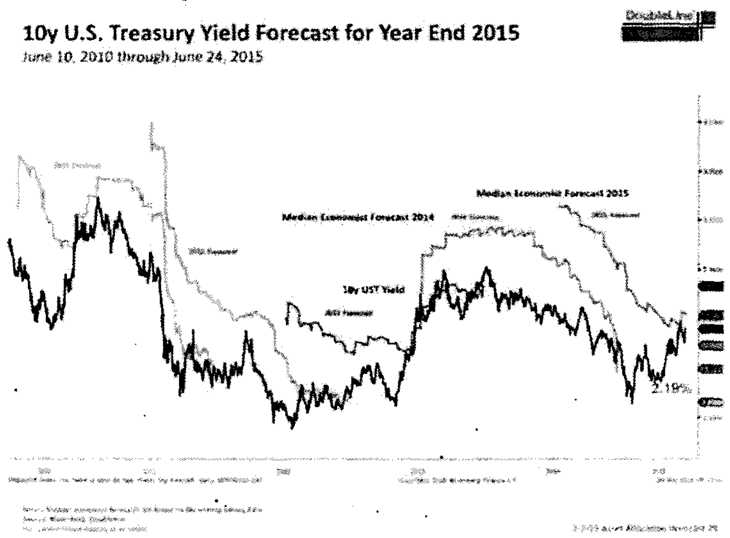
A. Recently, two other financial publications have produced studies on how economists consistently predict higher interest rates yet they have been wrong. The first publication, entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," evaluated economists' forecasts for the yield on ten-year Treasury bonds at the beginning of the year for the last ten years.[2] The results demonstrate that economists

[2] Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools," Bloomberg.com, March 16, 2015. http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

consistently predict that interest rates will go higher, and interest rates do not fulfill the predictions.

The second study tracked economists' forecasts for the yield on ten-year Treasury bonds on an ongoing basis from 2010 until 2015.[3] The results of this study, which was entitled "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," are shown in Figure 7 and demonstrate how economists continually forecast that interest rates are going up, and they do not.

Figure 7
Economists' Forecasts of the Ten-Year Treasury Yield
2010-2015



Source: Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

[3]Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

Q. PLEASE REVIEW THE FEDERAL RESERVE'S DECISION TO RAISE THE FEDERAL FUNDS RATE IN DECEMBER OF 2015.

A. On December 16th, 2015, the Federal Open Market Committee ("FOMC")" decided to increase the target rate for federal funds to ¼ - ½ percent.[4] In the release, the FOMC included the following observations:[5]

> The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will continue to expand at a moderate pace and labor market indicators will continue to strengthen. Overall, taking into account domestic and international developments, the Committee sees the risks to the outlook for both economic activity and the labor market as balanced. Inflation is expected to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.

This highly anticipated increase came after the range was kept in the 0.0 to ¼ percent range for over five years in order to spur economic growth in the wake of the financial crisis.

Q. WHAT IS THE FEDERAL FUNDS RATE?

A. The federal funds rate is set by the Federal Reserve and is the borrowing rate applicable only to the most creditworthy financial institutions when they borrow and lend funds <u>overnight</u> to each other.[6] Therefore, these are not long-term interest rates. As I discuss below, there is no direct link between the federal funds rate and long-

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[4] It should be noted that this significant development occurred after Mr. McKenzie's testimony was filed on November 6, 2015. For example, although he quotes *former* Federal Reserve President Charles Plosser as observing that U.S. interest rates are "outside historical norms," Mr. Plosser was referring to the zero percent rate.

[5] Board of Governors of the Federal Reserve System, *FOMC Statement* (Dec. 16, 2015).

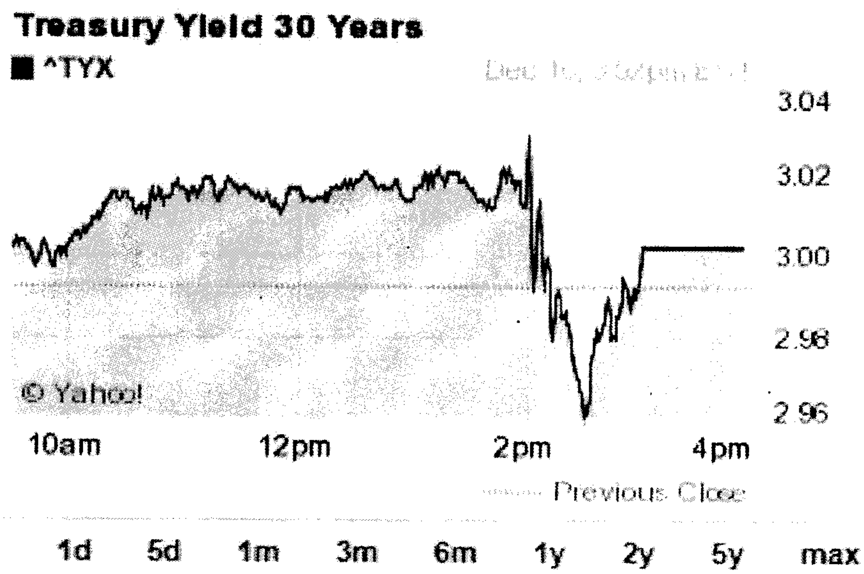
[6] http://www.investopedia.com/terms/f/federalfundsrate.asp

term interest rates.

Q. **HOW DID LONG-TERM INTEREST RATES REACT TO THE FEDERAL RESERVE'S DECISION TO INCREASE THE FEDERAL FUND RATE?**

A. The FOMC decision to increase the federal funds rate was highly anticipated in the markets. Nonetheless, as shown in the Figure 8, at the 2:00 PM announcement of the increase in the federal funds rate, the yield on 30-Year U.S. Treasury bonds actually decreased.

Figure 8
Intra-Day Thirty-Year Treasury Yields
December 16, 2015
Source: www.Yahoo.com



Q. **WHAT HAS HAPPENED TO THE YIELD ON LONG-TERM TREASURY BONDS SINCE THAT DECEMBER 16TH DECISION?**

A. They have continued to decline and are in the 2.70% range currently.

Q. WHY HAVE LONG-TERM INTEREST RATES DECLINED DESPITE THE FOMC'S DECISION TO INCREASE THE FEDERAL FUNDS RATE?

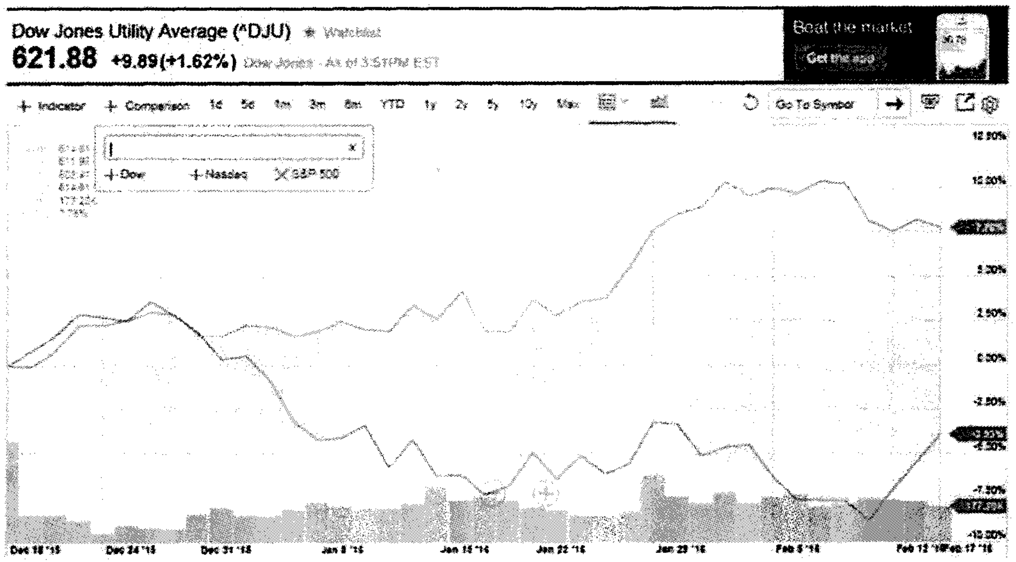
A. In my initial testimony, I referenced former Federal Reserve Chairman Ben Bernanke who stated that whereas the Federal Reserve can affect short-term rates, the Federal Reserve does not directly control long-term rates. Long-term rates are driven primarily by economic growth and inflation, which have both continued to decline.[7]

Q. FINALLY, MS BULKLEY NOTES THAT UTILITY STOCK PRICES HAVE "UNDERPERFORMED" BECAUSE INVESTORS EXPECT INTEREST RATES TO RISE. PLEASE RESPOND?

A. Once again, Ms. Bulkley is incorrect. As shown in Figure 9, since the Federal Reserve decided to increase the Federal Funds rate, the Dow Jones Utilities Index is up about 8.0%, and the S&P 500 is down about 4.0%.

Figure 9
Dow Jones Utilities versus the S&P 500
December 16, 2015 – February 16, 2016
Source: www.yahoo.com

[7]Ben S. Bernanke, "Why Are Interest Rates So Low?" Weekly Blog, Brookings, March 30, 2015. http://www.brookings.edu/blogs/ben-bernanke/posts/2015/03/30-why-interest-rates-so-low.



Q. WHAT DO YOU RECOMMEND THE COMMISSION DO REGARDING THE FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS?

A. I suggest that the Commission set an equity cost rate based on current market cost rate indicators and not speculate on the future direction of interest rates. As the above studies indicate, economists are always predicting that interest rates are going up, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. For example, consider a utility that pays a dividend of $2.00 with a stock price of $50.00. The current dividend yield is 4.0%. If, as Ms. Bulkley suggests, interest rates and required utility yields increase, the price of the utility stock would decline. In the example above, if higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline to $40, which would be a -20% return on the stock. Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, forecasting prices and rates that are determined in the financial markets, such as interest rates, the stock market, and gold prices, appears to be impossible to accurately do. For interest rates, I have never seen a study that suggests one forecasting service is better than others or that interest rate forecasts are better than just assuming the current interest rate will be the rate in the future.

B. Equity Cost Rate Issues

Q. PLEASE ADDRESS THE ISSUES HIGHLIGHTED BY MS. BULKLEY WITH RESPECT TO YOUR EQUITY COST RATE STUDIES AND ANALYSES.

A. Ms. Bulkley offers critiques of a number of issues related to my equity cost rate studies and analyses. I am addressing the following: (1) the proxy groups; (2) constant-growth DCF analysis; (3) multi-stage DCF analysis; (4) the application of the CAPM; (5) her application of the bond yield risk premium method using authorized ROEs; (6) the flotation cost adjustment and (7).the adequacy of my 8.75% ROE recommendation.

1. Proxy Groups

Q. PLEASE DISCUSS MS. BULKLEY'S CONCERNS WITH YOUR PROXY GROUPS.

A. Between pages 46-49 of her testimony, Ms. Bulkley makes the claim that her proxy group provides is more similar to the Company because her group has "comparable investment risk." She claims that your group is larger with less stringent screening criteria.

Q. PLEASE RESPOND TO THESE CLAIMS.

A. They are totally unfounded. First, she never mentions that, in addition to developing my proxy group, I also used her proxy group. Second, she has performed no analysis comparing the risk of her group to the Company. In Exhibit JRW-4, I directly compare the risk of UNS Electric to the two proxy groups using Moody's credit ratings. These comparison show that UNS Electric, with an A3 issuer credit rating, is one notch above the average of both the Electric and Bulkley Proxy Groups (Baa1). Third, the screening criteria used by Ms. Bulkley in developing her group, including factors such as including generation, are factors used by credit rating agencies in rating companies, As such, these are considered in my risk analysis.

Q. WHAT IS YOUR CONCLUSION OF THE PROXY GROUP ISSUE?

A. It is a non-issue. I have used her group and do a risk analysis of the Company and the two proxy groups using credit ratings. The bottom line is that UNS Electric is a little less risky than other electric utilities. Ms. Bulkley does not perform a risk assessment of UNSE and her proxy group using credit ratings.

2. Constant Growth DCF Analysis

Q. MS. BULKLEY CLAIMS THAT YOUR DCF ANALYSIS IS "SUBJECTIVE." PLEASE RESPOND.

A. On page 51 of her testimony, Ms. Bulkley states that my DCF growth rates is subjectively set within a range of results. She is correct. Estimating the cost of equity capital requires a degree of subjectivity in the selection of models, the inputs for the models, and the measurement of the inputs for the model. I have used the DCF and CAPM models, which are the two most generally accepted models to estimate an equity cost rate. In using the DCF model, the biggest issue is the expected growth rate. Investors have many sources of financial information that go into developing their expectations of the future, and the vast majority of this information is historic data. In estimating an expected growth rate, I have given primary weight to analysts' Earnings Per Share ("EPS") growth rate forecasts. In arriving at the DCF growth rate figure, I recognized that: (1) most data provided to investors is historic; (2) analysts' growth rate forecasts have a significant impact on investors' expectations; and (3) it is well known that the long-term EPS growth rate forecasts of financial analysts are overly optimistic and upwardly biased. In contrast to this approach, Ms. Bulkley mechanically added four different measures of projected growth to her dividend yields.

Q. PLEASE RESPOND TO MS. BULKLEY'S DISCUSSION OF ANALYSTS' LONG TERM EPS GROWTH RATE FORECASTS AT PAGES 51-53 OF HER REBUTTAL TESTIMONY.

A. As I discussed at length in my initial testimony, there are a number of studies that have demonstrated that the long-term EPS growth rate forecasts of Wall Street analysts are overly optimistic and upwardly biased. At pages 51-53 of her rebuttal testimony, Ms. Bulkley attempts to refute this evidence in two ways: (1) she cites a study by Hovakimian and Saenyasiri that indicates the upward bias has declined since the signing of the 2002 Global Financial Settlement; [8] and (2) she makes general assertions that such a bias, if it existed, would be eliminated by changes in regulations and reporting requirements.

Q. PLEASE RESPOND TO MS. BULKLEY'S ASSERTIONS.

A. First, the decline in the upward bias since 2002 found by Hovakimian and Saenyasiri was for <u>annual</u> EPS estimates that only forecast out one year, not for the <u>long-term</u> EPS growth rates used by Ms. Bulkley and myself. And second, the studies that I cite demonstrate that the upward bias has continued beyond the changes in regulations and reporting requirements cited by Ms. Bulkley. This is highlighted by a McKinsey study entitled "Equity Analysts: Still Too Bullish" which involved a study of the accuracy on analysts long-term EPS growth rate forecasts. The authors conclude that

[8] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analysts Behavior: Evidence from Recent Changes in Regulation," Financial *Analysts Journal*, Vol. 66, at 96-107 (2010) [emphasis added].

after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation (emphasis added):[9]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. <u>Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.</u>

This is the same observation made in a *Bloomberg Businessweek* article.[10] The author concluded:

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects*

Q. HOW DOES THE UPWARD BIAS IMPACT THE ESTIMATION OF THE COMPANY'S COST OF EQUITY?

[9] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

[10] Roben Farzad, "For Analysts, Things Are Always Looking Up," *BloombergBusinessweek* (June 10, 2010).

A. First, as discussed above, it is not appropriate to mechanically add analysts' EPS growth rates to a dividend yield to obtain a DCF equity cost rate. In addition, as discussed below, it has a large impact of Ms. Bulkley's calculation of a Market Risk Premium ("MRP").

3. Multi-Stage DCF Analysis

Q. PLEASE DISCUSS MS. BULKLEY'S MULTI-STAGE DCF ANALYSIS.

A. Between pages 56-58 of her rebuttal testimony, Ms. Bulkley responds to my criticism of the long-term Gross Domestic Product ("GDP") growth rate in her multi-stage DCF model. Her prospective GDP growth rate was based on real GDP growth rate which is calculated over the 1929-2014 time period; and (2) an expected inflation rate. In her rebuttal testimony, he uses a GDP growth rate of 540% in her initial testimony.

Q. WHAT ARE THE ERRORS WITH MS. BULKLEY'S MULTI-STAGE DCF ANALYSIS.

A. As I indicated in my initial testimony, there are two major errors in this analysis. First, Ms. Bulkley has not provided any theoretical or empirical support that long-term GDP growth is a reasonable proxy for the expected growth rate of the companies in her proxy group. Five-year and ten-year historic measures of growth for earnings and dividends for electric utility companies, as shown on page 3 of Exhibit JRW-10, suggest growth that is more than 100 basis points below Ms. Bulkley's GDP growth rate. In her rebuttal testimony, Ms. Bulkley provides no new empirical evidence to justify using GDP growth as a proxy for long-term earnings and dividend growth for electric and gas companies. On the second issue, I demonstrated in my initial testimony that the trends of GDP growth indicate prospective GDP growth of about 100 basis points below Ms. Bulkley's GDP growth rate. The lower trend in GDP growth is supported by the long-term GDP growth rate forecasts of government agencies and economists. These forecasts are also about 100 basis points below Ms. Bulkley's long-term historic GDP growth rate. The economists and government agencies that provide and use these forecasts are well aware of historic GDP growth and its trends over the decades that are referred to by Ms. Bulkley. Therefore, there is no reason to expect that these forecasts are under-stated. In addition, long-term GDP growth is a function of a number of factors, including population growth. As I reviewed in my direct testimony, the long-term trends in these factors all point to lower GDP growth in the future.

Q. WHAT GDP GROWTH RATE IS PROJECTED BY ECONOMISTS AND GOVERNMENT AGENCIES?

A. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed on page 5 of Exhibit JRW-14 that is attached to my initial prefiled testimony. The mean 10-year nominal GDP growth forecast (as of February 2015) by economists in the recent *Survey of Professional Forecasters* is 4.7%. The Energy Information Administration ("EIA"), in its projections used in preparing the *Annual Energy Outlook,* forecasts long-term GDP growth of 4.2% for the period

2013-2040.[11] The Congressional Budget Office ("CBO"), in its forecasts for the period 2015 to 2040, projects a nominal GDP growth rate of 4.3%.[12] Finally, the Social Security Administration ("SSA"), in its Annual OASDI Report, provides a projection of nominal GDP from 2015-2090.[13] The projected nominal GDP growth rate over this period is 4.5%. Overall, these projections of nominal GDP growth over extended future time periods provide direct evidence that Ms. Bulkley's long-term GDP growth rate of 5.42% is overstated by almost 100 basis points.

Q. IN YOUR OPINION, WHAT IS WRONG WITH MS. BULKLEY'S REAL GDP FORECAST ON HISTORIC DATA AND IGNORING THE WELL-KNOWN LONG-TERM GDP FORECASTS OF THE CBO AND EIA?

A. In developing a DCF growth rate for his constant-growth DCF analysis, Ms. Bulkley has totally ignored historic EPS, DPS, and BVPS data and relied solely on the long-term EPS growth rate projections of Wall Street analysts and *Value Line*. However, in developing a terminal DCF growth rate for his multi-stage growth DCF analysis, Ms. Bulkley has also totally ignored the well-known long-term real GDP growth rate forecasts of the CBO and EIA and relied solely on historic data going back to 1929. Simply put, she is inconsistent with respect to 100% belief in the forecasts of Wall Street analysts and 0% belief in the forecasts of major U.S. government agencies.

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[11] Energy Information Administration, *Annual Energy Outlook,* http://www.cbo.gov/publication/49973.

[12] Congressional Budget Office, The *2015 Long-term Budget Outlook,* July 2015. https://www.cbo.gov/publication/50250.

[13] Social Security Administration, 2015 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program. http://www.ssa.gov/oact/tr/2015/X1_trLOT.html

4. CAPM Approach

Q. PLEASE RESPOND TO MS. BULKLEY'S DISCUSSION OF YOUR CAPM ANALYSIS.

A. As I indicated in my initial testimony, the estimation and the measurement of the MRP is one of the biggest mysteries in Finance. In my testimony, I highlighted there are three procedures for estimating an MRP, and I explained how I factored in all three approaches and employed the results of more than 30 studies to estimate my MRP of 5.5%. My MRP reflects the market risk premiums: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs. Contrary to this approach, Ms. Bulkley conducts her own study using analysts' EPS growth rate projections to compute an expected market return and MRP. Her MRP 10.67% (based on the current risk-free rate) is larger than any MRPs discovered in any published academic or professional study or survey. As discussed below, this is because he "mechanically" computes an expected market return using the upwardly biased EPS growth rate forecasts of financial analysts.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM IN MS. BULKLEY'S CAPM APPROACH.

A. Ms. Bulkley has computed a MRP for her CAPM by applying the DCF model to the S&P 500. He has estimated an expected market return using Bloomberg and Value

Line projected five-year EPS growth rate estimates as the DCF growth rate. In both cases, she uses a projected long-term EPS growth rate of 11.06%

Q. WHAT ARE THE ERRORS WITH THIS MRP METHODOLOGY?

A. There are several errors to this methodology:

First, these "long-term growth" rates are indicated to be three-to-five year growth rates, yet Ms. Bulkley employs these to be for an infinite period of time. Second, as discussed above, there is ample empirical evidence that these forecasts are overly optimistic and upwardly biased measures of actual future three-to-five year actual earnings growth. The McKinsey article cited above indicates that, on average, the projected growth rates produce forecasted EPS that are 100% above actual EPS. And third, the projected EPS growth rates used by Ms. Bulkley of 11.06% is totally unrealistic since: (1) long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on EPS growth; [14] and (2) even Ms. Bulkley presumes that long-term GDP growth that he estimates for her multistage DCF analysis will be less than ½ of her 11.06% projected EPS growth.

Q. WHAT DO THESE ERRORS IMPLY ABOUT MS. BULKLEY'S CAPM RESULTS?

A. Ms. Bulkley's CAPM results should be ignored. Her CAPM results are based on expected market returns and MRPs that include unrealistic assumptions regarding future economic and earnings growth and stock returns.

[14] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February, 2010), p. 63.

5. Bond Yield Plus Risk Premium Approach

Q. PLEASE DISCUSS MS. BULKLEY'S BOND YIELD PLUS RISK PREMIUM ANALYSIS WHICH IS BASED ON THE AUTHORIZED ROES FOR ELECTRIC UTILITIES AND GAS DISTRIBUTION COMPANIES.

A. At pages 66-68 of her rebuttal testimony, Ms. Bulkley supports her risk premium analysis which is based on authorized ROEs for electric and gas companies. I critiqued her approach primarily because: (1) Ms. Bulkley added her risk premium to projected Treasury bond yields; and (2) her results do not reflect current authorized ROEs. On the first issue, Ms. Bulkley never really addresses the error I highlighted in my initial testimony. Specifically, it is incorrect to add a risk premium derived from historic Treasury yields and authorized ROEs to projected Treasury bond yields because, as I showed earlier in this testimony, Treasury yields are always projected to increase. A corrected study would have used projected Treasury yields and not historic Treasury yields. The second issue I addressed was the fact that her risk premium results does not reflect current authorized ROEs.

Q. PLEASE DISCUSS MR BULKLEY'S RISK PREMIUM RESULTS AND YOUR STUDY OF AUTHORIZED ROES FOR ELECTRIC UTILITIES.

A. In her rebuttal testimony, Ms. Bulkley updates her risk premium analysis and arrives at equity cost rates ranging from 9.87 to 10.67% for electric utility companies.

Q. HOW DO THESE AUTHORIZED ROES COMPARE TO CURRENT AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. They are above current authorized ROEs for both electric utility companies. As previously discussed, the authorized ROEs for electric utilities have declined from 10.01% in 2012, to 9.8% in 2013, 9.76% in 2014, and 9.58% in 2015 according to Regulatory Research Associates.[15] Flotation Costs

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[15] These figures exclude the Virginia cases that include ROE generation riders of up to 200 basis points.

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The expected range is based on 30 years of actual weather data at the given location and is intended to provide an indication of the variation you might see. For more information, please refer to this NREL report: The Error Report.

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The energy output range is based on analysis of 30 years of historical weather data for nearby , and is intended to provide an indication of the possible interannual variability in generation for a Fixed (open rack) PV system at this location.

EXHIBIT
tables
TASC 24
ADMITTED

RESULTS

1,713 kWh per Year *

System output may range from 1,619 to 1,727kWh per year near this location.

Month	Solar Radiation (kWh / m^2 / day)	AC Energy (kWh)	Energy Value ($)
January	4.77	115	12
February	5.45	117	12
March	6.20	150	15
April	7.37	167	17
May	7.65	173	18
June	7.74	163	17
July	6.79	150	15
August	6.80	151	15
September	6.70	145	15
October	6.23	143	14
November	5.44	126	13
December	4.66	113	11
Annual	**6.32**	**1,713**	**$ 174**

Location and Station Identification

Requested Location	Tucson
Weather Data Source	(TMY3) TUCSON INTERNATIONAL AP, AZ 6.3 mi
Latitude	32.13° N
Longitude	110.95° W

PV System Specifications *(Residential)*

DC System Size	1 kW
Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt	20°
Array Azimuth	180°
System Losses	14%
Inverter Efficiency	96%
DC to AC Size Ratio	1.1

Initial Economic Comparison

Average Cost of Electricity Purchased from Utility	0.10 $/kWh
Initial Cost	3.30 $/Wdc
Cost of Electricity Generated by System	0.16 $/kWh

These values can be compared to get an idea of the cost-effectiveness of this system. However, system costs, system financing options (including 3rd party ownership) and complex utility rates can significantly change the relative value of the PV system.

EXHIBIT
TASC 25
ADMITTED

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The expected range is based on 30 years of actual weather data at the given location and is intended to provide an indication of the variation you might see. For more information, please refer to this NREL report: The Error Report.

The energy output range is based on analysis of 30 years of historical weather data for nearby , and is intended to provide an indication of the possible interannual variability in generation for a Fixed (open rack) PV system at this location.

RESULTS

1,649 kWh per Year *

System output may range from 1,558 to 1,662kWh per year near this location.

Month	Solar Radiation (kWh / m² / day)	AC Energy (kWh)	Energy Value ($)
January	5.45	128	13
February	4.54	99	10
March	5.46	131	13
April	7.79	170	17
May	7.81	175	18
June	7.91	167	17
July	6.59	146	15
August	6.43	141	14
September	5.67	124	13
October	5.86	136	14
November	5.07	116	12
December	4.83	115	12
Annual	**6.12**	**1,648**	**$ 168**

Location and Station Identification

Requested Location	Tucson	
Weather Data Source	(TMY3) DAVIS MONTHAN AFB, AZ	4.6 mi
Latitude	32.17° N	
Longitude	110.88° W	

PV System Specifications *(Residential)*

DC System Size	1 kW
Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt	20°
Array Azimuth	180°
System Losses	14%
Inverter Efficiency	96%
DC to AC Size Ratio	1.1

Initial Economic Comparison

Average Cost of Electricity Purchased from Utility	0.10 $/kWh
Initial Cost	3.30 $/Wdc
Cost of Electricity Generated by System	0.16 $/kWh

These values can be compared to get an idea of the cost-effectiveness of this system. However, system costs, system financing options (including 3rd party ownership) and complex utility rates can significantly change the relative value of the PV system.