0000171009

Transcript Exhibit(s)

Docket #(s): E-00000J-14-0023

Exhibit #: Vote Solar-1 — VoteSolar-9

S-1 – S-5; S-9; S-14

Part 3 of 5

For parts 1 + 2, see barcodes 0000171007 + 0000171008

For parts 4 + 5, see barcodes 0000171040 + 0000171041

TRANSMISSION & DISTRIBUTION WORLD

EXHIBIT
VoteSolar-1
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APS First U.S. Utility to Use Advanced Inverters to Manage Solar Generation

T&D World Magazine
Tue, 2016-04-12 21:33

Last week, hundreds of APS Solar Partner Program customers helped their utility make history. Advanced technology installed along with participants' solar panels is beginning to collect data that will help APS better understand and manage the energy flowing into neighborhoods across the state. APS is the first utility in the nation to deploy and control this advanced technology remotely – meaning that the utility can operate the solar installations as they would a power plant, ramping up or curtailing power based on customers' real-time energy needs.

The device is called an advanced inverter. Inverters are installed with solar panels to convert the electricity from a one-way flow of energy (direct current) to a two-way flow of energy (alternating current – which matches the current on the electric grid). The advanced inverters used as part of APS's Solar Partner Program (SPP) just received their UL certification, allowing the utility to start full command and control of the device.

These advanced inverters will help APS regulate the amount of energy flowing into the grid in neighborhoods with participating SPP customers. This power quality regulation is no different than what the utility does 24/7/365. However, with the explosion of distributed energy installations across the state, managing the energy flow on the grid – to ensure customers continue to receive safe, reliable electricity – has become a greater challenge, with mini power plants appearing on rooftops all over Arizona.

"Energy used to flow in one direction, from our power plants to a customer's home or business. That is no longer true today," said Scott Bordenkircher, APS Director of Technology Innovation. "With the deployment of distributed generating resources like rooftop solar, energy now flows back and forth on the grid. Advanced inverters will help us better manage the grid – for the safety of our crews working on the power lines, and so customers can continue to receive the reliable electricity they have come to expect from APS."

The Solar Partner Program was launched in early 2015, when the company enlisted the help of 1,500 customers to host rooftop solar systems at no cost to the customer. In fact, the utility is essentially renting the customer's roof for $360 a year for the next 20 years. Advanced inverters were installed along with the solar panels, helping the utility test the new technology that will benefit all of APS's 1.2 million customers.

"The small power plants found on customer rooftops across the state present interesting challenges to service quality and reliability, and advanced inverters are a technology APS believes can help avoid service disruptions and power quality issues," Bordenkircher said. "APS is taking an industry lead with this program – and others like it – that will ultimately provide data essential to helping utilities achieve a more reliable and sustainable grid, while providing for greater customer technology choice."

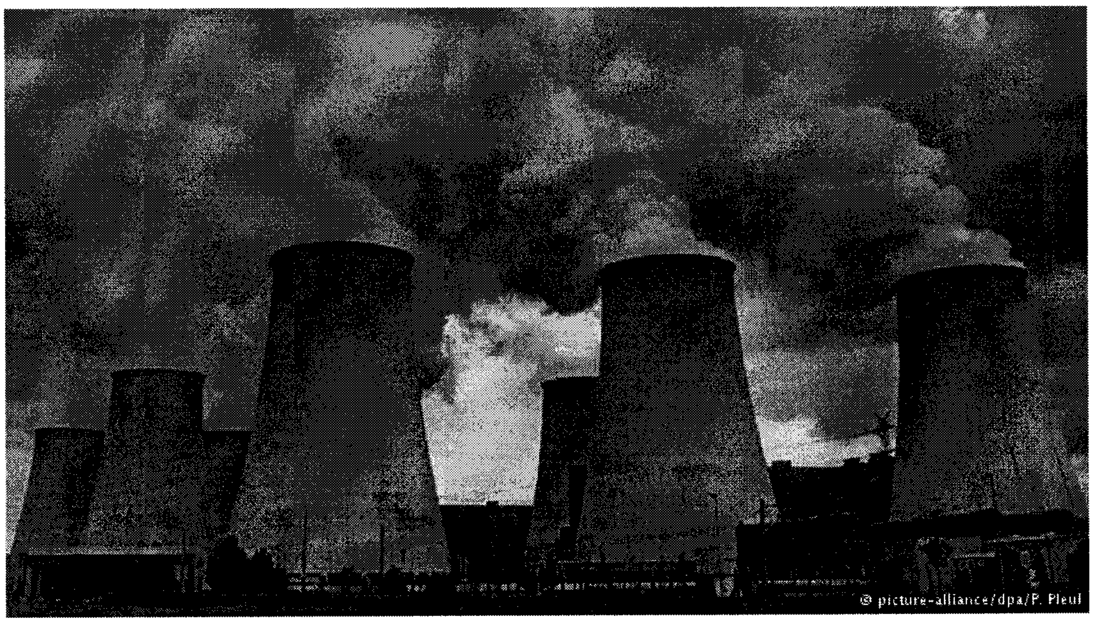
Source URL: http://tdworld.com/renewables/aps-first-us-utility-use-advanced-inverters-manage-solar-generation

EXHIBIT
Vote Solar-2
ADMITTED

ENVIRONMENT

German CO2 emissions targets at risk

A new coal-fired power plant has opened in Germany a day after an expert commission told the energy minister the country must triple its annual rate of decarbonization to meet its ambitious 2020 climate policy goals.



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On Thursday in the Hamburg suburb of Moorburg, Hamburg's mayor Olaf Scholz, a leading figure in Germany's Social Democratic Party (SPD), stood alongside Magnus Hall, president of Swedish energy utility Vattenfall, and pushed a big button.

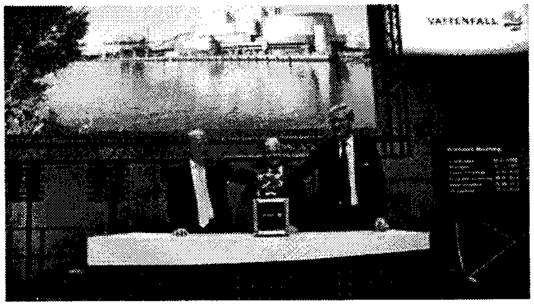
The button-pushing symbolized Vattenfall's ceremonial opening of a 1,600 Megawatt (MW) coal-fired power plant that had been under construction for eight years - despite heated opposition from Germany's greens, who want the country to exit from coal altogether.

One day earlier, in London, the UK government had announced a ten-year plan to close down all remaining coal-fired power stations in Britain. At the very same time as UK politicians were basking in the resulting applause, Scholz's fellow Social Democrat, Vice Chancellor Sigmar Gabriel, the leader of the SPD and the country's minister of economy and energy, sat in a Berlin conference room absorbing some bad news.

An independent commission of senior energy experts advising his ministry explained to him on Wednesday that Germany was on track to miss - rather badly - the carbon emissions goals the government had set for the country to meet by 2020.

Commitments outstripping actions

Germany is on track to meet some sub-goals, the experts reported, including continued brisk expansion of renewable energy generation capacity, which exceeded 30 percent of the country's total generation in the first half of 2015.



Perhaps the button pushed by officials at Moorburg's launch could equally well be interpreted as the detonation button on Germany's emissions reduction goals

But the central target of reducing CO2 emissions by 40 percent compared to 1990 levels by 2020 was "seriously in danger," according to Andreas Löschel, director of the four-person expert commission, as it presented its fourth annual monitoring report on Germany's *Energiewende* (energy transition).

"The tempo of total carbon emissions reductions achieved each year needs to be roughly tripled" in order to meet the government's 2020 target, Löschel told DW, saying the annual emissions reduction rate in recent years has been 9 million tons of CO2 per annum, but needed to be 27 million tons.

Protest erupted against the Garzweiler brown coal strip mine, Erkelenz, in western Germany

"The German government introduced a couple of new emissions reductions programs recently, including a national action plan for energy efficiency,# but the programs haven't been implemented yet and it's too early to say whether they'll be enough to close that gap," Löschel said. The commision's report detailed some reasons to suspect not

Excessive emissions from cars, houses, coal-fired power plants

One of the biggest problems the commission found was that energy use in the German transport sector had continued to increase - it was 1.7 percent higher in 2014 than in 2005. Another was slower-than-planned progress in improving energy efficiency, especially in the housing sector, where too little was being done to improve insulation.

A third was continued operation of too many coal-fired power plants, including lignite (brown coal) burning plants, which are especially emissions-intensive.

For these and other reasons, total carbon emissions were not dropping nearly as fast as the 2020 target demanded. Minister Gabriel admitted more needed to be done, pointing to an expansion in Germany's electric vehicle fleet as one of his priorities. However, he has been a stubborn defender of the coal industry, pointing to the undesirability of job losses in economically weak coal-producing regions.

A Greenpeace protest against coal strip-mining in the Lausitz region south of Berlin. The signs display names of villages that were destroyed to make way for lignite strip-mines

Meanwhile in Sweden, the government was getting ready to travel to Paris for COP21, the big UN climate policy conference, with a flashy "Fossil Free" campaign, boasting that it intends to be the first industrial country to go fossil-free, and inviting others to join in.

On both the corporate and government side, in Germany as well as Sweden, emissions numbers and climate policies were not adding up.

The Pontius Pilate of climate policy

On the corporate side, the problem was Vattenfall's intention to divest from its brown-coal assets. Vattenfall AB is a company wholly owned by the Swedish government, with subsidiaries in several European countries.

In Berlin, a citizen-driven referendum in 2013 aiming to force the city to buy its power grid off Vattenfall nearly succeeded

Vattenfall's German subsidiary is Germany's third largest power generator, with more than 20,500 employees, annual revenues of more than 11 billion euros ($12 billion), and a power-generation portfolio consisting primarily of coal-fired power plants - including several particularly dirty lignite-fueled power plants in eastern Germany, including the one at Jänschwalde, pictured at the top of the page. Those lignite mines and power plants employ about 8,000 people.

The government of Sweden has decided it wants to gradually wash its hands of coal-burning - which is the electricity sector's worst generation technology by far in terms of emissions of climate-disrupting carbon dioxide, as well as other air pollutants. So Vattenfall has been seeking to sell its German brown-coal power generation assets, plus several associated lignite mines - some 9,000 MW of generating capacity.

MIBRAG, a coal and lignite producing subsidiary of Czech company Energetickky a Prumyslovy Holding (EPH), is reportedly interested in buying them - but regulatory uncertainties have delayed a sale.

This coal fired power station in Cottbus, Germany, makes the issue visible

Greenpeace's pitch

"Selling its brown-coal mines and associated power plants to another company won't make the slightest difference to greenhouse gas emissions," Annika Jacobson of Greenpeace Nordic in Sweden said. Vattenfall would be able to boast in its annual report that it's shifting away from coal power, but if the only change is that some other company operates the plants, that does nothing at all for climate safety.

That's why Greenpeace Sweden has offered to acquire Vattenfall Germany's brown-coal power plants and mines - with a view to shutting them down over time.

"Greenpeace has proposed that Vattenfall transfer its brown-coal plants and mines to a newly set-up foundation, which in partnership with regional governments would negotiate a gradual exit from coal and an economic restructuring in the affected regions between now and 2030," Jacobson told DW.

Greenpeace didn't offer Vattenfall any money, arguing that the social and environmental costs of burning lignite far exceed the value of the financial profits - so it makes no sense to pay for assets that lose money on a total cost accounting basis.

The proposal was dismissed out-of-hand by Vattenfall. The Swedish government "seems intent on selling the assets to the highest bidder, while putting no environmental demands at all on potential buyers," Jacobson said. The price range: Between one and two billion euros - money gained at the expense of Sweden's environmental credibility.

The new power station at Hamburg-Moorburg is fuelled by hard, or "black" coal, which is slightly less polluting than lignite (brown coal) when burned

Fossil free or sincerity free?

Jacobson called Swedish government's policy on Vattenfall's brown-coal assets hypocrisy at its purest, asking:

"If Sweden and Germany refuse to manage a near-term exit from coal power in an environmentally and socially responsible way, what does this mean for the world?"

The Swedish government would be sending a devastating signal by selling Vattenfall's brown-coal assets rather than shutting them down responsibly, Jacobson argued. India, China and other less wealthy countries would take note and quietly conclude that if two of the richest and supposedly most environmentally progressive governments in the world clearly weren't serious about getting out of coal-fired power, then they needn't bother taking the issue seriously either.

DW RECOMMENDS

Greenpeace outlines plans for German coal exit

Greenpeace is serious about acquiring coal mines and power plants owned by Swedish utility Vattenfall in eastern Germany. But the environmentalists don't want to pay anything. The operations, they say, are worthless. (20.10.2015)

Britain turns its back on coal power

Britain has set out its plans to phase out coal power plants within the next ten years under tightening EU environmental standards, and turn towards gas, nuclear and potentially wind power, to make up the shortfall. (18.11.2015)

Greenpeace plans bid for Vattenfall's German coal business

Environmental group Greenpeace is exploring funding options to buy Vattenfall's lignite business in eastern Germany in a bid to scale back the operations put up for sale by the Swedish state-owned energy giant. (06.10.2015)

The end of lignite coal for power in Germany

Germany's economics minister and energy companies have agreed on steps towards taking lignite-fired power plants offline. The plan is to help Germany reach its climate targets, but environmentalists say it's 'weak.' (27.10.2015)

EXHIBIT
Vote Solar-3
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

DIRECT TESTIMONY AND EXHIBITS OF CURT VOLKMANN

ON BEHALF OF VOTE SOLAR

February 25, 2015

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Table of Exhibits

1 Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 290 Vine Avenue, Lake Forest, IL.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. At New Energy Advisors, I work with local governments and non-profits, such as Vote Solar, on a variety of clean energy issues and opportunities. In addition to this proceeding, I am currently working in California, Minnesota, Illinois, and the Northeast in various regulatory and legislative proceedings related to distributed energy resources.

Q. Please describe your professional background and experience.

A. I have 32 years of experience in the energy and utilities industry. My resume, attached as Exhibit CV-1, provides further detail of my work experience.

Prior to founding New Energy Advisors, LLC, I worked for the Environmental Law & Policy Center ("ELPC") in Chicago as a Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy, energy efficiency, and rate design regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Managing Director in Accenture's Sustainability Services practice, where I oversaw energy efficiency and demand reduction projects for commercial and industrial clients across multiple industries. I was also an Executive Director in Accenture's North America Utilities practice, with client account leadership responsibilities for several gas, electric, and water utilities in the US. In this role, I oversaw several utility cost reduction and smart grid programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities were from the United States, Canada, Australia, New Zealand, Europe, and Africa.

I also worked for nine years at Pacific Gas and Electric ("PG&E") in various transmission and distribution roles including Distribution Planning Engineer, where I evaluated the impact of demand-side management programs on the deferral of distribution substation upgrades.

Q. Please describe your educational background.

A. I graduated from the University of Illinois at Urbana-Champaign with a Bachelors of Science in Electrical Engineering with a concentration in Power Systems. I also received a Masters of Business Administration from the University of California at Berkeley with a concentration in Finance.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. No.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified before the Illinois Commerce Commission in its investigation into Commonwealth Edison's cost of service in Docket No. 14-0384, Commonwealth Edison's proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0495, and Ameren Illinois' proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0498. I have also testified before the Michigan Public Service Commission in its investigation into the application of Consumers Energy Company to amend its renewable energy plan in Case No. U-17752.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony serves three objectives. First, I will provide specific responses to a subset of the questions raised in Commissioner Doug Little's letter to interested parties dated December 22, 2015 (the "Guidance Letter"). Second, I will explain why and how solar distributed generation ("DG") and other Distributed Energy Resources ("DERs") can be valuable grid resources, rather than problems that utilities must address.[1] Finally, I will discuss how other jurisdictions are addressing these issues and share emerging best practices.

[1] DERs can include energy efficiency, demand response or direct load control, energy storage, electric vehicles, DG, combined heat and power, or microgrids.

Q. Please summarize your recommendations.

A. I recommend that the Commission:

1) Require utilities to conduct analyses to identify locations on the distribution system where DG solar and other DERs can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require utilities to publish the results of these analyses in a manner that is easily accessible by customers and DER providers. The results of these analyses will provide key inputs into the integration cost component of DG solar valuation.

2) Modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

3) Adopt a detailed marginal cost of service methodology for both transmission and distribution ("T&D") capacity, reflecting the unique system operating and load characteristics at each location. The methodology should credit DG solar and other DERs for their incremental contributions to T&D capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

4) Include the value of avoided water consumption in its DG solar valuation methodology.

5) Explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology.

6) Initiate changes to traditional utility distribution planning processes to proactively incorporate DG solar and DERs. This should include:

    - Increasing transparency regarding the grid's capacity to accommodate DG solar and other DERs, and the locational value of various DER solutions.

- Increasing the transparency of planned capital investments that could be deferred, avoided, or substituted by DER solutions.
- Implementing mechanisms to allow third-party provision of DER solutions as alternatives to traditional distribution capital investment.

7) Establish sufficient flexibility in the DG solar valuation methodology to allow for future inclusion of all DER types and portfolios of DERs.

3 Responses to Questions in the Guidance Letter

Q. What is the focus of this section of your testimony?

A. This section of my testimony will address questions from Commissioner Little in his Guidance Letter from December 22, 2015. Specifically, I will address:

- DER Integration costs (Guidance Letter questions 4, 11, 17, and 20)
- DG intermittency (question 8)
- Coincidence with peak demand (question 9)
- Ability to dispatch (question 10)
- Transmission capacity (questions 15)
- Distribution capacity (question 16)
- Water (question 18)
- Grid security and reliability (question 19)

3.1 DER Integration Costs

Q. Question 4 of Commissioner Little's letter states:

"Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?"

How do you respond?

A. The cost and value of DG solar and other DERs can vary significantly based on location, and this variability should be reflected in rates or other DER compensation mechanisms. I refer to the location-specific net benefits (the sum of all DER location-specific benefits less any associated cost) as Locational Value.

As I will describe below, targeted deployment of DER portfolios, including DG solar, can add significant value by deferring or eliminating the need for more costly traditional capital investment ("Deferral Value"). In these cases, Deferral Value is a significant component of the overall Locational Value of the DER. In other locations with sufficient capacity and no immediate need for system upgrades, there will still be Locational Value (from avoided energy, avoided line losses, etc.), but the Deferral Value from the DER may be less.

Similarly, the costs of DG and DER integration vary by location, based on the DER type and the distribution feeder characteristics at the point of interconnection. Generating-DERs (such as DG solar and storage) inject real power onto a feeder and can negatively impact voltage, depending on the distance from the substation and strength of the circuit at the interconnection location, and may require mitigation measures. Load-DERs (such as energy efficiency, demand response, electric vehicles, and other storage) can have zero cost or may require additional measures to accommodate the increased load on a feeder.

A hosting capacity analysis is a critical and necessary step for identifying the relative costs of DER integration by location on a circuit, and for establishing a foundation for determining the Locational Value of DERs.

Q. What is hosting capacity?

A. The Electric Power Research Institute ("EPRI") defines hosting capacity as the amount of DERs that may be accommodated on a distribution circuit without degrading reliability and power quality.[2] A hosting capacity analysis examines the thermal capacity, voltage, and reliability impacts of various levels of DER deployment for each circuit and subsections of each circuit on a distribution

[2] Elec. Power Research Inst., *The Integrated Grid: A Benefit-Cost Framework* 1-5 (Feb. 2015), *available at* http://goo.gl/cxof7W.

system. Ideally, utilities publish the results of the analysis in a way that makes it easy for customers and DER providers to access the results. For example, the California Distribution Resources Plan ("DRP") proceeding requires each utility to develop an Integration Capacity Analysis (comparable to a hosting capacity analysis), and the investor-owned utilities are publishing the results of the analysis using color-coded maps.[3]

Q. Why is this important?

A. A hosting capacity analysis informs utilities, customers, and other third parties about locations on the distribution system that can accommodate DERs with minimal interconnection costs. Conversely, the analysis also highlights constrained locations on the distribution system that cannot accommodate additional DER without system upgrades. By publicly disclosing the hosting capacity analysis results, along with the underlying data and assumptions, utilities can expedite interconnection processes and enable DER providers to offer innovative alternatives to traditional utility solutions.

Q. How can a hosting capacity analysis expedite interconnection processes?

A. As I explained, hosting capacity defines the quantity of DG solar that a feeder can safely incorporate without requiring modifications to existing infrastructure. Up to this level of penetration, utilities can easily interconnect DG solar systems and the systems should be subject to fast-track approval.

Q. How does a hosting capacity analysis lead to innovative alternatives?

A. Public disclosure of the hosting capacity results, including the nature of the constraints at each location (i.e., thermal, voltage, or system protection), allow customers and DER providers to design solutions that can overcome constraints, increase hosting capacity, and eliminate the need for redundant utility investment.

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[3] See, for example, the integration capacity maps for Southern California Edison at http://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7

For example, a utility's need to install or modify voltage regulation equipment may be eliminated if the DER provider is aware of the constraint and includes smart inverter functionality, as I will explain later.

Q. Question 11 of Commissioner Little's letter states:

"Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?"

How do you respond?

A. The interconnection of DG solar may require distribution system modifications, depending on the DG size and the distribution feeder characteristics at the point of interconnection. As I described previously, a hosting capacity analysis can inform utilities, customers, and other third parties about locations on the distribution system that can sufficiently accommodate DERs with no necessary upgrades, and locations where circuit modifications may be required. Any actual costs to accommodate the DG, whether incurred by a utility or by the DER provider, should be included in the determination of Locational Value.

The potential value of hosting capacity analyses is evident from recent experience in California. The California investor-owned utilities have developed initial hosting capacity analyses as part of the DRP proceeding and concluded that, despite increasing levels of DG solar penetration, there is significant capacity to accommodate additional DG with no required upgrades. For example, Southern California Edison ("SCE") found that depending on feeder voltage, existing circuits above 4 kV can accommodate between 2 and 26 MW of additional DG solar without requiring circuit modifications.[4]

[4] S. Calif. Edison, *Distribution Resources Plan* 38 (July 2015), *available at* http://goo.gl/egrgrd.

Technology and innovation are further eliminating the need for grid modifications to integrate DG solar. For example Hawaii, which has the highest penetrations of solar in the United States, has been able to accommodate rapid growth of DG solar by taking advantage of emerging technologies. In 2015, Hawaiian Electric Company ("HECO") eliminated a backlog of 4,000 customer DG solar interconnection requests and avoided the need to install expensive voltage regulation equipment after collaborating with smart micro-inverter vendor Enphase.[5] HECO's backlog stemmed from its concerns about unacceptable voltage fluctuations on high penetration circuits, but HECO lacked the detailed measurement capability to validate its concern. Enphase's highly-granular voltage and frequency data from its micro-inverters, once shared with HECO, revealed that voltage violations were only a concern on a small percentage of circuits, allowing HECO to proceed with the interconnections.

Q. Question 17 of Commissioner Little's letter states:

"Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?"

How do you respond?

A. The grid adds value to DG solar by allowing for exports of energy not consumed locally, and by providing voltage and frequency regulation services. However, as I will explain below, the need for the grid to provide regulation services can be significantly reduced with the widespread adoption of smart inverters.

DG solar and other DERs also add value to the grid by providing flexibility to avoid or delay "lumpy" investments in traditional system capacity upgrades, as I explain in response to Commissioner Little's questions 15 and 16.

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[5] Jeff St. John, *How HECO is Using Enphase's Data to Open its Grid to More Solar*, Greentech Media (Apr. 14, 2015), http://www.greentechmedia.com/articles/read/how-heco-is-using-enphase-data-to-open-its-grid-to-more-solar.

Q. Question 20 of Commissioner Little's letter states:

"What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?"

How do you respond?

A. Interconnected DG solar may require additional voltage and/or frequency support depending on the size of the DG and the circuit characteristics at the point of interconnection. However, widespread adoption of smart inverters can significantly reduce or eliminate the need for these costs. Additionally, widespread deployment of smart inverter functionality can stabilize the grid as DG solar and DER penetrations increase.

Q. What is a smart inverter?

A. Inverters convert the direct current electricity from DG solar or batteries to alternating current electricity – a necessary requirement for connection to a customer facility or to the grid. Traditional inverters are not capable of handling voltage and frequency fluctuations, and are required by the Institute of Electrical and Electronics Engineers ("IEEE") 1547 standard to disconnect from the grid when these fluctuations occur. Widespread and simultaneous disconnection can worsen grid instability.

Smart inverters have more advanced capabilities and can contribute to the stability of the grid. These capabilities include:

- Maintaining connection to the grid during minor voltage or frequency disturbances.
- Producing or absorbing reactive power, which can help with voltage support.
- Randomized timing of disconnection and reconnection during system disturbances to prevent a large decrease or increase of generation at one time.

- Real-time communications, enabling operator control and management of real/reactive power and voltage.

Q. Are smart inverters in use today?

A. Smart inverters are widely deployed in Europe and to some extent in California, and the technical capabilities of smart inverters I described above exist today. However, current U.S. technical standards that govern the use of inverters do not allow for full utilization of these technical capabilities. Revisions to these standards are in various stages of review and approval.[6] Until the revised standards are finalized, the potential legal liability resulting from an equipment malfunction has inhibited the widespread use of smart inverters.

Q. When will the revised standards be available?

A. It is unclear when the revised standards will be available. However, California has established a multi-stakeholder Smart Inverter Working Group that has led to California Public Utility Commission ("CPUC") approval of some smart inverter functions in its interconnection standards, referred to as Phase 1 of Rule 21. This CPUC approval and adoption of smart inverter functionality is in advance of the revised standards.

Q. Are the Arizona utilities and the Commission aware of the importance of smart inverters?

A. Yes. Arizona Public Service Company ("APS") found in its Flagstaff Community Power project that: "Another cost effective way to maintain feeder voltage profile within limits under high PV penetration levels is the use of reactive power capability of advanced inverters."[7] APS and Salt River Project are deploying

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[6] Specifically, Underwriter Laboratories 1741 and IEEE 1547.

[7] David J. Narang et al., *High Penetration of Photovoltaic Generation Study – Flagstaff Community Power* 48 (Feb. 2015), *available at* http://goo.gl/NWfEhG.

smart inverters in their residential solar pilots to further prove the capabilities of this technology.[8]

An August 2013 letter to the Commission from the Western Electric Industry Leaders ("WEIL") Group, an organization of utility executives including APS CEO Don Brandt, urged widespread adoption of smart inverters.[9] The WEIL letter explains: "[S]mart inverters will play a vital, transformative role. These simple and inexpensive devices can mitigate the voltage drops caused by the fluctuating solar generation, thus preventing potential power quality problems."[10]

Comments in the Commission's Notice of Proposed Rulemaking Regarding Interconnection of Distributed Generation Facilities (Docket No. RE-00000A-07-0609) from the Western Grid Group encouraged the Commission to require smart inverters for DG solar installations.[11]

Q. Please summarize your recommendations for addressing DER integration costs and benefits in the valuation of DG exports.

A. I recommend that the Commission require utilities to conduct hosting capacity analyses ("HCAs") to identify locations on the distribution system where DG solar and other DER can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require the utilities to publish the results of the analyses in a manner that is easily accessible by customers and DER providers.

The results of the HCAs will provide important inputs into the DG solar valuation framework. Specifically, the integration costs (or lack thereof) calculated for each

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[8] Jeff. St. John, *A State-by-State Snapshot of Utility Smart Solar Inverter Plans*, Greentech Media (Nov. 6, 2015), http://www.greentechmedia.com/articles/read/a-state-by-state-snapshot-of-utility-smart-solar-inverter-plans.

[9] Letter from W. Elec. Indus. Leaders Grp., to Governors, Commissioners, and Legislators (Aug. 7, 2013), *available at* http://goo.gl/2pSZZx.

[10] *Id.* at 1.

[11] Comments of W. Grid Grp., Dkt. No. RE-00000A-07-0609 (July 24, 2015), *available at* http://goo.gl/qTS5PH.

circuit location in the HCAs are inputs into the calculations for determining DG solar costs and benefits at each location.

As I describe above, smart inverters are a key technology for unlocking value from DERs, and DG solar in particular. Smart inverters will improve grid stability, and reduce or eliminate the need for traditional utility investments in reactive power management, voltage, and frequency regulation. I recommend that the Commission modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

Once the Commission adopts a smart inverter requirement, the benefits of avoided voltage or frequency support services will be an additional input into the DG solar valuation methodology.

3.2 Intermittency

Q. Question 8 of Commissioner Little's letter states:

"How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an 'intermittency factor' be applied to more accurately determine cost and value?"

How do you respond?

A. The intermittent nature and sudden changes in output from DG solar can cause voltage fluctuations on the distribution system. But as I previously explained, smart inverters can alleviate many of the impacts from DG solar intermittency at a significantly lower cost than traditional voltage regulation equipment. Intermittency is addressed in the valuation of DG exports as described under DER integration costs and benefits above. Any costs associated with additional voltage or frequency support to accommodate DER at a location (as determined by the hosting capacity analysis) can be direct inputs into the cost components of the valuation methodology. Similarly, avoided costs from the deployment of smart inverter functionality with the DER can be direct inputs into the benefits components of the valuation methodology. There is therefore no need for the Commission to apply an additional "intermittency" factor in the analysis.

3.3 Coincidence with Peak Demand

Q. Question 9 of Commissioner Little's letter states:

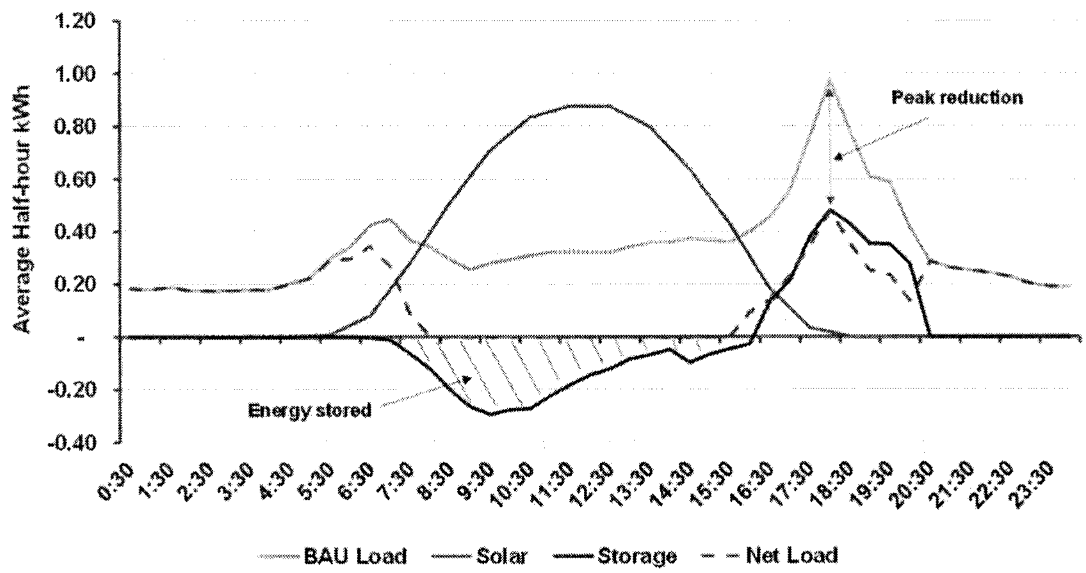
"To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?"

How do you respond?

A. A DG solar installation's contribution to the deferral of a planned capacity upgrade (i.e., its Deferral Value) is dependent on its coincidence with the local peak when the system is most constrained. For distribution feeders, these peak periods are typically only a few hours every year, they are not always coincident with the overall system peak, and they are very dependent on the nature of the load (i.e., residential, commercial, or industrial). If the load is primarily commercial, the peak is typically earlier in the day when businesses are open and customers are at work. If the load is primarily residential, the peak is typically later in the day when customers return home and increase their electricity usage.

The output from DG solar also peaks depending on its orientation – the peak output of south-facing panels is earlier in the day than for more west-facing panels. It is therefore possible to strategically deploy and orient DG solar to coincide with system or feeder peaks, but not always. Increasingly, storage combined with DG solar is proving to be an effective way to improve coincidence with local peaks.

The diagram below illustrates how storage can effectively enable DG solar to reduce a local peak demand.[12] The business-as-usual ("BAU") load for this hypothetical customer peaks at around 6:30 pm, while the maximum DG solar output occurs around noon. By directing the DG solar output to charge the storage during the day, then dispatching the storage during peak load periods, the solar PV + storage DER portfolio becomes fully coincident with peak demand and net load decreases.



Q. Is storage cost effective?

A. Energy storage is becoming increasingly cost effective as battery costs decline and as customers are able to monetize the value of storage services. Thermal energy storage technologies, such as those using ice[13] or electric hot water

[12] Lars Karlbom et al., *Why Isn't There More Talk About Network Storage-As-A-Service?*, QSI Online (July 21, 2015), http://www.marchmenthill.com/qsi-online/2015-07-21/why-isnt-there-more-talk-about-network-storage-as-a-service/.

[13] Jeff St. John, *How Solar Power and Ice Energy Can Play Together*, Greentech Media (Aug. 19, 2013), http://www.greentechmedia.com/articles/read/how-sun-power-and-ice-energy-can-play-together.

heaters,[14] are also becoming cost effective solutions for load shifting and peak demand reduction.

Q. What do you recommend?

A. I understand that this docket is primarily focused on establishing a methodology for determining the value of DG solar. However, I encourage the Commission to establish flexibility in the methodology to be able to include the value of multiple DER types and portfolios of DER, such as solar + storage, in the future.

3.4 Ability to Dispatch

Q. Question 10 of Commissioner Little's letter states:

"Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?"

How do you respond?

A. DG solar on its own is non-dispatchable. However, as illustrated above, a solar + storage portfolio can be dispatched in a manner that effectively contributes to a peak load reduction, and can therefore have a Deferral Value.

3.5 Transmission Capacity

Q. Question 15 of Commissioner Little's letter states:

"Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?"

How do you respond?

A. DG solar and other DERs have the potential to defer or eliminate the need for transmission expansion because they can decrease the peak load at substations

[14] David Podorson, *Battery Killers: How Water Heaters Have Evolved into Grid-Scale Energy-Storage Devices*, E Source (Sept. 9, 2014), https://www.esource.com/ES-WP-18/GIWHs.

served by the transmission system and provide congestion relief. The extent to which a DER has transmission Deferral Value depends on the coincidence of the DER output with system peak loads.

Q. Are other regulatory commissions addressing issues similar to those in this proceeding, specifically transmission capacity?

A. Yes. New York's Reforming the Energy Vision ("REV") proceeding,[15] and California's Distribution Resources Plan ("DRP") and Integrated Distributed Energy Resource ("IDER") proceedings[16] are addressing similar issues.

Q. How are these other commissions determining the value of transmission capacity deferral?

A. There is no clear consensus in the New York REV and California DRP/IDER proceedings on the preferred way to determine transmission Deferral Value. To determine the value of avoided transmission capacity value beyond that included in avoided generation and avoided energy, New York will use detailed transmission and distribution ("T&D") marginal costs. The utilities have historically used a system average $ per kW value for avoided T&D capacity, but are now required to develop detailed marginal cost of service studies to be included with their initial Distribution System Implementation Plans by June 30, 2016.

The three California investor-owned utilities have proposed different methods for valuing transmission Deferral Value. SCE proposes to calculate the net present value of the capital investment deferral over an identified deferral time-frame, based on the amount of DERs that can reasonably be deployed to address the specified grid need, applied over the timeframe of the deferral.[17] PG&E proposes that the locational impact be the difference between the deferral benefits and the

[15] New York Public Service Commission Case 14-M-0101.

[16] California Public Utilities Commission Rulemaking 14-08-013 and 14-10-003.

[17] S. Calif. Edison, *Distribution Resources Plan*, at 38.

capacity-related costs for interconnecting DERs, less additional benefits of deferring the project.[18] SDG&E proposes to use the cost to install a traditional project to meet a grid need as the T&D capacity value.[19]

Q. What do you recommend?

A. Because transmission and distribution system and load characteristics vary significantly by circuit and location, I recommend that the Commission adopt a detailed marginal cost of service methodology for valuing both transmission and distribution capacity. This approach is data-intensive, but tools are increasingly available to assist with the analysis.[20] I provide a high-level example of this methodology in my response below to the question on distribution capacity.

Q. For DG solar or other DERs to have transmission Deferral Value, is an immediate project addressing a grid capacity shortfall required?

A. No. There will be cases where DG solar or other DERs make small, incremental contributions to increase transmission capacity in areas where no immediate capacity upgrade is planned. I believe this contribution to longer-term capacity relief has value and should be recognized in the valuation methodology.

This approach is similar to how utilities treat avoided generation capacity value. As the Interstate Renewable Energy Council's Regulator Guidebook explains:

> For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to

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[18] Pac. Gas & Elec. Co., *Distribution Resources Plan* 70 (July 2015), *available at* http://goo.gl/bNKkCn.

[19] San Diego Gas & Elec. Co., *Distribution Resources Plan* 47 (July 2015), *available at* http://goo.gl/bNKkCn.

[20] *See, e.g.*, Jeff St. John, *Distributed Marginal Price: The New Metric for the Grid Edge?*, Greentech Media (Aug. 21, 2014), http://www.greentechmedia.com/articles/read/distributed-marginal-price-dmp-the-new-metric-for-the-grid-edge.

> defer or avoid the "lumpy" capacity additions. Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.[21]

Q. Please summarize your recommendations for addressing transmission capacity savings in the valuation of DG exports.

A. I recommend that the Commission adopt a detailed marginal cost of service methodology for both transmission and distribution capacity. The methodology should reflect the unique system operating and load characteristics at each location. The methodology should also credit DG solar and DER for incremental contributions to transmission capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

3.6 <u>Distribution Capacity</u>

Q. Question 16 of Commissioner Little's letter states:

> **"Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?"**

How do you respond?

A. DG solar and other DERs can decrease or increase the need for distribution system capacity investments. When strategically deployed, DERs can defer or eliminate the need for traditional investment. Where insufficient hosting capacity exists, feeder upgrades may be required.

[21] Interstate Renewable Energy Council, Inc., *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* 25 (Oct. 2013) (footnotes omitted), *available at* <u>http://goo.gl/SjblOA</u>.

As I described earlier, I recommend that the Commission adopt a detailed marginal cost of service methodology for valuing DER impacts to both transmission and distribution capacity.

The New York REV Benefit Cost Analysis Framework provides the following high-level example using marginal cost data from Con Edison.[22]

EXAMPLE: Battery Energy Storage located at a Con Edison Area Substation

A 1 MW battery with a 5-year service life is attached to an area substation in the Con Edison service territory. The battery is operated to reduce the peak load experienced by the area substation between 6 pm and 8 pm, whereas the system peak generally occurs at 4 pm. What is the value of avoided T&D infrastructure need for 2016?

First, consider whether the load reduction of the battery aligns with the cost drivers of the utility equipment which it is connected to. In this instance, operation of the battery does reduce demand during the peak hours experienced by the area substation, but not those of the system as a whole. Further, since the battery is connected directly at the area substation, for simplicity assume its operation does not decrease peak load on Con Edison's primary or secondary distribution feeders. Therefore, only consider the battery's contributions to avoided Area Station and sub-transmission costs.

To determine the value of avoided T&D for the battery, multiply the amount of load reduction caused by the battery by the marginal costs of the equipment that the load is being relieved from; this calculation should be done for the entire service life of the battery (calculations for 2015 and 2016 have been shown as a demonstration).

$$\begin{aligned}\text{Avoided T\&D}_{2015} &= \text{load reduction} * \text{marginal cost}_{2015}\\ &= (-1\text{ MW}) * \left(\frac{\$43.88}{\text{kW}}\right)\left(\frac{1000\text{ kW}}{\text{MW}}\right) = \$43{,}880\\ \text{Avoided T\&D}_{2016} &= \text{load reduction} * \text{marginal cost}_{2016}\\ &= (-1\text{ MW}) * \left(\frac{\$82.90}{\text{kW}}\right)\left(\frac{1000\text{ kW}}{\text{MW}}\right) = \$82{,}900\end{aligned}$$

The lifetime Avoided T&D Infrastructure of the battery can then be determined by finding the Net Present Value of the value streams.

[22] Order Establishing the Benefit Cost Analysis Framework, New York PSC Case No. 14-M-0101, at App. C, pp. 9–10 (Jan. 21, 2016), *available at* http://goo.gl/v5pDj5.

Table 2: Illustrative Example of the Avoided T&D Infrastructure Calculation

Year	Marginal Cost	Avoided T&D
2015	$ 43.88	$ 43,880
2016	$ 82.90	$ 82,900
2017	$ 49.68	$ 49,680
2018	$ 127.30	$ 127,300
2019	$ 119.43	$ 119,430
Discount Rate		5%
NPV		**$ 358,205**

Q. To have Deferral Value, does the DER need to directly defer a capital investment?

A. No. As I explained with regard to transmission capacity above, DERs that contribute incremental peak demand reductions or otherwise increase feeder capacity should get credit for the long-term capacity deferral, even if there is no immediate planned project.

Q. Please summarize your recommendations for addressing distribution capacity savings in a valuation of DG exports.

A. As with transmission capacity, I recommend that the Commission adopt a detailed marginal cost of service methodology for distribution capacity. The methodology should reflect the unique system operating and load characteristics at each location. The methodology should also credit DG solar and other DERs for incremental contributions to distribution capacity relief, even if the utility has not identified an imminent capacity expansion project on the interconnected feeder or at the associated substation.

3.7 <u>Water</u>

Q. Question 18 of Commissioner Little's letter states:

"Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?"

How do you respond?

A. Thermoelectric power generation plants withdraw and consume water for a variety of uses, primarily the condensation or cooling of steam. These plants consume and lose water through evaporation, and the amount of water lost at each facility depends on the generation and cooling technologies utilized at each plant. Arizona power generation facilities consume water from many sources, including the Colorado River (South Point Energy Center), Lake Powell (Navajo Generating Station), and various sources of groundwater and wastewater.

DG solar generation requires no thermoelectric cooling and consumes no water, so each kWh of DG solar serving a customer effectively avoids consumption of water from conventional generation. The Commission acknowledged this in its 2005 APS rate case order stating, "Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy-specific water usage."[23]

Commissioner Burns emphasized the importance of the energy-water relationship and the water conservation benefits of DG solar in his February 8, 2016 letter to stakeholders in this docket.

The Commission has further demonstrated leadership in recognizing the importance of the energy-water relationship, requiring utilities to report quantities and rates of water consumption in each Integrated Resource Plan ("IRP").[24] In

[23] Decision No. 67744, at 26:18–20 (Apr. 7, 2005).

[24] Decision No. 71722 (June 3, 2010).

response, APS reported average consumption of approximately 400 gallons per MWh in its 2014 IRP.[25] Tucson Electric Power ("TEP") reported a system average of 599 gallons per MWh in its IRP for the same period.[26] In earlier comments in this proceeding, TEP disclosed that its generation fleet consumes, on average, 605 gallons of water per MWh.[27]

In these same IRPs, both APS and TEP acknowledge the important role of renewable energy and other DERs in reducing water consumption. APS stated "due to the energy efficiency and renewable energy resources envisioned in the 2014 Resource Plan, the rate of water usage declines dramatically over the course of the Planning Period."[28] The TEP IRP includes the statement, "TEP plans to continue its development of low cost renewable projects that minimize both water usage and negative impacts to the environment and provide long-term value to TEP's retail customers."[29] TEP and UNS stated in their earlier comments in this docket that "PV systems provide immediate reductions in water use by offsetting energy production from fossil-fueled units."[30]

Q. How can the Commission incorporate the value of reduced water consumption in determining the value of DERs, specifically DG solar?

A. The value of water varies significantly by location. Generally, the value of water in Arizona is high and likely to increase as its population and associated water demand increase. Western Resource Advocates ("WRA") published a report in 2011 providing a methodology for valuing water by examining prices paid for alternative uses to thermoelectric cooling, specifically agriculture, municipal

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[25] APS, *2014 Integrated Resource Plan* 119 (Apr. 2014), *available at* https://goo.gl/whtaZa.

[26] TEP, *2014 Integrated Resource Plan* 166 (Apr. 2014), *available at* https://goo.gl/99IVAW.

[27] TEP and UNSE Comments at 6 (Feb. 14, 2014).

[28] APS, *2014 Integrated Resource Plan*, at 119.

[29] TEP, *2014 Integrated Resource Plan*, at 12.

[30] TEP and UNSE Comments at 6 (Feb. 14, 2014).

supply, and environmental uses.[31] The report provides a potential range of value for water in Arizona between $105 and $1,225 per acre-foot per year.[32]

The Commission could determine that prices for agricultural use are the fairest comparison for valuing cooling water consumption. As a proxy for the value of water for agricultural use, water sold by the Central Arizona Project to agricultural customers was $121 per thousand cubic meters in 2014,[33] or $149 per acre-foot.[34]

The Commission could adopt the WRA methodology, an agricultural use comparison, or another approach to determine a dollar value for water in Arizona today and in future years. Because its value is very location-specific, the Commission may determine a different value for water in each utility service territory. Once the Commission establishes a water value, it is straightforward to calculate the associated value of energy from DG solar or other DER by:

- Converting the water value in $/acre-foot to $/gallon (1 acre-foot = 325,851 gallons)
- Multiplying the self-reported water consumption rates of the utilities (in gallons/MWh) by the converted water value ($/gallon)

Q. Can you provide examples?

A. Yes. To illustrate, I will assume that the Commission determines that today's value of water in Arizona is $149/acre-foot per year, which was the price for Central Arizona Project water for agricultural use in 2014. I will also assume for simplicity that the value of water is the same in the APS and TEP service territory. Using the self-reported water consumption rates from each utility:

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[31] W. Res. Advocates, *Every Drop Counts: Valuing the Water Used to Generate Electricity* (2011), *available at* http://goo.gl/Zm6Sye.

[32] *Id.* at 65.

[33] Dennis Wichelns, Org. for Econ. Co-Operation & Dev., *Agricultural Water Pricing: United States* 21 (2010), *available at* http://goo.gl/ABAZF4.

[34] 1,000 cubic meters = 0.811 acre-foot.

- For APS, with 400 gallons per MWh from conventional generation, the value of avoided water consumption from a kWh of DG solar is:

$$\begin{aligned}\text{Value} &= \$149 \times (1/325{,}851) \times 400 \\ &= \$0.183 \text{ per MWh} \\ &= 0.018 \text{ cents per kWh}\end{aligned}$$

- For TEP with 605 gallons per MWh from conventional generation, the value of avoided water consumption from a kWh of DG solar is:

$$\begin{aligned}\text{Value} &= \$149 \times (1/325{,}851) \times 605 \\ &= \$0.277 \text{ per MWh} \\ &= 0.028 \text{ cents per kWh}\end{aligned}$$

Q. Is it worth including these relatively small avoided water consumption values in the DG solar valuation?

A. Yes. The resulting values may be small, but they are not zero. By including the water conservation component in the calculations, the Commission will continue its leadership in acknowledging and spotlighting the significance of the energy-water relationship.

Q. What do you recommend?

A. Because water is, and will increasingly be, a scarce and valuable resource for Arizona, I strongly recommend that the Commission include the value of avoided water consumption in its DER and DG solar valuation methodology. This requires that the Commission:

- Determine a current value for water in Arizona or within each utility's service territory using the WRA methodology or another approach.
- Establish an initial DG solar value of avoided water consumption using the rates reported in the utilities 2014 IRPs .

- Require utilities to explicitly report their current and forecasted average system water consumption rate (gallons per MWh) in each IRP.
- Periodically reassess the value of water in Arizona as new information becomes available.
- After each IRP submission, update the value of avoided water consumption in each service territory and update in the DG solar valuation methodology.

3.8 Grid Security and Reliability

Q. Question 19 of Commissioner Little's letter states:

"Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?"

How do you respond?

A. Yes, there are disaster-recovery or backup benefits associated with the deployment of DG solar and other DERs. As EPRI explains:

> Properly sited and configured DER can assist in the restoration of service after storm-related outages and power delivery component failures from other causes. Utilities often switch isolated feeder sections to alternate feeds at such times. Occasionally, there is insufficient capacity in the alternate feed to supply the load required to restore service to all consumers on the affected feeder section. The ability to support some of the load from DER output sited on the affected section may improve feeder reliability.
>
> If the DER can operate without the presence of the grid, they can be used to help restore power to sections of the distribution system that are completely isolated from the bulk power system (for example, as a result of storm damage). This is often referred to as a *microgrid* that can provide increased localized grid resiliency.[35]

For locations where DERs lead to avoided service interruptions, utilities could estimate the value of this service by determining the number and duration of

[35] Elec. Power Research Inst., *The Integrated Grid: A Benefit-Cost Framework*, at 4-16 to 4-17.

avoided outages, multiplied by the estimated cost of an interruption.

Q. Can you be more specific?

A. Yes. Utilities often use three metrics to measure and report service reliability: (1) the System Average Interruption Frequency Index ("SAIFI") measures average interruptions per customer, (2) the System Annual Interruption Duration Index ("SAIDI") measures average minutes of interruption per customer, and (3) the Customer Average Interruption Frequency Index ("CAIDI") measures the average minutes per interruption. Utilities can calculate these values for various time periods and at the system level, subsystem or feeder level, or at a very local level.

As I described above, portfolios of DERs, including DG solar, can avoid service interruptions or reduce the duration of an interruption once it occurs. At the time of DER deployment and valuation, distribution planners can estimate the expected reduction in SAIFI, SAIDI, and CAIDI from the DER, much like they do with conventional reliability improvement investments.

The Department of Energy's Interruption Cost Estimate ("ICE") calculator provides a standard way of estimating the dollar value of reliability improvement projects, including DER, for a given improvement in SAIFI, SAIDI, or CAIDI.[36] The ICE calculator provides the present value of reliability improvement, based on the specific customer types on each feeder or area, over the life of an investment.

Q. What do you recommend?

A. I recommend that the Commission explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology. The approach could include a requirement for the utilities to estimate the expected location-specific SAIFI and SAIDI improvement (if any) for each DG solar or DER

[36] U.S. Dep't of Energy, Interruption Cost Estimate Calculator, http://icecalculator.com/index.html (last visited Feb. 24, 2016).

location, and the conversion to a dollar value using the ICE calculator or other similar reliability calculator.

4 Important Considerations from Other Jurisdictions

Q. You previously mentioned that other commissions are currently addressing issues similar to those in this docket. Are there some common themes in these other proceedings that are relevant to Arizona?

A. Yes. The participants in these other proceedings recognize the potential for DERs to become valuable grid resources and are addressing the need to explicitly incorporate DER capabilities into traditional distribution planning. This includes fundamental changes to traditional planning methodologies, such as developing and publishing hosting capacity analyses. In addition, these other proceedings emphasize the need to analyze and value all DER types and DER portfolios, not just DG solar.

4.1 The Importance of Proactive Planning for DERs

Q. Why is it important to consider changes to traditional distribution planning?

A. Utilities have generally based distribution planning on assumptions of one-way power flow and the need to reliably and safely provide sufficient capacity to meet local peak demand, which may only occur only a few hours each year. Traditional planning models are static, and solutions to address distribution system capacity, voltage, or reliability issues have been almost exclusively limited to traditional utility capital investment. Most utilities have focused on overcoming the perceived challenges of DG solar and DER interconnection, rather than realizing the potential value of full DER integration.

The proliferation of DERs has fundamentally changed the nature of distribution systems, creating new complexities and opportunities for utilities, customers, and other third parties. Distribution planning assumptions and methodologies must therefore change to reflect this new reality. Additionally, DERs can provide significant grid services which, if not explicitly accounted for and incorporated into utility planning, will be underutilized and could lead to redundant utility investments.

Q. What changes to distribution planning are necessary?

A. First, distribution planning tools and methodologies must become more sophisticated to reflect the dynamic nature of DERs. This includes the need for more advanced circuit modeling, load and DER forecasting, and more granular load and voltage monitoring. A recent report by the Solar Electric Power Association and Black & Veatch provides details on the new tools and capabilities required for today's distribution planning functions.[37]

Second, to more fully enable market innovation and customer choice, distribution planning must become a more open and transparent process with utilities proactively seeking opportunities to deploy DERs. This requires closer collaboration within the utility between planning, interconnection, and energy efficiency/demand response functions. It also requires utilities to publicly share information about constraints and opportunities for DER deployment, including historical operational data, grid needs, the value of addressing specific grid needs, and overall grid hosting capacity.

Q. What do you mean by grid needs?

A. A grid need is an existing or anticipated distribution system deficiency, such as a capacity shortfall, violation of voltage limits, poor reliability, or replacement of aging or failing equipment. Grid needs may also include modifications required to increase a distribution circuit's hosting capacity.

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[37] Solar Elec. Power Ass'n and Black & Veatch, *Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources* (Feb. 2016), *available at* https://goo.gl/x1Y8JV.

Q. What other changes to distribution planning have you observed in these other jurisdictions?

A. New York and California also recognize that additional changes are needed to overcome the utility bias for traditional capital investments as preferred solutions to grid needs. This requires new methodologies for determining the Locational Value of DERs and portfolios of DERs at each location on the distribution system, and mechanisms for utilities to procure DERs and fairly recover the costs of the procurement. The New York REV and California DRP/IDER proceedings are exploring ways for distribution utilities to determine DER Locational Value, and to fairly consider and effectively procure DER as alternatives to traditional utility investment.

4.2 The Importance of Valuing All DER Types and DER Portfolios

Q. Why are other jurisdictions considering the value of all DER types and DER portfolios, not just DG solar?

A. The operating characteristics, impact, and value to a distribution system differ between generating-DERs (solar and other DG, CHP, sometimes storage) and load-DERs (energy efficiency, direct load control, EVs, sometimes storage). DERs can work together to shave the peaks and fill in the valleys of a load profile. Demand response/load control can shift load away from peak periods or make load coincident with intermittent generation. Storage absorbs energy from intermittent generation and can discharge to reduce peaks. Energy efficiency can provide targeted energy and demand reductions in specific end-uses. A DER portfolio of renewable generation, storage, demand response/load control, and EE can provide a more reliable and sustained peak demand reduction than any of the resources can provide individually. DER portfolios can therefore be the most reliable and cost-effective alternatives to traditional transmission and distribution capital investment.

Q. Are there any examples of this?

A. Yes, there are several examples demonstrating how portfolios of DERs can reliably and cost-effectively address local load characteristics to reduce peak demands.

In 2013, the Maine Public Utilities Commission established the Boothbay Smart Grid Reliability Pilot project to determine if DERs could effectively avoid the need for rebuilding a transmission line. The pilot sought to reduce 1.8 MW of demand to avoid an $18 million rebuild of a 34.5 kV transmission line in Central Maine Power's service territory. The DERs deployed in the pilot included DG solar, energy efficiency, demand response, energy storage, and back-up generation. Collectively, these DERs have exceeded the demand reduction target. The total cost for the pilot and deployment of the DERs is projected to be one-third the cost of rebuilding the transmission line and will save customers $17.6 million over the 10-year project life.[38]

The State of Rhode Island requires electric utilities to consider DERs or "non-wires alternatives" for certain types of transmission and distribution capital projects. In addition to deploying targeted energy efficiency and demand response measures, National Grid initiated a study to assess the ability of distributed solar to provide 250 kW of reliable load relief during periods of local peak demand in the Tiverton/Little Compton Region.[39] The study found that National Grid could deploy a mix of rooftop and medium-scale solar systems to help defer a multi-million dollar distribution investment. The company has also solicited proposals for development of 140 kW "peak contribution" capacity of medium-scale solar systems for deployment within a specific, load-constrained area of the distribution grid.

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[38] GridSolar, LLC, *Interim Report Boothbay Sub-region Smart Grid Reliability Pilot Project* (March 2014), *available at* http://goo.gl/46zKT1.

[39] R.I. Office of Energy Res., System Reliability Program, http://www.energy.ri.gov/reliability/ (last visited Feb. 24, 2016).

Finally, New York's Consolidated Edison, under the Brooklyn-Queens Demand Management Program, will spend $200 million deploying DERs to reduce 41 MW of customer demand by 2018 and help defer building a $1 billion substation. The program will include many types of DERs including energy efficiency, demand response, DG solar, and distributed storage. Con Edison's benefit-cost analysis shows a $40 million net present value benefit from this approach.[40]

Q. Why is this relevant in this proceeding?

A. I understand that this proceeding is primarily focused on establishing a methodology to inform future rate cases on how to determine the value and cost of DG solar. I encourage the Commission to acknowledge that the full value of DG solar and other DERs is best realized when distribution planning processes proactively and fairly consider DER as alternatives to traditional capital investments.

Q. What do you recommend?

A. In addition to establishing a methodology for valuing DG solar in this proceeding, I recommend that the Commission require modifications to distribution planning processes, including the identification and publication of DER hosting capacity and Locational Value. I also recommend that the Commission establish mechanisms for third-party provision of DER solutions as alternatives to traditional utility investment. Finally, I encourage the Commission to maintain flexibility in developing the DG solar valuation methodology for future accommodation of all DER types and DER portfolios.

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[40] Corina Rivera Linares, *New York PSC establishes Con Edison's demand management program in Brooklyn, Queens*, Transmission Hub (Dec. 18, 2014), *available at* http://www.transmissionhub.com/articles/2014/12/new-york-psc-establishes-con-edison-s-demand-management-program-in-brooklyn-queens.html.

5 Summary of Recommendations

Q. Please summarize your recommendations for the Commission

A. I recommend that the Commission:

1) Require utilities to conduct hosting capacity analyses to identify locations on the distribution system where DG solar and other DERs can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require utilities to publish the results of the analyses for easy access by customers and DER providers. The results of these analyses will provide key inputs into the integration cost component of DG solar valuation.

2) Modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

3) Adopt a detailed marginal cost of service methodology for both transmission and distribution ("T&D") capacity, reflecting the unique system operating and load characteristics at each location. The methodology should also credit DG solar and DER for incremental contributions to T&D capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

4) Include the value of avoided water consumption in its DG solar valuation methodology.

5) Explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology.

6) Initiate changes to traditional utility distribution planning processes to proactively incorporate DG solar and other DERs. This includes:

- Increasing transparency regarding the grid's capacity to accommodate DG solar and other DERs and the locational value of various DER solutions.
- Increasing the transparency of planned capital investments that could be deferred, avoided, or substituted by DER solutions.
- Mechanisms to allow third-party provision of DER solutions as alternatives to traditional distribution capital investment.

7) Establish flexibility in the DG solar valuation methodology to allow for future inclusion of all DER types and portfolios of DERs.

Q. Does this conclude your testimony?

A. Yes.

Exhibit CV-1

Statement of Qualifications

Curt Volkmann

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Experience

New Energy Advisors, LLC, Strategic Advisory Company, Lake Forest, IL (2015 – present)
President
Advising non-profits and local governments on energy, water and sustainability opportunities
- Advising environmental advocates in various regulatory proceedings related to distributed energy resources
- Led the development of a water and energy community education series for the City of Lake Forest
- Guest lecturer at Chicago-area universities on the topics of energy and sustainability

Environmental Law & Policy Center, Nonprofit Public Interest Advocacy Organization, Chicago, IL (2013 – 2015)
Senior Clean Energy Specialist
Supported advocacy work on various clean energy and transportation policy issues
- Expert witness in several energy efficiency, renewable energy, and rate design regulatory proceedings
- Focused on opportunities to integrate distributed energy resources into electric utility distribution systems

Accenture LLP, Management Consulting and Technology Company, Chicago, IL (1994 – 2013)
Managing Director, North America Strategy and Sustainability (2010 – 2013)
Led the management consulting practice ($260+ million annual sales) focused on energy efficiency and intelligent infrastructure. Clients spanned the chemicals, metals, consumer products, financial services, telecommunications, utilities and federal/state/local government sectors.
- Responsible for sales and project delivery, product/service development, recruiting, alliance management
- Contributed to sales growth of more than 400% in 2 years
- Led creation of Energy Analytics for Cities framework; identified $175 million of energy savings from building retrofits for the City of Chicago
- Frequent speaker and subject-matter expert on the topics of utilities, smart grid, sustainability, clean energy

Partner and Executive Director, North America Utilities Client Group (2000 – 2010)
Managed sales ($10-30 million annually), profitability, and client satisfaction for consulting projects across a portfolio of gas, electric and water utilities. Projects included strategic assessments, smart grid/meter planning, asset management, merger integration, benchmarking, and process improvements.

Senior Manager and Associate Partner, Strategic Services (1994 – 2000)
Led projects involving utility strategic planning, merger integration, cost reduction, and process reengineering

UMS Group, Management Consulting Company, Parsippany, NJ (1993 – 1994)
Senior Associate
Led the Power Delivery consulting practice and benchmarking programs for transmission, distribution and fleet management involving 40+ utilities in 10 countries (in Europe, Africa, North America, Australia/New Zealand)

Pacific Gas and Electric Company, Utility, San Francisco, CA (1984 – 1993)
Electrical Engineer, Operations Planning Consultant, Project Manager
- Assessed impacts to distribution systems from energy efficiency and demand-side management programs
- Modeled impacts of distributed generation on system reliability and safety

Energie- und Verfahrenstechnik (EVT), Power Generation Equipment Manufacturer, Stuttgart, Germany (1983)
Software Developer
Designed steam generating systems for coal-fired power plants

Education

University of California at Berkeley, Haas School of Business
MBA - Concentration in Finance

University of Illinois at Urbana-Champaign
BS - Electrical Engineering, Concentration in Electrical Power Systems

Community Involvement

- Chairman, Lake Forest Collaborative for Environmental Leadership (2012-Present)
- Chairman, City of Lake Forest Parks and Recreation Board (2012-2014)
- Member, City of Lake Forest Municipal Electricity Aggregation Committee (2011-2012)
- Member, City of Lake Forest Environmental Policy Advisory Committee and "Green Team" (2008-2009)
    - Led development of a baseline energy and emissions profile for the City of Lake Forest
- Treasurer, Board Member and Coach; American Youth Soccer Organization (2006-2009)

EXHIBIT
Vote Solar-4
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

REBUTTAL TESTIMONY OF CURT VOLKMANN

ON BEHALF OF VOTE SOLAR

April 7, 2016

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1 Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 290 Vine Avenue, Lake Forest, IL.

Q. On whose behalf are you submitting this rebuttal testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Did you submit direct testimony in this proceeding?

A. Yes, I did. My direct testimony includes an introduction to Vote Solar and a summary of my professional experience.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit CV-R-1, which shows illustrative line loss calculations during higher load periods.

2 Summary of Testimony

Q. Please provide a brief summary of your testimony.

A. In their direct testimony, APS and TEP/UNSE stated that transmission and distribution ("T&D") and generation benefits from solar distributed generation ("DG") are minimal or non-existent. I will explain how solar DG, together with other distributed energy resources ("DER"), can reduce or eliminate the need for traditional utility investments, including capacity upgrades and voltage regulation equipment. I will also explain why it is important that the incremental investment-deferral contribution from DER is captured in any valuation methodology.

The utilities have also stated that T&D system enhancements are necessary to accommodate increasing penetration of solar DG, and that T&D line loss savings from DER are minimal. I will explain why grid enhancements to accommodate solar DG are minimal, and explain the importance of properly accounting for line loss reductions when valuing DER.

In my direct testimony, I explained the importance of establishing a methodology for valuing all DER types and DER portfolios.[1] I continue to believe it is important for the Commission to consider this broader approach, which I refer to as a VOS/DER methodology throughout this testimony.

3 Capacity benefits from DER are real and should be reflected in the VOS/DER methodology

Q. Are there generation and T&D benefits associated with the deployment of solar DG and other DER?

A. Yes. The output from solar DG reduces system loads and reduces the need for future T&D capacity expansion. The generation and transmission capacity deferral benefits are greater if the solar DG output coincides with system or regional peak demand. Distribution capacity deferral benefits are greater when the solar DG output coincides with local substation or circuit peak demand.

As I explained in my direct testimony, strategic orientation of solar DG and bundling solar DG with energy storage can effectively align solar DG output with load profiles to reduce local peak demands.[2] Furthermore, solar DG equipped with smart inverters can provide reactive power support and reduce the need for traditional utility voltage regulation and power quality investments.

Q. Does APS recognize the T&D benefits from solar DG and other DER?

A. APS witnesses Brown and Albert deny the T&D benefits of solar DG in their direct testimony. However, I believe APS does recognize the potential T&D benefits of solar DG, particularly when combined with storage and smart

[1] Curt Volkmann Direct Test. 30:12–32:22 (Feb. 25, 2016) (hereinafter "Volkmann Direct").
[2] *Id.* at 14:19–15:8.

inverters. The company is validating these benefits through its Solar Partner Program, approved in Decision No. 74878.

In response to a Vote Solar discovery request, APS describes the key design elements of the Solar Partner Program as:

- Install rooftop solar on approximately 1,500 homes
- Systems will include smart inverters (UL listing will be achieved by the end of March 2016) and 2-way communications to control each rooftop solar site
- Install 2MW of battery storage on 2 selected feeders
- Collection and analysis of real time data on energy production, energy usage, power regulation capabilities, and curtailment options
- Validate ability to manage solar impacts by configuring smart inverters and issuing real-time commands in a cyber secure environment
- Validate ability to mitigate adverse effects of increased photovoltaic (PV) through enhanced power regulating capabilities
- Validate ability to provide ancillary services from a series of grid-tied batteries in coordination with solar inverters and traditional grid devices
- Collection and analysis of information that helps anticipate, identify, and avoid impacts on the distribution grid
- Validate distribution system models to more accurately and efficiently plan grid upgrades[3]

Q. Do APS and TEP/UNSE recognize the generation capacity benefits from solar DG and other DER?

A. Yes. Generation capacity benefits from DG are widely accepted. Each of the utilities' most recent IRPs included estimates of the level of DG that they expect to contribute to system peak. Vote Solar witness Briana Kobor provided a table

[3] APS Resp. to VS 3.11 (Ex. CV-R-2 at 1).

with estimated of DG peak capacity contribution in 2020 for APS, TEP, and UNSE.[4]

3.1 Testimony of Mr. Brown

Q. Have other parties in this proceeding stated opinions on the T&D benefits of solar DG and DERs?

A. Yes. APS witness Ashley Brown and TEP/UNSE witness Edwin Overcast have offered opinions. Mr. Brown states: "It is virtually impossible to demonstrate that rooftop solar will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit."[5] He also states that "[i]t is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings."[6]

Q. Do you agree with Mr. Brown?

A. No. It is possible to not only envision, but to demonstrate and quantify, the transmission and distribution savings from strategic deployment of solar DG and other DER. In fact, in my direct testimony, I provided several examples of other utilities that are realizing these benefits, including Con Edison, National Grid, and Central Maine Power.[7]

3.2 Testimony of Dr. Overcast

Q. What statements did Dr. Overcast make related to the T&D benefits of solar DG and DERs?

A. Dr. Overcast states that "there are no avoided distribution costs as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system occurs when solar DG

[4] Briana Kobor Direct Test. 30:10 (Feb. 25, 2016).
[5] Ashley Brown Direct Test. 35:16–17 (Feb. 25, 2016) (hereinafter "Brown Direct").
[6] *Id.* at 36:2–4.
[7] Volkmann Direct 31:5–32:6.

customers are delivering excess generation to the system and there is no time diversity of solar DG production as there is with customer load."[8]

Dr. Overcast also states:

> Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers. This further confirms that the distribution system must be designed to meet this higher solar class NCP load rather than the residential class customer NCP load used for full requirements customers. The maximum average customer NCP (the sum of the highest hourly loads for all customers in the data base) for full requirements customers occurs in July at 12.87 kW per customer. The maximum excess delivery by a partial requirements customer occurred in April at 13.79 kW per customer. Although the differences are small, about one kW, the data confirms that there would be no distribution cost savings associated with the equipment in accounts 364-368. . . . Taken with other load data on class NCP it is also reasonable to assume that there would be no savings at the substation level for peak loads of solar DG customers.[9]

Q. Do you agree?

A. I do not agree or disagree without reviewing the data and analysis that Dr. Overcast references, which I am unable to do because TEP/UNSE has claimed it is confidential.

Based on the limited information I was able to review, it appears that the excess delivery of 13.79 kW by a solar DG customer cited by Dr. Overcast is high and not reflective of the majority of solar DG systems installed in TEP's service territory. Assuming PV system losses of 15%, it would require at least a 16.22 kW system to deliver 13.79 kW of power. According to data provided by TEP, only 80, or 0.9%, of installed solar DG systems have capacity of 16.22 kW or

[8] Edwin Overcast Direct Test. 5:26–6:4 (Feb. 25, 2016) (hereinafter "Overcast Direct").
[9] *Id.* at 17:11–18:4.

higher.[10] While there potentially may be a very small number of circuits where excess solar generation exceeds non-coincident peak ("NCP") load, it is not the case for all TEP circuits and it is therefore incorrect to conclude that there are no T&D cost savings from solar DG.

4 The VOS/DER methodology must recognize DER capacity benefits on a continuous basis

Q. What is an appropriate way to consider the capacity benefits of DER in the VOS/DER methodology?

A. As I stated in my direct testimony, DER can make small, incremental contributions to increase T&D capacity in areas where no immediate capacity upgrade is planned, and this contribution to longer-term capacity relief should be recognized in the valuation methodology.[11]

A recent Nexant report explains:

> The main value of integrating distributed energy resources into distribution planning and operations is in managing local, coincident demands that are shared across many customers. If a customer helps reduce coincident demand, either by injecting power within the distribution grid (e.g., behind-the-meter generation) or by reducing demand, the unused capacity can accommodate another customer's load growth and thereby help avoid or defer investments required to meet load growth.[12]

The Nexant report provides an example to illustrate this point. Figure 1 below shows how, absent DER, capacity upgrades for a hypothetical circuit are required in years 4, 9, and 14 to meet increasing demand. Deployment of DER to reduce

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[10] *See* work papers provided in TEP Resp. to TASC 1.1.
[11] Volkmann Direct 18:13–19:11.
[12] Josh Bode et al., Nexant, *Designing and Unlocking Markets for Distributed Energy Resources* 6 (June 2015), *available at* http://www.nexant.com/resources/designing-and-unlocking-markets-distributed-energy-resources.

peak demand results in the need for only a single capacity upgrade in year 9. The economic impact is significant, as the DER solutions reduce the 15-year net present value (NPV) by $72 million, as shown in Figure 2.

Figure 1: Local peak demand and distribution capacity

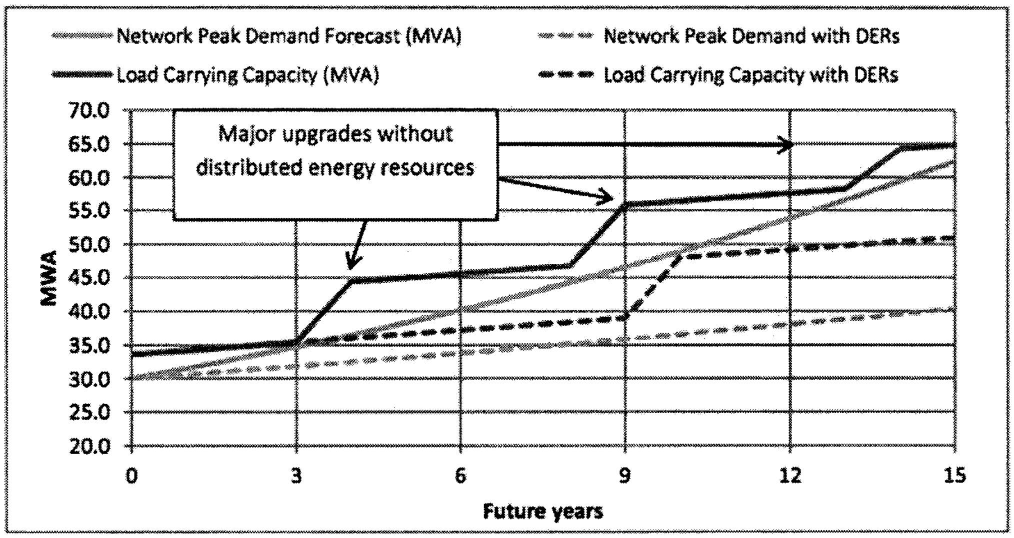
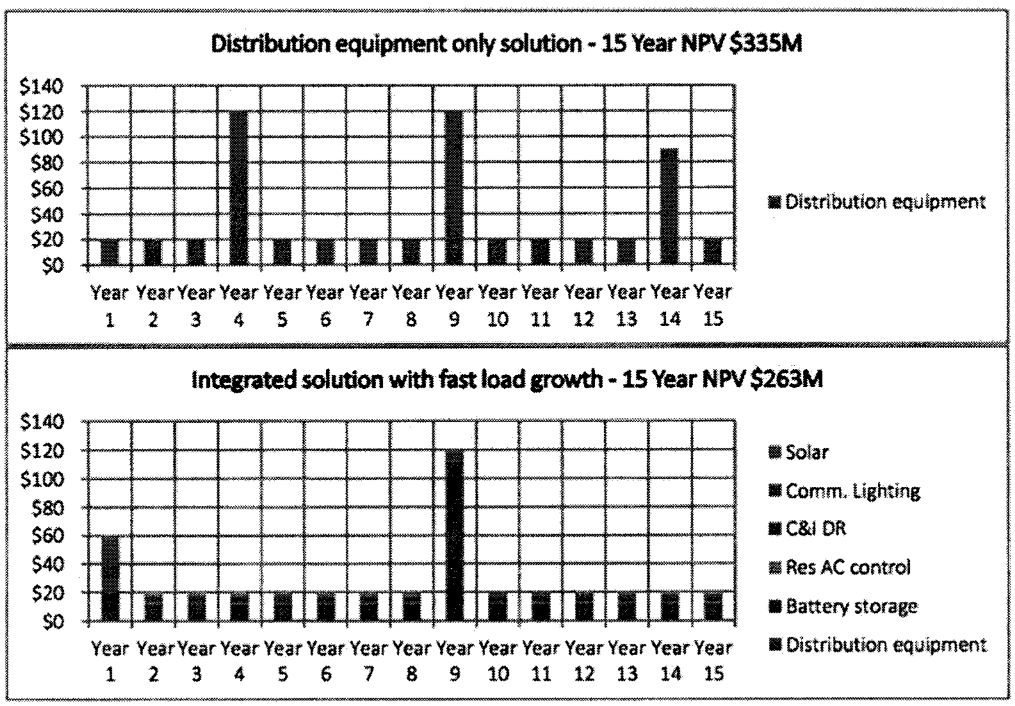


Figure 2: Impact of DER on expenditures



Q. Have other parties in this proceeding commented on this issue?

A. Yes. The updated report by Crossborder Energy included in the TASC testimony states:

> Solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods. Like energy efficiency and demand response resources, solar DG helps the utility to manage and to reduce load growth, thus avoiding and deferring the need for load-related transmission investments.[13]
>
> As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed can be challenging to predict or to manage.[14]
>
> Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction.[15]

Q. Do you agree?

A. Yes. I agree that integrating existing and expected DER capacity and capabilities into T&D planning, including future capabilities from smart inverters, is critical to fully unlock the value of DER.

4.1 Testimony of Mr. Brown

Q. What statements does Mr. Brown make related to the capacity benefits of solar DG and DER?

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[13] Thomas Beach Direct Test. Ex. 2 at 13 (Feb. 25, 2016).
[14] *Id.* at 15.
[15] *Id.*

A. Mr. Brown states:

> [T]he addition of rooftop solar, absent a truly massive amount of installation, will almost inevitably have no impact on transmission capacity planning. Indeed, since transmission must be sufficient to serve peak load, the fact that rooftop solar is intermittent, and non-coincident with peak, means that it will have no real impact on transmission capacity.[16]

Q. Do you agree?

A. No. While solar DG peak production may not fully coincide with system peak demand, solar DG does produce some level of output during system peaks and makes some incremental contribution to system capacity. Utilities conduct transmission planning over long time horizons and make large, "lumpy" capacity additions that may result in over-capacity for some periods of time. In order to ensure least-cost development of the electric delivery system, utilities must acknowledge the incremental capacity benefits of DG and other DER. Failure to recognize these benefits will result in premature, redundant, or unnecessary capital expenditures.

5 Grid upgrades and system resources to accommodate DER are minimal until penetrations significantly increase

Q. Do T&D systems require upgrades to accommodate the proliferation of solar DG and other DER?

A. T&D systems may require upgrades, depending on the system characteristics at each interconnection location. In addition, at very high penetration levels, utilities may need system resources to accommodate intermittency associated with DG. However, I believe T&D system upgrades and system resource needs to accommodate solar DG in Arizona are minimal until DER penetrations significantly increase.

[16] Brown Direct 34:3–7.

Q. Why do you believe T&D system upgrades are minimal now?

A. As I explained in my direct testimony, conducting a hosting capacity analysis identifies how much DER each circuit and each subsection of a circuit can accommodate.[17] Utilities that have conducted detailed hosting capacity analyses have found that existing circuits can accommodate significant amounts of DER without the need for upgrades.[18] Furthermore, smart inverter technologies are eliminating the need for traditional grid enhancements to accommodate DER.[19]

5.1 <u>Testimony of Mr. Albert</u>

Q. What do the parties say about the need for grid investment to accommodate solar DG and DER?

A. APS witness Brad Albert states:

> APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders.[20]

Q. Do you agree?

A. No, I do not believe it requires the installation of additional equipment. In response to a Vote Solar discovery request related to this issue, the company stated:

> APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. . . .
>
> However, APS did receive 95 inquiries in 2015 from customers with installed rooftop solar systems specifically related to

[17] Volkmann Direct 6:21–7:15.
[18] *Id.* at 8:20–27.
[19] *Id.* at 9:1–13.
[20] Bradley Albert Direct Test. 13:12–16 (Feb. 25, 2016) (hereinafter "Albert Direct").

> substantiated high voltage issues. These 95 customers are located on 68 separate feeders, with 12 of those inquiries on a single feeder (the highest number for any one feeder in 2015). All 12 of these high voltage instances occurred in non-summer months, when customer loads are low, rooftop solar production is high, and rooftop systems are exporting energy to the grid.
>
> To date, APS has not incurred equipment or system costs directly attributable to high voltage concerns due to rooftop solar. . . .[21]

It is unclear what a customer "inquiry" entails, but the 95 customers that inquired represent 0.34% of the 28,254 rooftop solar customers in the APS service territory in 2014.[22] This does not indicate a widespread problem. In addition, smart inverter functionality can effectively address high-voltage conditions without the need for more expensive utility equipment installations.

5.2 Testimony of Mr. Brown

Q. What does Mr. Brown say related to this issue?

A. Mr. Brown states:

> It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer.[23]

Q. Do you agree?

A. No, I do not believe that rooftop solar causes more costs than it saves, nor do I believe it will inevitably increase transaction costs for a utility. In response to a Vote Solar discovery request seeking specific examples of the increased costs Mr.

[21] APS Resp. to VS 3.16 (Ex. CV-R-2 at 3).
[22] *See* work papers provided in APS Resp. to VS 1.1.
[23] Brown Direct 35:25–36:2.

Brown refers to, APS acknowledges that "[t]his statement is a general statement not based on specific analysis of APS data."[24]

5.3 Testimony of Mr. Tilghman

Q. What does Mr. Tilghman say related to this issue?

A. TEP/UNSE witness Carmine Tilghman states:

> The bi-directional flow of energy associated with DG solar will require modifications and upgrades to the distribution system. As it is a newly identified phenomenon, the Companies do not have specific measures in place to address any adverse effects as a result of reverse power flow. The bi-directional energy flow on the electrical distribution system varies based on many system electrical parameters that are created by the location and size of the solar system. The problems that are created with bi-directional flows also vary by the time of day and seasonality.
>
> Additional measuring and monitoring equipment will be needed. New methods of modeling the distribution system will need to be developed to model and predict the impacts of a reverse power condition. Upgrades in system automation will be needed to phase balance transformer connections for load and for distributed generation. As reverse power affects the feeder power factor, the placement and sizing of switched distribution capacitor banks is affected as well as distribution transformer sizing.[25]

Q. Do you agree?

A. No. Until the companies conduct hosting capacity analyses to assess the distribution systems' ability to accommodate solar DG and other DER, any conclusions about required upgrades are purely speculative. Also, utilizing smart inverter functionality is a more cost effective approach for power factor correction than installing switched distribution capacitor banks. I do, however, agree that the utilities will require new methods of modeling distribution systems to fully integrate DER into system planning, as I describe in my direct testimony.[26]

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[24] APS Resp. to VS 3.23 (Ex. CV-R-2 at 5).
[25] Carmine Tilghman Direct Test. 16:9–22 (Feb. 25, 2016).
[26] Volkmann Direct 29:5–19.

5.4 Testimony of Mr. Huber

Q. What does Mr. Huber say related to this issue?

A. RUCO witness Lon Huber states: "The general production characteristic of solar, aggregated and at high penetrations, can change system wide load shapes to create new demands on the system. Large amounts of solar without batteries can create ramping needs and fast-start backup generation requirements."[27]

Q. Do you agree?

A. To the extent that Mr. Huber indicates that his statements refer to the potential for increased ramping capabilities and fast-start backup generation requirements at high penetration levels, I agree. However, I do not believe that one can assume the need for additional system resources at current or near-term DG penetration levels.

5.5 Testimony of Mr. O'Sheasy

Q. What does Mr. O'Sheasy say related to this issue?

A. AIC witness Michael O'Sheasy states:

> The energy generated from solar DG is non-firm, which means that it cannot be relied upon by the utility as a source to serve load. Solar DG output flows onto the grid periodically depending upon the operations of the rooftop solar system and the site load requirements of the customer. This excess energy saves the utility from incurring some costs to serve, such as avoided fuel, variable operations and maintenance charges, and losses that would have occurred had the excess solar DG generated energy been otherwise produced by the utility. In addition, solar DG may impose some additional costs such as integration cost to accommodate the two-way flow of power on the distribution grid.[28]

[27] Lon Huber Direct Test. 12:1–4 (Feb. 25, 2016).
[28] Michael O'Sheasy Direct Test. 10:16–24 (Feb. 25, 2016).

Q. Do you agree?

A. Like Mr. Huber's above quoted statement, Mr. O'Sheasy's statement is correct in regard to high penetration levels of DG, though such results cannot be assumed at current levels of DG penetration. A hosting capacity analysis will determine what, if any, integration costs are required to accommodate current and forecasted levels of solar DG and DER penetration.

6 The VOS/DER methodology must properly account for reduced line losses

Q. What are line losses?

A. Line losses include technical losses from the heat and magnetic energy created by the various system components, and non-technical losses from theft or utility usage. Non-technical losses are not relevant for purposes of this discussion.

Engineers further categorize technical losses into fixed and variable losses. Fixed losses take the form of heat or noise from energized equipment and do not vary with changes in current flow. These fixed or no-load losses are a characteristic of a specific system component, such as a transformer, and utilities can only reduce fixed losses by replacing components with lower-loss units or by removing components from the system altogether.

Variable technical losses occur when electrical energy converts to heat at a rate proportional to the square of the current flowing through a system component, also referred to as I^2R losses. Variable losses are therefore lower at low levels of energy delivery and increase as current and energy flows increase. For purposes of valuing solar DG and DER, avoided variable technical losses are the most important to consider.

Variable technical losses fluctuate whenever a DER increases or decreases the load on the T&D system. The magnitude of the change in losses also depends on the interconnection point of the DER. For example, a utility-scale solar PV system connected directly to the transmission system only reduces transmission line losses. Alternatively, a residential load reduction measure reduces variable losses from the distribution secondary, distribution primary, substation, and transmission systems.

The timing of the DER load change also matters, as variable losses are proportional to the square of the current. Losses during peak periods are greater than the losses during off-peak periods. APS reports that average line losses on their system are about 7% annually, and approximately 12% at the time of peak demand.[29]

Q. Are reduced line losses important to consider in the VOS/DER methodology?

A. Yes. For the reasons I explained above, DER can alter load at or near the point of interconnection and therefore impact variable line losses.

Q. Have other parties addressed line losses in this proceeding?

A. Yes, but the APS witness testimony from Mr. Albert and Mr. Brown is conflicting. In addition, TEP/UNSE witness Dr. Overcast provides analysis of losses related to solar DG. I address each of these witnesses' testimonies regarding line losses below.

6.1 Testimony of Mr. Albert

Q. What does Mr. Albert say about line losses?

A. Mr. Albert states:

> Energy losses occur as electricity is transmitted across the grid. A portion of the electricity produced by a remotely-located power plant is lost as that electricity moves across the transmission and distribution system before arriving at the customer's premises. Because of this, there is an advantage to having generation sources like rooftop solar that are located

[29] Albert Direct 24:4–5.

> at the customer's premises. To the extent that this energy is consumed at the same site, energy losses are reduced because this power does not have to travel across the grid before arriving where it will be consumed[30]

Mr. Albert further states:

> Energy losses average about 7% over the course of the entire year and are estimated at approximately 12% at the time of peak demand. Both of these values are routinely factored into APS's load forecasts. To be clear, the values calculated for rooftop solar are higher than they would be otherwise because of the expected energy losses saved by reducing the need to transmit electricity from remotely located generation sources to the customer's site.[31]

Q. Do you agree with Mr. Albert?

A. Yes, I agree with Mr. Albert's explanation of how rooftop solar reduces line losses. I also consider the estimated losses of 7% average and 12% during peak periods to be reasonable for variable technical losses and consistent with what I have seen at other utilities.

Q. Does Mr. Albert address any uncertainty about line losses?

A. Yes. He states:

> . . . The logic that supports reduced losses is based on the actual mechanics of how electricity is transferred to customers. When energy is generated remotely, it goes through step-up transformers, is transmitted over long-distance transmission lines, gets transformed down to be put on the distribution system, and ultimately reduced to a voltage that customers can use. While this is an efficient means of transporting electricity over these distances, energy losses occur throughout this process. When the energy is generated locally, however, it doesn't go through this process. As a result, this logic concludes that locally generated energy avoids energy losses.
>
> Equally valid logic supports the opposite conclusion. Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage

[30] *Id.* at 8:26–9:5.
[31] *Id.* at 24:4–9.

> conditions. The result is higher customer energy usage due to higher voltage levels.[32]

Q. Do you agree?

A. No. Mr. Albert is attempting to link the ongoing 7-12% T&D line loss reduction from DER with the potential for increased end-use energy consumption from temporary higher-voltage conditions. These are two entirely different concepts.

Q. Is the increased energy consumption from temporary higher-voltage conditions significant?

A. APS did not provide data in response to a Vote Solar discovery request that would allow me to answer this definitively.[33] However, since these temporary higher-voltage conditions occur during the times of year when customer demand is relatively low,[34] and APS is only experiencing customer "inquiries" related to voltage on 0.34% of rooftop solar installations, I do not believe this increased energy consumption is significant. Regardless, I recommend using the 7-12% line loss reduction values in the VOS/DER methodology for APS.

6.2 <u>Testimony of Mr. Brown</u>

Q. What does Mr. Brown say about line losses?

A. Mr. Brown contradicts Mr. Albert's testimony by stating:

> Whether or not rooftop solar systems "reduce the amount of energy lost in generation, long distance transmission and distribution" is a fact specific question. It is flat wrong to claim that solar PV systems, ipso facto, reduce losses. On distribution systems, even the theory underlying this claim is controversial among experts. The truthful answer appears to be that sometimes rooftop solar reduces energy losses on the distribution system, but often does not, and, indeed, could in some circumstances actually cause more losses. The validity of the claimed loss avoidance is very situation specific.[35]

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[32] *Id.* at 24:14–27.
[33] *See* APS Resp. to VS 3.18 (Ex. CV-R-2 at 4).
[34] Albert Direct 25:11–16.
[35] Brown Direct 26:3–9.

Q. Do you agree with Mr. Brown?

A. No. While I agree that the specific level of losses is indeed situation specific, as I stated previously, I agree with Mr. Albert's explanation of how solar DG reduces T&D line losses and find APS's 7-12% loss reduction estimate reasonable.

6.3 Testimony of Dr. Overcast

Q. What does Dr. Overcast say about line losses?

A. Dr. Overcast address line losses frequently in his testimony and states: "Solar DG customers are also likely to have higher costs than their full requirements counterparts because of costs they cause that are not tracked such as higher losses from the low power factor . . . and the higher losses they cause during low load periods."[36]

Dr. Overcast also includes in his testimony an analysis conducted by TEP engineers of line losses during low load, high solar production periods.[37] Specifically, the engineers calculated the impact of one, two, and three 7 kVA solar DG systems on a typical circuit configuration of 8 homes on a single 50 kVA transformer at noon in the month of March. The analysis shows that line losses and transformer loading increase as more solar is added to the typical circuit from energy flowing back through the distribution system during low load, high solar production periods.

Q. Do you agree with this analysis?

A. I agree with the analysis, but it fails to illustrate the full impact on line losses from solar DG. During warmer, higher load periods, increasing penetrations of solar can significantly reduce line losses and transformer loading. As the TEP engineers explain in their memo: "Typically, solar can reduce losses during high demand times by lowering transformer loading and reducing current . . . . The highest

[36] Overcast Direct 50:12–16.
[37] Overcast Ex. HEO-3.

values of losses associated with residential solar generation occur when the distribution system's demand is at noon peak and solar production is at its noon peak."[38]

Q. Can you provide an example to illustrate this?

A. Yes. Using the same circuit configuration, assumptions, and calculations as the TEP engineers, Exhibit CV-R-1 shows the impact on transformer loading and line losses from one, two, and three solar DG systems at noon on a hot day. I assume each of the eight homes has a demand of 3.5 kVA and, like the TEP engineers' analysis, ignore the impacts of reactive power.[39] Below is a comparison of the TEP engineers' analysis with the illustrative solar DG impacts on a hot day.

Figure 3: Comparison of distribution line losses on cool and hot days

	Cool day		Hot day	
Solar PV Systems per Transformer	Transformer Loading	Losses (W)	Transformer Loading	Losses (W)
0	12%	22.94	56%	499.5
1	2%	44.2	42%	346.9
2	16%	107.95	28%	258.5
3	30%	228.45	14%	89.9

This shows that the magnitude of transformer loading and line loss reductions from solar DG during warmer, higher load days is much greater than the impacts during cool days. This analysis of hot day impacts is conservative, since it does not account for losses associated with reactive power and excludes the full distribution primary, substation, and transmission line loss impacts during high load periods.

Since Tucson experiences more warm days than cool days each year,[40] the line loss reductions and transformer loading relief from solar DG is a net positive, and should

[38] *Id.* at 1.

[39] Dr. Overcast has indicated that customers who install DG tend to have larger annual consumption. *See* TEP/UNSE Resp. to VS 1.16 (b), (c) (Ex. CV-R-2 at 6). Data provided by UNSE in Docket No. 15-0142 indicates that 3.5 kVA demand at noon in the summer is a reasonable assumption for larger customers.

[40] *See, e.g.*, Tucson Climate Info., Climate-zone.com, http://www.climate-zone.com/climate/united-states/arizona/tucson/ (last visited Apr. 6, 2016) (Tucson has an average or 2,954 cooling degree days and 1,678 heating degree days each year).

be fully accounted for in the VOS/DER methodology.

7 Summary of Recommendations

Q. Please summarize your recommendations for the Commission

A. I recommend that the Commission explicitly consider generation capacity and T&D benefits in the VOS/DER methodology. These benefits are real and significant, particularly if DER capabilities are explicitly integrated into distribution planning. I also recommend that the Commission require the utilities to conduct hosting capacity analyses to determine what system enhancements, if any, are required to accommodate increasing penetrations of DER. Finally, I recommend that the VOS/DER methodology fully account for the line loss reductions from DER deployment.

Q. Does this conclude your testimony?

A. Yes.

Exhibit CV-R-1

Illustrative Line Loss Calculations During Higher Load Periods

Exhibit CV-R-1

Figure 1 - Loading at noon on a hot day with no Solar Generation

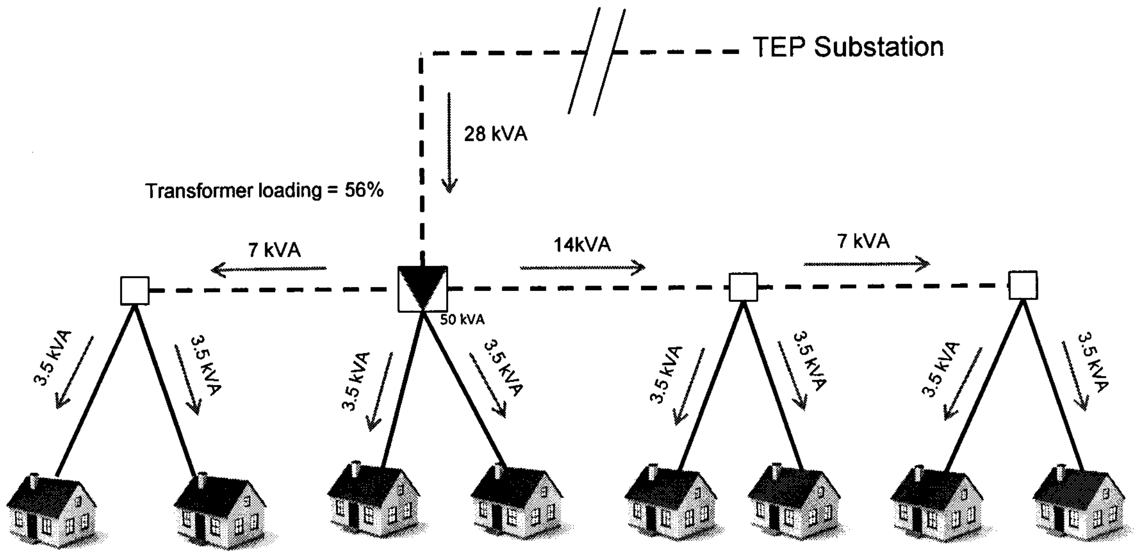
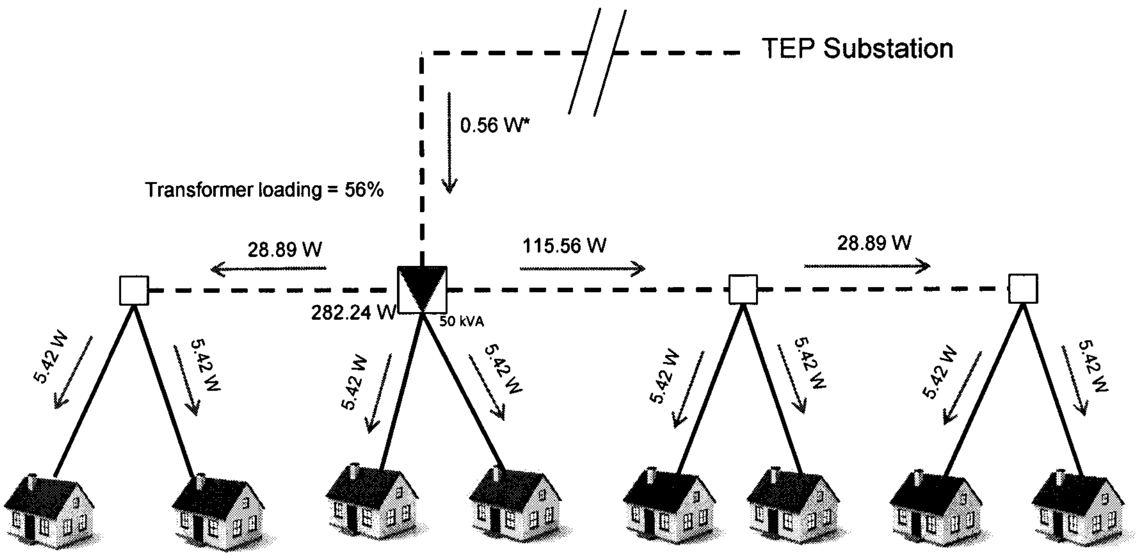


Exhibit CV-R-1

Figure 2 – Primary/secondary losses at noon on a hot day with no Solar Generation



Total primary/secondary losses = 499.5 watts

* - assuming only 400 ft. of primary conductor

Figure 3 - Loading at noon on a hot day with 1 solar customer

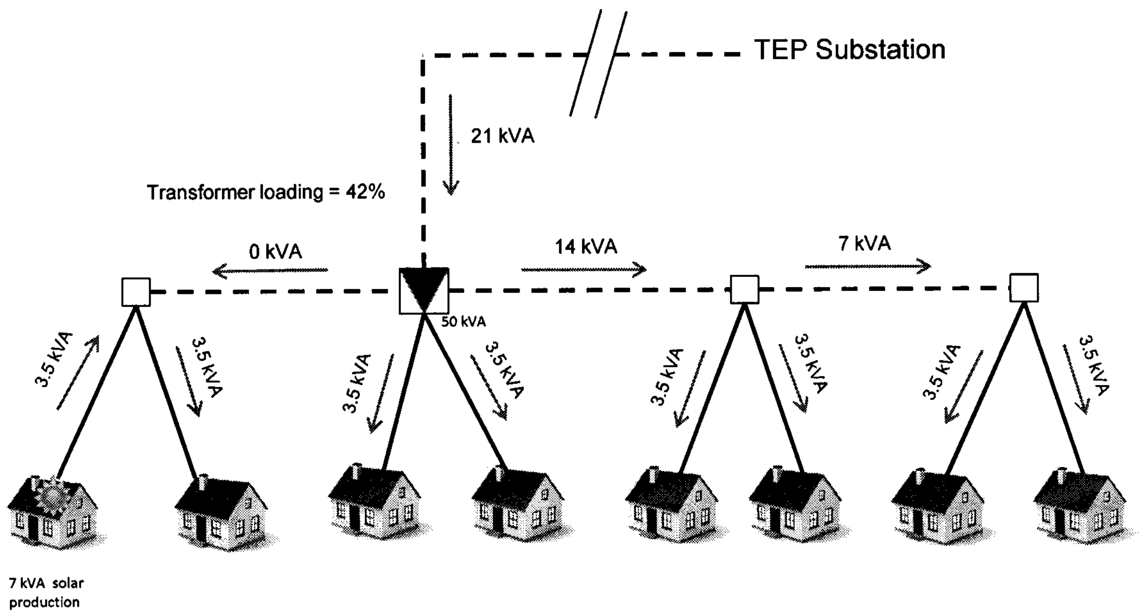
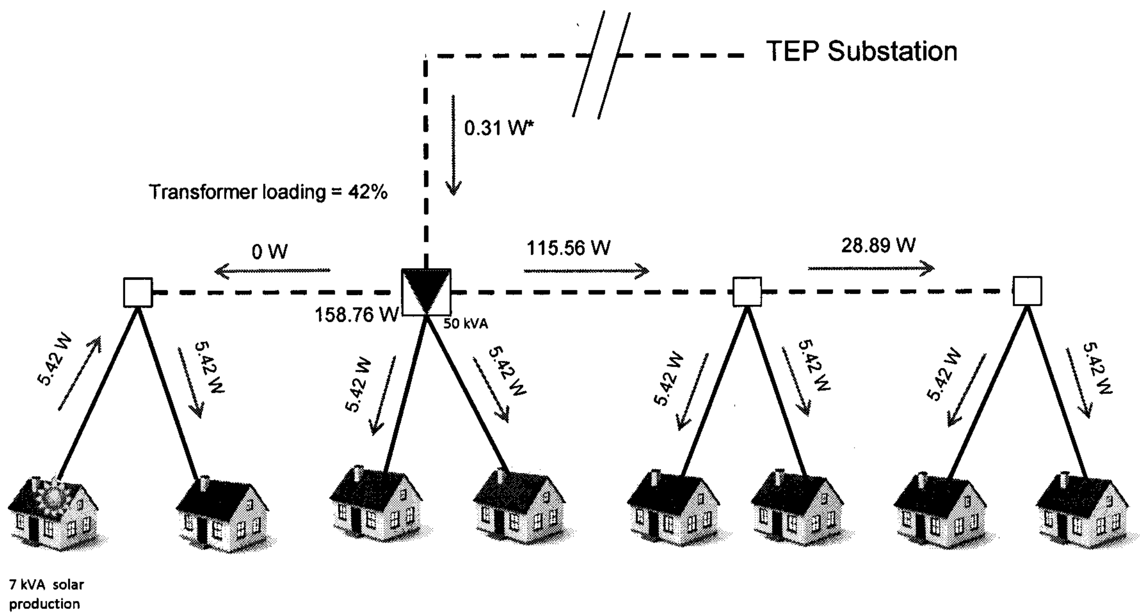


Figure 4 – Primary/secondary losses at noon on a hot day with 1 solar customer



Total primary/secondary losses = 346.9 watts

* - assuming only 400 ft. of primary conductor

Figure 5 - Loading at noon on a hot day with 2 solar customers

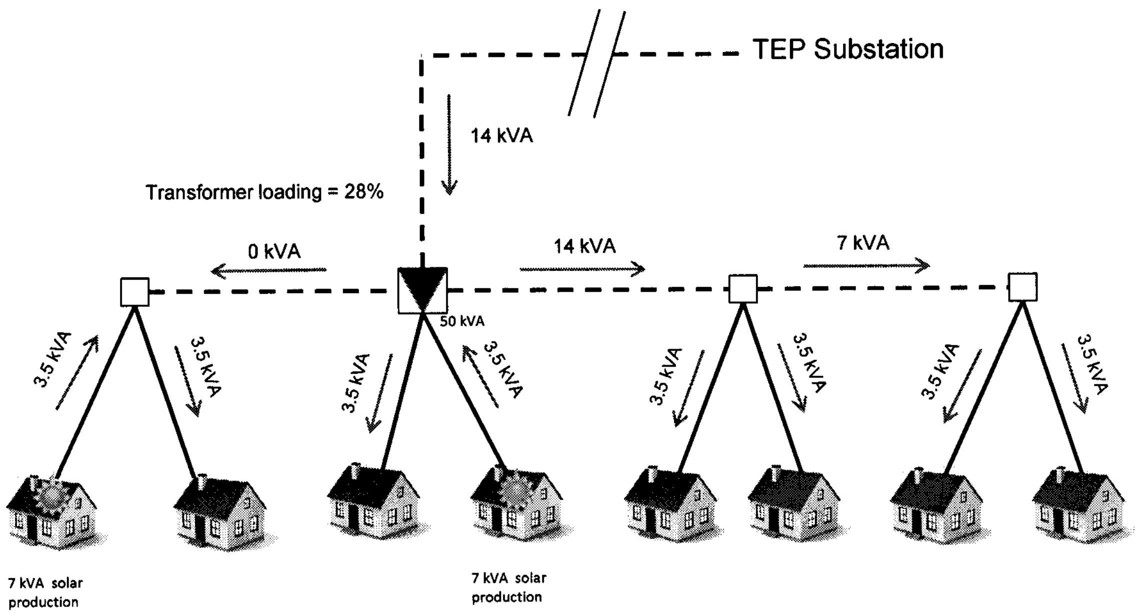
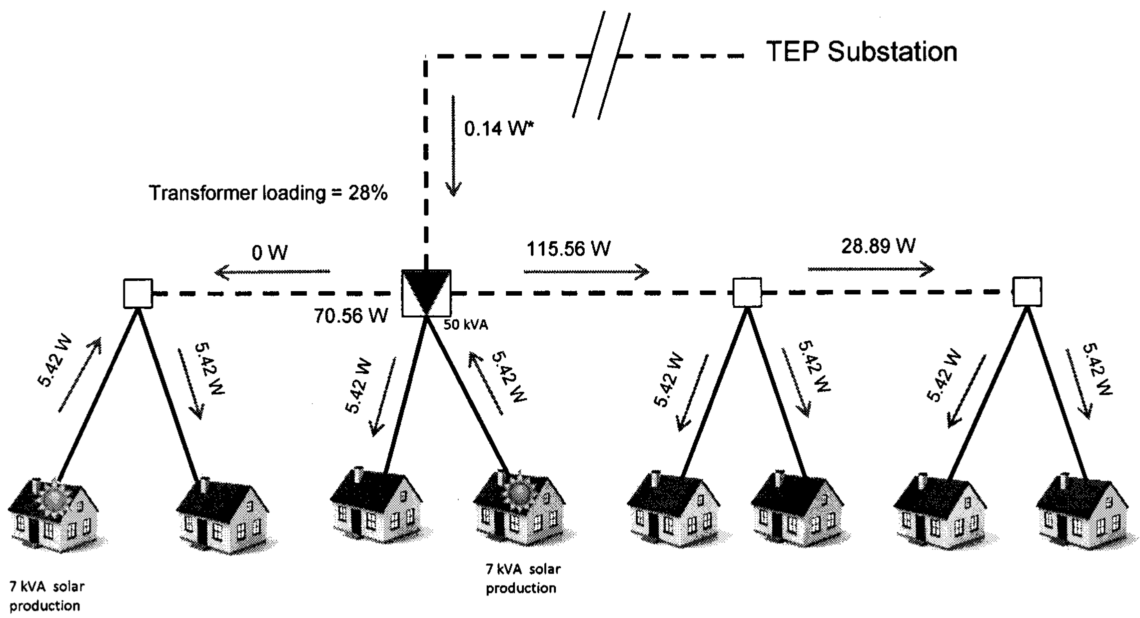


Figure 6 – Primary/secondary losses at noon on a hot day with 2 solar customers



Total primary/secondary losses = 258.5 watts

* - assuming only 400 ft. of primary conductor

Exhibit CV-R-1

Figure 7 - Loading at noon on a hot day with 3 solar customers

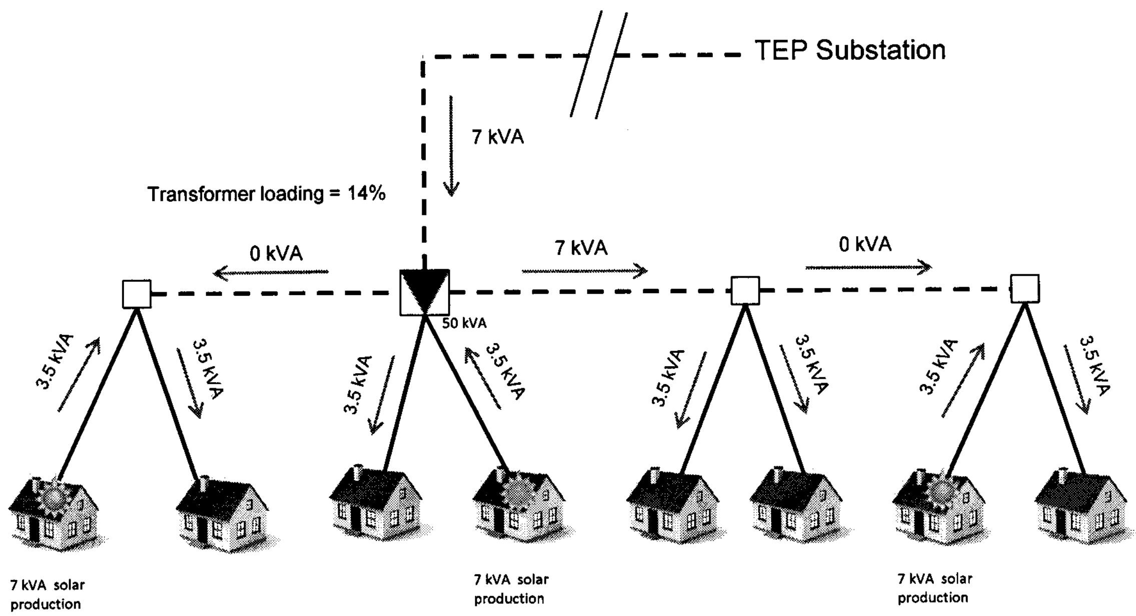
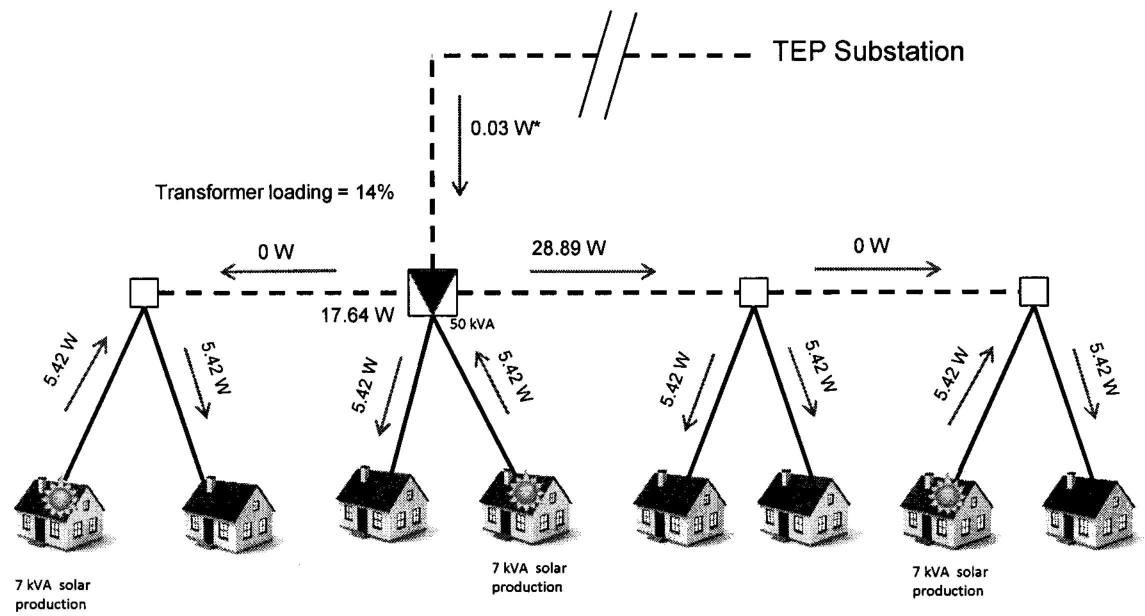


Figure 8 – Primary/secondary losses at noon on a hot day with 3 solar customers



Total primary/secondary losses = 89.9 watts

* - assuming only 400 ft. of primary conductor

Figure 9 – Summary of illustrative solar DG impacts at noon in cool and hot seasons

	Cool day*		Hot day	
Solar PV Systems per Transformer	Transformer Loading	Losses (W)	Transformer Loading	Losses (W)
0	12%	22.94	56%	499.5
1	2%	44.2	42%	346.9
2	16%	107.95	28%	258.5
3	30%	228.45	14%	89.9

* - data for cool day (March) from Overcast testimony, Exhibit HEO-3

Exhibit CV-R-2

Discovery Responses Referenced in Testimony

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.11: **Regarding the direct testimony of Mr. Snook**

Please provide a description of the program design and results to date of the Solar Partners Program (ACC Decision No. 74878) referred to on page 17, lines 20-21 of Mr. Snook's direct testimony.

Response: APS Solar Partner is an APS-owned rooftop solar research and development initiative that will help APS enable grid integration of rooftop solar and battery storage while advancing secure communications.

The key design elements of the program are as follows:

- Install rooftop solar on approximately 1,500 homes
- Systems will include smart inverters (UL listing will be achieved by the end of March 2016) and 2-way communications to control each rooftop solar site
- Install 2MW of battery storage on 2 selected feeders
- Collection and analysis of real time data on energy production, energy usage, power regulation capabilities, and curtailment options
- Validate ability to manage solar impacts by configuring smart inverters and issuing real-time commands in a cyber secure environment
- Validate ability to mitigate adverse effects of increased photovoltaic (PV) through enhanced power regulating capabilities
- Validate ability to provide ancillary services from a series of grid-tied batteries in coordination with solar inverters and traditional grid devices
- Collection and analysis of information that helps anticipate, identify, and avoid impacts on the distribution grid
- Validate distribution system models to more accurately and efficiently plan grid upgrades

The status of the program to date is as follows:

- Collaboration with research partners like the Electric Power Research Institute, or EPRI, has been ongoing since 2015, beginning with the collecting and sharing of baseline data on research feeders
- Power quality monitors were installed across the research feeders between December 2015 and February 2016 to provide feeder visibility during the project
- APS established communication and control ability with the

Response to Vote Solar 3.11 continued:

advanced inverters in January 2016

- This control feature will be activated both in the advanced inverters already installed, as well as in those units awaiting installation, starting the first week of April 2016
- Customer interest in the APS Solar Partner project is high
  - As of March 15, 2016, more than 5,300 customers have applied to participate (many more than are eligible)
  - There are currently 1600+ active applications:
    - Operational systems—468
    - Installed, awaiting activation—383
    - Approved for construction—436
    - Awaiting application review or installer assignment for site visits—319
- All systems will be installed (with advanced inverters operational) by the end of June 2016
- Research continues through December 2017

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.16: **Regarding the direct testimony of Mr. Albert**

Please provide the information requested below regarding the following statement by Mr. Albert on page 13, lines 11–15 of his direct testimony: "APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders."

a) How many APS feeders are experiencing high-voltage conditions during certain times of the year due to high penetrations of rooftop solar? What percentage of total APS feeders does this represent?

b) How many hours of the year is each feeder experiencing high voltage conditions due to high penetrations of rooftop solar?

c) Please provide details, including equipment type, locations and costs, of all additional feeder equipment installed by APS to date in response to high-voltage conditions from rooftop solar.

Response: APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. APS is currently expanding our voltage monitoring capability at all metering sites.

However, APS did receive 95 inquiries in 2015 from customers with installed rooftop solar systems specifically related to substantiated high voltage issues. These 95 customers are located on 68 separate feeders, with 12 of those inquiries on a single feeder (the highest number for any one feeder in 2015). All 12 of these high voltage instances occurred in non-summer months, when customer loads are low, rooftop solar production is high, and rooftop systems are exporting energy to the grid.

To date, APS has not incurred equipment or system costs directly attributable to high voltage concerns due to rooftop solar. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of high voltage issues will only increase.

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.18: **Regarding the direct testimony of Mr. Albert**

Please provide the information requested below regarding the following statement by Mr. Albert on page 24, lines 23-27 of his direct testimony: "Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage conditions. The result is higher customer energy usage due to higher voltage levels."

a) How many customers are experiencing high-voltage conditions during certain times of the year due to high penetrations of rooftop solar?

b) How much has energy use increased for these customers (in both total kWh and as a percentage of average annual usage) due to high-voltage conditions from rooftop solar?

Response: APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. APS is currently expanding our voltage monitoring capability at all metering sites. However, as noted in the Company's response to Vote Solar Question 3.16, APS received 95 inquiries in 2015 regarding high voltage issues from customers with rooftop solar.

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.23: **Regarding the direct testimony of Mr. Brown**

Please provide the information requested below regarding the following statements made by Mr. Brown beginning on page 35, line 25 of his direct testimony: "It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings."

a) Please provide specific examples and associated costs of adjustments and maintenance conducted by APS in response to changes in voltage flows from rooftop solar.

b) Please provide the full set of data describing the nature, timing, and magnitude of the increased transaction costs incurred by APS to execute interconnection agreements and bill rooftop solar customers.

Response: This statement is a general statement not based on specific analysis of APS data.

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
March 28, 2016

VS 1.16

Please provide the information requested below regarding the following statement by Dr. Overcast on page 17, lines 11–16 of his direct testimony: "Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers."

a. Please provide all work papers, data, and analyses to support the above-quoted statement.

b. Please indicate the rationale for the 374 customer sample size and selection and whether this sample is statistically representative of TEP's customers.

c. What is the customer class (i.e., residential, commercial, etc.) of each of the 374 customers in the sample?

d. What is the average annual kWh usage for each of the customer classes that are represented in the 374 customer sample?

RESPONSE:

a. See VS 1.16 NCP Residential Summary 13000kWh Plus.xlsx.

b. This was a sample of large users only to test customers who were larger than average since one hypothesis is that solar DG customers tend to be larger than average. The analysis was not used to draw any conclusions related to the population and just represents a subset of larger residential customers.

c. See b. above.

d. The annual average use for the residential class in the test period is about 10,700 kWh.

RESPONDENT:

Edwin Overcast

WITNESS:

Edwin Overcast

Typical loading in March at 12 PM with no Solar Generation

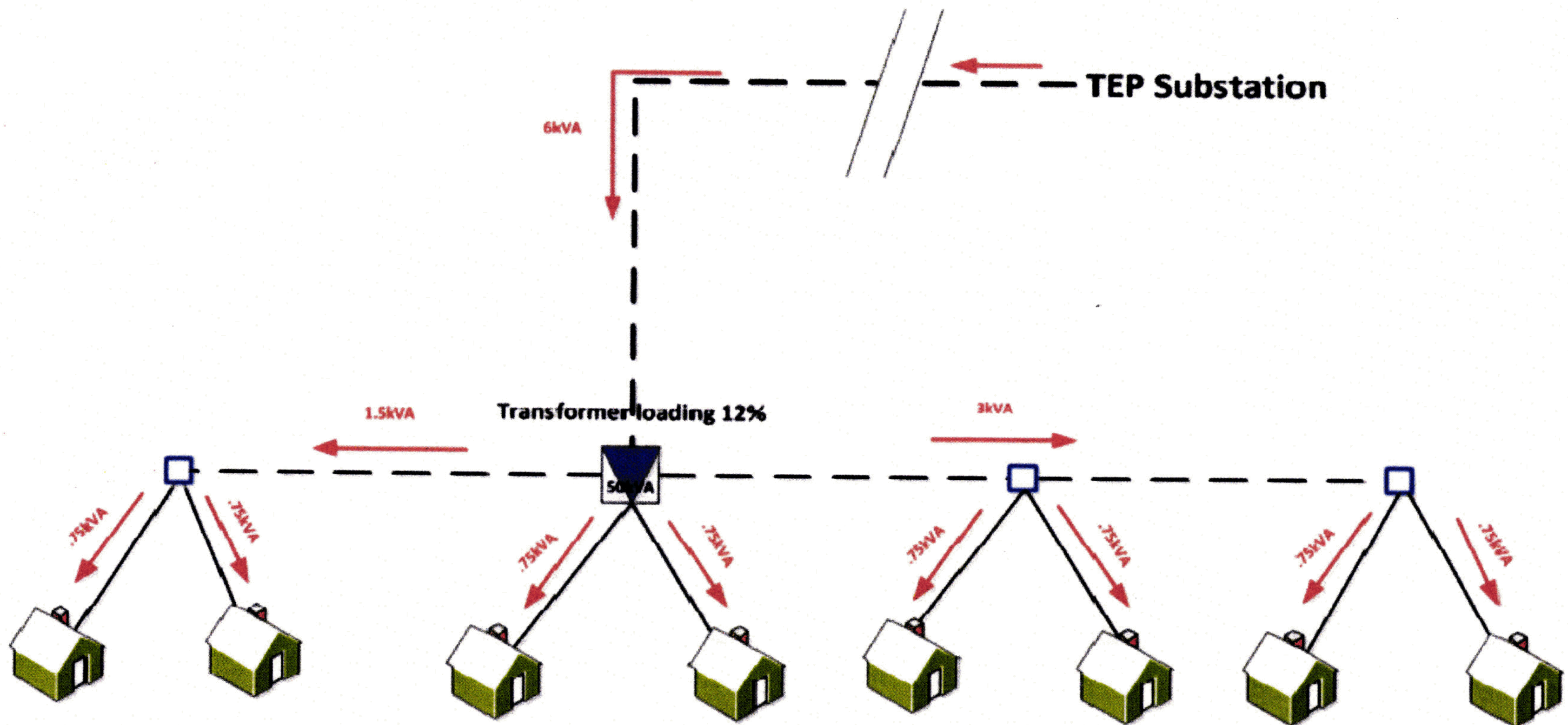


Exhibit 1

Exhibit 1 is the typical residential configuration present within TEP's distribution system. This configuration consist of 8 residential customers being served from a 50kV transformer. To find the average loading of the transformer in March at 12pm where solar production would be at its peak, DP&E collected data from 20 feeders. The average loading of the transformers at this time was found to be 12%.

Typical loading in March at 12PM with 1 solar customer

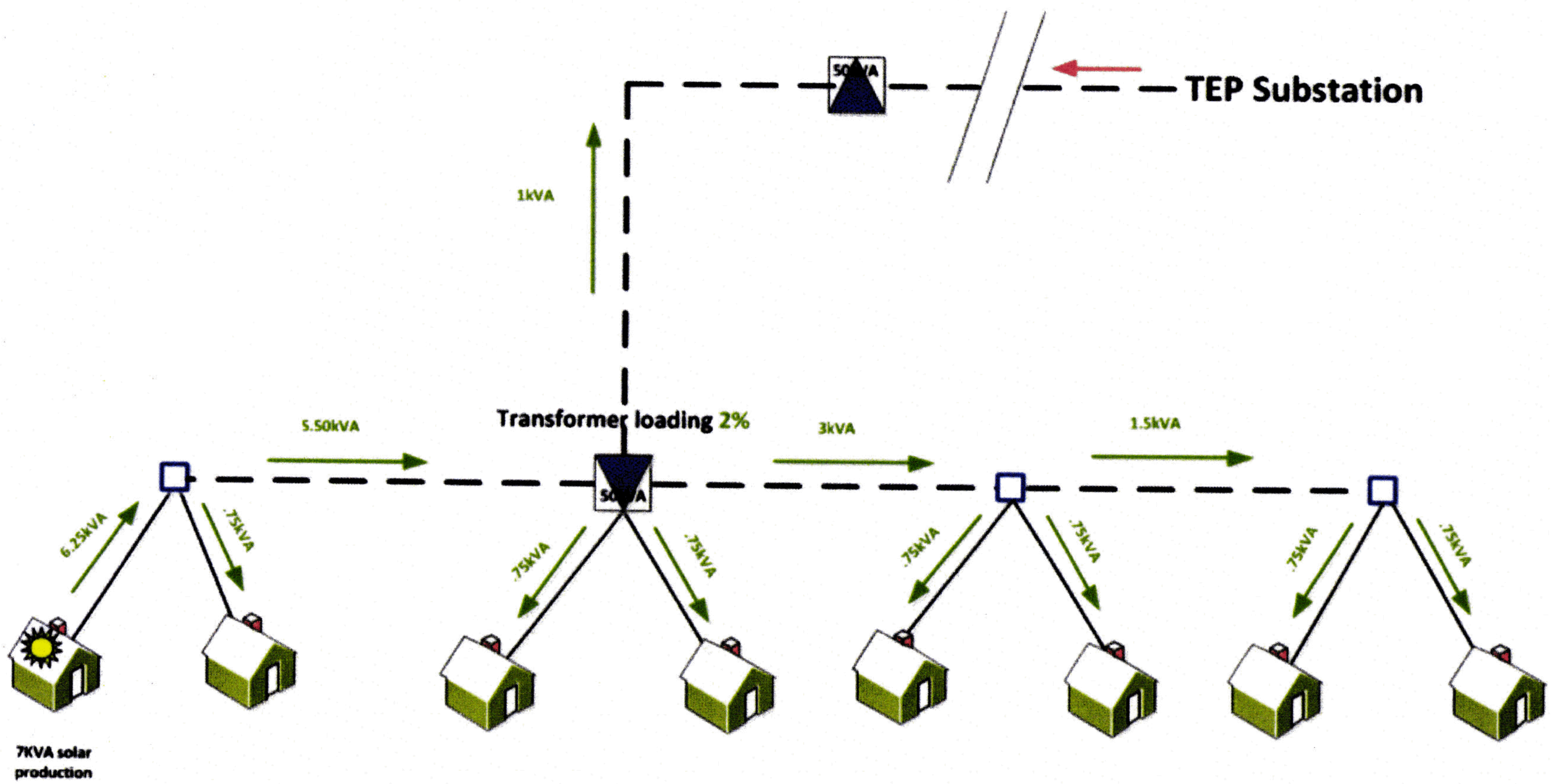


Exhibit 2

Exhibit 2 demonstrates the effects one house with solar generation can have on TEP's system. The green power flow arrows are the results of 7kVA of residential solar generation.

TEP Distribution Transformer Loading with Solar DG

(Based on typical circuit configuration and assumptions from TEP Distribution Planning and Engineering analysis in Overcast Direct Exhibit HEO-3)

7 kW Solar DG Systems

	Cool day	**Hot day**
Solar DG Systems per Transformer	Transformer Loading	Transformer Loading
0	12%	56%
1	2%	42%
2	16%	28%
3	30%	14%

(From Overcast Rebuttal Exhibit HEO-3 and Volkmann Rebuttal Figure 3)

8.75 kW Solar DG Systems

	Cool day	**Hot day**
Solar DG Systems per Transformer	Transformer Loading	Transformer Loading
0	12%	56%
1	6%	39%
2	23%	21%
3	41%	4%

Assumptions:
- 50 kVA distribution transformer
- 8 residential customers per transformer
- Maximum solar DG output occurs at noon
- Demand is 0.75 kW per customer at noon on cool days
- Demand is 3.5 kW per customer at noon on hot days

EXHIBIT
Vote Solar-7
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

DIRECT TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

FEBRUARY 25, 2016

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List of Tables and Figures

List of Exhibits

1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 360 22nd Street, Suite 730, Oakland, CA.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I serve as Program Director of Distributed Generation ("DG") Regulatory Policy for Vote Solar. I analyze policy initiatives, development, and implementation related to distributed solar generation. I also review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation.

Q. Please describe your education and experience.

A. I have a degree in Environmental Economics and Policy from the University of California, Berkeley, and I have been employed in the utility regulatory industry since 2007. Prior to joining Vote Solar in August 2015, I was employed for eight years by MRW & Associates, LLC ("MRW"), which is a specialized energy consulting firm. At MRW, I focused on electricity and natural gas markets, ratemaking, utility regulation, and energy policy development. I worked with a variety of clients at MRW, including energy policy makers, developers, suppliers, and end-users. My clients included the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and several Publicly Owned Utilities. I have experience evaluating utility cost-of-service studies, revenue allocation and ratemaking, wholesale and retail electric rate forecasting, asset valuation, and financial analyses. A summary of my background is attached as Exhibit BK-1.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. Yes. I submitted direct and surrebuttal testimony in Docket No. E-04204A-15-0142, the UNS Electric, Inc. General Rate Case. I am scheduled to testify at the evidentiary hearing in the same docket on March 15, 2016.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified in proceedings before the California Public Utilities Commission. I have testified on behalf of the Coalition for Affordable Streetlights in A.14-06-014, Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. I have also testified on behalf of the Utility Consumers' Action Network in A.14-11-003, Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2016.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony first addresses the role that long-term DG value analysis should have in policy-making and rate-setting. Second, I provide a brief summary of DG valuation in Arizona and examples of DG valuation in other states. Third, I discuss important parameters to consider when determining the most appropriate methodology for analyzing the various categories of costs and benefits that result from DG deployment in Arizona. Fourth, I recommend methodologies specific to each category of costs and benefits that should be assessed in a long-term DG value analysis. Fifth, I provide responses to the specific questions posed by Commissioner Little and Commissioner Stump in this docket. Finally, I offer recommendations for the procedure to develop a robust, standardized methodology for analysis of the long-term costs and benefits of DG, which could inform future solar policy in Arizona.

Q. What is your understanding of how this proceeding could advance the ongoing discussions related to the costs and benefits of solar in Arizona?

A. Considerable tension has built up over DG rate design in Arizona and elsewhere. I believe that developing a robust, standardized approach to evaluating the long-term costs and benefits of DG could inform future policy decisions in a balanced manner. Arizona utilities have claimed that the current rate structure causes customers who do not participate in the net energy metering ("NEM") program (i.e., "non-NEM" customers) to subsidize NEM customers. However, these claims have largely been based on short-term evaluations that inherently exclude many of the long-term value streams that accrue with additional DG deployment. Ignoring long-term benefits, while focusing primarily on short-term costs, will not result in an accurate assessment of optimal DG policy. I commend the Commission for taking up this issue in the present docket. DG is only the first of many new distributed technologies that will change the way customers interact with the grid. Development of a robust, standardized approach for DG can inform future evaluation of other distributed energy resources ("DERs") to help ensure that the transition to the modern grid happens in the most efficient and least-cost manner for all ratepayers.

Q. Please summarize your findings and recommendations.

A. I recommend that this proceeding be used to develop a robust, standardized methodology for DG valuation. In developing this methodology, I recommend that the Commission recognize that every customer should have the right to consume as much or as little electricity from the utility as they wish, regardless of whether they have installed a solar array, invested in energy efficiency measures, or purchased a larger air conditioning unit or electric vehicle. DG only differs from these other examples I mention in its ability to export energy to the electric grid. The individual customer's right to self-consume energy she generates on private property from her own private investment should be maintained. As a result, I recommend that the study of DG costs and benefits focus on evaluation of the energy that is exported from the NEM customer to the utility grid. The methodology defined by this proceeding should seek to answer one fundamental question: whether the price paid for DG exports appropriately reflects the value of the energy provided.

I recommend that the standardized methodology for valuation of DG exports examine cost-effectiveness from the perspective of non-participating ratepayers, including: impact on utility rates, incorporation of environmental impacts, improved electric reliability, and economic development benefits. If the Commission instead decides to evaluate DG consumed onsite in addition to DG exports, my recommendation regarding the appropriate cost test would change. If all DG is to be evaluated, the standardized methodology should examine cost-effectiveness using the Societal Cost Test.

In addition, I recommend that any valuation of DG exports not be limited to a certain customer class, but include valuation of exports from residential, commercial, and industrial classes. I recommend that the standardized methodology for valuation of DG exports focus on current and near-term levels of DG penetration. In addition, I recommend that the capacity benefits associated with DG be evaluated on a continuous basis to capture the unique modulatory and scalability of DG in contrast to traditional utility-scale energy resources.

I additionally recommend that the full range of costs and benefits be quantified and included in the standard DG valuation methodology. These costs and benefits include: (1) utility distributed solar costs, (2) energy generation savings, (3) generation capacity savings, (4) transmission capacity savings, (5) distribution capacity savings, (6) environmental benefits, (7) economic development benefits, and (8) grid security benefits. My testimony includes detailed recommendations on the methodology to quantify each of these categories of costs and benefits.

Finally, I recommend that the Commission require any utility requesting reform of the existing rate structure for DG to provide the necessary data for an independent, third-party analysis using the standardized methodology developed in this proceeding. The Commission should develop a stakeholder process that would allow interested parties to provide input on the independent, third-party DG export valuation. The utility should provide funding for the independent, third-party analysis that would be recoverable in rates. Because this expense would be directly related to DG, it would be appropriate to include costs of this analysis as a cost to be evaluated in the context of the DG valuation study. I recommend that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.

3 How a Full DG Value Analysis Impacts Ratemaking and Policy

Q. Please explain the relationship between DG and the utility system.

A. Customers who install DG under the NEM program install small power plants on their own properties. Rooftop solar panels comprise the vast majority of DG in Arizona, although some customers have installed wind generators as well. Customers that install DG, or "participating customers," use their small power plants to supply a portion of their own electricity needs and feed the excess energy, called "exports," into the utility distribution system. In addition to benefiting the participating customer, this private investment in energy infrastructure provides a number of benefits to utilities, other customers, and the public. The benefits of DG include environmental benefits, economic benefits, reliability benefits, and a reduced need for the utility to build new power plants and infrastructure.

Q. What is net metering?

A. Net metering is the process by which DG owners are compensated for the energy produced by their generating asset. Net metering is codified in Arizona law.[1] Under net metering, the participating customers self-consume the energy they generate. When the participating customer's energy usage is more than their DG system can supply, the utility grid supplies the customer with the balance of the needed energy. Conversely, when the energy generated by the DG system exceeds the participating customer's usage, that energy is exported to the utility distribution system.

Net metering provides a simple and easily understood means of valuing the energy exports from rooftop solar and compensating the participating customers who have invested private funds in an electricity system asset. Under net metering, a participating customer has the right to a one-to-one offset for the

[1] A.A.C. R14-2-1801(M).

excess energy produced by their rooftop solar system.[2] Both the customer's energy purchases from the utility and the excess energy they send to the grid are valued at the full retail rate per kilowatt-hour ("kWh"). This system has been adopted in most states around the country, and while this process involves an inherent approximation of the value of exports, the approximation is logical and easily understood by customers.

Q. Under net metering, where does the excess energy exported to the utility system go?

Exported energy will flow from the DG system to the nearest load.[3] The nearby customer will pay the utility the full retail rate for the energy they consume from their neighbor's DG system. Thus, the utility is both crediting the participating customer for the energy at the retail rate and receiving payment for that energy from the other customer at the retail rate.

Q. Does net metering require utilities to "bank" the participating customers' excess energy?

No. Utilities often refer to the need to "bank" excess energy on the system, but such a characterization is misleading. The utility is not required to take any active role in physically "banking" kWh, and only a minimal portion of the utility distribution system is used to carry DG exports. Rather, the entire transaction typically takes place on a single circuit and the utility only sees the transaction as a reduction in load on the circuit.

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[2] *Id.*

[3] R. Thomas Beach & Patrick G. McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California*, Crossborder Energy, 9 (Jan. 2013), http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf.

Q. What is a DG value analysis and why is it important?

A. When private citizens make investments in energy infrastructure that serves their own needs and the needs of nearby customers, those investments result in a number of benefits and costs. A DG value analysis attempts to quantify those benefits and costs, and can be used to evaluate the appropriate rate treatment for DG on a utility's system. A proper assessment of the value of DG on the system must include the full range of long-term benefits and costs that result from the private customer's investment. DG value analyses are inherently system specific and may furnish different results for different utilities. If a robust and reliable DG analysis is completed, it can provide a useful tool for decision makers to evaluate the appropriateness of different rate treatments for DG. A robust and reliable DG analysis can assist decision makers in evaluating whether the current NEM structure, including compensation for NEM exports at the retail rate, provides a reasonable approximation of the value of DG to non-participating ratepayers.

The remainder of this testimony will address the appropriate methodology for undertaking a complete and robust DG value analysis that can be used to inform future DG policy.

3.1 Only DG exports are germane to the value discussion

Q. Should the DG value analysis extend to the value of the DG that is consumed onsite by the participating customer?

A. No. The methodology defined by this proceeding should seek to answer one fundamental question: whether the price paid for DG exports appropriately reflects the value of the energy provided. While there are certainly benefits and costs associated with self-consumption of DG, these benefits and costs accrue to the participating customer and should not be considered in an assessment of the value of DG to non-participating ratepayers. Every customer has the individual right to choose how much energy to consume or not consume from the utility, regardless of whether they modify their consumption through DG, conservation, or by buying an electric car or installing a bigger AC unit.

The right to consume self-generated electricity is reflected in the Public Utility Regulatory Policy Act ("PURPA") and other laws and regulations. Customers should not be discriminated against for the technological choices they make regarding their personal energy consumption. The only thing that differentiates customers who install DG from customers who employ other forms of technology that change consumption patterns is the fact that DG systems can export energy to the grid, which will be consumed by neighboring customers. As discussed above, current Arizona law dictates that when exports are fed to the grid, the utility must compensate the participating customer for that energy at the full retail rate.

To the extent that a reduction in consumption from DG may affect fixed cost recovery by the utility, that issue is best addressed through a general rate case. In a rate case, any reduction in consumption due to DG can be considered on equal footing with other drivers of reduced consumption, such as energy efficiency, economic recession, seasonal or vacant homes, etc.

Q. Does the Commission evaluate the value of reductions in consumption from other programs, such as Demand Side Management ("DSM") programs?

A. Yes, the Commission does employ cost-effectiveness tests to examine the value of reductions in consumption from DSM programs. However, the purpose of that review is to evaluate the benefits and costs of incentives offered for DSM reductions. The DSM program is thus distinct from DG, as state incentives for DG have been phased out. The question of behind-the-meter consumption of self-generated electricity should be recognized as a personal choice available to Arizonans. The discussion should thus be limited to valuation of exports to answer the fundamental question at hand, which is whether the price paid for DG exports appropriately reflects the value of the energy provided.

3.2 The relationship between this proceeding and cost-of-service ratemaking

Q. How does an assessment of the value of DG exports relate to cost-of-service ratemaking?

A. Cost-of-service ratemaking is used for setting rates in each utility's general rate case. This approach is based on a test year, which is essentially a one-year snapshot of utility costs. Cost-of-service ratemaking focuses on current utility costs and does not account for the long-term benefits of resource supply options, like DG exports. The appropriate rate treatment for DG has caused significant controversy in Arizona in recent years, due in part to the difficulties in properly assessing the value of DG in a cost-of-service ratemaking proceeding. Utilities have claimed that DG causes a cost shift on non-participating customers. However, these claims often fail to account for the full range of benefits DG provides. Instead, the utilities' claims are largely based on results from utility cost-of-service studies, which are ill-suited to value such long-term benefits and assets.

Q. How should the valuation of DG exports be approached?

A. When discussing the appropriate means for valuation of DG exports, it is helpful to consider how other supply resources are evaluated. Utilities evaluate various supply resources through the Integrated Resource Plan ("IRP") process. This process includes an examination of utility needs and the long-term costs and benefits of various supply options. It is common practice to build or acquire power plants in the near-term, paying a large amount of fixed costs upfront. Utilities – or, more accurately, the utility's ratepayers – pay these large upfront fixed costs with the expectation that in the future, there will be a benefit from this investment.

This practice is exemplified by the 2015 acquisition of natural gas combined cycle capacity from the Gila River Power Station by Tucson Electric Power Company

("TEP") and UNS Electric, Inc. ("UNSE"). TEP's IRP explains that the utilities acquired Gila River to add capacity that would otherwise be lost by 2018 due to coal capacity reductions.[4] UNSE's most recent general rate case application describes the long-term benefits of the Gila River acquisition as a rationale for Commission approval of rate recovery. UNSE states:

> Ownership of Gila River provides numerous benefits to UNS Electric's customers, the most significant being long-term rate stability through the use of a highly efficient, combined cycle natural gas plant. [...] ownership of Gila River reduces the Company's reliance on the wholesale power markets, thus reducing risk to UNS Electric's customers by minimizing unpredictable swings in wholesale market costs.[5]

Resources, like Gila River, are selected through the IRP process based on long-term costs and benefits, rather than needs specific to the test period. Similarly, value of DG exports must take into account the costs and benefits over the resource's useful life, not a single-year snapshot.

Q. Does a cost-of-service study provide the costs of DG that should be evaluated in an analysis of the value of DG exports?

A. No. That is an important distinction to make. Cost-of-service studies are short-term, single-year snapshots of utility costs and are used to develop revenue allocation and rate design. The costs referred to in the context of valuation of DG exports are the long-term costs that result from additional DG deployment. These costs are described in further detail below, but most of these costs are related to the price non-participating ratepayers pay for exported DG over the useful life of the asset.

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[4] TEP IRP at 15, 2013-2014 Resource Planning and Procurement, No. E-00000V-13-0070 (Ariz. Corp. Comm'n Apr. 1, 2014), Barcode No. 0000152206.

[5] UNSE Application at 6:26-7:10, UNSE General Rate Case, No. E-04204A-15-0142 (Ariz. Corp. Comm'n May 5, 2015), Barcode No. 0000161983.

3.3 Potential outcomes and implications of this proceeding

Q. If rates are set through cost-of-service ratemaking, how could decision makers use the results of the analysis guided by this proceeding?

A. If this proceeding results in the development of a robust, standardized methodology for analysis of the value of DG exports, it would make significant progress in easing the tension that has developed over solar rate design in Arizona. This tension has built up in part because cost-of-service ratemaking, by design, does not capture the long-term benefits of a resource like DG. Results from a robust valuation of DG exports will be able to tell the Commission whether the long-term impacts of the NEM policy result in net benefits or net costs, and thus whether DG exports are properly valued under net metering. If the long-term analysis of DG results in net benefits, the Commission should continue to run net metering programs at the full retail rate. Conversely, if a robust valuation of DG exports shows that net value of DG is a net cost, then the Commission can consider whether it would be appropriate to modify the NEM rules and develop an alternative export rate.

Absent a robust and reliable value of solar analysis, the utilities will continue to ask for rate modifications based on the short-term cost-of-service cost shift argument. If the Commission approves this short-term view without considering the long-term benefits, the result will be more expensive for all ratepayers and for society.

Q. Why would it be more expensive for ratepayers and society to consider only the short-term picture captured by a cost-of-service study?

A. If DG provides net benefits but the Commission approves rates based on cost-of-service ratemaking, the Commission may leave those benefits on the table based on an unreasonably narrow view of DG's costs and benefits. DG provides significant benefits, including offsetting the need for additional generation, transmission, and distribution infrastructure. DG also provides a number of environmental and economic development benefits that should not be ignored simply because they do not fit the historical mold of cost-of-service ratemaking.

The fundamental operation of the distribution grid is changing with the increasing availability of new technologies like DG, energy storage, demand response, and electric vehicles. If utilities continue to ignore the fact that DG and other DERs have the real potential to offset the need for additional generation, transmission, and distribution infrastructure, the result will be less efficient and more costly for all ratepayers. In a recent report from the Lawrence Berkeley National Laboratory ("LBNL"), economists found that "DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs . . . ."[6]

DG is only the first of many DERs to force utilities to confront these issues. The transition to the modern grid is already happening and will continue to accelerate as prices for photovoltaic generators, distributed energy storage, electric vehicles, and other technologies continue to decrease. As we look to greater deployment of increasingly complex technologies, the task at hand in this proceeding becomes even more important. Now is the time to standardize the way of valuing DG and to support future valuation of other DERs. Vote Solar commends the Commission for taking up this important issue in this docket.

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[6] *See* Steve Corneli and Steve Kihm, *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future*, Lawrence Berkeley Nat'l Lab., 1 (Nov. 2015), https://emp.lbl.gov/sites/all/files/lbnl-1003823.pdf.

4 History of Solar Cost-Benefit Analysis in Arizona

Q. Have distributed solar cost-benefit analyses been completed for any regulated Arizona utilities in the past?

A. Yes. A series of cost-benefit analyses have addressed the value of distributed solar energy on the Arizona Public Service Company ("APS") system. To my knowledge, no public studies have examined the value of distributed solar energy on the TEP or UNSE systems.

Q. What were the results of the APS analyses?

A. The results were extremely mixed. The first analysis was commissioned by APS and completed in 2009 by consultant R.W. Beck.[7] In 2013, APS commissioned an update to the 2009 study which was completed by SAIC, the company that had acquired R.W. Beck.[8] Also in 2013, Crossborder Energy completed an alternative cost-benefit analysis commissioned by the solar industry.[9] Each of these studies developed significantly different results, which are summarized in Table 1 below.

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[7] R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study*, R.W. Beck (Jan. 2009), http://files.meetup.com/1073632/RW-Beck-Report.pdf (R.W. Beck Report).

[8] SAIC, *2013 Updated Solar PV Value Report*. SAIC (May 10, 2013), https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf ("SAIC Report").

[9] R. Thomas Beach & Patrick G. McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, Crossborder Energy (May 8, 2013), https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.

Table 1: Results of Existing APS DG Solar Valuation Studies

Study Author and Year	Present Value of Distributed Solar (¢/kWh)
RW Beck, 2009	7.91 to 14.11
SAIC, 2013	3.56
Crossborder Energy, 2013	21.5 to 23.7

As Table 1 shows, the results from the three studies of APS's territory are very different. The first APS-commissioned study found that distributed solar had a value of roughly 8-14¢/kWh. Three years later, APS commissioned an update to that study, which found that values were less than half of the lower range of the original estimate. Meanwhile, a solar industry-sponsored study that relied on much of the same data as the APS update found values to be roughly double the original 2009 estimate. Such a large variation in results can be problematic for policy makers to use as a basis for decision-making.

The experience with distributed solar valuation analyses in APS territory illustrates the need for Commission guidance regarding the appropriate methodology for developing a comprehensive assessment of the full range of costs and benefits from distributed solar generation.

Q. Have any other states commissioned their own value of distributed solar analyses?

A. Yes. A number of notable studies have been sponsored by independent state entities. Each of these studies concluded that the benefits distributed solar generation provides to the utility exceed the costs. Table 2 below summarizes the results of recent studies performed by or for state governments.

Table 2: Recent Distributed Solar Valuation Studies

State	Date	Sponsor	Resulting Value
ME	Mar-2015	Legislature	33.7¢/kWh levelized[10]
VT	Nov-2014	Legislature	23.7¢/kWh levelized[11]
MS	Sep-2014	PSC	17.0¢/kWh levelized[12]
NV	Jul-2014	PUC	18.5¢/kWh levelized[13]
MN	Jan-2014	Dep't of Commerce	14.5¢/kWh levelized[14]

As the studies in Table 2 demonstrate, state-sponsored studies have found that the benefits of solar can be as high as 25-30¢/kWh in some jurisdictions. While each of these studies employed different variations in methodology, the results of these studies indicate that a good faith undertaking to capture the full range of benefits of distributed solar generation may result in a valuation of solar above the retail rate.

[10] Clean Power Research, LLC, *Maine Distributed Solar Valuation Study*, Me. Pub. Util. Comm'n, 6 (Mar. 1, 2015), http://www.ripuc.org/eventsactions/docket/4568-WED-Ex6-MaineSolarReport(11-23-15).pdf.
[11] Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, 17 (Nov. 7, 2014), http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.
[12] Elizabeth A. Stanton, et al., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*, Synapse Energy Econ., Inc., 43 (Sep. 19, 2014), http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.
[13] Energy and Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation*, Energy and Envtl. Econ., 93 (July 2014), http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study ("E3 Report").
[14] Peter Fairly, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

5 General Methodological Approach to Valuation of DG Exports

Q. Are there any independent reports that the Commission should look to for guidance regarding the appropriate methodology for valuing distributed generation?

A. Yes. The Interstate Renewable Energy Council ("IREC") has developed a useful guidebook on calculating the costs and benefits of distributed solar generation that can inform the Commission's process. This guidebook is attached as Exhibit BK-2. The guidebook builds on experiences throughout the country to propose a standardized and reliable approach to the analysis. Many of my recommendations in this testimony are informed by the IREC guidebook, and I recommend that the Commission adopt the guidebook's approach in Arizona.

Q. Do you have any recommendations regarding the general methodological approach for valuation of DG exports?

A. Yes. A number of factors are important to consider regarding the general methodological approach for valuing DG exports. These include the following recommendations, which are each addressed below:

- Use an appropriate cost-effectiveness test;
- Analyze all distributed solar generation, both residential and commercial/industrial;
- Require utilities to provide sufficient and reliable data;
- Use an appropriate timeframe that analyzes value over the life of a DG system;
- Use an appropriate discount rate;
- Use a realistic near-term forecast of DG penetration;
- Analyze capacity benefits on a continuous basis.

5.1 Use an appropriate cost-effectiveness test

Q. Do you have any recommendations regarding the cost-effectiveness test to be used in the analysis?

A. Yes. A fundamental component of the analysis is from whose perspective the costs and benefits of DG should be measured. As discussed above, the analysis should ultimately seek to answer the question of whether the price paid for DG exports appropriately reflects the value of the energy provided. To this end, it is most reasonable to examine whether non-participating customers are paying a fair price for DG exports, based on the value of DG to the non-participating ratepayer, including impact on utility rates and incorporation of environmental, economic development, and grid reliability benefits. If the Commission instead decides to evaluate DG consumed onsite in addition to DG exports, I recommend that the Commission evaluate DG from a societal impact perspective.

California has developed a "Standard Practice Manual" for examining the cost-effectiveness of demand-side programs; this manual is widely used across the country as a framework for discussing specific valuation approaches.[15] While the cost-effectiveness measure I advocate for in evaluating the value of DG exports is not directly defined in the Standard Practice Manual, it could be considered a modified version of the Ratepayer Impact Measure ("RIM") test, plus adders from the Societal Cost Test ("societal adders"). The RIM test would capture the impact of DG exports on utility rates and the societal adders would allow for necessary incorporation of other benefits.

[15] Cal. Pub. Util. Comm'n, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Cal. Pub. Util. Comm'n (Oct. 2001), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7741 ("SPM").

The RIM test is defined in the Standard Practice Manual as follows:

> The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[16]

In Commissioner Little's letter to the parties in this docket, he asked questions about whether or not the cost of photovoltaic ("PV") panels should be considered in the analysis.[17] Examining the value of DG exports from the perspective of non-participating ratepayers excludes the cost of PV panels from the equation. The question is whether the price paid by non-participating customers is fair, given the value they receive from DG systems' exported energy. The goal of this process is to develop a framework to ensure that an appropriate price signal is sent to customers to help them decide whether or not to install DG. The price of PV panels will likely weigh heavily into that equation, but the economics for the customer who installs solar do not impact the value of the exports to his/her neighbors.

Q. What are the societal adders that you recommend be included in the analysis?

A. The RIM test defined in the Standard Practice Manual takes a very narrow look at the impact a program will have on utility rates. This approach does not include a number of other very real benefits that will accrue to non-participating ratepayers and to society in general. These benefits include environmental impacts, improved electric reliability, improved system operations, and economic development benefits. I recommend that the Commission consider these benefits, in addition to the standard RIM test categories, when valuing the costs and benefits of DG exports.

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[16] *Id.* at 13.

[17] Commissioner Little's Letter to the Parties at Question Nos. 2 and 3, Dec. 22, 2015.

Q. Has the Commission ever taken these types of societal adders into account when evaluating the cost-effectiveness of its programs?

A. Yes. Commission rules regarding cost-effectiveness testing for DSM programs require that the societal test be used to determine cost-effectiveness.[18] Moreover, the rules specifically address the inclusion of environmental impacts, improved electric reliability, and improved system operations.[19]

Q. If Commission rules require use of the Societal Cost Test for DSM programs, should the Societal Cost Test be used for DG exports?

A. As I have discussed above, the cost-effectiveness evaluation for DSM is used to inform the level of incentives for programs that result in reductions in customer consumption. I recommend that the methodology developed in this docket be limited to an analysis of the value of DG exports, which is different than DSM, because it excludes the energy consumed onsite by the customer who has installed a DG system. Valuation of the DG exports should only be examined from the perspective of the non-participating ratepayer, including impact on utility rates and incorporation of environmental, economic development, and grid reliability benefits.

Q. Does your recommendation for the cost-effectiveness test change if the Commission decides to examine the costs and benefits of both the DG that is consumed onsite and the DG that is exported to the grid?

A. Yes. While I strongly recommend that the Commission develop a methodology to value only DG exports, if the Commission decides to additionally value the DG that is consumed onsite, the modified RIM test with societal adders would no longer be the appropriate cost-effectiveness test for the analysis. If the Commission elects to examine the value of onsite DG consumption, the most appropriate cost-effectiveness test would be the Societal Cost Test consistent with

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[18] A.A.C. R14-2-2412(B).
[19] *Id.* at (C).

the Commission's approach for valuation of DSM programs. This test would take into account the benefits that accrue to the participating customers, in addition to the benefits that accrue to non-participating ratepayers.

5.2 Analyze all distributed solar generation, both residential and commercial/industrial

Q. Do you have any recommendations regarding the type of DG that should be considered in the analysis?

A. Yes. In order to capture the full range of costs and benefits of DG, it is crucial that the analysis be comprehensive and not limited to DG within a specific customer class. In other words, attempts to limit the analysis to an examination of the costs and benefits of residential DG ignores the costs and benefits of commercial and industrial DG. This is because residential customers have a much larger portion of their costs recovered through the volumetric portion of their rate, and thus receive a higher per kWh credit for their DG exports. Commercial and industrial customers generally have demand charges in their rates that reduce the volumetric rate, dampening the price signal for energy from the DG system. The result is that the net benefits per kWh of DG may be smaller for residential customers than for commercial and industrial customers, where the benefits more clearly outweigh the costs.

Commission policy addresses both residential and commercial/industrial DG, and therefore it is prudent that both be considered in this docket. Arizona's RES rules call for specified levels of DG from both residential and commercial sectors.[20] In order to gain a full understanding of the value of DG exports, all rate classes must be considered.

[20] A.A.C. R14-2-1805(D).

5.3 Require utilities to provide sufficient and reliable data

Q. Do you have any recommendations regarding data from the utilities for the valuation of distributed solar generation?

A. Yes. Many aspects of this analysis require data that can only be supplied by the utilities. In order to complete a reliable and comprehensive analysis, the utilities must provide stakeholders with access to that data for review. The necessary data include customer usage and distributed solar generation data from the utilities' existing NEM and non-NEM customers, a reliable and transparent forecast of future utility rates, hosting capacity analyses, and inputs required for a detailed marginal cost study valuing transmission and distribution capacity.

This issue is of the utmost importance for ensuring that the valuation can provide a credible basis for decision-making. To the extent that the utilities may seek to modify existing NEM structures, they have the burden of proof regarding new or additional charges.[21] In its current rate case, UNSE has proposed wide-sweeping changes to net metering rates, but has not provided intervenors with actual data on the consumption patterns of customers on their system with distributed solar.[22] This lack of cooperation and critical data makes a reliable assessment difficult. The Commission should require the utilities to produce needed data as a precursor to asking for reform of existing rate structures.

5.4 Use an appropriate timeframe that analyzes costs and benefits over the useful life of a DG system

Q. Do you have any recommendations regarding the time scale of the analysis?

A. Yes. I support Commissioner Little's guidance indicating that the analysis should examine the levelized costs and benefits of DG over the economic life of the

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[21] A.A.C. R14-2-2305.

[22] *See* Direct Test. and Exs. of Briana Kobor at 47-50, UNSE General Rate Case, No. E-04204A-15-0142 (Ariz. Corp. Comm'n Dec. 9, 2015).

system.[23] This is generally considered to be twenty to thirty years. This approach is inherently distinct from cost-of-service ratemaking, which looks at a single test year and is consistent with the methodologies used for evaluating other generation technologies.

5.5 Use an appropriate discount rate

Q. Do you have any recommendations regarding the discount rate to be used in the analysis?

A. Yes. The chosen discount rate is a crucial assumption in a levelized cost analysis. The discount rate is used to quantify the time value of money by looking at how the value of costs and benefits change over the time period of the analysis, which in this case should be twenty to thirty years. Utilities generally advocate using a discount rate related to their weighted average cost of capital ("WACC") for all costs and benefits included in the value-of-solar analysis. Utility WACC, which is generally in the range of 6-9%, may undervalue future benefits and costs of distributed solar generation from the perspective of non-NEM ratepayers. To the extent that the costs and benefits are being examined from the perspective of non-participating ratepayers, the discount rate employed should be reflective of the time value of money for these ratepayers. For this purpose, it is reasonable to use a societal discount rate similar to inflation, rather than the utility WACC. While I recommend that the Commission apply a societal discount rate to all the categories of benefits and costs, at a minimum the societal discount rate should be applied to the categories that are separate from utility costs, including environmental benefits, economic development benefits, and grid security.

[23] Little Letter at 2.

5.6 Use a realistic near-term forecast of DG penetration

Q. Do you have any recommendations regarding the level of DG penetration to be considered in the analysis?

A. Yes. The amount of DG on a utility's system can significantly impact the costs and benefits of DG, and the cost/benefit equation can therefore change as DG penetration levels increase. The valuation of DG exports will be most relevant if it examines current and/or near-term expected penetration levels on the utility's system. The Commission can additionally consider requiring that the valuation of DG exports be revisited when DG penetration reaches a certain point.

While the utilities have claimed that DG causes significant grid impacts, the impacts are likely minimal at current penetration levels.[24] While Arizona is a leading solar state, DG still accounts for only a small proportion of total energy supplied by the utilities. While it can be informative to examine the value of DG exports at higher levels of penetration, the economics of DG at high penetration levels does not impact the economics of DG at current and near-term levels, and therefore should not influence current policy. For purposes of this analysis, I recommend DG exports be evaluated at penetration levels expected to occur in the next one to three years and that valuation be revisited periodically as the market grows.

[24] *See* Direct Testimony and Exhibits of Curt Volkmann on behalf of Vote Solar at 8:24-9:15, Feb. 25, 2016 (discussing integration costs).

5.7 Analyze capacity benefits on a continuous basis

Q. Do you have any recommendations regarding the general approach to valuing the capacity benefits of DG exports?

A. Yes. Valuing the capacity benefits of DG requires an analysis of avoided generation, transmission, and distribution capacity. These capacity benefits should be evaluated on a continuous basis. Like the tension between using a single-year snapshot for rate setting based on cost-of-service and the need to consider long-term benefits of DG, the unique benefits associated with the modularity of DG additions do not fit the mold of traditional utility resource planning. Utility planning models typically forecast capacity that will be needed to meet increasing demand in large, "lumpy" increments, but the modularity and scalability of DG has the potential to offset or delay the need for forecasted capacity additions. Moreover, FERC regulations recognize that DG may impact future capacity needs by leading to smaller needed increments and shorter lead times.[25]

It is vital that the Commission recognize that the appropriate means for valuing avoided capacity costs related to DG exports is on a continuous basis that recognizes the modularity of DG additions and does not simply try to fit DG into the traditional planning model that cannot, by design, properly account for its benefits.

6 Recommended Approach to Valuation of DG

Q. How have you organized your testimony regarding your recommended approach to valuation of DG?

A. I describe below my recommendations for valuation of DG based on the seven core cost categories identified by Commissioner Little in his letter dated December 22, 2015. In addition to these seven categories, I also discuss

[25] 18 C.F.R. 292.304(e)(2)(vii) (2015).

recommendations for including DG benefits related to grid security. The categories to be covered in this section are listed below:

1. Utility Distributed Solar Costs;
2. Energy Generation Savings;
3. Generation Capacity Savings;
4. Transmission Capacity Savings;
5. Distribution Capacity Savings;
6. Environmental Benefits;
7. Economic Development Benefits; and
8. Grid Security Benefits

The appropriate methodology for valuing integration costs (a subset of utility distributed solar costs), transmission capacity savings, distribution capacity savings, water usage impacts (a subset of environmental benefits), and grid security benefits is covered in detail in the direct testimony of Curt Volkmann, filed in this docket on behalf of Vote Solar. In the sections below, I refer to Mr. Volkmann's testimony on these topics.

6.1 Utility distributed solar costs

Q. Please describe the utility distributed solar costs that result from DG exports.

A. There are two categories of utility costs resulting from DG exports that should be included in the DG value analysis: (1) cost to provide participating ratepayers with credits for exported generation, and (2) net integration costs.

The cost incurred to provide participating ratepayers with credits for exported generation is by far the largest cost to be assessed. Under the NEM program, participating ratepayers are credited for the kWh they export to the grid on a one-to-one basis with the kWh they take from the grid. This means that exports are valued at the full volumetric retail rate.

Q. What methodology do you recommend for valuation of utility distributed solar costs?

A. In order to quantify the levelized costs per kWh of DG export credits, the analysis must include a forecast of utility rates over the twenty- to thirty-year timeframe of the analysis. This is an instance where it will be necessary for utilities to provide reliable and transparent data from their own systems. Utilities should provide data on the current price paid to customers for their DG exports by customer class, in addition to the utility's forecast of how those prices are expected to change over the timeframe of the analysis. Interested parties should assess the reasonableness of the utility's assumed rate escalations prior to inclusion in the DG valuation.

It should be noted that the cost for DG is a direct function of the volumetric portion of the retail rate by customer class. To the extent that significant changes in rate design are expected—such as movement toward time-varying rates or rates that include a demand charge—it would be critical to consider the impacts those changes may have on the price paid for DG exports. In the event of uncertainty over future rate design, a scenario analysis that addresses various potential rate design structures may help the Commission determine the impact of rate design changes on the value and cost of DG exports.

Integration costs and benefits are discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that hosting capacity analyses specific to each utility system be developed to assess the locational-specific costs of DG additions. I support Mr. Volkmann's recommendation.

6.2 Energy generation savings

Q. Please describe the energy generation savings that result from DG exports.

A. When participating customers install DG capacity that exports energy to nearby customers, the exported energy replaces energy that would have been generated by central station power plants and delivered over the utility's transmission and distribution system to the end-use customer. Each kWh of DG exports offsets the need for a kWh of energy generated at the marginal generation plant. The cost that would have been incurred to produce the offset kWh of energy can be considered energy generation savings.

Q. What methodology do you recommend for valuation of energy generation savings?

A. Energy generation savings should be valued by estimating the cost to produce the energy that would be offset by additional DG exports. The type of resource that will be offset by additional DG exports will depend on the individual utility and the timing and seasonality of DG exports. As a result, it will be necessary for the utilities to supply data on the current export profile of their NEM customers, which can be used to develop assumptions about the marginal generator that would serve various portions of the load expected to be served by additional DG exports.

Once the type of marginal generator or generators is identified, it will be necessary to determine the avoided cost of energy from these plants. Avoided cost of energy from a natural gas-fired plant is a function of three key inputs: (1) natural gas price, (2) heat rate, and (3) variable costs of operations and maintenance ("O&M").

While there is considerable uncertainty regarding the price of natural gas over the next twenty to thirty years, it is reasonable to develop a projection of future prices based on available information from the commodity futures trading market. I recommend that a natural gas price forecast be developed by examining available NYMEX futures trading data and extrapolating longer-term values based on publicly available forecasts, such as the twenty-five-year forecast developed by the Energy Information Administration ("EIA").[26] Market center prices would need to be converted to local burnertip prices by using futures data on basis swaps

[26] EIA, *Annual Energy Outlook 2015* (Apr. 2015), http://www.eia.gov/forecasts/aeo/.

prices, as well as estimated costs to bring the gas to generators over the local gas transportation system. Developing a forecast of long-term natural gas prices is an exercise that brings significant uncertainty to the analysis. As a result, it would be reasonable to include sensitivity analyses based on higher- and lower-than projected natural gas prices to assess how this uncertainty may impact the overall DG value analysis.

The heat rate assumption is specific to the type of plant and should reflect expected average heat rate, including accounting for long-term heat rate degradation that may occur over the period of the analysis. In addition, a reliable estimate of variable O&M must be developed and forecasted over the period of the analysis.

Because DG exports offset the need for energy at or near customer load, the calculation of energy generation savings must also include avoided line losses associated with delivering electricity from a central station generator to customer load. Line losses vary by utility and are typically about 7%, though they may be higher during periods of congestion.[27] Because line losses may vary by season and time of day, it is important that marginal line losses expected during the periods of DG exports be used to estimate the avoided line losses from DG. Because DG exports are expected to occur during heavier loading periods, estimating avoided line losses using average line loss figures would likely undervalue the benefit from DG exports. Avoided line losses must also be accounted for in the calculation of generation, transmission, and distribution capacity savings.

6.3 Generation capacity savings

Q. Please describe the generation capacity savings that result from DG exports.

A. The utility must build sufficient generation capacity to meet system peak demand, which in Arizona typically occurs in the late afternoon during the summer

[27] Ex. BK-2 at 23 of 46.

months. Because system peak demand occurs at a time when solar power is generating, energy from solar DG systems will contribute to meeting system peak. While individual DG systems may not be able to provide dependable peak capacity due to the potential for passing clouds to temporarily reduce generation, geographically diverse groups of DG systems can reliably contribute to peak capacity. This fact is widely recognized by the utilities in their IRPs, which include estimates of the levels of DG that can be expected to contribute to system peak. For example, the 2020 peak capacity assumptions from DG for APS, TEP, and UNSE are summarized in Table 3 below.

Table 3: Forecasted DG Peak Capacity Contribution, 2020[28]

Utility	Peak Capacity Contribution
APS	119 MW
TEP	41 MW
UNSE	8 MW

Because DG can reliably contribute to system peak, it can reduce or delay the need for additional capacity on the system. Delaying and/or offsetting the need for additional generation capacity will result in savings that can be attributed to DG.

Q. What methodology do you recommend for valuation of generation capacity savings?

A. As described above, evaluation of DG capacity savings from generation, transmission, and distribution must take into account the modularity of DG additions. Moreover, it must evaluate savings on a continuous basis, not based on large tranches of "lumpy" additions, as done in the R.W. Beck and SAIC reports for APS's system.

An appropriate analysis would examine the marginal benefit of additional DG capacity to delay or offset the need for future generation capacity additions. In

[28] APS IRP at 300, 2013-2014 Resource Planning and Procurement, No. E-00000V-13-0070 (Ariz. Corp. Comm'n Apr. 1, 2014), Barcode No. 0000152210; TEP IRP at 28; UNSE IRP at 20.

order to quantify this benefit, assumptions must be made regarding the generation capacity additions that would be needed but for the additional DG export capacity. Capacity cost from a new generator can be estimated by developing assumptions for capital costs, fixed O&M, and gen-tie transmission costs to develop an estimate of the $/kW of installed capacity.

Once the cost of new installed capacity is developed, the analyst must determine the level of DG export capacity that is expected to contribute to the system peak. Such a calculation may be completed using an assessment of the effective load-carrying capacity ("ELCC"). ELCC is a statistical measure of capacity that can be relied on by the utility to meet load that accounts for the intermittency associated with solar DG. The ELCC measures the load increase that the system would be able to carry while maintaining the designated reliability criteria.[29] ELCC can vary by technology. For example, single-axis tracking PV has a higher estimated ELCC than fixed-array PV. In developing the assumptions for ELCC of DG exports, it will be necessary to evaluate the expected technology of future DG additions.

With these assumptions in place, calculating the generation capacity savings of DG is a relatively simple undertaking. As discussed above, under energy generation savings, marginal avoided line losses associated with DG capacity located at or near load must be accounted for by applying an adder to the expected cost of new generation capacity. In addition, utilities are required to maintain certain levels of capacity reserve margins (e.g., 15% above peak load) to ensure reliability in the event of extreme load circumstances or unexpected outages of transmission or generation infrastructure. Dependable DG capacity will reduce the need for additional capacity to meet the reliability criteria. This reduction in needed reserves should be accounted for by developing an adder to be multiplied by the cost of new generation capacity. The resulting value is then multiplied by the ELCC to determine the generation capacity savings attributable to DG.

[29] Ex. BK-2 at 24-25 of 46.

6.4 Transmission capacity savings

Q. What do you recommend regarding assessment of transmission capacity savings?

A. Assessment of transmission capacity savings associated with DG is discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that the Commission adopt a detailed marginal cost-of-service methodology that would allow for quantification of the transmission capacity deferral benefits associated with DG. This methodology would recognize the unique benefits associated with the modularity and scalability of DG and would not be constrained by assessment of only large, "lumpy" capital projects. I support Mr. Volkmann's recommendation.

6.5 Distribution capacity savings

Q. What do you recommend regarding assessment of distribution capacity savings?

A. Assessment of distribution capacity savings associated with DG is discussed in detail in the testimony of Mr. Volkmann. Like his recommendation for evaluating transmission capacity savings, Mr. Volkmann recommends that the Commission adopt a detailed marginal cost-of-service methodology that would allow for quantification of the distribution capacity deferral benefits associated with DG. This methodology would recognize the unique benefits associated with the modularity and scalability of DG and would not be constrained by assessment of only large, "lumpy" capital projects. I support Mr. Volkmann's recommendation.

6.6 Environmental benefits

Q. Please describe the environmental benefits that result from DG exports.

A. Unlike the conventional generation that it is expected to offset, solar DG provides clean, carbon-free renewable energy. Solar DG also uses minimal amounts of water when compared to conventional generation. The categories of environmental benefits that occur as a result of DG exports include avoided utility compliance costs, avoided carbon emissions benefits, benefits related to avoided emissions other than carbon, and benefits related to water conservation. Each category warrants separate consideration and quantification in an analysis of the value of DG exports.

Q. What methodology do you recommend for valuation of avoided utility compliance costs?

A. Valuation of avoided utility compliance costs should account for the reduction in needed renewable procurement attributable to additional DG. Arizona's Renewable Energy Standard ("RES") rules require utilities to procure certain levels of renewable generation: 10% of sales by 2020 and 15% of sales by 2025.[30] Because increases in DG capacity will result in reductions in sales from the utility, DG will reduce the total amount of renewable energy that must be procured to comply with the RES rules. This will produce savings commensurate with average renewable energy cost premiums compared with the cost of conventional energy. The renewable energy cost premium can be evaluated by comparing the levelized cost of energy from conventional and renewable generation.

Q. What methodology do you recommend for valuation of avoided carbon emissions benefits?

A. The value of avoided carbon emissions benefits should be taken into account when examining the environmental benefits of DG. The value of avoided carbon emissions attributable to DG has been widely recognized in past DG valuation studies in Arizona and elsewhere. For example, both APS-sponsored DG valuation reports included a measure of carbon benefits.[31] Moreover, last year EPA finalized regulations limiting carbon emissions from coal- and gas-fired

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[30] A.A.C. R14-2-1804(B).
[31] R.W. Beck Report at 6-19; SAIC Report at 1-3.

power plants, which will require carbon reductions from Arizona's power sector. The White House has developed a standard method for evaluating avoided carbon benefits known as the social cost of carbon ("SCC").[32] I recommend that the SCC value related to emissions reductions from additional DG exports be used to estimate avoided carbon emissions benefits.

Q. What methodology do you recommend for valuation of benefits related to avoided emissions other than carbon?

A. DG will also reduce emissions of criteria air pollutants, including sulfur oxides ("SO_x"), nitrogen oxides ("NO_x"), and particulate matter. While the cost of compliance with pollution regulation is likely to be rolled into the estimate of avoided energy costs, regulations still allow some level of pollution that has been widely acknowledged to result in impacts to public health.[33] Additional consideration should be given to the value of avoiding air pollution from a societal perspective. EPA has estimated social costs of major pollutants, and I recommend that these estimates be netted against the level of compliance costs embedded in avoided energy costs in order to assess the total additional environmental benefit of DG from reduced air pollution.[34]

Q. What methodology do you recommend for valuation of benefits related to water conservation?

As Commissioner Burns described in his letter to this docket dated February 8, 2016, strong consideration should be given to the water-energy nexus in the context

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[32] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*, U.S. Gov't (May 2013), https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.
[33] Ex. BK-2 at 34 of 46.
[34] *See* U.S. Envtl. Prot. Agency, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* at Chapter 4: Estimated Climate Benefits and Human Health Co-Benefits, U.S. Gov't (June 2014), http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.

of energy planning decisions in Arizona.[35] A full discussion of the water-energy nexus is provided in Mr. Volkmann's testimony. Mr. Volkmann recommends that the Commission include a value for avoided water consumption in its valuation of the costs and benefits of DG. I support Mr. Volkmann's recommendation.

6.7 Economic development benefits

Q. Please describe the economic development benefits that result from DG exports.

A. Installation of rooftop DG solar systems requires a robust local workforce that includes installers, manufacturers, sales associates, and distribution workers. Increases in jobs provide stimulation to local economies and greater tax revenue to state and local jurisdictions. It has been found that solar PV creates more jobs per megawatt-hour ("MWh") than other energy sources, implying that additional DG capacity is likely to garner economic benefits.[36]

Q. What methodology do you recommend for valuation of economic development benefits?

A. A number of methodologies exist for quantifying the economic impact of additional jobs that would be created with additional DG capacity. Economic input-output analysis that would examine the potential multiplier affect associated with DG-related jobs is one such possible methodology. Other options include quantification of tax enhancement value resulting from increased employment.

[35] Letter from Commissioner Robert L. Burns at 1, Feb. 8, 2016.
[36] Daniel M. Kammen et al., *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?*, Renewable and Appropriate Energy Lab., 2 (Jan. 31, 2006), http://rael.berkeley.edu/old_drupal/sites/default/files/very-old-site/renewables.jobs.2006.pdf.

6.8 Grid security benefits

Q. What do you recommend regarding assessment of grid security benefits?

A. Assessment of grid security benefits associated with DG is discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that the Commission explicitly consider the reliability improvement benefits associated with DG in its valuation methodology and provides an example of how those benefits may be quantified. I support Mr. Volkmann's recommendation.

7 Response to Questions Raised by Commissioner Little in His December 22, 2015 Letter

Q. Please address the specific questions raised by Commissioner Little in his December 22, 2015 letter.

A. Answers to each of Commissioner Little's questions are provided below:

1. **How was the value and cost of solar considered in the development of the current net metering tariffs?**

The current net metering tariffs were developed as part of the Commission's RES rules to promote development of renewable DG. In developing the tariffs, it was recognized that retail rate compensation provides a reasonable approximation of the value and cost of DG for purposes of tariff design. In Decision No. 69127 approving the RES rules, the Commission stated:

> [C]ustomers who pay capital costs to install distributed generation, benefit not only themselves, but the system by not contributing to overloading of transmission lines, overheating of distribution lines, wear and stress on substations and transformers, and the need for utilities to procure or generate the most expensive peaking power during peak load times, and utility

customers who do not install distributed generation will therefore receive a benefit from distributed generation.[37]

2. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?

The answer to this question depends on the perspective from which the value proposition is examined. As described in this testimony, I recommend that the question the Commission should seek to answer is whether non-participating ratepayers are paying the right amount for the DG exports they receive. This means that the analysis should be limited to DG exports and should be evaluated from a non-participating ratepayer perspective, including impact on utility rates and incorporation of environmental impacts, improved electric reliability, and economic development benefits. Non-participating ratepayers will be indifferent as to whether the NEM customer next door spent $10,000 or $100,000 on his/her solar installation; what is important to them is whether the price paid for the exports is commensurate with the value received. As a result, the declining cost of PV panels would be irrelevant to the analysis.

3. Is it appropriate to factor the cost of the panels into the reimbursement rate for net metering? If so, how?

No. The cost of panels relative to the rate provided for solar DG exports will factor into the participating customer's decision to install DG, but is irrelevant to the core issue in this proceeding: development of a robust and standardized methodology to inform whether the price paid for DG exports appropriately reflects the value of the energy provided.

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[37] Decision No. 69127 at Appendix B p. 6, Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules, No. RE-00000C-05-0030 (Ariz. Corp. Comm'n, Nov. 14, 2006), Barcode No. 0000063561.

4. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?

There is some variation in the distribution-related value and costs of DG solar depending on location. Please see Mr. Volkmann's testimony for a full discussion.

5. How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?

There will be some variation in the avoided-energy benefit and avoided-generation, -distribution, and -transmission capacity benefit based on the orientation and technology of the DG solar system. The valuation of DG exports can take this into account by assessing how these benefits may change if differing PV orientation and technologies are deployed in the future. To the extent that westward panel orientation and/or tracking systems may result in a larger net benefit, the Commission could consider adoption of rates that vary based on time of day ("TOU rates") to incent customers to install DG systems to maximize production during the peak period.

6. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?

Storage has the potential to impact customer load profiles for customers who employ DG solar. The way in which storage would impact the value and cost of DG solar is highly dependent on rate design. If customers are fairly compensated for the energy from their DG systems, storage may incent them to maximize benefits to the grid. In contrast, if rates are designed such that customers do not receive a fair value for the energy from their DG systems, storage may enable them to minimize grid usage or defect from the grid entirely. Storage has a large potential to enable more efficient usage of the utility grid, bringing huge cost savings to all customers. The Commission should encourage deployment of storage technologies with rate designs that capture the costs and benefits that storage can provide to the grid.

7. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?

There are numerous factors that would need to be taken into consideration to appropriately compare the value and cost of DG solar with community- and utility-scale solar, other renewables, and efficiency. An important first step in any comparison would be to develop a robust methodology for fully valuing each resource. Until such a methodology is used to analyze the value of specific resources, it is difficult to compare the value and cost of these different resources.

8. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

Intermittency affects the dependable peak capacity contribution of DG solar. This is accounted for in the estimation of avoided generation capacity costs through an evaluation of the ELCC of DG solar. There is no need for an additional “intermittency factor,” as this phenomenon should be fully captured by the ELCC.

Mr. Volkmann’s testimony includes additional discussion of intermittency impacts in relation to grid integration.

9. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

Peak demand typically occurs in the afternoon during the summer, when solar provides energy and capacity. Valuation of avoided energy, generation capacity, distribution capacity, and transmission capacity costs vary based on peak demand coincidence; the methodology outlined in this testimony takes each of these factors into account. To the extent the Commission wishes to incent greater peak coincidence from DG solar, TOU rates that value energy higher during peak hours should be considered.

Mr. Volkmann's testimony includes additional discussion of peak coincidence of DG.

10. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

Please refer to Mr. Volkmann's testimony for a full discussion.

11. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?

Please refer to Mr. Volkmann's testimony for a full discussion.

12. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

It has been found that solar PV creates roughly seven to eleven times more jobs per MWh than gas- or coal-fired generation.[38] Secondary economic impacts of additional DG solar deployment should be considered in the valuation study through economic input-output modeling or quantification of tax enhancement value resulting from increased employment.

13. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

As penetration levels rise, the value and cost of DG solar may change in several ways. Large-scale deployment of solar may depress market prices for conventional energy, and large amounts of DG solar may shift the system peak. In this proceeding, it is most useful to consider the value and cost of solar based on current and near-term projected penetration levels, and to consider revisiting the analysis periodically as penetration levels increase.

14. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

Yes. Dealing with fuel price uncertainty is an inherent issue in any long-term energy resource evaluation, but the uncertainty in fuel prices does not negate the very real avoided energy costs associated with DG solar. In fact, DG solar provides the additional benefit of shielding consumers from the uncertainty inherent in fuel market pricing. As discussed in detail Section 6.2 of this

[38] Kammen et al., *Putting Renewables to Work*, Renewable and Appropriate Energy Lab., http://rael.berkeley.edu/old_drupal/sites/default/files/very-old-site/renewables.jobs.2006.pdf.

testimony, fuel price uncertainty can be addressed by looking at available forward market data and evaluating scenarios in which fuel prices are higher than and lower than expected.

15. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?

Please refer to Mr. Volkmann's testimony for a full discussion.

16. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?

Please refer to Mr. Volkmann's testimony for a full discussion.

17. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?

Please refer to Mr. Volkmann's testimony for a full discussion.

18. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?

Please refer to Mr. Volkmann's testimony for a full discussion.

19. Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?

Please refer to Mr. Volkmann's testimony for a full discussion.

20. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

Please refer to Mr. Volkmann's testimony for a full discussion.

8 Response to Questions Raised by Commissioner Stump in His February 19, 2016 Letter

Q. **Please address the specific questions raised by Commissioner Stump in his February 19, 2016 letter.**

A. Answers to each of Commissioner Stump's questions are provided below:

1. The Commission's May 7, 2014 Workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

This is discussed in response to Commissioner Little's question number 7 on page 39 of this testimony. In addition, there are a number of differences between utility-scale solar generation and DG that would need to be taken into account in order to compare resource costs and benefits. Namely, DG may have additional benefits associated with avoided line losses and capacity benefits resulting from geographic diversity.

2. Why argue that a value-of-solar proceeding is important only for resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG?

Vote Solar believes that the tension that has built up over solar rate design in Arizona is in part a function of the disconnect between short-term cost-of-service ratemaking and accounting for long-term benefits of DG. Utilities in Arizona have alleged that DG is causing a cost-shift, but these analyses are largely based on short-term evaluations that, by design, cannot fully account for the long-term benefits associated with DG. Robust valuation of DG exports can help to inform cost-of service ratemaking, as discussed in Section 3.3 of this testimony.

3. In 2014, lost fixed costs associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per-customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

Please refer to the response to Commissioner Little's question number 7 on page 39 of this testimony.

4. How do we calculate regressive social costs into the value of solar, given that non-solar utility customers subsidize solar customers?

It is Vote Solar's contention that it has not been established whether non-NEM customers subsidize NEM customers under the current rate structure. The Commission's findings have been limited by focus on short-term cost-of-service-based analysis and have not fully evaluated the long-term value and cost of DG exports. Vote Solar is hopeful that this proceeding may inform a robust, standardized methodology for evaluation of the long-term costs and benefits attributable to DG that may enable the Commission to better evaluate whether any cost shifts may occur as a result of DG in Arizona.

5. **Are solar DG users being overcompensated or undercompensated for remitting excess solar power to the utility at the retail rate?**

This is the central question to be answered by the methodology developed in this proceeding. Vote Solar is hopeful that a robust long-term evaluation of the costs and benefits attributable to DG exports will be able to answer this question.

6. **To what degree do intermittency and non-dispatchability affect the value of solar?**

Please see response to Commissioner Little's question number 8 on page 39 of this testimony.

7. **How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U.S. installation costs into a value-of-solar determination?**

Please see response to Commissioner Little's question numbers 2 and 3 on page 37 of this testimony.

8. **In value-of-solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words, are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower instillation costs? How does the cost and value of DG compare with alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that of utility-scale and community-scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility-scale or community-scale solar?**

Please refer to the response to Commissioner Little's question number 7 on page 39 of this testimony.

9. How should we go about attempting to quantify largely externalized and unmonetized factors, such as projected financial, energy security, social, and environmental benefits? How are long-term forecasts accurately incorporated into present value-of-solar calculations?

Renewable DG assets provide a number of quantifiable environmental benefits, economic benefits, and benefits to grid security and reliability. Recommended methodologies for calculating each of these factors are provided in Section 6 of this testimony.

10. Despite recognized advantages, a number of states are reexamining their traditional net metering policies and underlying rate designs. The increasingly pervasive review of conventional net metering policies by states is attributable to a multitude of trends, including decreasing solar rebate incentives, rapid encroachment of renewable portfolio standards, the realization of net metering caps, as well as raised public awareness surrounding prospective cost-shift concerns.

For instance, the Hawaii Public Utilities Commission brought an end to the state's net metering program when it cut payments to new solar customers by approximately half the going rate. Nevada alternatively reduced payments to existing solar customers from the retail to the wholesale rate and raised customers' fixed charges to cover the cost of using the grid. Moreover, the California Public Utilities Commission recently approved a NEM 2.0 successor tariff, which effectively preserves retail rate payments for residential DG systems while imposing new interconnection fees, non-bypassable charges, and a shift to time-of-use rates for DG customers.

a. Given this context, how did Hawaii, Nevada, and California value the costs and benefits of net-metered solar?

b. What analyses on the cost of solar did these states use when they changed their net metering policies in light of an acknowledged cost-

shift? Did such analyses adequately account for the costs associated with redesigning and maintaining the distribution system to accommodate DG?

c. **How would a value-of-solar methodology facilitate the successful implementation of similar updated policies in Arizona?**

Quantification of the value and costs of DG is an inherently context-specific exercise and caution should be taken in extrapolating findings from one utility service territory to another. As a result, we recommend that a robust, long-term evaluation of the costs and benefits attributable to DG exports be completed specific to any utility requesting modification to the existing NEM structure. Notwithstanding the need for system-specific analysis, there are several lessons that can be learned from the experience in other jurisdictions.

In reference to Hawaii, it is important to consider that the penetration levels of DG on Hawaii's isolated island systems are vastly larger than DG penetration in Arizona. In fact, DG currently accounts for as much as 30-53% of system peak on Hawaii systems.[39] The experience in Hawaii highlights the strength of the NEM policy, which was kept in place until DG penetration reached much higher levels of penetration than is expected in Arizona. The Hawaii Public Utilities Commission's order states the following:

> The commission has determined that DER policies and programs in Hawaii must evolve to meet changing customer and utility system needs. <u>This is in sharp contrast to the attempts in other states to alter or limit net metering *before* customer sited renewables have had the opportunity to scale or have resulted in significant technical integration challenges</u>. The NEM program has fulfilled its core objective of providing a simple and effective tool to jumpstart the adoption of distributed renewable energy. As a corollary, this policy also moved the DER industry in Hawaii past the early stages of development. Hawaii's electric utilities and the DER industry are now adapting to technical challenges not yet experienced in

[39] Decision and Order No. 33258 at 160, Instituting a Proceeding to Investigate Distributed Energy Res. Policies, No. 2014-0192 (Haw. Pub. Util. Comm'n, Oct. 12, 2015).

other jurisdictions, while developing advanced solutions that, in some cases, have not yet been tested in operating power systems.[40]

In addition, even with such large levels of DG penetration, Hawaii has continued to embrace solar development. The state recently passed legislation directing the utilities to generate 100% renewable power by 2045 and to promote deployment of additional distributed PV through community solar projects.[41]

Additional lessons can be learned from the recent developments in Nevada. In 2014, the Public Utilities Commission of Nevada ("PUCN") commissioned a study to evaluate the long-term costs and benefits of DG. A stakeholder process was convened to select an independent, third-party to complete the analysis and the results indicated that long-term benefits attributable to the NEM program exceeded costs, benefitting Nevada ratepayers by a total of $36 million.[42] Despite these findings, the PUCN recently approved a proposal to single out NEM customers for punitive rate treatment.[43] This approval was based only on a short-term evaluation of utility cost-of-service, and failed to take into account any long-term benefits attributable to DG. In addition, Vote Solar contends that the utility-sponsored cost-of-service study presented in the docket was flawed and should not have been relied on. It is notable that the PUCN decision on NEM changes has caused significant controversy and economic impacts in the state of Nevada. As a result of the PUCN decision, major solar companies have eliminated jobs in Nevada, putting hundreds of people out of work.[44]

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[40] *Id.* at 161-162 (emphasis added).

[41] *Governor Ige Signs Bill Setting 100 Percent Renewable Energy Goal in Power Sector*, Governor of the State of Haw. (June 8, 2015), http://governor.hawaii.gov/newsroom/press-release-governor-ige-signs-bill-setting-100-percent-renewable-energy-goal-in-power-sector/.

[42] E3 Report at 93.

[43] Order, Application of NV Energy for approval of a cost-of-service study and net metering tariffs, Nos. 15-07041 and 15-07042 (Nev. Pub. Util. Comm'n, Dec. 23, 2015).

[44] Sean Whaley, *Utility regulators reject call to delay new rooftop-solar rates*, Las Vegas Review-Journal (Jan. 13, 2016, 10:52 AM), http://www.reviewjournal.com/business/energy/utility-regulators-reject-call-delay-new-rooftop-solar-rates.

Finally, the California process included evaluation of the long-term costs and benefits of solar DG through a publicly-vetted process that allowed stakeholders to suggest appropriate modifications and inputs to the valuation tool. Based on the evidence developed in the proceeding, the California Public Utilities Commission determined that it was appropriate to continue full retail-rate net metering for DG in California.[45] In addition, California has taken the lead in planning for DERs through various processes discussed in detail in the testimony of Mr. Volkmann.

9 Recommendations

Q. Please summarize your recommendations.

A. I recommend the following:

- The Commission should develop a robust, standardized methodology for valuation of DG that can be employed to develop specific findings for each Arizona utility.
- Because customers have the right to self-consume the energy they generate on their own private property as a result of private investments, DG valuation studies should be limited to DG exports.
- This proceeding should seek to answer the question of whether the price paid for DG exports appropriately reflects the value of the energy provided.
- The standard methodology should include the following requirements:
    - If only DG exports are evaluated: use a modified RIM test plus societal adders;
    - If DG consumed onsite is evaluated in addition to DG exports: use the Societal Cost Test;
    - Examination of commercial and industrial DG, in addition to residential DG;

[45] Decision 16-01-044 Adopting Successor to Net Energy Metering Tariff, Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, Rulemaking 14-07-002 (Cal. Pub. Util. Comm'n, Feb. 5, 2016), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K285/158285436.pdf.

- Analysis on the basis of levelized cost of electricity as examined over useful life of a DG system;
- Use of appropriate discount rate to reflect non-participating ratepayer perspective;
- Use of realistic near-term forecast of DG penetration;
- Analysis of capacity benefits on a continuous basis to capture modularity unique to DG;
- Inclusion of full accounting of utility distributed solar costs, energy generation savings, generation capacity savings, transmission capacity savings, distribution capacity savings, environmental benefits, economic development benefits, and grid security benefits.

Q. How should this analysis be used by the Commission and utilities?

A. I recommend that the Commission require that any utility seeking reform of the existing rate structure for DG provide necessary data for an independent, third-party to complete a full long-term evaluation of the costs and benefits of DG exports. This independent analysis should be specific to the utility's system, using the standardized methodology developed in this proceeding. The Commission should also develop a stakeholder process to allow interested parties to provide input on the independent, third-party DG export valuation. I recommend that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.

Q. Who would pay for the independent, third-party analysis?

A. The utility should provide funding for the independent, third-party analysis that would be recoverable in rates. Because this expense would be directly related to DG, it would be appropriate to include costs of this analysis as a cost to be evaluated in the context of the DG valuation study.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit BK-1

Statement of Qualifications

Briana Kobor
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Oakland, CA 94612
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PROFESSIONAL EMPLOYMENT

Program Director – DG Regulatory Policy, Vote Solar
August 2015-present

- Analyze policy initiatives, development, and implementation related to distributed solar generation
- Review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation

Senior Associate, MRW & Associates
April 2007-August 2015

- Develop and sponsor expert witness testimony for numerous clients to assist intervention in the utility regulatory process including investor-owned utility general rate cases, policy rulemakings, utility applications for power plant and transmission development, and other rate-related proceedings
- Represent clients at regulatory workshops, hearings and settlement discussions
- Perform in-depth quantitative analysis of utility models and testimony in support of general rate case and other regulatory proceedings
- Conduct extensive analysis of energy policy, regulation, economics, and emerging energy trends
- Build and maintain spreadsheet models to forecast utility rates and rate components tailored to client needs
- Create analytical models to assess generator production, profitability and electricity costs under a variety of regulatory and market scenarios and conduct pro forma analyses and technical assessments of infrastructure development in support of business decisions
- Provide analyses to investors and developers on the impact of laws, regulations, and procurement practices on potential sales of generation in various markets, assess current procurement progress, estimate pricing expectations for power sales, identify potential considerations that affect the marketability of project generation
- Provide policy recommendations to the State of California regarding greenhouse gas reduction, nuclear power generation and natural gas storage

EDUCATION

University of California, Berkeley
Bachelor's of Science with Honors, Environmental Economics and Policy

PREPARED TESTIMONY

- CPUC Application A.14-06-014
  Testimony of Briana Kobor on behalf of the Coalition for Affordable Streetlights Concerning SCE's Proposed Street Light Rates. March 13, 2015.
- CPUC Application A.14-11-003
  Testimony of Briana Kobor on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for San Diego Gas & Electric and SoCalGas. May 15, 2015.

- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. December 9, 2015.
- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Surrebuttal Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. February 23, 2016.

SELECTED PUBLICATIONS AND PRESENTATIONS

- Kobor, Briana. Rate Design to Support the Distributed Energy Future. Arizona Energy at the Crossroads Conference. November 2015.
- Monsen, Bill and Kobor, Briana. California Rules Worry Out-of-State Generators. Project Finance Newswire, Chadbourne & Parke. May 2012.
- McClary, Steven C., Heather L. Mehta, Robert B. Weisenmiller, Mark E. Fulmer and Briana S. Kobor (MRW & Associates). 2009. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California. California Energy Commission. CEC-700-2009-009.
- Mehta, Heather, Kobor, Briana, & Weisenmiller, Robert. California Plans a Carbon Diet. Project Finance Newswire, Chadbourne & Parke. January 2009.

Exhibit BK-2

IREC Report

October | 13

A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation

Interstate Renewable Energy Council, Inc.

IREC

About the Authors

Interstate Renewable Energy Council

Jason B. Keyes, Partner, Keyes, Fox & Wiedman, LLP. Mr. Keyes has represented the Interstate Renewable Energy Council in state utility commission rulemakings regarding net energy metering for the past six years. Prior to becoming an attorney, he managed government contracts for a solar energy R&D company and developed load forecasts and related portions of integrated resource plans at a large electric utility. Mr. Keyes can be reached at jkeyes@kfwlaw.com.

Rábago Energy LLC.

Karl R. Rábago, Principal. Mr. Rábago is an attorney with more than 20 years experience in utility regulation and clean energy, including as a former utility executive with Austin Energy and the AES Corporation, Commissioner for the Texas Public Utility Commission, and Deputy Assistant Secretary for the U.S. Department of Energy. Mr. Rábago can be reached at karl@rabagoenergy.com.

Executive Summary

As distributed solar generation ("DSG") system prices continue to fall and this energy resource becomes more accessible thanks to financing options and regulatory programs, regulators, utilities and other stakeholders are increasingly interested in investigating DSG benefits and costs. Understandably, regulators seek to understand whether policies, such as net energy metering ("NEM"), put in place to encourage adoption of DSG are appropriate and cost-effective. This paper first offers lessons learned from the 16 regional and utility-specific DSG studies summarized in a recent review by the Rocky Mountain Institute ("RMI"),[1] and then proposes a standardized valuation methodology for public utility commissions to consider implementing in future studies.

As RMI's meta-study shows, recent DSG studies have varied widely due to differences in study assumptions, key parameters, and methodologies. A stark example came to light in early 2013 in Arizona, where two DSG benefit and cost studies were released in consecutive order by that State's largest utility and then by the solar industry. The utility-funded study showed a net solar value of less than four cents per kilowatt-hour ("kWh"), while the industry-funded study found a value in excess of 21 cents per kWh. A standard methodology would be helpful as legislators, regulators and the public attempt to determine whether to curtail or expand DSG policies.

Valuations vary by utility, but the authors contend that valuation methodologies should not. The authors suggest standardized approaches for the various benefits and costs, and explain how to calculate them regardless of the structure of the program or rate in which this valuation is used. Whether considering net NEM, value of solar tariffs, fixed-rate feed-in tariffs, or incentive programs, parties will always want to determine the value provided by DSG. The authors seek to fill that need, without endorsing any particular DSG policy in this paper.

Major Conclusions

Three conclusions stand out based on their potential to impact valuations:

- DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
- DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
- The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits, should be included in valuations, as these were typically among the reasons for policy enactment in the first place.

[1] *A Review of Solar PV Benefit & Cost Studies* (RMI), July 2013 ("RMI 2013 Study"), *available at* http://www.rmi.org/elab_empower.

I. Introduction

There is an acute need for a standardized approach to distributed solar generation ("DSG") benefit and cost studies. In the first half of 2013, a steady flow of reports, news stories, workshops and conference panels have discussed whether to reform or repeal net energy metering ("NEM"), which is the bill credit arrangement that allows solar customers to receive full credit on their energy bills for any power they deliver to the grid.[2] The calls for change are founded on the claim that NEM customers who "zero out" their utility bill must not be paying their fair share for the utility infrastructure that they are using, and that those costs must have shifted to other, non-solar customers. Only a thorough benefit and cost analysis can provide regulators with an answer to whether this claim is valid in a given utility service area. As the simplicity and certainty of NEM have made it the vehicle for nearly all of the 400,000+ customer-sited solar arrays installed in the United States,[3] changes to such a successful policy should only be made based on careful analysis. This is especially so in light of a body of studies finding that solar customers may actually be subsidizing utilities and other customers.

The topic of NEM impacts on utility economics and on rates for non-solar customers seems to have risen to the top of utility priorities with the publication of an industry trade group report in January 2013 calling NEM "the largest near-term threat to the utility model."[4] Extrapolating from the current NEM penetration of just over 0.1% of U.S. energy generation to very high market penetration assumptions (e.g., if "everyone goes solar"), some have speculated that unchecked NEM growth will lead to a "utility death spiral." One Wall Street rating agency questioned the value of utility stocks in light of the continued success of NEM programs, claiming that it was "a scheme similar to net metering that led to the destabilization of the power markets in Spain in late 2008."[5]

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[2] NEM allows utility customers with renewable energy generators to offset part or all of their electric load, both at the time of generation and through kWh credits for any excess generation. This enables customers with solar arrays to take credit at night for excess energy generated during the day, for instance. Forty-three states have implemented NEM (*see* www.freeingthegrid.org for details on state NEM policies).

[3] Larry Sherwood, *U.S. Solar Market Trends 2012* (Interstate Renewable Energy Council), at p. 5 (316,000 photovoltaic installations connected to the grid at year-end 2012, with 95,000 in 2012 alone), July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. Forecasts for 2013 installations surpass 2012. *See, e.g., U.S. Solar Market Insight Report Q1 2013*, Greentech Media, Executive Summary, at p. 14, June 2013, *available at* http://www.greentechmedia.com/research/ussmi.

[4] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Edison Electric Institute), at p. 4, Jan. 2013.

[5] *Solar Panels Cast Shadow on U.S. Utility Rate Design* (FitchRatings), July 17, 2013, *available at* http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776. The piece was wrong on its facts. The Spanish model used a feed-in tariff ("FIT") based on solar energy costs and set at over US $0.60/kWh, leading to a massive build-out in a single year when solar prices dipped below the FIT rates. See *Spain's Solar Market Crash Offers a Cautionary Tale About Feed-In Tariffs*, N.Y. Times, Aug. 18, 2009, *available at* http://www.nytimes.com/gwire/2009/08/18/18greenwire-spains-solar-market-crash-offers-a-cautionary-88308.html?pagewanted=all (for up to 44 eurocent incentives, and using 0.711 average euro to U.S. dollar exchange rate in 2008, per IRS tables).

Numerous trade and industry publications have joined the chorus, with little indication that the rhetoric will abate anytime soon.[6]

DSG benefit and cost studies are important beyond the context of NEM. To address concerns about the cost-effectiveness of NEM, Austin Energy implemented the first Value of Solar Tariff ("VOST") in 2012, which is now under consideration in other jurisdictions. Under the Austin Energy approach, all of the customer's energy needs are provided by the utility, just as they would be if the customer did not have DSG, and the utility credits the residential solar customer for the value of all of the energy produced by the customer's solar array.[7] Though intended to offer a new approach to address the valuation issue, Austin Energy's VOST did little to quell the larger debate; indeed, this new policy highlights the fact that valuation is the key issue for any solar policy—NEM, VOST or otherwise.

Austin Energy's VOST rate, as initially calculated, was about three cents higher than retail rates, giving customers an even greater return than the NEM policy that the VOST replaced. However, as with NEM, discussions about "value of solar" rates have now turned to how to calculate the benefits of customer-generated energy. Claiming the use of their own VOST approach, City Public Service, the municipal utility serving San Antonio, Texas (just 80 miles from Austin) used an undisclosed, annualized value approach to conclude that the value of customer-sited energy from solar arrays was roughly half of the retail rate. A competing study for San Antonio, sponsored by Solar San Antonio and using publicly available data, showed twice that value.[8] As with NEM, the VOST approach is still subject to significant variation in valuation methodologies.

In early 2013, competing studies looking at DSG values for Arizona Public Service ("APS") kept the debate over valuation raging. APS funded a study that concluded DSG value was only 3.56 cents per kilowatt-hour ("kWh"), based on the present value of a kWh from DSG in the year 2025. Subsequently, APS filed an application to either change the rate schedule available to NEM customers or switch to a Feed-In Tariff ("FiT"), with both approaches relying on valuation in the range of 4 to 5.5 cents per kWh. At the same time, a solar industry-sponsored study found a 21 to 24 cent range for the value of each kWh of DSG, far exceeding costs, which it found to be in the range of 14 to 16 cents per kWh.[9] The lack of a consistent study approach drives the disparity in results.

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[6] *See* David Roberts, *Solar panels could destroy U.S. utilities, according to U.S. utilities*, Grist, April 2013, *available at* http://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/; Herman Trabish, *Solar's Net Metering Under Attack*, GreenTech Media, May 2012, *available at* http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack.

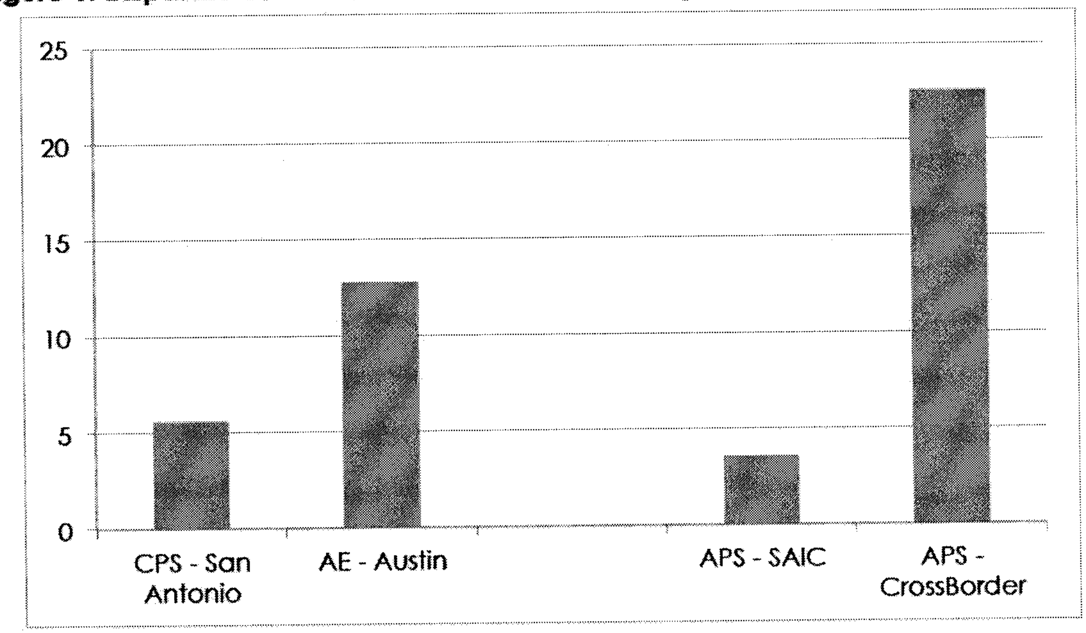
[7] *See* Austin Energy's Residential Solar Tariff, *available at* www.austinenergy.com/About%20Us/Rates/pdfs/Residential/ResidentialSolar.pdf (last accessed September 9, 2013).

[8] *See* N. Jones and B. Norris, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013 ("San Antonio Study"), *available at* www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf.

[9] Arizona Corporation Commission Docket No. E-01345A-13-0248 regarding NEM valuation opened with APS's application in July, 2013, and is available at http://edocket.azcc.gov/. The May 2013 APS study prepared by SAIC is available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf. The May 2013 solar industry-sponsored study prepared by Crossborder Energy is available at http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

Figure 1 displays the 150% difference between the Austin Energy and San Antonio City Public Service DSG valuations, alongside the 6X difference in values found in the two APS studies.

Figure 1: Disparate DSG Valuations in Texas Studies (cents/kWh).



The figure above shows that Austin Energy's latest valuation of 12.8 cents per kWh is 150% greater the 5.1 cent valuation by City Public Service in San Antonio, just 80 miles away. Even more dramatic is the difference in DSG values for APS, with 3.56 cents by the utility consultant and a range of 21.5 to 23.7 cents by the solar industry consultant.

Overview of a proposed standardized approach. This paper explains how to calculate the benefits and costs of DSG, regardless of the structure of the program or rate in which this valuation is used. Whether considering NEM, VOST, FiTs or incentive programs, parties will always want to understand DSG value. Indeed, accuracy in resource and energy valuation is the cornerstone of sound utility ratemaking and a critical element of economic efficiency. Fortunately, at least 16 studies of individual utilities or regions have been performed over the past several years, providing a backdrop for the types of benefits and costs to consider. While the variation in the purposes, assumptions and approaches in these studies has been wide, the body of published work is sufficient to draw some conclusions about best practices via a meta-analysis.

Rocky Mountain Institute ("RMI"), a Colorado-based not-for-profit research organization, looked at these 16 studies and summarized the range of valuations for each benefit and cost category in *A Review of Solar PV Benefit and Cost Studies* ("RMI 2013 Study"), providing a very useful tool for regulators determining whether a new study has considered all of the relevant benefits and costs. As well, an IREC-led report in early 2012 summarized these key benefits and costs and provided a generalized, high-level approach for their inclusion in any study ("Solar ABCs Report").[10] Together, the Solar ABCs Report and the RMI 2013 Study provide a detailed summation of efforts to date to assess the net benefits and costs of DSG.

This paper discusses various studies, but does not attempt to replicate RMI's thorough meta-analysis. Rather, this paper proposes *how* each benefit should be calculated and *why*. To assist state utility commissions and other regulators as they consider DSG valuation studies and the fate of NEM, VOST, or other programs or rate designs, we offer a set of recommended best practices regulators can use to ensure that a DSG benefit and cost study accurately measures the net impact of DSG.[11]

This paper synthesizes the prevalent and preferred methods of quantifying the categories of benefits and costs of DSG. One point of agreement is that DSG-related energy benefits are well accepted and are typically employed in cost-effectiveness testing, as well as in avoided cost calculations. Additional benefits and costs, related to capacity, transmission and distribution ("T&D") costs, line losses, ancillary services, fuel price impacts, market price impacts, environmental compliance costs, and administrative expenses are less uniformly treated in regulation and in the literature, and are addressed here in an effort to establish more commonality in approach. The quantification of societal benefits (beyond utility compliance costs) is also addressed. While typically not quantified in cost-effectiveness tests, these benefits—especially as related to evaluation of the risk associated with alternate resources—also merit more uniform treatment.

Organizationally, this paper covers the types of studies undertaken in relation to DSG valuation and overarching issues in DSG valuation studies, followed by the benefits and costs considered in various studies, the rationale for them, and the authors' recommendations on how to approach them.

> *The premise of this paper is that while calculated values will differ from one utility to the next, the approach used to calculate the benefits and costs of distributed solar generation should be uniform.*

II. DSG Benefit and Cost Studies

A history of DSG benefit and cost studies. There have been an increasing number of studies conducted and published over the past 10-15 years addressing the value of DSG and other distributed energy resources. The first comprehensive effort to

[10] J. Keyes and J. Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012 ("SolarABCs Report"), *available at* www.solarabcs.org/about/publications/reports/rateimpact.

[11] In addition, the Interstate Renewable Energy Council, Inc. ("IREC") is proactively working with state utility commissions to ask these questions before studies are undertaken, with the expectation that having clarified the assumptions, commissioners will be more confident in the results.

characterize the value of distributed energy resources was *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, published by RMI in 2002. Drawing from hundreds of sources, pilot project reports, and studies, *Small Is Profitable* set the stage for more specific technology-based studies, including the NEM cost-benefit studies and solar valuation studies that followed. Studies specific to DSG systems have appeared with increasing frequency since the Vote Solar Initiative published Ed Smeloff's *Quantifying the Benefits of Solar Power for California* in 2005 and Clean Power Research ("CPR") published its evaluation of *The Value of Solar to Austin Energy and the City of Austin* in 2006.

The reasons behind the appearance of these studies are several. DSG represents an increasingly affordable, interconnected form of distributed generation, creating the potential for significant penetration of small-scale generation into grids generally built around a central station model. In addition, economic and policy pressure on rebates and other mechanisms to foster DSG penetration has increased interest in improving understanding of the DSG value proposition. Utilities, policymakers, regulators, advocates, and service and hardware providers share a common interest in understanding what benefits and costs might be associated with such increased deployment of DSG, and whether net benefits outweigh net costs under a variety of deployment and analysis scenarios.

Many recent DSG valuation studies have been cost-effectiveness analyses of NEM policies for a given utility or group of utilities. NEM has proven to be one of the major drivers of distributed generation in the United States; 43 states and the District of Columbia feature some form of NEM.[12] The success of NEM as a policy to drive distributed generation market growth has caused several states to examine the impact that the policy has on other non-participating ratepayers. Efforts are currently underway in California, Arizona, Hawaii, Colorado, Nevada, North Carolina and Georgia to quantify the benefits and costs of the policy in order to inform the appropriate level of support for distributed energy generation, particularly rooftop solar photovoltaic ("PV") generation. Other states may follow soon, even those with relatively few DSG installations; for example, the Louisiana Public Service Commission indicated that it would launch a cost-benefit analysis for net-metered systems.

Another major use for DSG value analysis is in resource planning and other regulatory proceedings. In December 2012, Lawrence Berkeley National Laboratory ("LBNL") published a review of how several utilities account for solar resources in *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes.*[13] At this writing, Integrated Resource Plan ("IRP"), avoided cost, or renewable plan dockets are, or soon will be, underway at several utilities[14] where the value of DSG is directly at issue. In addition, the state of Minnesota has recently adopted legislation that establishes a

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[12] *See* Database of State Incentives for Renewables and Energy Efficiency ("DSIRE"): Summary Maps – Net Metering Policies, *available at* www.dsireusa.org (last accessed Aug. 18. 2013).

[13] Andrew Mills & Ryan Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, December 2012 ("LBNL Utility Solar Study 2012"), *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

[14] *See, e.g.,* Georgia Public Service Commission Docket No. 36989 (Georgia Power Rate Case); North Carolina Utilities Commission Docket No. E-100, Sub 136 (Biennial Avoided Cost); Colorado Public Utilities Commission Docket No. 13A-0836E (Public Service Company Compliance Plan).

Value of Solar rate for DSG.[15] The authors anticipate that additional valuation studies will result from one or more of these proceedings.

As of this writing, relatively few jurisdictions have conducted full cost-effectiveness studies for DSG and fewer still provide sufficient detail to guide development of a common methodology. CPR's Austin Energy study, updated in 2012, established an approach that has been applied in other regions, including a recent study on the value of DSG in Pennsylvania and New Jersey.[16] The California Public Utilities Commission ("CPUC") and APS commissioned comprehensive studies in 2009; both commissioned revised studies in 2013.[17] In January 2013, Vermont's Public Service Department[18] completed a cost-benefit analysis of NEM policy.

While not identical in structure, these works typify the recent reports and illustrate some commonalities in approaching the valuation of distributed energy. NEM-specific studies include the 2009 California Energy and Environmental Economics ("E3") Study, Crossborder Energy's 2013 updated look at that E3 study,[19] Crossborder Energy's 2013 analysis of DSG cost-effectiveness in Arizona,[20] and the Public Service Department's own analysis for Vermont.

As noted earlier, this paper complements IREC's recent publication, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*.[21] That paper reviews the DSG valuation studies that had been published to date and provides general approaches to calculating the widely recognized categories of benefits and costs that are relevant to the consideration of the cost-effectiveness of VOST, NEM, and other policy mechanisms impacting DSG. The intent of this examination is to dive deeper, find more common ground for discussion and foster greater consistency in how these values are determined across jurisdictions.

Also as noted earlier, this paper benefits from analysis recently published by RMI, entitled *A Review of Solar PV Benefit and cost Studies*.[22] That report reviews 16 studies in a meta-analysis that examines methodologies and assumptions in great detail. Figure 2 is from that study, and characterizes the differences and similarities in the studies. As

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[15] Minn. Stat. § 216B.164, subd. 10 (2013): Chapter 85--H.F. No. 729, Article 9, Distributed Generation, Section 10.

[16] Richard Perez, Thomas Hoff, and Benjamin Norris, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*, 2012 ("CPR 2012 MSEIA Study"), *available at* http://communitypowernetwork.com/sites/default/files/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

[17] APS studies: *Distributed Renewable Energy Operating Impacts and Valuation Study*, RW Beck, Jan. 2009, available at http://www.solarfuturearizona.com/SolarDEStudy.pdf; *2013 Updated Solar PV Value Report*, SAIC, May 2013, available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf.
CPUC studies conducted by Energy and Environment Economics ("E3"): http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

[18] *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*, January 15, 2013 ("Vermont Study"), *available at* www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] Thomas Beach and Patrick McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California* (Vote Solar Initiative), 2013 ("Crossborder 2013 California Study"), *available at* http://www.seia.org/research-resources/evaluating-benefits-costs-net-energy-metering-california.

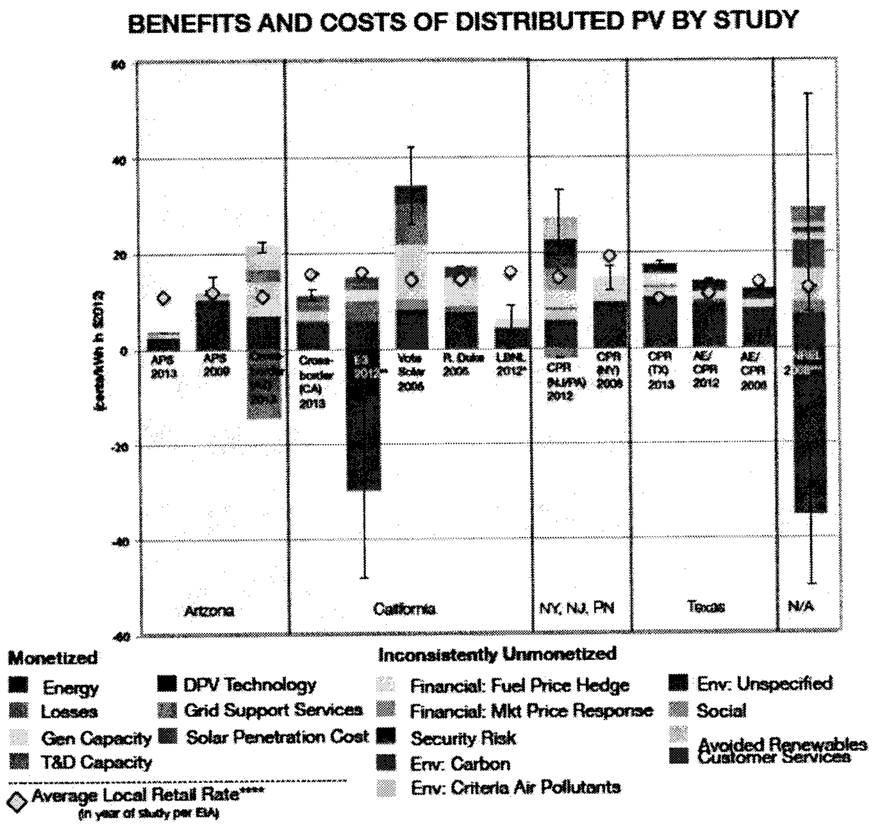
[20] Thomas Beach and Patrick McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Vote Solar Initiative), at p.12, 2013 ("Crossborder 2013 Arizona Study"), *available at* http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

[21] *See* SolarABCs Report, *supra*, footnote 10.

[22] *See* RMI 2013 Study, *supra*, footnote 1.

well as considering benefits and costs the RMI 2013 Study points out that the various studies differ significantly in the amount of DSG penetration considered, which can drastically impact values. Another important differentiator is whether the studies are based on high-level, often secondary, review of benefits and costs, or whether they rely on more granular and detailed modeling of impacts.[23]

Figure 2: Rocky Mountain Institute Summary of DSG Benefits and Costs



The RMI 2013 Study figure is reprinted here to make three important points. First and foremost, the calculated benefits often exceed residential retail rates, shown in the figure with diamonds, implying that NEM would not entail a subsidy flowing from non-solar to solar customers. Second, commercial customers almost always have unbundled rates and NEM has minimal impact on their demand charges because they still have demand after the sun sets. That means that DSG benefits compared to commercial customer energy rates would be strongly positive based on almost all of these studies. And third, costs are accounted for in varying ways: three studies show costs including lost retail rate payments, with large bars below the zero line indicating total costs, one shows costs other than retail rate payments (CPR NJ/PA), and the rest include costs as a deduction within the benefits calculation. As an overarching point,

[23] *Id.* at p. 21.

the RMI 2013 Study figure confirms that there is no single standard DSG valuation methodology today.

Types of Studies. Distributed solar valuation requires quantitative analysis of a wide range of data in an organized way. Fortunately, there are abundant existing approaches that can contribute to estimation of DSG value. This section briefly introduces the two major types of studies that underlie DSG valuation. The first category of studies is input and production cost models. These have general application in the utility industry in the comparison of resource alternatives. The second category, DSG-specific studies, includes three sub-types, depending on the purpose for which the study was conducted. In practice, most DSG-specific studies rely on inputs from input and production cost models.

A. Input and Production Cost Models

Utility planners and industry experts rely on a wide range of models and analytical tools for calculating costs associated with generation and systems. Power flow, dispatch, and planning models all provide input to the financial models used to evaluate DSG cost effectiveness and value. While detailed treatment of the utility models providing input to the DSG models is beyond the scope of this paper, they impact the DSG models and need to be understood. Often, these utility models are deemed proprietary, creating "black box" solutions regarding what generation is needed and when. Among the most critical decisions made at this juncture is whether the generation that will be offset by DSG is a relatively efficient natural gas combined-cycle combustion turbine ("CCGT")or a less efficient single cycle "peaker" plant running on natural gas, or some combination of the two.

As most of the gas-fired energy delivered by utilities comes from CCGTs, and peakers will still be needed to handle changes in load, models should reflect that DSG is primarily offsetting CCGTs. However, the APS 2013 study is an example in which the input model results are confounding, and there is no way to review the black box solution. Oddly, APS found that baseload coal would be displaced for part of the year. We believe that such an example deserves more careful study; it is a nearly universal truth that coal plants are run as much as possible. While many coal plants have been shut down in the past decade, those that remain are typically only curtailed for maintenance. Regulators should consider whether input assumptions such as coal or nuclear displacement are reasonable, particularly if the results are based on proprietary, opaque modeling.

Capacity needs in planning models are typically forecasted several years in the future and, because of the legacy of the central station utility plant paradigm, in large increments of capacity. These so-called "lumpy" capacity investments generally overshoot capacity requirements in order to ensure resource adequacy in the face of multi-year development lead times. As a result, the opportunity for DSG to provide useful capacity is generally seen as too little and too early. For example, a typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 megawatts ("MW") of generation capacity. In such a situation, traditional resource planning and avoided cost estimates assign no capacity value to DSG installed on customer roofs before 2018, and none in

2018 unless the systems provide the equivalent to 200 MW of capacity. This ignores the benefit of DSG's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. DSG can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued DSG installations.

Today, many input and production cost planning models include the opportunity to adjust assumptions about customer adoption of DSG (and energy efficiency), which assume that those resources are going to play a role in the utility's near term capacity requirements. With these adjustments, the in-service requirement date can possibly be deferred, generating both energy and capacity savings attributable to the distributed resources. Accordingly, models that do not address DSG installations are inadequate and could lead to costly overbuilding and, given planning and construction lead times associated with large plants, premature expenditure of development costs.

B. DSG-Specific Studies

DSG-specific studies often start with inputs from the models just described. These studies are themselves usually of three types:

Studies of studies. Like this white paper, these studies start with work conducted by one or more experts and organize the information and data in a form that addresses questions of interest. In some cases, the authors report the results and the source conditions for the data. In others, study authors attempt to adjust the results for different local conditions. The RMI 2013 Study on solar PV reports the results of 16 different studies spanning some eight years. These studies provide useful introductions to the emerging discipline and demonstrate the ways in which differences in assumptions, methodologies, and underlying data can impact outcomes. In addition, when adjusting for outlier conditions, the studies can demonstrate where there exists relatively strong coherence in approach and results.

Cost-Benefit Analysis studies. Cost-benefit studies focus on using avoided cost methodologies and cost-benefit test approaches to review large-scale DSG initiatives and programs. They seek to answer the question of whether total costs or total benefits are greater over a specified period of time. For these studies, forward-looking cost estimates for DSG interconnection, lost revenues, avoided RPS costs, and incentive programs are important inputs. The best-known examples of this study approach were conducted by E3, reviewing the California Solar Initiative and NEM programs, and those by Crossborder Energy, reviewing the E3 reports. Most of the studies reviewed by the RMI 2013 Study are of this sort. There are several cost-benefit analysis varietals, as described in the California Standard Practice Manual and summarized in the box below.

Value of Solar studies. Smeloff and CPR pioneered the "value of solar" genre of study. As the name implies, this study approach focuses on using avoided cost and financial analysis methods in discerning the future investment value of distributed solar to the utility, ratepayers, and society. Generally, these evaluations ignore utility lost revenues, instead focusing on valuation that can be used in designing and setting incentive levels, program limits, and other features of utility DSG programs. The studies stop short of rate or tariff design features, and as a result, do not typically address lost revenue issues. Perhaps best known is the Austin Energy Value of Solar study conducted by CPR in 2006 and updated in 2012.[24]

With reference to the California Standard Practice Manual study descriptions summarized in the prior box, the type of test that the authors suggest in this paper is a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") approaches. The RIM test addresses the impact on non-participating ratepayers in terms of how benefits and costs impact the utility and are passed along to those ratepayers. That necessarily does not account for the participating ratepayers' outlay for DSG systems, nor should it. The SCT approach looks at whether it is a good idea for society as a whole to pursue a policy, and includes participating ratepayers' investment in DSG systems. The authors contend that the participants' investment is outside of the scope of the appropriate investigation. The goal should be to determine whether non-participants have a net benefit from the installation of DSG systems. As the job creation, health and environmental benefits accrue to non-participants just as much as they accrue to participants, there is no apparent reason why societal benefits should not be included. In its consideration of benefits, this approach aligns with the VOST methodology which aims to include all benefits that can reasonably be quantified and assigned to utility operations.

Utilities often object, stating that valuing societal benefits conflates customers with citizens, and note that utility rates must be based on costs directly impacting utilities. By this line of reasoning, job creation and health benefits may be the basis of legislative policies supportive of DSG, but should not be considered when developing DSG tariffs. We are reluctant to accept an artificial division between citizens and utility customers; the overlap is complete for most benefits and costs. Moreover, a major reason for establishing NEM, VOST or other DSG programs is primarily related to the same broad societal benefits that drive utility regulatory systems—economic efficiency, and rates and services in the public interest—so those benefits should be considered in any programmatic or policy analysis.

Recommendation: Use a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") Cost-Benefit Tests

[24] Author K. Rábago, while at Austin Energy, helped establish the nations' first VOST. *See* K. Rábago, *The Value of Solar Rate: Designing an Improved Residential Solar Tariff*, Solar Industry, at p. 20, Feb. 2013, *available at* http://solarindustrymag.com/digitaleditions/Main.php?MagID=3&MagNo=59.

Cost-Benefit Tests

The California Standard Practice Manual is used for economic analysis of demand-side management ("DSM") programs in California. The cost-benefit tests in the Standard Practice Manual have also been used to evaluate DSG value, most notably in California, where the tests have been applied to a review of the cost effectiveness of the California Solar Initiative. The various tests differ in the perspective from which cost effectiveness is assessed.

- ***Participant Cost Test ("PCT").*** Measures benefits and costs to program participants.
- ***Ratepayer Impact Measure ("RIM") Test.*** Measures changes in electric service rates due to changes in utility revenues and costs resulting from the assessed program.
- ***Program Administrator Cost Test ("PACT").*** Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. This test differs from the RIM test in that it considers only the revenue requirement, ignoring changes in revenue collection, typically called "lost revenues."
- ***Total Resources Cost Test ("TRC").*** Measures the total net economic effects of the program, including both participants' and program administrator's benefits and costs, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall economic welfare over the entire utility service territory.
- ***Societal Cost Test ("SCT").*** The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, such as induced economic development effects, which are not considered in the TRC.

III. Key Structural Issues for DSG Benefit and Cost Studies

Underlying study assumptions and major study components. The evaluation of the cost-effectiveness of a given DSG policy, particularly NEM, is a complex undertaking with many potential moving parts. Before delving into the specific benefits and costs, it is important to recognize that the ultimate outcome of the analysis is highly dependent on the base financial and framework assumptions that go into the effort. Much of the work involves forecasting—estimating the future benefits and costs, performance, and cumulative impacts associated with increasing penetration of distributed generation into the electric grid. It is important to develop a common set of base assumptions that reflect the resource being studied and to be as transparent as possible about these assumptions when reporting the results of the analysis. At the outset of a study, it is important to define these structural parameters. Below we present key questions for regulators to explore at the onset of a study:

Q1: WHAT DISCOUNT RATE WILL BE USED?

The discount rate should reflect how society evaluates costs over time. Utilities use a discount rate based on the time value of money, using the rate of return available for investments with similarly low risk, now in the 6% to 9% range. However, society may prefer the use of a lower discount rate, closer to the rate of inflation. The difference is important. High discount rates improve the evaluation of resources with continuously escalating or high end-of-life costs. For instance, an 8% discount rate may favor a natural gas generator because much of the cost (the fuel, operation and maintenance) to run the generator is incurred over the life of the generator, while the cost of DSG is almost entirely at the front end. A low discount rate improves the valuation of resources with high initial costs and low or zero end-of-life costs. The same analysis based on a 3% inflation rate may favor DSG resources, as there are no fuel costs over time and the operations and maintenance ("O&M") costs are low because there are fewer or no moving parts. While the utility's discount rate is appropriate when considering utility procurement because those funds could be invested elsewhere at competitive rates, the utility is not procuring the DSG resources in the case of NEM, VOST or FiT arrangements. It is worth questioning whether the future benefits of DSG resources should be heavily discounted, based on the utility's cost of capital, when the customer (or a third party owning a system at the customer's site) is making the investment. As utility valuation techniques improve, is it reasonable to discount future benefits and costs by the inflation rate rather than the utility's cost of capital.

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Under NEM, utility customers can take advantage of a federal law[25] allowing for on-site generation to offset consumption, with the opportunity to sell excess generation to the utility at the utility's avoided cost. Because the customer has a right to avoid any and all consumption from the utility, studies of NEM cost-effectiveness will often look only at the utility cost associated with exports to the grid. The assumption under NEM is effectively that at or below the total consumption level, the value of offset consumption is the retail rate. This valuation is supported by the concept behind cost-of-service rate regulation—that the retail rate is the accumulation of costs to generate and deliver energy for the customer.[26] Note that to the extent that NEM benefits are calculated to

[25] *See* Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. *et seq.*
[26] VOST studies, on the other hand, presume a difference between the value of generation at or near the point of consumption and the level of the rate. That is, the customer with DSG may well be generating electricity of greater value than that being provided by the utility.

outweigh costs, consideration of all generation amplifies the calculated net benefit. However, if NEM costs outweigh benefits, the opposite is true.

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Utility planners routinely consider the lifecycle benefits and costs of traditional utility generators, typically over a period in excess of 30 years. Solar arrays have no moving parts and are generally expected to last for at least 30 years, with much less maintenance than fossil-fired generation. Solar module warranties are typically for 25 years, and many of the earliest modules from the 1960s and 1970s are still operational, indicating that modules in production today should last for at least 30 years. This useful life assumption creates some data challenges, as utilities often plan over shorter time horizons (10-20 years) in terms of estimating load growth and the resources necessary to meet that load. As described below, methods can be used to estimate the value in future years that interpolate between current market prices or knowledge, and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Recommendation: We suggest that the most appropriate timeframe for evaluating DSG and related policy is 30 years, as that matches the currently anticipated life span of the technology.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Key to determining the value of DSG is a reasonable expectation of what customer loads will look like in the future, as much of the value of distributed resources derives from the utility's ability to plan around customer-owned generation. Other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, as customer facilities contribute to the available capacity of utility resources as small contracted generators.

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, we recommend that the assigned capacity value of the distributed systems reflect the fact that the utility can plan for lower loads than it otherwise would have.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Many benefits and costs are sensitive to how much customer-owned generation capacity is on the grid. Most studies assume current, low penetration rates. Several of the studies consider higher penetration levels, as well, typically out to 15% or 20% of peak load, with some outlier studies looking at 30% and 40% penetration levels. In a high-penetration scenario, the utility may face higher integration expenses that might undermine the specific infrastructure benefits of distributed generation. Studies that address the issue often find that marginal capacity benefits decline with high penetration.

On the other hand, some studies such as those by APS, conclude that capacity benefits are dependent on having enough DSG to offset the next natural gas generator, and therefore that there are no capacity benefits in low-penetration scenarios. Market penetration estimates should also be reasonable in light of current supply chain capacity and local market conditions. Generally, the most important penetration level to consider for policy purposes is the next increment. If a utility currently has 0.1% of its needs met by DSG and a study shows that growth to 5% is cost-effective, but growth to 40% is not, then it would be economically efficient to allow the program to grow to 5% and then be reevaluated.

Recommendation: We recommend the establishment of an expected level of DSG penetration, and the development of low and high sensitivities to consider the full range of future impacts.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?

Analysts have used a wide variety of tools to calculate the benefits and costs of DSG. There is almost no commonality at the model level, even though many of the analyses address similar or identical issues. Several studies use some version of investment and dispatch models in order to determine which resources are displaced by solar and the resulting impacts. As noted earlier, utility DSG studies have often relied on proprietary models for these inputs. The fact that CPR and Professor Richard Perez[27] have published a number of studies creates some commonality among those studies, but over time, even the CPR approaches have evolved as tools have been improved.

Recommendation: We suggest that transparent input models accessible to all stakeholders are the proper foundation for confidence and utility of DSG studies. If necessary, non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?

Value of solar analysis is heavily influenced by local resource and market conditions. Most published studies are geographically scoped at the state, service territory, or interconnected region level. Given its leadership in solar deployment, California also leads as the subject of studies and as a data source. Some studies relating to economic development and environmental impacts use a national and regional scope.

Recommendation: We suggest that it is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

The majority of studies consider benefits and costs in the generation, transmission, and distribution portions of the system. Of the studies that consider environmental impacts,

[27] Richard Perez is a Research Professor at the University at Albany-SUNY.

most only look at avoided utility environmental compliance costs at the generation level.

Recommendation: We recommend considering impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG.[28]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Nearly all the studies consider impacts from the perspective of the utility and ratepayers. Several also consider customer and societal benefit and costs. Cost-benefit studies apply California Standard Practice Manual tests for Demand Side Management, discussed earlier.

Recommendation: We suggest that rate impacts and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

When a DSG system is installed, it is like commissioning a 30-year power plant that will, if properly maintained, produce energy and other benefits during that entire period. Several studies look at snapshots of benefits and costs in a given year, which fails to answer the basic question of whether DSG is cost-effective over its lifetime. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options. As such, levelization of the entire stream of benefits and costs is appropriate.

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the entire DSG life of 30 years.

Q11: WHAT DATA AND DATA SOURCES ARE USED?

As the number of solar valuation studies has increased, so has the frequency with which newer studies cite data provided in prior studies. There are two reasons behind this trend, cost and availability of data, which we discuss in detail below.

As with any modeling exercise, models are only as good as the data fed into them. The ability to precisely calculate the benefits of DSG often rests on the availability and granularity of utility operational and cost data. More granular data yields more reliable analysis about the impacts of DSG deployment and operation.

Calculating many of the benefit and cost categories requires that analysts address utility-specific or regional conditions that can vary significantly from utility to utility, even within the same state. In addition, the availability of the type of granular data needed

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[28] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012, *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

to accurately project location and time-specific benefits varies from one utility to the next. Much of the data needed to quantify the benefits of DSG resides with utilities.

Fortunately, additional data, such as energy market prices, is often publicly available, or can be released by the utility without proprietary concerns. In some limited cases, the utility may have proprietary, competitive, or other concerns with plant- or contract-specific information. And in some cases, the form and format of utility data may require adjustments.

These problems are not insurmountable. Utility general rate cases and regulatory filings with the Federal Energy Regulatory Commission ("FERC") are good sources for data relevant to utility peak demand and for the components of cost of service, including transmission costs, line loss factors, O&M costs, and costs of specific distribution upgrades or investments, among other cost categories. Additionally, the federal Energy Information Administration ("EIA") and various state agencies compile utility cost data that can be used as a reference to determine heat rates, the costs of O&M associated with various plants, and the overall capital cost of new construction of generating capacity.[29]

Recommendation: Require that utilities provide the following data sets, both current information and projected data for 30 years[30]:

1) The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG.
2) Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy.
3) Hourly production profiles for NEM generators. The use of time-correlated solar data is important to correctly assess the match of solar output with system loads. In the case of solar PV, this could vary according to the orientation of the system. For example, while south-facing systems may have greater overall output, west or southwest facing systems may produce more overall value with fewer kWh because of peak production occurring later in the day than a south-facing system.
4) Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated.
5) Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
6) Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
7) Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades.

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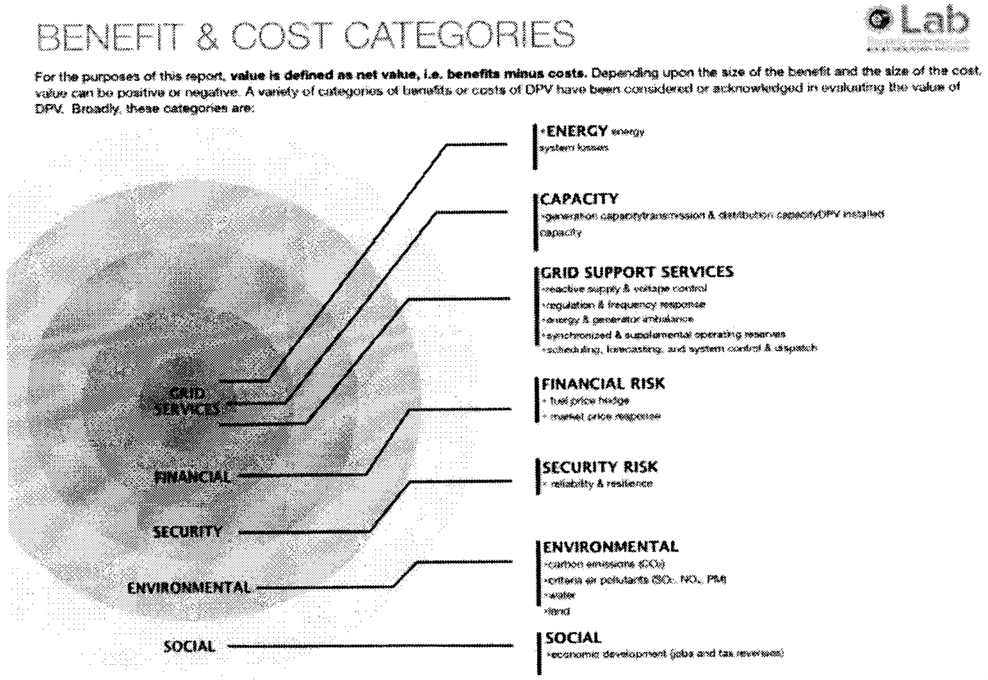
[29] *See Updated Capital Cost Estimates for Electricity Generation Plants* (EIA), November 2012, *available at* http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (providing estimate of capital cost, fixed O&M, and variable O&M for generation plants with various technical characteristics).

[30] Note: Where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

IV. Recommendations for Calculating the Benefits of DSG

Benefits of DSG get categorized and ordered in various ways from study to study, typically based on the relative magnitude of the benefits. The RMI 2013 Study is structured around a list of "services," encompassing flows of benefits and costs to and from solar PV. That list is replicated here in an effort to coordinate with that study.[31] The RMI services categories are depicted in the graphic below.

Figure 3: Rocky Mountain Institute Summary of DSG Benefits



While replicating the RMI services categories, we have subdivided them in recognition that the divide between utility avoided costs and other societal benefits is not clear from the list above. For instance, utilities can avoid certain environmental compliance costs, which are direct utility avoided costs, while other environmental benefits inure to society more generally. As another example, reliability or resiliency is only a utility avoided cost to the extent that the utility was going to take some other measures to achieve the levels enabled by DSG. If DSG enables higher reliability than would have otherwise been achieved, that is undoubtedly a benefit, though it is most notably realized by utility customers when a storm event does not cause a major service interruption, which may occur once in a decade. As a further example, market price

[31] *See* RMI 2013 Study.

response benefits can be felt by the utility itself but will also extend to citizens who are customers of nearby utilities.

To track utility avoided costs and societal benefits separately, separate subsections are provided below, with the final three RMI environmental and social benefit categories covered after utility avoided costs. We note where some categories listed under utility avoided costs have societal benefits as well, and we separately create an environment category under utility avoided costs to capture utility avoided environmental compliance costs.

Calculating Utility Avoided Costs

1. *Avoided energy benefits*

To determine the value of avoided generation costs, the first step is to identify the marginal generation displaced. In most instances, the next marginal generator will be a natural gas-fired simple-cycle combustion turbine ("CT") or a more efficient CCGT. Avoiding the operation of that marginal generating facility to produce the next increment of electricity means that the solar generator allows the utility to avoid both variable O&M activities (i.e., those activities and expenses that vary with the volume of output of the CT or CCGT plant) and the fuel that would be consumed to produce that next unit at the time that the customer-generator allows the utility to avoid that operation.

To calculate the avoided generation cost over the life of the DSG system—assumed throughout this paper to be 30 years—the calculation must estimate the market price of energy throughout that time span. Given the limitations on the availability of data, including the future price of a historically volatile commodity like natural gas, many studies have used interpolation and extrapolation to estimate gas prices in the 30 year horizon by taking the readily attainable current market price for natural gas and referencing it against the most forward natural gas price available.

Additionally, the calculation of avoided generation costs over time must account for degradation in the marginal generation plant and adjust expected heat rates (i.e., the measure of efficiency by which a unit creates electricity by burning fuel for heat to power a turbine). Over time, the marginal generation plant will become less efficient and require incrementally more fuel to reach the same production levels. Production cost modeling enables the utility to cumulate value of avoided costs throughout the useful life of the solar generating system. However, due to built in constraints or other issues, such modeling can produce results that are illogical, as has been seen in Arizona (baseload coal generation displaced by DSG) and Colorado (high cost of frequent unit startups reducing energy benefits).

A standard approach to determining the value of avoided generation over the life of a DSG system is to develop: (1) an hourly market price shape for each month and (2) a forecast of annual average market prices into the future.[32] One way to forecast the annual market prices, with less reliance on forward market prices, is to project the rolled-in costs of the marginal generation unit, accounting for variable O&M and

[32] E3 Study, Appendix A at pp.10-11.

Comparison with PURPA Avoided Cost Calculations

Value of solar analysis literature is complemented by other studies and reports related to the issue. These include studies relating to avoided cost methodologies under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and those addressing utility resource planning evaluation of distributed resources.

Because both the cost-benefit and value-of-solar approaches start with avoided cost calculations, publications and processes used in conducting such calculations are informative in establishing the costs and benefits of DSG. State utility commissions and public utility regulators have approached PURPA valuation of avoided costs quite differently, and FERC has rarely constrained the approach selected. Rather than attempt to discern a consensus approach, a more fruitful approach is to consider what PURPA allows.

IREC recently published a paper to do this, cataloguing the kinds of DSG-related avoided cost calculations that could improve understanding of DSG value, and citing most of the utility avoided costs discussed in this paper.

See the full report:
http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf

degradation of heat rate efficiency in future years. This method still relies on forecasts of natural gas prices in future years, but provides more certainty for variable O&M costs.[33]

In the Vermont study, the Public Service Department assumed that the New England Independent System Operator ("ISO-NE") wholesale market would provide the marginal generation price for energy displaced by solar generation. To account for the high correlation of solar PV with system peak, and therefore the offset of higher value generation, the Department created a hypothetical avoided cost for 2011 using real output data that was matched with actual hourly market data from the ISO-NE market.[34] This adjusted hourly market price was then scaled to future years by utilizing an energy price forecast, based on the forward market energy prices for the first five years and for the forward natural gas prices for years five to ten.[35] Prices for years after year ten were based on an extrapolation of the market prices for electricity and natural gas for years one through ten.

As CPR observes, there are inherent shortcomings in relying on future market prices for marginal generation decades into the future.[36] A more straightforward method would be to "explicitly specify the marginal generator and then to calculate the cost of the generation from this unit."[37] In this way the avoided fuel and O&M cost savings are roughly equivalent to capturing the future wholesale price. Of course, this approach still relies on forward projections in the natural gas market.

[33] CPR 2012 MSEIA Study at pp. 28-29.
[34] Vermont Study at p. 16.
[35] *Id.*
[36] CPR 2012 MSEIA Study at pp. 28-29.
[37] *Id.* at p. 29.

2. Calculating system losses

DSG sited at or near load avoids the inefficiencies associated with delivering power over great distances to the end-use customer due to electric resistance and conversion losses. When a DSG customer does not consume all output as it is being produced, the excess is exported to the grid and consumed by neighboring customers on the same circuit, with minimal losses in comparison to electricity generated by and delivered from a utility's centralized but distant plant. Without DSG and its local load reduction impact, utilities are forced to generate additional electricity to compensate for line losses, decreasing the economic efficiency of each unit of electricity that is delivered.

Including avoided line losses as a benefit is relatively straightforward and should be non-controversial. For instance, FERC's regulations implementing PURPA recognize that distributed generation can account for avoided line losses.[38] This benefit exists for all types of DG technologies and, to some extent, in all locations. Typically, average line losses are in the range of 7%, and higher during heavier load periods, which can correlate with high irradiance periods for many utilities.[39] Additional losses termed "lost and unaccounted for energy" are also likely associated with T&D functions and, with further research, may also be avoided by DSG.[40]

Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the "true reduction in losses on a marginal basis."[41] Considering losses on a marginal basis is more accurate and should be standard practice as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses. In its Austin Energy study, CPR evaluated marginal T&D losses at times of seasonable peak demand using load flow analysis. CPR decided to average the marginal energy losses on the distribution system, for purposes of the study, and added marginal transmission losses in order to report hourly marginal loss savings due to solar generation. According to one APS study, the degree of line losses may decrease as penetration increases.[42]

As with the effect of reducing market prices by reducing load at times of peak demand, and therefore reducing marginal wholesale prices (see below), DSG-induced reduction of losses at times of peak load has a spillover effect. The ability of customers to serve on-site load without use of the distribution system reduces transformer

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[38] *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.").

[39] For example, the E3 study assumes an average loss factor of 1.073, which indicates that 7.3% more energy is supplied to the grid than is ultimately delivered and metered by the end-use customers. In contrast, Vermont's study noted that the Department's energy efficiency screening tool concluded that typical marginal line losses are about 9%. Vermont Study at p.17.

[40] *See, e.g.,* A. Lovins *et al.*, Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute, at p. 212, August 2002; U.S. Energy Information Administration's Annual Energy Review, *available at* http://www.eia.gov/totalenergy/data/annual/diagram5.cfm.

[41] CPR 2012 MSEIA Study at p. 27.

[42] *Distributed Renewable Energy Operating Impacts and Valuation Study, R. W. Beck for Arizona Public Service, Jan. 2009, at p. 4-7 and Table 4-3. (Finding that a "law of diminishing returns" applies to solar distributed energy installations.) Available at:* http://www.solarfuturearizona.com/SolarDEStudy.pdf.

overheating, a major driver of transformer wear and tear, and in turn allows customers to receive power from utility generators at lower marginal loss rates. Without on- or near-peak DSG, all customers would face higher marginal loss rates with the contribution to thermal transformer conditions caused by all customers seeking grid delivered power for all on-site needs at times of peak load.

With consideration of the line losses avoided in relation to both the energy that did not have to be delivered due to DSG, and the marginal improvement in line losses to deliver power for the rest of utility's customers' needs, the appropriate methodology developed by CPR is to look at total line losses without DSG and total line losses with DSG. In practice this can equal 15-20% of the energy value.

Separately, line losses figure into capacity value as well, as a peak demand reduction of 100 MW means in turn that a generation capacity of more than 100 MW is avoided. This aspect of avoided line losses should be included with generation and T&D capacity benefits, discussed below.

3. <u>*Calculating generation capacity*</u>

Determining the capacity benefits of intermittent, renewable generation is a more complex undertaking than analyzing energy value, but there is a demonstrated capacity value for DSG systems. Capacity value of generation exists where a utility can count on generation to meet its peak demand and thereby avoid purchasing additional capacity to generate and deliver electricity to meet that peak demand.

While individual DSG systems (without energy storage) provide little firm capacity value to a utility given the potential for cloud cover, there is compelling research supporting the consideration of the aggregate value of DSG systems in determining capacity value. A recent study by LBNL demonstrates that geographic diversity tends to smooth the variability of solar generation output, making it more dependable as a capacity resource.[43] As well, FERC considered the fact that distributed solar and wind should produce some capacity value when considered in the aggregate when it was developing its avoided cost pricing regulations.[44] Capacity value for DSG systems should look to the characteristics of all DSG generators in the aggregate, including the smoothing benefits of geographic diversity.

Solving for Intermittency. CPR developed the most prominent and widely used method to address the intermittency of DSG technologies. This method recognizes a capacity value for intermittent, non-dispatchable resources, and is referred to the as the "effective load carrying capability" ("ELCC"). ELCC is a statistical measure of capacity that is "effectively" available to a utility to meet load. "The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while

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[43] *See* Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Lawrence Berkeley National Laboratory), LBNL-3884E, September 2010.
[44] FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.").

maintaining the designated reliability criteria (e.g., constant loss of load probability)."[45] In this way, ELCC provides a reliable statistical method to project the capacity value of intermittent resources.

On the other hand, the ELCC method can be data intensive and complex to some stakeholders. Simpler methods may also yield reasonable results. For example, an alternate method, based on the utility's load duration curve, looks at the solar capacity available for the highest load hours, usually the top 50 hours.

Implemented in a rate, a capacity credit for DSG denominated in kWh represents the best approach. This ensures that DSG only receives capacity credit for actual generation.

Valuing Small, Distributed Capacity Additions. An often controversial issue in determining avoided capacity value is the fact that distributed generation provides small, incremental additions and utility resource planning typically adds capacity in large, or "lumpy," blocks of capacity additions. For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to defer or avoid the "lumpy" capacity additions.[46] Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.

One solution around the valuation of incremental capacity additions versus lumpy additions that would follow more traditional utility planning is laid out in Crossborder Energy's 2013 update to the 2009 E3 Net Metering Cost-effectiveness study for California. In the E3 study, a mix of short-run and long-run avoided capacity costs are applied to renewable generators based on the fact that additional capacity would not be required until a certain year, called the "Resource Balance Year" in the E3 study. Crossborder's update recognizes the incremental value of small capacity additions for the years leading up to the Resource Balance Year and uses a long-run capacity value methodology for the life of the distributed generation system.[47] In other words, utilities are responsible for predicting load growth and planning accordingly, so the full penetration of DSG installations should already be built into their plans, reflecting the incremental capacity benefits these systems provide.

Adding It All Together: Determining the capacity credit for DSG systems. There are two basic approaches taken to determine capacity credit: (1) determine the market value

[45] CPR 2012 MSEIA Study at pp. 32-33.

[46] 18 C.F.R. 292.304(e)(2)(vii) (providing that avoided cost may value "the smaller increments and shorter lead times available with additions of capacity from qualifying facilities").

[47] Crossborder 2012 California Study, Appendix B.1.

of avoided capacity; or (2) estimate the marginal costs of operating the marginal generator, typically a CCGT.[48] For the same reasons that it is less than ideal to rely solely on the future projected market price for energy, it is also unreliable to credit DSG based on the projected future capacity market. The preferred approach is to determine the capacity credit by looking at the capital and O&M costs of the marginal generator.[49]

The resulting value is often termed a capacity credit—a credit for the utility capacity avoided by DSG. It is important to recognize that this credit is different from the "capacity value" of DSG. Capacity value is a term for the percentage of energy delivered as a fraction of what would be delivered if the DSG unit was always working at its rated capacity, that is, as if the sun were directly overhead with no clouds and the temperature was a constant 72 degrees at all times. Capacity value is typically in the range of 15-25% in the United States, depending on location. Because DSG generates electricity during daylight hours, often with high coincidence with peak demand periods, it earns a capacity credit based on the higher value of its generation during the hours in which it operates—a higher amount than simple capacity value. Alternatively, for a utility with an early evening peak or a winter peak, the capacity credit may be based on a lower percentage of its rated capacity than the capacity value.

Once the ELCC is determined for DSG resources for a given utility, the calculation of generation capacity is straightforward. The capacity credit for a DSG system is "the capital cost ($/MW) of the displaced unit times the effective capacity provided by PV."[50] Inherent in the ELCC calculation are the line losses associated with capacity, as discussed earlier.

4. <u>*Calculating transmission and distribution capacity*</u>

Distributed solar generation, by its nature, is usually located in close proximity to load on the distribution system, which may help reduce congestion and wear and tear on T&D resources. These benefits can reduce, defer, or avoid operating expenses and capital investments. Tactical and strategic targeting of distributed solar resources could increase this value.

The ability of DSG systems to yield T&D benefits is location-specific and also depends on the extent to which system output correlates to cost-causing local load conditions, especially before and during peak load periods. Utilities undertake system resource planning (i.e., planning for upgrades or additions to T&D capacity) to meet peak load conditions, so the correlation of DSG output to peak load conditions is important to understand. On the distribution system, unlike the bulk transmission system, this is a more difficult undertaking because local cost-causing load conditions (i.e., the timing, duration, and ramping rates associated with peak load on a given circuit) will vary according to a number of factors. These factors include customer mix, weather conditions, system age and condition, and others. As a simple example, a circuit that carries predominantly single-family residential load is likely to rise relatively smoothly to a peak in early evening, when solar PV output is waning. A circuit primarily serving

[48] CPR 2012 MSEIA Study at p. 32.
[49] *Id.* at pp. 32-33.
[50] *Id.*

commercial customers in a downtown setting will typically peak in the early afternoon. All other things being equal, DSG systems on circuits primarily serving commercial customers are more likely to avoid distribution capacity costs.

It is also important to consider system-wide T&D impacts. Transmission lines, and to an extent, substations, serve enough of a cross-section of the customer base to peak at approximately the same time as the utility as a whole. DSG coincidence with system peak means that DSG, even located on residential circuits, contributes to reduced demand at the substation level and above. Based on interconnection procedures, DSG systems in the aggregate on a circuit do not produce enough to export power off of the circuit; they simply reduce the need for service to the circuit. The avoided need for transmission infrastructure creates an avoided cost value to a utility and should be reflected as a benefit for DSG systems. Combining any granular distribution value with avoided, peak-related transmission costs, all DSG may demonstrate significant T&D value in allowing the utility to defer upgrades or avoid capital investments.

Estimating T&D Capacity Value. To determine the ability of DSG systems to defer T&D upgrades or capacity additions, it is critical to have current information on the system planning activities of utilities, and to periodically update that information. Often, the cost information is obtainable through rate case proceedings, where the utility ultimately seeks to include the upgrade or capital project in rate base. To make use of any cost data, however, it is important to have a sufficient amount of hourly data on both load and solar resource profiles. Much of the relevant information is also contained in utility maintenance cost data, grid upgrade and replacement plans, and capital investment plans. Beyond the planning horizon, expense and investment trends must be extrapolated to match the expected useful generating life of DSG.

With the data in hand, T&D capacity savings potential can be determined in a two-step process.[51] As described by CPR, "The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations."

For solar PV profiles, output can be estimated at particular places using irradiance data and various methods of estimating the output profile.[52] By looking at the load profile for a year, it is possible to isolate peak days at the circuit or substation level and calculate a capacity credit by measuring the net load with solar PV production. By reducing absolute peak load, DSG systems may allow a utility to avoid overloading transformers, substations or other distribution system components and, thereby, to defer expensive capital upgrades.

To determine deferral value, it is necessary to monetize the length of time that DSG allows a utility to defer a capital upgrade. Deferring an upgrade allows a utility to avoid the carrying cost or the cost of ownership of an asset and defers substantial expenditures that may be, at least to some extent, debt financed. Generally, the

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[51] *Id.* at p. 33 (citing T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Energy Journal: 17(4), 1996).

[52] M. Ralph, A. Ellis, D. Borneo, G. Corey, and S. Baldwin, *Transmission and Distribution Deferment Using PV and Energy Storage*, published in Photovoltaic Specialists Conference (PVSC), 2011 37th IEEE, June 2011, *available at* http://energy.sandia.gov/wp/wp-content/gallery/uploads/TransandDistDeferment.pdf.

avoided capital is multiplied by the utility's weighted average cost of capital or authorized rate of return to determine the value of deferring that investment.[53] However, as noted earlier, a lower discount rate could be used. For instance, the avoidance of a million dollar transmission upgrade five years from now—for a utility with a 7% discount rate—is arguably worth that amount divided by (1.07)^5, or approximately $713,000. From the ratepayers' perspective, avoiding the million dollar upgrade in five years might be worth more; based on an estimated inflation rate of 3%, the value would be $862,000.

System-Wide Marginal Transmission and Distribution Costs. When conducting a statewide or utility-wide analysis, it may be difficult to hone in on specific locations to determine the ability of DSG systems to enable deferment or avoidance of system upgrade activity. In some cases, distribution deferral value manifests in changes in distribution load projection profiles and should be calculated as the difference in what would have happened without the DSG. E3's approach to valuing avoided T&D takes a broader look at the ability to avoid costs and estimates T&D avoided costs in a similar manner to other demand-side programs, such as energy efficiency. E3's avoided cost methodology develops "allocators" to assign capacity value to specific hours in the year and then allocates estimates of marginal T&D costs to hours. E3 acknowledges that it lacks sufficient data to base its allocators on local loads and that, ideally, "T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads."[54]

E3 determined that temperature data, which is available in a more granular form for specific locations in the many climate zones of California's major utilities, would be a suitable proxy method for allocating T&D costs. After determining these allocators and assigning them to specific hours, E3 determined the marginal distribution costs by climate zone, using a load-weighted average. Since marginal transmission costs are specific to each utility, those are added to the marginal distribution costs to arrive at the overall marginal T&D for a specific climate zone. This approach lacks the potential for capturing high-value, location-specific deferral potential, but it does approximate some value without requiring extensive project planning cost and load data for specific feeders, circuits, and substations. E3's methodology may be suitable in circumstances where there is limited local load data to develop what E3 described as an "ideal" methodology, but it does come with drawbacks. For example, allocating costs to certain hours by temperature may not correlate to peak conditions in certain locations.

Alternative Approaches to T&D Valuation. Clean Power Research also approached T&D value broadly in its study of Pennsylvania and New Jersey, taking utility-wide average loads in a conservative approach to valuation. CPR's Pennsylvania and New Jersey report notes that T&D value may vary widely from one feeder to another and that "it would be advisable to . . . systematically identify the highest value areas."[55]

Where information on specific upgrade projects is known, and there is sufficiently detailed local load data, a more detailed analysis of deferral potential should yield far more accurate results that better reflect the T&D value of DSG. For example, CPR was

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[53] *Id.*
[54] E3 Study, Appendix A at p. 16.
[55] CPR 2012 MSEIA Study at p. 20.

ablle to take a more granular and area-specific look at T&D deferral values of DSG in its Austin Energy study, where it had specific distribution system costs for discrete sections of the city's distribution system.[56]

In Vermont, the Public Service Department took a reliability-focused approach. Noting that T&D upgrades are driven by reliability concerns, the Department determined that the "critical value is how much generation the grid can rely on seeing at peak times." To capture this benefit, the Department calculated a "reliability" peak coincidence value by calculating the average generator performance of illustrative generators for June, July and August afternoons.[57] The resulting number reflects the percentage of a system's nameplate capacity that is assumed to be available coincident with peak, as if it is "always running or perfectly dispatchable."[58] Accordingly, the generation system receives the same treatment as firm capacity in terms of value for providing T&D upgrade deferrals at that coincident level of output.

The risk of the Vermont approach is that it may overstate the ability of certain generators to provide actual deferral of T&D upgrades, since system planners often require absolute assurance that they could meet load in the event that a particular distributed generation unit went down. Another apparent weakness of this approach is the inability to target or identify location-specific values in the dynamic, granular nature of the distribution system.

T&D Capacity Value Summary. Distributed solar systems provide energy at or near the point of energy consumption. When they are generating, the loads they serve are therefore are less dependent on T&D services than other loads. In addition, because DSG provides energy in coincidence with a key driver of consumption—solar insolation—these resources can reduce wear and tear. Calculating the T&D benefits of DSG requires data that allows estimation of marginal T&D energy and capacity related costs. Ideally, utilities will collect location-specific data that can support individualized assessment of DSG system value. In the absence of such data, system-wide estimations of T&D offset and deferral value can be used with reasonable confidence.

5. <u>Calculating grid support (ancillary) services</u>

Grid support services, also referred to as ancillary services in many studies, include VAR support, and voltage ride-through. Existing studies often include estimates of ancillary services benefits as well as costs associated with DSG, as reported in the RMI 2013 Study. Costs, also called grid integration costs, are discussed below.

Currently, DSG systems utilize inverters to change direct current to alternating current with output at a set voltage and without VAR output, and with the presumed functionality of disconnecting in the event of circuit voltage above or below set limits. This disconnection feature has become a concern, as a voltage dip with the loss of a major utility generator could lead to thousands of inverters disconnecting DSG systems, reducing voltage inputs and exacerbating the problem. In practice, inverters could be

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[57] Vermont Study at p. 19 (The Department looked at ten two-axis tracking solar PV systems, four fixed solar PV systems, and two small wind generators.).
[58] *Id.* at p. 19.

much more functional or "smart"; indeed Germany is in the process of changing out hundreds of thousands of inverters to achieve added functionality.

Because U.S. electrical codes generally preclude inverters that provide ancillary services, many valuation studies have concluded that no ancillary service value should be calculated. While that approach had some merit in the past, when more versatile inverters where generally unavailable and regulatory change seemed far off, the present circumstances warrant a near-term recognition of ancillary services value. With proof of the viability of advanced inverters, it is highly likely that advanced inverters will be standard in the next few years, and ancillary services will be provided by DSG.

A group of Western utilities and transmission planners recently issued a joint letter on the issue of advanced inverters, calling for the deployment as soon as feasible to avoid the sort of cascading problem described above, which could lead to system-wide blackouts.[59] With the utilities themselves calling for advanced inverter deployment, and costs expected to be only $150 more than current inverters, there will be good reason to collect the data and develop the techniques to quantify ancillary services benefits of DSG. Modeling these ancillary services is important to inform policy decisions such as whether to require such technology as a condition of interconnection, and under what circumstances.

6. Calculating financial services: fuel price hedge[60]

DSG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility. In addition DSG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. DSG 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.

The ideal method to capture the risk premium of natural gas uncertainty is to consider the difference between an investment with "substantial fuel price uncertainty" and one where the uncertainty or risk has been removed, such as through a hypothetical 30-year fixed price gas contract. As CPR explains, a utility could quantitatively set aside the entire fuel cost obligation up front, investing the dollars into a risk free instrument while entering into natural gas futures contracts for future gas needs.[61] Performing this calculation for each year that DSG operates isolates the risk premium and provides the value of the price hedge of avoiding purchases involving that risk premium.

Interestingly, utilities often used to hedge against fuel price volatility, but do less such hedging now. That leads some utilities to conclude that since the fuel price hedge benefit is not avoiding a utility cost, it should not be included. In practice, the risk of fuel price volatility is falling on customers even if the utility is not mitigating the risk. Reducing that risk has value to utility customers, even if the utility would not otherwise protect against it.

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[59] *See* L. Vestal, *Utility Brass Call for Smart-Inverter Requirement on Solar Installations*, California Energy Markets No. 1244, at p. 10, August 11, 2013.
[60] Clean Power Research now uses the term "Fuel Price Guarantee" in order to distinguish this benefit from traditional utility fuel price hedging actions.
[61] CPR 2012 MSEIA Study at p. 31.

7. Calculating financial services: market price response

Another portfolio benefit of DSG is measured in reductions to market prices for energy and capacity. By reducing demand during peak hours, when the price of electricity is at its highest, DSG reduces the overall load on utility systems and reduces the amount of energy and capacity purchased on the market. In this way, DSG reduces the cost of wholesale energy and capacity to all ratepayers.[62] This benefit is not captured by E3's methodology; it is reflected in CPR's most recent Pennsylvania and New Jersey study, where it is illustrated and explained in much greater detail.[63]

The premise of this benefit is that total expenditures on energy and capacity are less with DSG generation than without. The total expenditure, as CPR explains, is the current price of power times the current load at any given point in time. Because the amount of load affects the price of power, a reduced load condition, such as occurs as a result of DSG generation, reduces the market price of all other power purchases at those times.[64] While this change in market price is incrementally small, it represents a potentially significant system-wide benefit. This means that all customers, including non-solar customers, enjoy the benefit of lower prices during these reduced load conditions. As CPR notes, however, the reduction in price cannot be directly measured, as it is based on a hypothetical of what the price would have been without the load reduction, and must be modeled. The total value of market price reductions is the total cost savings calculated by summing the savings over all time periods during which DSG operates.[65] A similar analysis for capacity market prices can be conducted as well.

8. Calculating security services: reliability and resiliency

Particularly with the extended blackouts from Hurricane Sandy in 2012, a value is being attributed to added reliability and resiliency due to DSG, at both the grid and the individual customer levels. For grid benefits, this value in particular is difficult to quantify; it depends on the assumed risk of extended blackouts, the assumed cost to strengthen the grid to avoid that risk, and the assumed ability of DSG to strengthen the grid. With utility generation and T&D out of service, DSG can only do so much, and storm conditions often occur during periods of limited sunshine, so it is particularly hard to determine what DSG can do in this regard.

The ancillary services benefit discussed earlier is closely related to this benefit when considering the potential for the grid as a whole to continue operation. Even at the level of a circuit outage, the ancillary services benefit is capturing the value of providing VAR support and voltage ride-through. Arguably, the ancillary services benefit captures this level of grid support.

On the other hand, CPR noted in its first Austin Energy study that reliability and resiliency are very real DSG benefits at the individual customer level. The hospital with traditional backup generation powers up during an outage, and can be supported during a prolonged outage by the addition of DSG. Instead of relying entirely on the traditional generation and a substantial fuel supply, it can get by with less fuel. Likewise the

[62] *Id.* at 15.
[63] *Id.* at pp. 33-43.
[64] CPR 2012 MSEIA Study at p. 34.
[65] *Id.* at p. 36.

residential customer with a medical condition requiring certainty can rely on DSG plus battery storage rather than a generator.

To the extent that utilities have an obligation to provided heightened reliability to vulnerable customers, DSG can be counted as avoiding those utility costs. On a larger scale, to the extent that customers enjoy greater reliability than the utility would otherwise provide, that is a benefit to participating customers that can be included.

9. *Calculating environmental services*

A. Utility avoided compliance costs. The cost of complying with regulatory and statutory environmental requirements is a real operating expense of a generating plant and should be included in the avoided cost of generation. This avoided cost typically is included in the studies as a direct utility cost. In the CPUC's 2010 CSI Impact Evaluation report, conducted by Itron, the CSI general market program and the Self-Generation Incentive Program ("SGIP") were estimated to be responsible for reducing over 400,000 tons of CO_2 emissions in 2010. Additionally, the report estimated that the CSI general market program and the SGIP provided over 52,000 pounds of PM_{10} and over 92,000 pounds of NOx emissions reductions in 2010.[66] These reductions can be quantified and calculated against the market price for the relative compliance instrument. To the extent these values are fully reflected in the cost of the avoided energy, they should not be counted again in a DSG valuation analysis. It is important to account for only residual environmental compliance costs in estimating the benefit of DSG.

While certain emissions credit markets will be geographically tied to a small area with no established compliance market, the markets for NOx, SOx, and CO_2 are more readily identified and quantified with publicly available sources. Accordingly, any study of DSG should include the value of avoided compliance costs reflected in air emissions, land use, and any consumption and discharge costs associated with water.

Likewise, utilities in states with Renewable Portfolio Standards ("RPS") avoid RPS compliance costs due to DSG. For example, if a utility must comply with a 20% RPS and has a billion megawatt hours ("MWh") of annual load, it has to secure 200 million MWh of renewable generation. If instead, 100 million MWh is generated by DSG facilities, the utility's annual load is reduced by that amount and its RPS compliance obligation is reduced by 20 million MWh. The utility's cost of procuring those 20 million MWh should be considered, to the extent that the procurement is greater than the utility's avoided natural gas energy and capacity costs already attributed to those 20 million MWh.

Quantification of societal benefits is particularly difficult and controversial. Regarding environmental benefits, avoided utility compliance costs capture what society has decided are the proper tradeoffs of electricity generation for pollution, but society recognizes additional value related to not generating electricity from fossil generation in the first place. If DSG within a given utility service territory avoids a 100 million MWh of gas-fired generation, the utility avoids paying for the required clean up the emissions

[66] *California Solar Initiative 2010 Impact Evaluation* (California Public Utilities Commission), prepared by Itron, at p. ES-2, 2011, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

that never occurred. However, had the utility generated those 100 million MWh, millions of pounds of pollutants would have gotten past the required emissions controls, and not emitting all of those pollutants is a significant benefit to the society.

While most utility avoided costs benefit the utility's ratepayers directly, societal benefits tend to be spread beyond the utility's customers. Job creation can be expected to center in the utility's service territory, but will also lead to jobs in adjoining service territories. Emissions benefits are even more dispersed. The benefits are regional or global, with utility generation often far removed from utility customers. This is the traditional "tragedy of the commons[67]" problem, but on a global scale. As with the problem of colonial farmers not having an incentive to care for the commons on which their cows grazed, utilities use the environment but have no incentive to care for it beyond what is legally required. By recognizing the value of not emitting pollutants in a DSG valuation study, analysts capture this value that utilities would otherwise ignore. To say that this benefit is realized by society, but somehow not by utility customers, is to ignore the reality that society is made up of utility customers.

Again, we use the benefits categories outlined in the RMI 2013 Study, of which the last three address societal benefits and are listed here.

B. Carbon. The RMI 2013 Study breaks out carbon as a separate avoided cost, based on the significant uncertainty of carbon regulation. On the one hand, carbon markets and restrictions on carbon emissions have been frequently discussed, and tied to climate change. On the other hand, almost no carbon restrictions are currently in place, despite all of the discussion. Studies now five years old that presumed carbon costs by 2013 have been proven wrong. However, with the establishment of a carbon market in California, and the continuation of carbon markets in Europe, the likelihood of carbon costs throughout the U.S. is well beyond zero.

Even in the absence of a carbon market or carbon restrictions, the benefits of not emitting carbon are considered to be real by many people. While some have touted the benefits of carbon for plant life, the widespread view appears to be that emitting more carbon has a negative impact. One way to approach this is to consider what customers are willing to pay for reduced emissions of both carbon and other matter. For instance, Austin Energy uses the premium value for their GreenChoice® green power product in the absence of compliance cost information in its Value of Solar rate.

Another carbon valuation option is to use the added utility cost to comply with RPS targets. The argument for this approach is that if society has determined that a 20% RPS is appropriate, and renewable energy costs an extra $10 per MWH to procure, then it would presumably value additional avoided emissions (both carbon and other matter) at the same rate. However, RPS systems are compliance systems that integrate price impact controls, credit trading schemes, and other features that impact compliance certificate prices without direct relationship to the value of associated emissions reductions. Caution should be used in applying a regulatory system designed to minimize the cost of compliance with an effort to accurately value benefits net of costs.

[67] G. Hardin, "The Tragedy of the Commons," Science 13 December 1968: 1243-1248. Available at: http://www.sciencemag.org/content/162/3859/1243.full?sid=f031fb58-2f56-4c25-ac0e-d802771c92ef

Where a state has a RPS mandate for its utilities, DSG provides a dual benefit. First, it lowers the number of retail sales that comprise the compliance baseline. Second, it results in the export of 100% renewable generation to the grid to offset some mix of renewable and fossil-fuel generation being produced to meet customer load.[68] The first benefit was discussed above, under avoided utility compliance costs. The second benefit accounts for the fact that energy exports from DSG are 100% renewable generation and arguably should be valued at 100% of the RPS value for purposes of a cost-benefit study.[69]

Another way to look at this is to say that all exports from a DSG system should receive the value of a market-priced renewable energy certificate, even where such a generator cannot easily create a tradable certificate.[70] This is justified because DSG exports help meet other customers' load on the utility's grid with 100% renewable energy and displace grid delivered electricity, which is only partially renewable. If a state has an RPS of 33% renewables, as does California, then DSG exports give rise to at least a 67% improvement in the renewable component of electricity.[71]

C. Airborne Emissions Other than Carbon and Health Benefits. Exceeding utility compliance with air regulations can be taken into account in a manner akin to that described for valuation of avoided carbon emissions. The public health impacts of fossil fuel generation have been well documented, though not well reflected in electricity pricing. In particular, air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants. Impacts on crops and forest lands have also been documented.

DSG reduces fossil fuel generation, especially from less efficient peaker plants and potentially from thermal plants that emit higher levels of pollution during startup operations. We are not aware of a dominant methodology, but note that public health literature will continue to grow in the area of recognizing and quantifying the public health impacts of electric generation, including health impacts related to climate change. Valuing emissions of carbon and other matter based on green energy pricing programs or RPS compliance costs, as described earlier, is an effective way to capture this benefit. Even outside of states with such programs, the value of reduced emissions is not zero; the value ascribed by nearby states with programs could serve as a proxy.

D. Avoided Water Pollution and Conservation Benefits. The utility industry uses and consumes a substantial portion of the nation's freshwater supplies for thermoelectric generation.[72] The benefit of not using the water for fossil-fuel generation should be

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68 A third benefit associated with reducing overall market costs for renewable energy certificates may also manifest with increased DSG penetration.

69 Crossborder 2013 California Study at pp.18-21.

70 For example, owners of California NEM systems rarely bother to establish RECs related to their output given required documentation, and the treatment of RECs from NEM systems in a lower value "bucket" than RECs from systems with in-state wholesale sales to utilities.

71 Crossborder 2013 California Study at p. 18.

72 *How It Works: Water for Energy* (Union of Concerned Scientists), July 2013, *available at* http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-overview.html.

based on the value of the water to society, that is, the value of conserving water for other beneficial uses.

Valuing water is intrinsically difficult. The tangle of water rights laws among the states complicate the determination of water value. To the extent that utilities have specific contracts for delivery or withdrawal of water to serve particular plants, it is likely that those expenses are already captured as an operating expense of the plant, but those are often at historic, ultra-low rates. Where a plant uses potable water, the value should be based on what society is willing to pay for that water. Likewise, where a plant is using non-potable, reclaimed water for cooling purposes, the appropriate value might be the price that someone would pay for an alternate use, such as irrigation.

The value to society of conserving water, which is of growing importance in water constrained regions of the country, is not adequately captured by the contract price for water or in the retail price that one would pay for an alternate use. We are not aware of a dominant methodology for measuring the conservation value of water, but this value should be considered as utilities consume a tremendous amount of water each year and will be increasingly competing for finite water resources. Avoiding the increased risk associated with maintaining secure, reliable, and affordable supplies of water is a benefit that DSG, with its 30-year expected operating life, delivers to all customers of the utility system.

10. *Calculating social services: economic development*

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 and generates revenue locally. Economic activity associated with the growing rooftop solar industry creates 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.

Taking a conservative approach, CPR's Pennsylvania and New Jersey study focused solely on tax enhancement value, which derives from the jobs created by the PV industry in those states. CPR used representative job creation numbers from previous studies in Ontario and Germany that quantify the number of jobs created by installing a unit of solar PV. CPR used assumptions that construction of solar PV involves a higher concentration of locally traceable jobs than construction of a centralized CCGT plant and determined the net local benefit of a solar project on the economy.

There remains a legitimate regulatory policy question of whether economic development benefits should be considered in calculating the value of DSG for use in setting electricity rates, or avoided cost calculations, even though there is a long history of economic development factors influencing commercial rates and line-extension fees. In any event, the economic development and tax base benefits of DSG deployment and operation should be consider when evaluating the societal cost-effectiveness of the technology and policies to support it.

Checklist of Key Requirements for a Thorough Evaluation of DSG Benefits

- ☑ **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.

- ☑ **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.

- ☑ **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.

- ☑ **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.

- ☑ **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for their use; ancillary services will almost certainly be available in the near future. Modeling the costs and benefits of ancillary services can also inform policy decisions like those related to interconnection technology requirements. and provides a hedging benefit.

- ☑ **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.

- ☑ **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase for less, saving money.

- ☑ **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.

- ☑ **The utility's avoided environmental compliance costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture those pollutants.

- ☑ **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, and should not be ignored or not quantified.

V. Recommendations for Calculating the Costs of DSG

Distributed solar generation comes with a variety of costs. These include the costs for the purchase and installation of the DSG equipment, the costs associated with interconnecting DSG to the electric grid, the costs of incentives, the cost associated with administration and billing, and indirect costs associated with lost revenues and other system-wide impacts. As with cost of service regulation in general, the important principles of cost causation and cost allocation are critical in dealing with DSG costs as well.

DSG cost estimation depends on the perspective from which one seeks to examine policies. Some costs, depending on perspective, should not be treated as costs in a DSG valuation study at all. For example, the cost of a DSG system net of incentives and compensation that the individual solar customer ultimately bears—the net investment cost, does not impact other customers. Whether a customer pays $100,000 or $20,000 for a five kilowatt ("kW") DSG system, the avoided utility costs and the societal benefits are unchanged.

In general, solar valuation studies address costs in varying degrees according to the aim of the individual study. A convenient way to characterize solar costs is according to who bears them. Costs relevant to determining value or cost effectiveness can generally be grouped into three categories:

1. Customer Costs—Customer costs are costs incurred by or accruing to the customers who use DSG. These include purchase and installation costs, insurance costs, maintenance costs, and inverter replacement, all net of incentives or payments received.
2. Utility and Ratepayer Costs—Utility and ratepayer costs are costs incurred by the utility and ratepayers due to the operation of DSG systems in the utility grid. These include integration and ancillary services costs, billing and metering costs, administration costs, and rebate and incentive expenses. In NEM valuation studies, utility lost revenues are potentially a significant utility cost, under the assumption that there are no other mechanisms to adjust for these losses.[73]
3. Decline in Value for Incremental Solar Additions at High Market Penetration—A number of studies also identify modeled impacts associated with significant penetration of solar on the utility system. Most studies characterize low penetration as less than 5% of peak demand or total energy met by solar generation, and characterize high penetration as 10%-15% or more. These

[73] Lost revenues arise when market penetration of consumption-reducing measures like energy efficiency and distributed generation have sales impacts that exceed those forecasted in the last rate-setting procedure, and only last until the next rate-setting, when a true-up can occur. Between rate cases, trackers or other mechanisms to mitigate impacts of regulatory lag can also be installed. Valuation studies themselves do not dictate whether lost revenues occur or are recovered. This is a function of tariff design. In some jurisdictions, for example, stand-by charges are used to adjust for revenue losses under NEM. In others, Buy All-Sell All arrangements or Net Billing models are used.

impacts can be accounted for as a cost or as an adjustment to value credit for solar energy when long-term impacts are considered.

When evaluating the cost-effectiveness of NEM, most utilities have access to cost-of-service data that can measure energy-related impacts. As noted earlier, the most direct and obvious source of potential cost or benefit of NEM policy is the mechanism that sets NEM customers apart from general ratepayers—the ability to use electricity not consumed instantaneously (i.e., exported energy) against future purchases of electricity in the form of a kWh or monetary bill credit. The value that customers derive from these bill credits is solely assignable to NEM as a policy, as distinguished from changes in behind-the-meter consumption that could occur under PURPA, in the absence of NEM policy. Accordingly, it is only appropriate to examine the net value of exports, and not behind the meter consumption, as a cost to non-participating ratepayers. It is also appropriate to note that NEM export costs are likely different depending on the class of customer generating excess solar energy. The good news is that the easy starting point for calculating NEM export energy costs is the monthly sum of the bill credits appearing on the customer bill, already adjusted by customer class. These credit costs can then be netted against the value of avoided produced or purchased energy.

1. Recommendations for calculating customer costs

Most value of solar studies focus on utility, ratepayer, and society costs, but not private costs. Therefore, these studies do not address customer investments or expenses in DSG. On the other hand, these costs are part of the total cost effectiveness of solar and have been addressed in broader societal perspective studies or in evaluating cost effectiveness for a solar incentive program. NEM and VOST programs are not intended to be incentive programs, but rather to fairly compensate customers for DSG.

When customer costs are included for a broader societal test, a major challenge in evaluating forward-looking solar customer costs associated with a long-term policy relates to accurately predicting the market prices for solar systems and installation as well as maintenance costs.

Regarding customer O&M costs, NREL has estimated costs between 0.05 and 0.15 cents per kWh.[74] E3 estimates customer O&M costs at $20 per kW with an escalator of .02% per year, factors inverter replacement at $25 per kW, once every 10 years, and estimates insurance expenses at $20 per kW, escalating at .02% per year.[75] Together, these O&M costs are fractions of a cent when converted to kWh, in line with the NREL estimate.

As noted, customer costs are rarely relevant to DSG policy valuation studies. The relevant question when evaluating DSG programs is what the net effect is on other utility customers.

2. Recommendations for calculating utility costs

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[74] *Photovoltaics Value Analysis* (National Renewable Energy Laboratory), February 2008, *available at* http://www.nrel.gov/analysis/pdfs/42303.pdf.

[75] *Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment* (Energy & Environmental Economics, Inc.), March 2012 ("E3 Technical Potential Study 2012"), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

The most significant utility cost for NEM program valuation purposes is avoided revenue. A customer who used to pay $1000 per year to her utility and then installed a NEM system and cut her bills to only $200 per year is seen as costing the utility $800 of lost revenue. Again, to the extent that the customer could install the same system under PURPA and reduce her bill to $300 per year, the net cost of the NEM program would only be $100, representing the extra savings that she realized due to the NEM program. For a VOST program, the intent is to determine the value of the benefits and credit that amount to customers for all generation. In effect, the cost of the program is automatically equated to the benefits of the program, net of charges for consumption or network services.

The second largest utility or societal cost of DSG programs is the cost of incentives, though this cost is declining rapidly. Incentive costs are direct costs when the utility provides the funding from ratepayers, but are indirect when considering taxpayer-funded incentives. While incentive costs are real, they are primarily justified on market-stimulation bases, and scheduled to expire in a matter of years. Given that independent rationale for incentives, incentive costs are generally not included in DSG valuations. As the installed cost of DSG has declined, the need for incentives and rebates has diminished, with the California market reaching the end of its state incentive program almost entirely, and federal incentives slated to end in 2016.

Integration costs are the third most important utility cost for NEM programs, and the leading factor for value of solar studies addressing utility costs. Integration costs include the direct costs associated with administration of utility functions associated with distributed solar systems, rebates and incentives, and other administrative tasks. Direct costs can be addressed as a cost or as a decrement to the benefits of DSG, since these costs enable the benefits.

Reports of utility costs vary most significantly with the assumed solar penetration rate used in the study. Integration costs are variously labeled as "integration costs," "grid support expenses," or "benefits overhead." Estimates of these costs range from 0.1 to 1 cent per kWh in studies that attempt to account for increased variability in the overall generation mix and resulting increases in ancillary services costs starting from very low solar penetration rates. Solar integration costs for a 15% market penetration level were estimated at 2.2 to 2.3 cents per kWh by Perez and Hoff, based on an analysis that focuses on the need and cost of storage to complement solar intermittency in order to provide firm capacity.[76] Navigant and Sandia performed an assessment of high penetration of utility scale solar in 2011 and estimated integration costs associated with increasing production to account for solar variability at between 0.31 cents for low penetration and 0.82 cents for higher penetration of roughly one gigawatt of installed solar.[77]

In states like California, where utilities are prohibited from charging solar customers for interconnection costs or upgrades, interconnection costs may be a substantial source of costs directly assignable to a DSG program. Where this is the case, it is necessary to have real, disaggregated data that tracks the exact interconnection costs of DSG. In

[76] CPR 2012 MSEIA Study at p. 47.

[77] *Large Scale PV Integration Study* (Navigant), July 2011, *available at* http://www.navigant.com/insights/library/energy/2011/large-scale-pv-integration-study/.

the E3 study, for example, utilities did not have sufficient detail on interconnection costs in 2009 to provide a clear or transparent picture on the extent of those costs, or whether the costs incurred were reasonable and not blended in with other upgrades that would have occurred without the solar generator's interconnection. Interconnection costs should, in theory, be clearly identifiable through utility-provided data. In analyzing the value of distributed solar, these costs should also be amortized against the useful life of the measures.

In states where customers are responsible for interconnection costs and upgrades, however, this would not be a cost assignable to DSG policy. As with other customer costs, this is not a cost borne by the utility and should not be factored into an evaluation of the impact of a DSG policy on other customers.

Experience and more sophisticated modeling will be required to understand the shape and ultimate level of the integration cost curve. While integration costs are likely low at low market penetration levels, they are also likely to increase with market penetration. But these increases may decline as solar systems become more widely dispersed and as utilities begin targeting deployment to high-value locations within the grid. In addition, increased deployment of other distributed technologies, such as electric vehicles, distributed storage, load control, and smart grid technologies will impact the costs associated with larger scale DSG deployment.

The billing and administration costs associated with DSG encompass the one-time setup expenses of processing and verifying applications and the ongoing expense of administering unique features of solar customer bills. In states with modest numbers of solar customers, it is not uncommon to manually adjust solar customer bills, with associated incremental costs. Depending on the utility's accounting practices and billing capabilities, solar-specific billings cost should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be, as was determined in the Vermont study, nearly zero.[78]

In some cases, utilities will incur costs directly associated with DSG that are not fairly assignable to DSG policy. For example, in Texas, renewable energy generators under one MW are classed as "microgenerators," subject to registration and reporting requirements under the state's renewable energy portfolio standard law.[79] To the extent that the utility acts as a program manager and aggregator of renewable energy certificates assigned by solar generators, these costs are not fairly assigned to NEM or other solar promotional program unless also offset by the value of the assigned certificates.

3. Recommendations for calculating decline in value for incremental solar additions at high market penetration

The incremental positive value of additional solar deployment within a particular utility service territory is anticipated to decline as solar penetration levels increase. There are two major drivers of these impacts, which are not technically costs, but actually

[78] Vermont Study at p. 15.
[79] *See* 16 Tex. Admin. Code 15, *available at* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

decrement adjustments that impact value of solar in the context of expanding markets and higher solar penetration.

These impacts address the value of additional deployments and not past installations, and not replacement installations. The two major drivers are the expected reduction in capacity credit for solar and reduced peak energy value as market penetration increases. Capacity credits for solar are typically higher than capacity factor due to good solar coincidence with peak demand periods. However, as more solar is added to a system, the difference between peak and non-peak demand dissipates. Without storage, solar has a limited ability to reduce a system peak that is essentially shifted forward into evening hours. As a result, the incremental capacity benefit of solar is reduced for incremental additions as penetration increases. This impact could reduce capacity credit by 20-40% as penetration rates approach 15%.[80]

To the extent that solar energy is generated at periods of high utility cost, it provides great value. As the penetration rate of solar increases, peak market prices are likely suppressed, reducing the value of incremental solar energy. E3 estimated the reduced energy value at 15% over ten years in a study for California.[81]

Much work is needed in measuring and modeling the impact of high penetrations of DSG to address exactly how much DSG creates high penetration impacts, and inserting this clarity in valuation and cost effectiveness studies. Most states receive less than 0.5% of peak energy from distributed solar generation, while most studies looking at high penetration model levels at 10-15%. As noted earlier, the most relevant costs to consider are those that will occur at more modest penetrations. For example, if capacity benefits decline significantly at higher penetrations, that does not justify finding low capacity benefits at early stages.

Other important issues to be addressed include the impacts of different assumptions regarding geographic region, system size, and long-term changes in energy demand. It is important to note that both the capacity credit and energy value deterioration could be mitigated through consideration of energy sales from areas of high solar penetration to areas of lower penetration. For example, utilities facing near term surplus capacity situations could incur short-term lost revenues that could be mitigated over the period that solar systems operate, creating the potential for net benefits over that longer term.

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[80] *See* LBNL Utility Solar Study 2012, *supra*, footnote 13.
[81] *See* E3 Technical Potential Study 2012, *supra*, footnote 74.

Checklist of Key Requirements for a Thorough Evaluation of DSG Costs

- ☑ **Is lost revenue or utility costs the basis of the study?** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
- ☑ **Assumptions about administrative costs must reflect an industrywide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
- ☑ **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
- ☑ **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

VI. Conclusion

Valuations vary by utility, but valuation methodologies should not. In this report IREC and Rabago Consulting LCC suggests a standardized approach for calculating DSG benefits and costs that we hope proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Please see the mini-guide at the end of this report for a quick reference guide to the recommendations in this report.

IREC

REGULATOR'S MINI-GUIDEBOOK

Calculating the Benefits and Costs of Distributed Solar Generation

Valuations vary by utility, but valuation methodologies should not. IREC and Rábago Energy LLC suggest a standardized approach for calculating DSG benefits and costs in the white paper "A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation." We hope that this paper proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Below is a high-level summary of the recommendations in the white paper. Please see the full report for more detail per section.

A. KEY QUESTIONS TO ASK AT THE ONSET OF A STUDY

Q1: WHAT DISCOUNT RATE WILL BE USED?

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Recommendation: Expect DSG to last for thirty years, as that matches the life span of the technology given historical performance and product warranties. Interpolate between current market prices (or knowledge) and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, the utility can plan for lower loads than it otherwise would have. In contrast, other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, but rather the customer facilities contribute to the available capacity of utility resources.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Recommendation: The most important penetration level to consider for policy purposes is the next increment: what is likely to happen in the next three to five years. If a utility currently has 0.1% of its needs met by DSG, consideration of whether growth to 1% or even 5% is cost-effective is relevant, but consideration of whether higher penetrations are cost-effective can be considered at a future date.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?
Recommendation: Transparent input models that all stakeholders can access will establish a foundation for greater confidence in the results of the DSG studies. When needed, the use of non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?
Recommendation: It is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

Recommendation: It may also be appropriate to consider impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [82]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Recommendation: We recommend that ratepayer and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the full assumed DSG life of 30 years. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options.

B. DATA SETS NEEDED FROM UTILITIES

- ☑ The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG
- ☑ Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy
- ☑ Hourly production profiles for NEM generators, including south-facing and west-facing arrays
- ☑ Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated
- ☑ Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit

[82] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012 (nt Processes energy credits could *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

- ☑ Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth
- ☑ Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades

Note: where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

C. RECOMMENDATIONS FOR ASSESSING BENEFITS

1. **The following benefits should be assessed:**
    1. Energy
    2. System Losses
    3. Generation Capacity
    4. Transmission and Distribution Capacity
    5. Grid Support Services
    6. Financial: Fuel Price Hedge
    7. Financial: Market Price Response
    8. Security: Reliability and Resiliency
    9. Environment: Carbon& Other Factors
    10. Social: Economic Development
2. **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
3. **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
4. **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
5. **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
6. **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for

their use; ancillary services will almost certainly be available in the near future. Modeling the benefits and costs of ancillary services can also inform policy decisions like those related to interconnection technology requirements.

7. **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and that the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.

8. **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase these services for less, saving money.

9. **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be reduced or avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.

10. **The utility's avoided environmental compliance and residual environmental costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture or control those pollutants.

11. **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, which should not be ignored and should be quantified.

D. RECOMMENDATIONS FOR ASSESSING COSTS

1. **Determine whether lost revenue or utility costs are the basis of the study.** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.

2. **Assumptions about administrative costs should reflect an industry-wide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.

3. **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.

4. **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

EXHIBIT
Vote Solar-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

REBUTTAL TESTIMONY OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

APRIL 7, 2016

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1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 360 22nd Street, Suite 730, Oakland, CA.

Q. On whose behalf are you submitting this rebuttal testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Did you submit direct testimony in this proceeding?

A. Yes, I did. My direct testimony contains an introduction to Vote Solar, as well as a summary of my professional experience.

2 Purpose of Testimony and Summary of Recommendations

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of five main sections. The first section discusses the common ground among parties to this proceeding on analyzing exports and self-consumption separately. The second section discusses the cost-of-service study ("COSS") evidence presented in the direct testimonies of Arizona Public Service Company ("APS") and Tucson Electric Power Company and UNS Electric ("TEP/UNSE"). The third section addresses various proposals for approaching the valuation of distributed generation ("DG"), and discusses why DG should be valued using the long-term avoided-cost approach. The fourth section discusses two issues brought up in the direct testimony of other parties concerning (1) the distribution of DG benefits, and (2) attempts by parties to make rate design recommendations in this docket. Finally, the fifth section summarizes my recommendations.

Q. Please summarize your findings and recommendations.

A. First and foremost, I find it is important for the Commission to determine what aims to accomplish in this proceeding. Commissioner Little's letter to the docket indicated that he envisions the following result from this proceeding:

> Development of a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Since the specifics of each rate case are different and can vary widely for each utility and service area, the methodology would not assign specific values, but rather provide guidance as to how values would be determined in the context of an individual rate case.[1]

I fully support this approach and recommend that the Commission keep this vision in mind while evaluating the testimony provided by parties to this proceeding. To this end, I recommend that the Commission not make findings on specific evidence from cost of service studies introduced in this docket, nor analyses of the long-term value of solar. The role of this docket should remain the development of a robust and standardized methodology for the valuation of DG; a methodology that can be employed in future proceedings to develop specific findings for each Arizona utility.

In my review of other parties' testimonies I found there appears to be common ground among several parties on the need to analyze self-consumption and DG exports separately. This approach is supported by Commission Staff ("Staff"), The Alliance for Solar Choice ("TASC"), and Vote Solar, and appears to be in line with statements made by APS. I recommend that the Commission recognize that what truly differentiates DG customers from other utility customers is the ability to export excess energy to the grid. All customers should have the right to make a choice to consume as much or as little energy from their utility as they like—whether they modify their consumption patterns through behavioral change, use of technology (including efficiency and DG), or because their life circumstances change (e.g., their kids go off to college).

[1] Commissioner Little's Letter to the Parties at 1, Dec. 22, 2015 ("Guidance Letter").

As a result, I recommend that the Commission separately consider the value of DG exports and the value of self-consumption, and that this proceeding develop a robust, standard methodology for valuing DG exports. To determine the appropriate rate treatment for utility service to DG customers, these customers should be analyzed in forthcoming utility cost-of-service studies in a fair and transparent way based on well-developed COSS allocation methodologies. Through a separate analysis, appropriate compensation for DG exports should be evaluated over the useful life of the DG system using a long-term avoided cost approach. I do not recommend that the Commission set the export rate precisely at the value determined for solar. Rather, the best approach would be to quantify the value of solar and then to make a policy decision regarding the best export rate level that would ensure the benefits of solar are shared with non-participating ratepayers, while also providing sufficient compensation to incent DG adoption.

I was only able to conduct a limited review of the COSS evidence provided in this docket by APS and TEP/UNSE. APS's COSS evidence in this docket is the product of a proprietary back-end model that does not allow intervenors to fully evaluate the model functionality nor carry out alternate analyses. As a result I was able to review the assumptions made by APS but was not able evaluate how the COSS findings would change if the assumptions were modified. APS found that net energy metering ("NEM") customers shift $29-67 per month in costs to non-NEM customers, but I found significant flaws that overinflate the costs allocated to NEM customers and conflate costs and revenues associated with utility services with compensation provided to NEM customers for exported energy. As a result, I do not find that there is sufficient evidence in this proceeding to support the alleged cost shift calculation put forth by APS.

My ability to review the TEP/UNSE COSS evidence has been even more limited. TEP/UNSE has presented evidence from three TEP-related cost of service studies in this docket but failed to provide Vote Solar with timely access to working COSS models or functioning work papers that would allow for an evaluation of the methodologies and assumptions therein.[2] As a result, my ability to review the reasonableness of the COSS-based evidence, including TEP/UNSE's claim that NEM customers shift $874-967 per year to non-NEM customers has been extremely limited. The limited information from TEP/UNSE that I was able to review indicates that TEP/UNSE's analysis overinflated the cost to serve NEM customers, conflated revenues and costs associated with utility service with compensation paid for exports, and did not appropriately take into account the impact of TEP's request for a $109.5 million revenue increase in its currently open rate case.[3] As a result, there is insufficient evidence in this proceeding to support the alleged cost shift calculation put forth by TEP/UNSE.

In light of my findings that there are significant methodological flaws in APS's and TEP/UNSE's approaches to quantification of the alleged NEM cost shift and the intended scope of this proceeding as indicated by Commissioner Little, I recommend that the Commission not make findings on specific evidence regarding the existence of a NEM cost shift in this proceeding.

I recommend that future cost of service studies evaluated in the context of individual utility rate cases analyze NEM customers in the same manner in which other customers are analyzed: based on delivered load. Utility cost of service studies include standard measures of load for purposes of cost allocation, including energy usage, non-coincident peak demand of the customer class, average and excess demand, etc. These allocation factors are designed to model the load attributes that

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[2] In response to discovery due March 30, 2016 and negotiations between TEP/UNSE and Vote Solar regarding the confidentiality of the spreadsheet analyses, TEP/UNSE provided Vote Solar with confidential work papers to its analyses on April 5, 2016, two days prior to the due date for filing rebuttal testimony in this case. I have not had a chance to conduct any substantive review of the work papers in advance of filing this testimony, but may conduct such review in advance of the hearing, and reserve the right to provide additional substantive response to the evidence at that time.

[3] *See* ACC Docket No. E-1933A-15-0322, *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 the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona and for related approvals*, Sep. 9, 2015.

cause costs to the utility system and may be used to analyze the cost to serve a utility's NEM customers.

I also recommend that this proceeding develop a robust, standardized methodology for valuing DG exports, and that DG exports be analyzed separately from self-consumption. I review the valuation methodologies discussed by other parties to this proceeding. I find that the short-term avoided cost approach is flawed and would not fully capture the costs and benefits associated with DG. I additionally find that the grid-scale benchmarking approach creates a false comparison between DG and utility-scale solar and does not have merit for consideration as an approach to setting an export rate for DG. I recommend that a robust and standardized methodology be developed to quantify the long-term valuation of DG exports from the perspective of the non-participating ratepayer over the useful life of the DG asset. The results of such an analysis can be used to inform the appropriate compensation of DG customers for energy exports.

I additionally discuss two other issues raised by parties in this proceeding. The first issue relates to a mischaracterization of the empirical evidence regarding income distribution of solar customers. I find that empirical evidence from Arizona demonstrates that DG is being installed across the income spectrum with a proportionate amount of solar installations at the lower ends of the income spectrum. I additionally find that if a robust approach to the quantification of the costs and benefits associated with DG can be used to set a rate for exports that allows a sharing of net benefits between customers that do and do not install DG, all customers will benefit, regardless of income level.

The second and final issue relates to the attempt by parties in this proceeding to affect rate design policy in this docket. I recommend that the Commission determine that this docket is not the appropriate venue for such recommendations and that it would not be appropriate to consider specific rate design proposals absent a body of evidence to support those proposals including utility cost of service studies and bill impact analyses—neither of which have been provided for the rate design recommendations discussed in this case.

3 Common Ground Among Parties on Analyzing Exports and Self-Consumption Separately

Q. Have you reviewed the direct testimony filed by other parties to this proceeding?

A. Yes. I have reviewed the direct testimony filed by Staff; the Arizona Investment Council ("AIC"); APS; the Grand Canyon State Electric Cooperative Association ("GCSECA"),; the International Brotherhood of Electrical Workers ("IBEW"),; the Residential Utility Consumer Office ("RUCO"); Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"),; TASC; and TEP/UNSE.

Q. Have you identified any areas of agreement among the parties in this proceeding?

A. Yes. While there are a number of significant disagreements among the parties in this proceeding, it appears that a number of parties support similar positions on analyzing DG exports and self-consumption separately.

Q. Please discuss the parties' positions on the separate consideration of self-consumption and exports.

A. Staff witness Howard Solganick addresses this issue directly with the following statement:

> Staff's perspective is based on the concept that what happens behind the meter is the customer's business. Whether load is reduced by conservation, insulation, high efficiency appliances, storage or the installation of a DG system that is solely the customer's right and decision and a proper rate structure will offer accurate price signals to assist a customer making a decision. Any excess energy not needed by the customer can then be delivered to the utility and purchased at its value at the time and location of delivery.[4]

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[4] Direct Test. of Howard Solganick 7:8-13 ("Solganick Direct").

TASC witness Beach also recommends "that the appropriate framework for assessing the relative benefits and costs of net metering is to focus on the value that customer receives for the electricity that is exported from their premises."[5]

These statements echo Vote Solar's argument presented in my direct testimony that every customer should have the individual right to choose how much energy to consume or not consume from the utility.[6] In support of this position, Vote Solar has proposed that the methodology for evaluating the costs and benefits of DG focus on the question of "whether the price paid for DG exports appropriately reflects the value of the energy provided."[7] Self-consumption of DG is best addressed in individual utility rate cases.[8]

Q. Do any of the utilities share this view?

A. Yes, statements by APS appear to show common ground on this issue. For example, APS witness Snook states:

> [T]he methodology for determining Value of Solar established by the Commission as a result of this docket should be approved as an appropriate analysis tool for determining (i) the value of solar in the resource planning context; and (ii) calibrating the price paid for *energy exported to the grid from rooftop solar arrays*.[9]

Q. Based on your review of other parties' positions on this issue, do you have any recommendations for the Commission?

A. I recommend that the Commission recognize that a bright line exists between self-consumption of DG and the energy customers export to the grid. The Commission should explicitly recognize the right to self-consume electricity generated on private property largely through private investment. Based on this recognition, the Commission should ensure that customers who choose to install DG or any other technologies that modify their consumption of utility-delivered energy are treated the

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[5] Direct Test. of R. Thomas Beach at i ("Beach Direct").
[6] Direct Test. of Briana Kobor 8:26-9:2 ("Kobor Direct").
[7] Kobor Direct 8:21-23 (emphasis omitted).
[8], *Id.* 9:12-16.
[9] Direct Test. of Leland Snook 2:9-12 ("Snook Direct") (emphasis added).

same as their next-door neighbors who have not installed such technologies regarding cost-of-service allocation and rate design methodologies, tariffs under which they may take service, and/or any applicable charges imposed by their utility. This proceeding should focus on the appropriate level of compensation for DG exports only. The Commission should seek to develop a methodology for ensuring that the price paid for exports reflects the long-term value of the energy provided from the perspective of the non-participating ratepayer.

4 Cost of Service Studies should analyze NEM Customers in a fair and transparent way

Q. Please describe the COSS evidence put forth by parties to this proceeding.

A. Witnesses from APS and TEP/UNSE have sponsored cost of service studies purporting to show that a cost shift exists from NEM customers to non-NEM customers. APS claims that NEM customers on two-part rates shift approximately \$29-67 per month in costs to non-NEM customers.[10] TEP/UNSE claims that TEP's NEM customers shift \$874-967 per year to non-NEM customers.[11]

Q. Have you been able to evaluate the reasonableness of these utility-reported cost shifts?

A. Unfortunately, I have not been able to comprehensively evaluate the utility-reported cost shifts because the utilities have not provided data allowing me to do so.[12] I was able to evaluate inputs to APS's COSS and have found it to be based on flawed and inconsistent methodologies. As a result, the APS COSS overinflates the cost to serve

[10] Snook Direct 3:18-22.

[11] Direct Test. of H. Edwin Overcast 5:14-15 ("Overcast Direct").

[12] APS has indicated that they are using a new cost-of-service model with a proprietary back-end. They have provided spreadsheets with inputs and outputs to the model as well as a proxy version of the model, but the proxy version is not linked to the inputs and outputs provided and therefore does not enable a full evaluation nor assessment of results under alternate scenarios. In conversations with APS they indicated that they would not be willing to re-run the model with alternate assumptions in this case.

NEM customers, conflates the cost to serve with the compensation paid for DG exports, and skews the results. While TEP/UNSE has entered testimony in this docket regarding various measures of the cost of service and purported cost shifts, it has failed to provide Vote Solar with functioning copies of the cost of service studies in a timely manner and as a result I have not been able to fully examine the methodologies used, nor the conclusions reached in the testimony of Dr. Overcast.[13] My limited review based on the available information indicates flaws in the TEP/UNSE methodology that overinflate the results. These findings are discussed in detail separately for APS and TEP/UNSE in the following sections.

4.1 APS Cost-of-Service Study

Q. Please describe the approach used by APS to evaluate the costs to serve its NEM customers.

A. Mr. Snook uses a cost-of-service study based on embedded costs from test year 2014 to evaluate costs to serve APS's NEM customers.[14] Mr. Snook describes the COSS as follows:

> A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."[15]

To examine NEM customers specifically, APS grouped its existing NEM customers into two classes: NEM customers on "energy-based" or two-part rates (Schedules E-12, ET-1 and ET-2) and NEM customers on "demand-based" or three-part rates

[13] In response to discovery due March 30, 2016 and negotiations between TEP/UNSE and Vote Solar regarding the confidentiality of the spreadsheet analyses, TEP/UNSE provided confidential work papers to its analyses on April 5, 2016, two days prior to the due date for filing rebuttal testimony in this case. I have not had a chance to conduct any substantive review of the work papers in advance of filing this testimony but may conduct such review in advance of the hearing and reserve the right to provide additional substantive response to the evidence at that time.
[14] Snook Direct 8:3-5.
[15] *Id.* 7:8-12.

(Schedules ECT-1 and ECT-2).[16] APS allocated costs to these groups of customers based on the NEM customer's entire load at the customer's home, including the portion of the load served by APS-delivered energy and the portion served by the energy the customer generated with his/her DG system.[17] APS then applied "credit[s]" to the NEM customers based on APS's assessment of capacity and energy savings resulting from the customer's DG production.[18] Mr. Snook summarizes his discussion of this methodology by stating: "The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide."[19]

Q. Do you support this methodology?

A. I do not. In APS's own words, the COSS is designed to "align the rates customers pay for the services received."[20] However, allocating costs to NEM customers based on their total site load does not align with the services received. NEM customers' site loads are served only partially by their utility, with their DG systems serving some portion of their loads as well. It is wholly inappropriate to allocate utility costs to NEM customers based on services the utility did not provide. The only appropriate basis for allocating costs in the COSS is allocation based on the services provided by the utility, which for all customers, NEM and non-NEM, is delivered load.

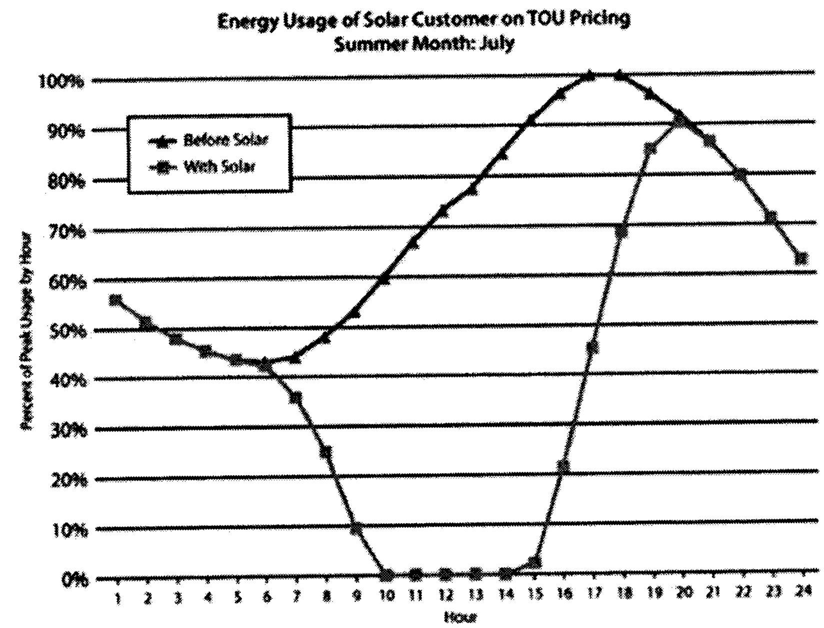
Reaching behind the meter and allocating NEM costs based on total site load (regardless of whether a portion of the load is met by self-generation) is equivalent to allocating costs to a customer for the energy they would have consumed had they not installed energy-efficient windows, or the energy they would have consumed had their kids not gone off to college. When a customer chooses to install new technology or undergoes a lifestyle change that affects their energy consumption, the services

[16] *Id.* 15:9-12.
[17] *Id.* 15:14-17.
[18] *Id.* 15:18-23.
[19] *Id.* 15:26-16:2.
[20] *Id.* 7:9-11.

they require of their utility change. As a result, the utility's service to that customer changes.

Mr. Snook claims that NEM customers have "vastly different load characteristics, [that] warrant evaluating them as a separate sub-class."[21] To support this, he provides a figure depicting hourly energy usage by a NEM customer during July. That figure is copied below for illustrative purposes.

Figure 1: Figure from APS Witness Mr. Snook's Direct Testimony[22]



APS's methodology would allocate costs to NEM customers based on the "Before Solar" load shape shown on the top of Figure 1, with measures for crediting the customer based on APS's definition of the energy and capacity value associated with DG production. APS claims this load difference necessitates separate evaluation of NEM customers, but it ignores this difference in the COSS. The only way to fully capture the different load characteristics of NEM customers in the cost-of-service study is to examine the cost to serve those customers based on their delivered load. Delivered load is depicted as the "With Solar" load shape on the bottom of Figure 1.

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[21] *Id.* 12:12-14.
[22] *Id.* 13, fig. 2.

Q. How do you propose APS evaluate the cost to serve its NEM customers?

I recommend that APS examine the cost to serve its NEM customers using standard COSS allocation methods based on their delivered load. APS has presented an embedded cost study providing an historical snapshot of utility costs. APS has additionally presented a methodology for allocating those costs to its customers based on a number of standard measures (i.e., energy-related costs are allocated based on kilowatt-hour ("kWh") consumption, distribution costs are allocated based on non-coincident peak and individual customer peak, etc.). This method is widely accepted and may be used to capture the cost to serve groups of customers based on the allocation methods contained therein. Evaluating NEM customer costs based on delivered load would appropriately capture the cost to serve these customers.

Q. How does your recommended COSS methodology address costs and benefits of energy exports?

A. It doesn't. My recommended methodology separates self-consumed DG from DG exports. I recommend that the Commission ensure that customers who choose to install DG or any other technologies that modify their consumption of utility-delivered energy be treated the same as their next-door neighbors who have not installed such technologies regarding cost of service allocation and rate design methodologies, tariffs under which they may take service, and/or any applicable charges imposed by their utility. Rates that solar customers pay for energy deliveries from the utility should be based on standard cost-of-service principles and developed through utility cost-of-service studies in the context of individual utility rate cases.

What truly differentiates customers with solar DG from other customers is the DG customers' ability to export energy to the grid. The Commission should recognize that exports are appropriately evaluated separate from self-consumption and should use this proceeding to develop a robust, standardized methodology that would allow the Commission to adjust the DG export rate such that the price paid for exports appropriately reflects the value of the energy provided. To be clear, I do not recommend that the Commission set the export rate precisely at the value determined for solar. Rather, the best approach would be to quantify the value of solar and then to make a policy decision regarding the best export rate level that would ensure the benefits of solar are shared with non-participating ratepayers while providing sufficient compensation to incent DG adoption.

My recommendations are in line with APS's own statements that "compensation to a solar customer for net energy exported to the grid is distinct from the design of that customer's rate as established through a COSS."[23] Separating self-consumed DG from DG exports also recognizes Staff's position that "what happens behind the meter is the customer's business."[24] The costs and benefits associated with energy exports are better addressed through a value of solar study than conflated with cost-of-service ratemaking.

APS states "[a] valid Value of Solar study is a resource planning exercise and should not be conflated with a cost-of-service analysis used for ratemaking."[25] However, their own proposed methodology conflates the two. Rather than heed their own advice by "[u]sing a COSS to set rates [to protect] customers by ensuring that customers pay only for actual costs that they cause,"[26] APS has elected to allocate costs to NEM customers based on services not provided by the utility and to partially credit these customers based on their short-term evaluation of the value of solar. This short-term evaluation of the value of solar is flawed and including it in the COSS does not align with APS's own goals of cost-of-service ratemaking.

Q. **Why do you believe that APS's short-term evaluation of the value of solar is flawed?**

A. APS's short-term evaluation of the value of solar includes two "credits" that are applied to NEM customers in the COSS. The first is a credit for all energy produced by the DG system, both that which is consumed onsite and that which is exported to

[23] *Id.* 28:22-24.
[24] Solganick Direct 7:8-9.
[25] Snook Direct 30:18-20.
[26] *Id.* 29:10-11.

the grid.[27] The second is a credit for self-provided capacity that APS says is based on a comparison between site load and delivered load.[28]

It is not appropriate to allocate costs to NEM customers based on energy they do not consume from the utility, and then to partially "credit" them for that energy. APS's 2014 COSS data show that NEM customers on energy-based rates consumed an average of 14,700 kWh, yet APS only delivered an average 10,600 kWh to those customers. Rather than account for the fact that APS did not provide the difference of 4,100 kWh per customer, APS's methodology instead credits them based on the rate applied to net excess generation under the current net metering tariff (Schedule EPR-6) at a value of 2.895 c/kWh.[29] This approach is akin to allocating costs to a customer who installed a more efficient air conditioning unit based on what they would have consumed absent the new air conditioning unit and crediting them 2.895 c/kWh for their reductions. The more appropriate methodology would be to allocate costs to the customer based on what the utility actually provides: delivered load.

APS's approach to crediting NEM customers for self-provided capacity suffers from similar methodological issues. APS has indicated that this credit is designed to provide NEM customers with a credit for their reduced demand on APS's system.[30] To accomplish this, APS employs a complicated methodology that involves averaging the difference between delivered and site load based on the measures of demand during the system's four summer peaks ("4CP") and non-coincident peak demand. APS claims that "[t]his is consistent with the 'average and excess' method of allocating production demand cost required by the ACC."[31] While it is not clear that this approach is in fact consistent with the average and excess demand method, it also begs the question of why this after-the-fact calculation would be necessary if APS instead employed the average and excess demand method to allocate costs based on delivered load in the first place.

[27] *Id.* 15:22-23.
[28] *Id.* 15:20-21.
[29] APS's Resp. to Vote Solar 2.3, APS15768 at 1 of 37.
[30] *See generally id.*
[31] *Id.* at 1 of 2.

Q. Have you evaluated the cost to serve NEM customers based on your recommendation to use delivered load instead of site load?

A. Unfortunately, I have not been able to carry out an evaluation of the cost to serve APS's NEM customers based on delivered load. It appears APS has chosen to use a new approach to its COSS that involves a back-end proprietary model. While APS has been able to provide spreadsheets showing many of the inputs and outputs to that model and a proxy version that they call the "Cost of Service Working Model," there is no linkage between the various parts of the study.[32] As a result, I was unable to modify the allocation methodology and produce revised results in the COSS; moreover, APS has indicated that it will not re-run the proprietary model using alternative inputs defined by Vote Solar.[33] While this barrier to comprehensive analysis of the COSS by intervenors has troubling implications for APS's upcoming rate case, my understanding of the purpose of this docket is that it is intended to address methodological recommendations, rather than make findings based on results.

However, APS has used results from its COSS methodology to make various claims regarding the existence of cost shifting from NEM customers to non-NEM customers. Namely, APS has alleged that NEM customers on energy-based rates shift $67 per month in costs and NEM customers on demand-based rates shift $29 per month in costs to non-NEM customers.[34] These claims are inaccurate and cannot be relied on for two reasons: (1) the claims are based on a drastic over-allocation of costs to NEM customers, and (2) APS's cost shift estimates conflate costs and revenues associated with services provided by the utility with compensation paid for energy exports under the NEM program.

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[32] APS's Resp. to VS 1.1, APS15747.
[33] Conversation between Vote Solar and APS, March 25, 2016.
[34] Snook Direct 3:18-22.

Q. Please elaborate on your statement that APS's reported cost shift is based on over-allocation of costs to NEM customers.

A. I have not been able to verify whether the actual cost to serve APS's NEM customers based on their delivered load characteristics is above or below the revenues they pay for those deliveries. However, comparing the COSS allocators using site load as proposed by APS, and using delivered load as I propose, reveals that APS's method drastically overstates the cost to serve NEM customers.

APS's COSS uses various allocation measures in its evaluation of cost to serve. These measures are based on the following usage characteristics: total energy consumption (MWh); demand coincident with the four summer peaks ("4CP (kW)"); non-coincident peak demand of the customer class ("NCP (kW)"); individual customer peak demand ("Individual Max (kW)"); and the number of customers in the customer class. Each of these allocators, with the exception of the number of customers, is higher when site load is considered instead of delivered load. This implies that COSS allocation based on site load will over-allocate costs to NEM customers. Table 1 and Table 2 compare each relevant allocator using site load and delivered load for NEM customers on energy-based rates and demand-based rates, respectively.

Table 1: Comparison of Allocators Using Site Load and Delivered Load, NEM Customers on Energy-Based Rates

	Energy Consumption (MWh)	4CP (kW)	NCP (kW)	Individual Max (kW)
Site Load Allocation	1.36%	2.02%	1.76%	1.89%
Delivered Load Allocation	0.99%	1.46%	1.65%	1.71%
Difference	38%	38%	7%	10%

Table 2: Comparison of Allocators Using Site Load and Delivered Load, NEM Customers on Demand-Based Rates

	Energy Consumption (MWh)	4CP (kW)	NCP (kW)	Individual Max (kW)
Site Load Allocation	0.09%	0.12%	0.11%	0.11%
Delivered Load Allocation	0.07%	0.10%	0.11%	0.10%
Difference	29%	28%	3%	7%

As shown in Table 1 and Table 2, allocation based on site load inflates energy-related costs and peak demand-related costs by 28-38%. Because energy- and peak demand-related costs drive roughly 63% of the overall revenue requirement, this is expected to have a significant impact on the assessment of cost to serve NEM customers.[35] Allocation based on site load rather than delivered load also inflates costs related to the non-coincident peak by 3-7% and individual maximum peak by 7-10%. Because APS did not serve site load, it is wholly inappropriate to allocate costs to NEM customers based on site load. The only appropriate methodology for cost allocation is to allocate costs based on the service that the utility provides which is delivered load.

Q. **Please elaborate on your statement that APS's cost shift estimates conflate costs and revenues associated with services provided by the utility with compensation paid for energy exports under the NEM program.**

A. APS's claim that NEM customers shift $29-67 of costs each month is based on a comparison between its assessment of the cost to serve these customers and the revenues received from these customers under the current rate structure. Issues with APS's assessment of the cost to serve these customers are described above. The value for revenues received from customers in APS's cost shift calculation improperly conflates revenue received from NEM customers for delivered energy with compensation provided to NEM customers for exported energy. Under the net metering program, customers are able to offset delivered energy with exported energy, effectively valuing exported energy at the retail rate.

[35] VS 1.1 Cost of Service Working Model 2014TY_APS15748.

For the purpose of evaluating NEM customers in the COSS, it is important to separate revenues received from NEM customers for delivered energy from compensation provided to NEM customers for exported energy. COSS methodologies and findings should address only the services provided to the customer through delivered load and the revenues paid by the customer for delivered load. The costs and revenues associated with energy exports should be evaluated through the Value of Solar approach.

Q. Please comment on Mr. Snook's comparison of the cost to serve NEM customers in comparison to the cost to serve other subgroups of residential customers.

A. Mr. Snook has compared cost recovery from apartment dwellers, seasonal customers, and customers with gas appliances to his estimate of cost recovery from solar customers. Mr. Snook makes this comparison in an attempt to make the case that differences in cost recovery from these other customer subgroups reflect the normal variations in energy usage within the class, while solar customers do not.[36] In support of these claims, Mr. Snook presents two figures showing the delivered load shapes of each subclass of customer compared with the average residential load shape. These figures are reproduced below.

[36] *Id.* 24:10-18.

Figure 2: Residential Customer Usage Comparison, July

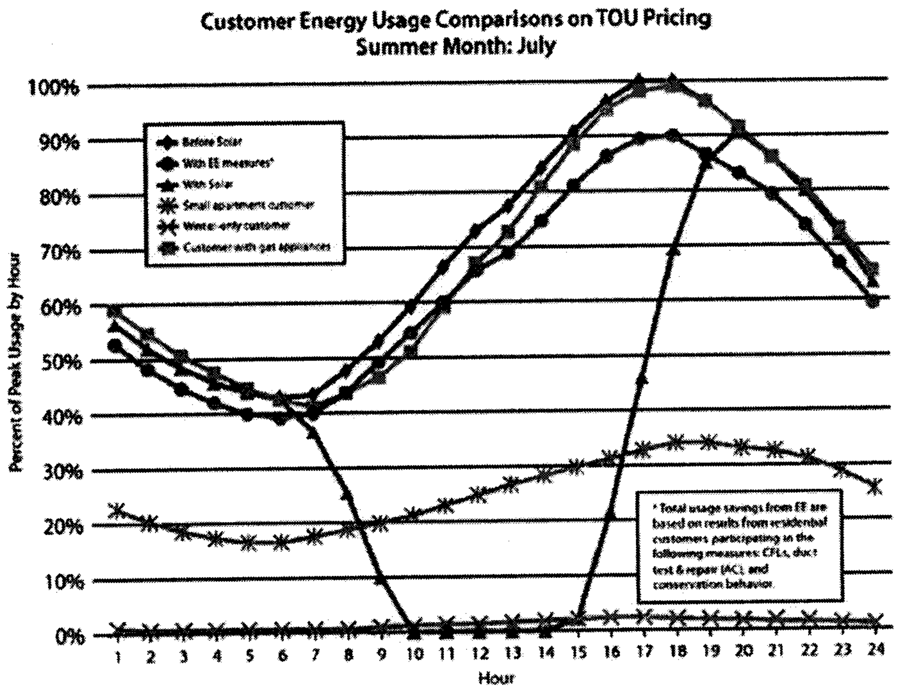
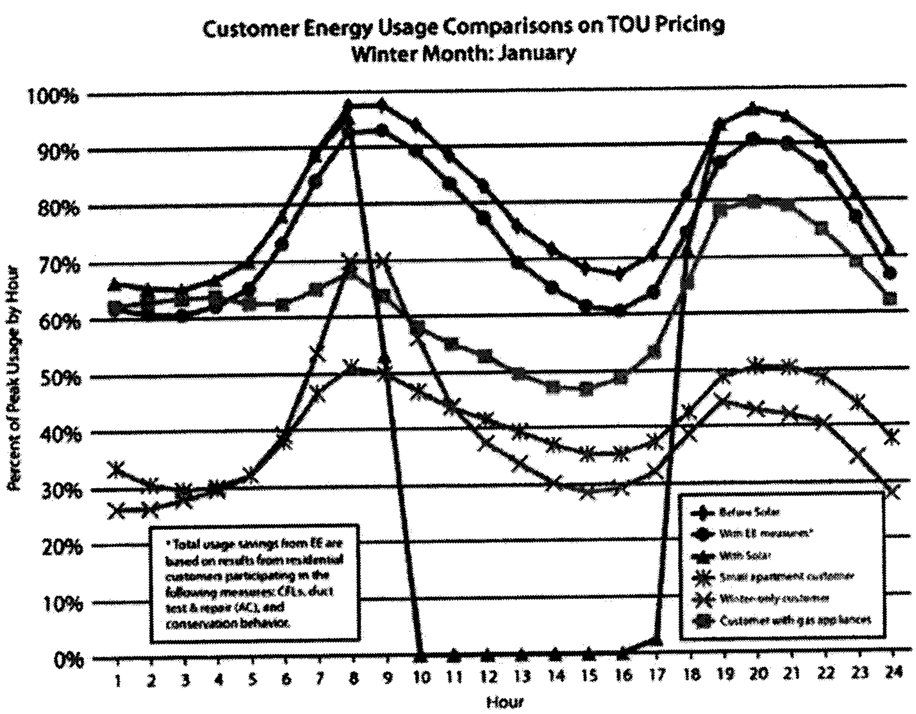


Figure 3: Residential Customer Usage Comparison, January



Mr. Snook's estimation of cost recovery from apartment dwellers, seasonal customers, and customer with gas appliances is based on the delivered load to each of those subgroups of customers and the revenues received from those customers for those deliveries. In contrast, his estimation of cost recovery from solar customers is not based on delivered load, but onsite load with partial credits. As a result, this is an apples-to-oranges comparison and cannot reasonably compare cost recovery from solar customers with cost recovery from any of the other subcategories.

Q. How can an appropriate comparison be made between the cost to serve NEM customers and other subgroups of residential customers?

A. An appropriate comparison could be made in one of two ways: (1) evaluate cost recovery for all customer subgroups, including solar customers, based on delivered load and revenue received for deliveries; or (2) analyze cost recovery for all customer subgroups based on average residential customer costs with credits applied for sub-class reductions. The second option would entail estimating what the seasonal customer's load would look like if he occupied his residence year-round, and what the customer with gas appliances would consume if she did not have gas service in her home. The second approach would be problematic for obvious reasons and I recommend that the first approach be adopted.

Q. Please summarize your conclusions and recommendations regarding the APS COSS presented in this docket.

A. APS's COSS methodology is deeply flawed and should not be approved by the Commission. The only appropriate treatment for NEM customers in the COSS is to allocate costs to those customers based on the service actually provided by the utility, which is delivered load. This approach is consistent with how cost responsibility is allocated to other customers and groups of customers, and it is consistent with APS's own statements regarding the goals of cost-of-service ratemaking.

I additionally find APS's claims regarding a cost shift from NEM customers to other residential customers on the order of $29-67 per month are based on over-allocation of costs to NEM customers and a conflation of cost to serve with the values and costs of energy exports. APS has claimed that their cost shift estimate "affirms the Commission's finding that the cost shift resulting from NEM under current APS residential rate design exists."[37] To the contrary, no evidence exists to support any finding regarding the existence of a cost shift under the current rate design.

4.2 TEP Cost-of-Service Study

Q. Please describe the approach used by TEP/UNSE to evaluate the costs to serve its NEM customers.

A. TEP/UNSE witness Dr. Overcast has completed a series of three cost of service studies for the TEP system.[38] In his direct testimony, Dr. Overcast described the first study as a "standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class."[39] The second study is referred to as the "counterfactual cost study" and analyzes costs that would be incurred if all TEP NEM customers did not have DG.[40] The third study is similar to the first, but includes "a separate class for evaluating the embedded costs of solar DG customers."[41]

Q. Did TEP/UNSE present any results regarding a cost shift from NEM customers to non-NEM customers?

A. Yes. Dr. Overcast presented a table of results that provides his estimate of the cost shift at $874-967 per NEM customer per year.[42] This total is based on the sum of four separate categories of costs estimated by Dr. Overcast: (1) "non power supply base rate," which appears to be his estimate of the difference between costs allocated to NEM customers in his COSS analyses and revenue received from those customers;

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[37] *Id.* 33:5-6.
[38] Overcast Direct 21:8-10.
[39] *Id.* 21:21-22.
[40] *Id.* 21:22-25.
[41] *Id.* 22:4-8.
[42] *Id.* 5:4-15.

(2) "banking arbitrage," which is based on his estimates of differing marginal costs associated with delivered energy and exported energy; (3) "excess generation," which applies a short-term value figure to all energy exports and contrasts that value with the full cost of energy embedded in the rate; and (4) "premise use," which is similar in concept to the "excess generation" figure though is based on energy consumed onsite.[43] My ability to review each of these categories has been severely limited by TEP/UNSE's failure to provide timely access to the models on which they are based. However, I have reviewed the available information and have identified issues with each of these categories.

Q. What are the issues associated with Dr. Overcast's estimate of the difference between costs allocated to NEM customers in his COSS analyses and the revenues received from those customers?

A. Dr. Overcast's estimate of a $729-822 annual per-customer cost for this category is based on the difference between two figures: (1) the cost of service for solar customers identified in the COSS models, and (2) the revenue received from NEM customers.[44] The first figure is the result of the COSS analysis completed by Dr. Overcast. The range reflects the difference between results from his "base COSS" and the "solar class COSS."[45]

Q. Have you been able to evaluate the reasonableness of the COSS results?

A. I have not. The reasonableness of any COSS results depends on the methodologies and assumptions employed in the specific study. One of the most critical assumptions in terms of differentiating the cost to serve various customer subgroups is the COSS allocation methodology. Unfortunately, TEP/UNSE failed to provide Vote Solar with functioning copies of the cost-of-service studies in a timely manner. As a result, my ability to analyze the methodologies employed in each of the three studies has been extremely limited.

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[43] *Id.* 5:4-15 Tbl. 1, 33:14-21, Ex. HEO-8.
[44] *Id.* 33:15-18 & nn. 5-6.
[45] *Id.*

TEP/UNSE provided a work paper in Adobe PDF format that purports to show the allocation factors used in each of the cost of service studies[46]; but the values shown in this work paper are inconsistent with the values shown in Exhibit HEO-8 of Dr. Overcast's testimony, which purports to show the inputs and results of the energy cost study.[47] As a result I cannot verify what measure (site load, delivered load, other) TEP/UNSE used to allocate costs to NEM customers in the various cost of service studies presented in the testimony of Dr. Overcast.

Q. **What implication does this have regarding the reasonableness of the COSS results?**

A. As I stated earlier in the section regarding APS's COSS, the only reasonable approach to an analysis of the cost to serve NEM customers as a separate group of customers is to allocate costs to these customers based on standard allocation measures applied to the load actually served by the utility. For all types of customers, NEM and non-NEM, this means the COSS must allocate costs based on delivered load.

Exhibit HEO-8 indicates that the annual delivered load to TEP's solar customers based on metered billing data was roughly 73 million kWh.[48] The "base COSS" appears to have used a higher value for annual kWh cost allocation and the "solar class COSS" appears to have used a lower value.[49] This indicates to me that costs were likely allocated on something other than delivered load, which would skew the results.

Q. **Have you been able to evaluate the reasonableness of the revenue Dr. Overcast compared with costs to quantify the alleged cost shift?**

A. Yes. Dr. Overcast used a figure of $3,352,194 in revenues from residential NEM customers,[50] and has indicated that this number was provided to him by TEP based on

[46] TASC 1.1 TEP Datasheet v5, Feb. 8, 2016.
[47] Overcast Direct 22:4-8, Ex. HEO-8.
[48] *Id.* Ex. HEO-8 Tbl. 1.
[49] *See id.* at **Error! Reference source not found..**
[50] Overcast Direct 33:14-15.

actual revenues collected from TEP NEM customers during the rate case test year.[51] This implies the revenues on which the cost shift calculation was based reflect actual billed costs, while the cost to serve was calculated based on TEP's most recent rate case filing that includes a requested $109.5 million non-fuel revenue requirement increase.[52]

There are two issues with this methodology. The first is the same issue that is present in APS's cost shift analysis: the revenues to which costs are compared conflate revenues received by the utility for deliveries with the compensation awarded to the NEM customer for energy exports. To understand the relative cost to serve NEM and non-NEM customers, deliveries must be analyzed separately from exports. Allocating costs based on deliveries or site load and comparing those costs to revenues received net of compensation for exports will inflate the purported cost shift.

The second issue with this methodology is that it does not put NEM customers on equal footing with non-NEM residential customers in terms of cost recovery. In TEP's open rate case, the Company has requested an increase in the non-fuel revenue requirement of $109.5 million.[53] TEP's application indicates that this request would result in an increase of over 12% in adjusted test year revenues.[54] It is not surprising that costs allocated to NEM customers based on a total revenue requirement 12% higher than the revenues used to develop current rates would show an under-recovery of costs. In fact, I would expect Dr. Overcast's analysis to result in a showing of cost-shift for the non-NEM residential class as well.

In order to appropriately compare cost to serve with revenues to ascertain the magnitude of the potential cost shift, NEM customer cost recovery must be compared on equal terms with non-NEM customer cost recovery. This methodology was used in the APS study and should be applied to the TEP study as well. Dr. Overcast's

[51] Conversation with Dr. Overcast April 2, 2016. Dr. Overcast informed me in a telephone conversation that this number was provided to him by TEP based on actual revenues collected from TEP NEM customers during the rate case test year.
[52] *See* TEP Rate Case Appl. 1:14-16, No. E-1933A-15-0322.
[53] *Id.*
[54] *Id.*

comparison of NEM cost to serve based on TEP's rate case request with revenues received based on prior-approved rates overinflates the resulting assessment of the cost shift.

Q. **Have you assessed the reasonableness of Dr. Overcast's estimates of cost shift associated with "banking arbitrage," "excess generation," and "premise use"?**

A. Again, due to the limited data TEP/UNSE provided, I have only been able to conduct a limited review of these alleged cost shift categories. Dr. Overcast indicates that his analysis for these categories was based on the energy cost analyses conducted outside of the cost of service studies and presented in Exhibit HEO-8.[55] Because TEP/UNSE declined to provide any work papers supporting Exhibit HEO-8, it is difficult to assess the reasonableness of the calculations therein. In addition, little to no explanation of the methodology or meaning of each of these cost shift categories is provided in the body of the testimony.

Based on the brief descriptions of the methodology provided in Exhibit HEO-8, it appears that the value for "banking arbitrage" is based on an estimate of the differing marginal costs associated with delivered energy and exported energy. Exhibit HEO-8 indicates that the average marginal cost associated with DG exports was $24.62/MWh, while the average marginal costs associated with deliveries to DG customers was $26.97/MWh.[56] It is unclear precisely what data were used to conduct this analysis. However, in the recent UNSE rate case, Dr. Overcast made a similar claim, stating, "excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG."[57] In the UNSE rate case, Dr. Overcast provided the work papers to support this statement; however, it was found that the work papers did not provide support for

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[55] Overcast Direct, Ex. HEO-8 tbl. 2.
[56] *Id.*
[57] Overcast Rebuttal Test. 13:9-14, No. E-04204A-15-0142, Jan. 19, 2016.

his conclusion.[58] In fact, when other available data from the docket were examined, it was found that the average marginal cost during hours of energy exports actually exceeded the average marginal cost during hours associated with deliveries.[59] While a contradictory finding based on UNSE data does not indicate that Dr. Overcast's finding based on TEP is incorrect, it does indicate that the result should be closely examined prior to adoption by the Commission.

Descriptions of the other two categories of alleged costs—"excess generation" and "premise use"—appear to be based on comparison of the full retail rate with different levels of short-term valuation of energy exported to the grid and consumed onsite.[60] The short-term valuation of energy exports appears to be based on the average marginal cost associated with deliveries to DG customers while the short-term valuation of onsite DG consumption appears to be based on avoided fuel cost.[61]

Q. Do you have any comments about the inclusion of the three energy cost categories in the cost shift assessment?

A. While Dr. Overcast's methodology for allocating energy-related costs to NEM customers outside the COSS is considerably more complicated than the methodology employed by APS to allocate energy-related costs to NEM customers within the COSS, it appears Dr. Overcast's approach suffers from similar methodological flaws. By assigning costs to NEM customers based not only on load consumed onsite, but also total embedded costs associated with energy exports, Dr. Overcast's approach unfairly assigns costs to NEM customers based on services not provided by the utility. The more appropriate methodology would be to include energy-related costs in the COSS and to allocate energy-related costs to NEM customers based exclusively on delivered load. The long-term costs and benefits he associates with energy exports should be considered through the value of solar analysis separate from the COSS.

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[58] Surrebuttal Test. of Briana Kobor at 15:17-21, No. E-04204A-15-0142 ("Kobor Surrebuttal").
[59] Kobor Surrebuttal 15:21-16:5.
[60] Overcast Direct, Ex. HEO-8 Tbl. 1.
[61] *Id.* Tbl. 2.

Q. Do you have any comments on TEP/UNSE's use of the counterfactual cost of service study?

A. TEP/UNSE witness Mr. Tilghman has indicated the Companies recommend use of a counterfactual COSS "that assumes away the existence of NEM customers' power generation"[62] as part of a "more comprehensive [value of solar ("VOS")] model."[63] Dr. Overcast's testimony presents the results of such a counterfactual COSS.[64] Notably, the results of the counterfactual COSS do not appear to be used in Dr. Overcast's assessment of the alleged NEM cost shift, and it is not clear how he recommends that the results of such an analysis be used to set rates.

I do not recommend the counterfactual COSS approach for a number of reasons. First, the entire premise of comparing hypothetical costs based on the assumption that DG never existed is problematic. Development of such a study requires assumptions of what NEM customer consumption and utility costs would have been had customers never made the decision to invest in DG resources. This would create challenges associated with NEM customer load shape determination as well as quantification of how utility costs would have changed but for the DG assets offsetting a portion of customer load. In addition, the counterfactual COSS approach limits consideration of the costs and benefits associated with DG to the COSS test year, while the benefits of DG investment will accrue over the useful life of the system. This approach is unlikely to fully capture the costs and benefits associated with DG.

The preferred approach would be to consider the cost to serve NEM customers based on delivered load characteristics in the context of the traditional utility COSS and to evaluate the long-term costs and benefits associated with DG exports through the valuation of solar analysis using the methodology adopted in this proceeding.

[62] Direct Test. of Carmine Tilghman 7:6-8 ("Tilghman Direct").
[63] Tilghman Direct 6:5-9.
[64] Overcast Direct 33:6.

4.3 Conclusions regarding the role of COSS-based evidence and methodological recommendations in this docket

Q. Have you reached any conclusions regarding the COSS-based evidence presented in this docket?

A. Yes. First, I do not believe sufficient evidence has been provided to support the alleged cost shift figures put forth by either APS or TEP/UNSE in this docket. A review of the methodology employed to arrive at APS's estimated $29-67 monthly cost shift reveals the underlying analysis overinflates the cost to serve NEM customers and conflates the costs and revenues associated with delivered energy with the compensation awarded to NEM customers for energy exports. Due to APS's adoption of a proprietary COSS model, I have been unable to determine what level of cost shift, if any, would result from adoption of my recommended methodological corrections.

My review of TEP/UNSE's alleged $874-967 annual cost shift figures was unfortunately limited by TEP/UNSE's failure to provide timely access to functioning work papers to support the analysis. However, information provided in the testimony and the PDF work papers indicates that the TEP/UNSE analysis likely suffers from similar methodological issues resulting in an over-inflation of the assessment of the cost to serve NEM customers. Moreover, the analysis includes an inaccurate comparison of costs with revenues, which conflates revenues from deliveries with compensation for exports and does not compare NEM customers on equal footing with non-NEM customers in terms of expected cost recovery in light of the large revenue increase requested in TEP's open rate case.

Commissioner Little has been clear in his guidance for this docket that he envisions the following outcome of this proceeding:

> Development of a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Since the specifics of each rate case are different and can vary widely for each utility and service area, the

> methodology would not assign specific values, but rather provide guidance as to how values would be determined in the context of an individual rate case.[65]

Keeping with Commissioner Little's statement and in light of the lack of evidence provided to support the alleged cost shift attributable to NEM customers, I do not recommend that the Commission adopt any specific COSS findings in this docket.

Q. Do you have any recommendations regarding the methodology for determination of the cost to serve solar customers in the context of a utility COSS?

Both APS and TEP have requested that the Commission adopt their proposed COSS methodologies in this proceeding. I have identified several significant flaws in these proposed methodologies and offer the alternative recommendation that all customer groups be evaluated in future cost of service studies in a fair and transparent way based on the services they are provided by the utility. This means that cost allocation for all customers, NEM and non-NEM, must be consistent and based on delivered load. In addition, I recommend DG exports be considered separate from the COSS and evaluated based on a long-term avoided cost analysis as I discuss in the next section.

5 The value of DG exports must be based on long-term avoided costs to the non-participating ratepayer

Q. What approaches to the valuation of DG have been discussed by parties in this docket?

A. There are three approaches to the valuation of DG that have been discussed by parties in this docket: (1) short-term avoided cost, (2) grid-scale benchmarking, and (3) long-term avoided cost. In my opinion there are significant flaws with both the short-term

[65] Guidance Letter at 1.

avoided cost and grid-scale benchmarking approaches. I recommend that the Commission adopt the long-term avoided cost approach.

5.1 Short-term avoided cost approach

Q. What is the short-term avoided cost approach to the valuation of DG?

A. In general, the short-term avoided cost approach seeks to evaluate the costs and benefits of DG over the near-term. An example of this was provided in APS's testimony, where APS described a methodology for evaluating short-term avoided costs based on a year's worth of historical data.[66]

Q. What do proponents argue are the merits of the short-term avoided cost approach?

A. APS witness Albert implies that the short-term approach would avoid potential issues due to future failure of DG suppliers to maintain a resource that is available and capable of producing power over the expected life of the system.[67]

TEP/UNSE witness Dr. Overcast states that payment of levelized cost in the long-term approach "is inconsistent with rates and creates issue[s] of intergenerational equity and potential excess payments since solar DG has no obligation to operate at rated capacity over its useful life."[68] He additionally claims that inclusion of future energy costs would create an inter-temporal subsidy to the extent that future benefits are reflected in current rates.[69] Finally, Dr. Overcast states:

> The only way to provide for efficient outcomes is to separate the capital and the energy components of the payment stream. Energy payments based on short run costs is the exact same way that utility generation recovers energy costs. Over the life of some power plants that energy cost moves up and down with competitive input prices. There is no economic reason that solar DG should be any different

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[66] Direct Test. of Bradley Albert 17:22-18:27 ("Albert Direct").
[67] *Id.* 19:9-19.
[68] Overcast Direct 46:23-25.
[69] *Id.* 45:26-46:3.

> than a competitive power plant that bears the fuel cost risk in the short term.[70]

Q. Do you agree with these statements?

A. No. Mr. Albert's and Dr. Overcast's criticisms are based on the premise that evaluating DG over the long-term would create some sort of risk of long-term benefits not being realized if the DG customer were to fail to deliver as expected. But this is not unique to DG. It is standard practice to evaluate the long-term benefits and costs of utility investments, such as power plants and transmission lines. Often the decision is made to invest in these large projects in advance of the actual need for the total capacity the investment would provide. In any such case, one could argue that "inter-temporal inequities" exist from placing such investments in a utility rate base in advance of their need. Moreover, in the case that expected benefits of utility investments do not materialize, ratepayers are often still obligated to pay for the investment. If the utility provides the DG customer with compensation for the excess energy from their DG system that is linked to energy production, there is no reason to believe that any significant number of DG customers would fail to perform over the useful life of the system. While parties have raised future performance of DG as a hypothetical issue, none has provided evidence in this docket to support their theories.

In addition, Dr. Overcast's claim that "[e]nergy payments based on short run costs is the exact same way that utility generation recovers energy costs"[71] ignores the fact that the majority of utility-scale power purchase agreements ("PPA") for renewable generation are 10-20-year fixed or escalating contracts. Indeed, there is no economic reason for compensating DG at short-term avoided costs based on fluctuations in fuel markets when "competitive power plants" are routinely offered long-term fixed-price contracts.

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[70] *Id.* 47:25-48:4.
[71] *Id.* 47:26-48:1.

Q. What do you conclude regarding the short term avoided cost approach?

A. The short-term avoided cost approach is not recommended for the valuation of the costs and benefits of DG exports. Indeed, neither APS nor TEP/UNSE appear to directly endorse this method either. Valuation of the costs and benefits of DG based only on the short term would ignore many significant benefits associated with DG that only accrue over the longer term. Compensation for exports that does not take into account the long-term benefits would result in a suboptimal level of DG deployment from the perspective of the non-participating ratepayer and society.

5.2 Grid-scale benchmarking approach

Q. What is the grid-scale benchmarking approach to valuation of DG?

A. Again, there is some variation in the exact methodology for the grid-scale benchmarking approach. TEP/UNSE has proposed a type of grid-scale benchmarking in the open rate cases for both TEP and UNSE.[72] TEP/UNSE's proposals are to link the price paid for DG exports to the price of the most recent utility-scale PPA signed by either TEP or UNSE and connected to the TEP/UNSE distribution system. In addition, APS witness Albert introduces the concept of a grid-scale benchmarking methodology in his testimony, which includes benchmarking the price of utility-scale PPAs and making adjustments for various "valuation differences" between grid-scale and rooftop solar.[73]

Q. What do proponents argue are the merits of the grid-scale benchmarking approach?

A. The main arguments in support of a grid-scale methodology are centered on the idea that utility-scale solar photovoltaic ("PV") provides many similar benefits and attributes when compared with distributed solar PV, yet due to the benefits of economies of scale is generally available at a lower unit price. APS witness Albert

[72] *See* Docket Nos. E-04204A-15-0142 and E-1933A-15-0322, respectively.
[73] Albert Direct 28:25-29:5.

states the "adjusted grid-scale value would represent the cost at which the utility could realize the same value attributes that rooftop solar systems supply."[74] Similarly, TEP/UNSE witness Dr. Overcasts states, "the proliferation of roof top solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as the utility costs benefit from scale economies."[75]

Q. Do you agree with these statements?

A. I agree that due to economies of scale, utility-scale PV is generally available at a lower unit price when compared to distributed solar generation. However, I caution against drawing a parallel between the two resources in terms of valuation. The statements in support of the grid-scale methodology inappropriately conflate the value of DG from the perspective of the utility with the value of DG from the perspective of the non-participating ratepayer and result in a false comparison between the two resources.

For example, Mr. Albert states:

> Based upon the prudent utility planning principles that have been a basic premise upon which utility resource procurement decisions have historically been made, a utility has an obligation to seek out the lowest-cost, best-fit approach to fulfilling a resource need. The grid-scale adjusted methodology is consistent with this principle in that it identifies the lowest-cost, best-fit manner of achieving the same resource value."[76]

This concept is echoed by Dr. Overcast:

> DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year round contract for solar generation. This is just another example of how markets have both a competitive option and regulation of the remaining natural monopoly.[77]

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[74] Albert Direct 29:3-5.
[75] Overcast Direct 8:19-22.
[76] Albert Direct 32:13-18.
[77] Overcast Direct 9:2-6.

Both of these statements illustrate how the grid-scale benchmarking methodology approaches the issue of DG valuation from the utility perspective, making a false comparison between the two resources. While I agree that utility-scale solar provides many of the same attributes to the electric system, often at a lower unit price, utility-scale solar prices should not be used to set DG compensation because DG customers cannot participate in that market and it would be inappropriate to bring prices from the competitive utility-scale market to bear on individual customers who make the choice to install DG when they do not have access to a market in which to sell their power.[78]

The utility customer who installs solar on his rooftop chooses to make a private investment in an energy resource that can export excess power to the grid to be consumed by nearby customers. There is only one buyer for his power—the utility. Currently, there is not a market in which, if he installs solar on his rooftop and is not using all of his power, he can sign a contract with his neighbor who can purchase that power. That market does not exist because the utility has been granted monopoly rights to deliver power in its service territory.

The comparison of utility-scale pricing with distributed-scale pricing from the perspective of the utility additionally ignores the fact that while utility-scale contracts may in fact be cheaper, no one is offering the non-participating ratepayer access to utility-scale solar at 5 c/kWh. The only product available to the non-participating ratepayer is delivered energy available at the full retail rate. The non-participating ratepayer will be generally indifferent to and unaware of whether the electrons he is consuming are coming from their neighbor's PV array or whether they have been carried across the entire utility transmission and distribution system from a faraway power plant. Asking why the utility should pay more for DG than they pay for utility-scale solar PPAs asks the wrong question. From a non-participating ratepayer perspective, the right question to ask is: What is the level of costs avoided by the non-

[78] In addition, DG provides unique benefits when compared to utility-scale solar, including higher generation capacity value due to the geographic diversity of DG systems, higher avoided line losses, and potentially greater avoided distribution costs and grid services from DG.

participating customer as a result of the exported DG? The answer to this question is independent of the price paid for utility-scale solar.

Q. What do you conclude regarding the grid-scale benchmarking approach?

A. I do not believe the grid-scale benchmarking approach has any merit for the valuation of the costs and benefits associated with DG exports. I disagree with APS's recommendation that the value resulting from the grid-scale benchmarking methodology be considered a ceiling on the price paid for DG exports.[79] RUCO's witness, Mr. Huber, agrees, stating, "[f]avorable costs of utility and community scale solar should not be used to determine that DG solar cannot be cost-effective, or should not be pursued."[80] The attempt to set pricing for DG exports based on utility-scale prices rather than based on non-participating ratepayer avoided costs creates a false choice. Arizona's utility customers support choice and they support clean energy.[81] DG exports can be priced to ensure that non-participating ratepayers benefit from the transaction and both utility-scale and distributed-scale solar PV should be encouraged.

5.3 Long-term avoided cost approach

Q. What is the long-term avoided cost approach to valuation of DG?

A. The long-term avoided cost approach is the methodology that is commonly referred to as a "value of solar analysis." In my direct testimony in this proceeding I outlined my recommendations for specific methodologies to assess the long-term values and costs of DG exports. The long-term avoided cost approach is the standard approach to DG valuation and was the approach used by APS in the R.W. Beck study from 2009[82] and

[79] Albert Direct 3:20-26.
[80] Direct Test. of Lon Huber 23:20-22.
[81] Adrian Gray Consulting, *Survey of Arizona Voters*, Adrian Gray Consulting, LLC, 2 of 4 (Oct. 14, 2014), http://www.edfaction.org/sites/edactionfund.org/files/press-releases/edaf-az-2014.pdf.
[82] R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study*, R.W. Beck, § 1.5 (Jan. 2009), http://files.meetup.com/1073632/RW-Beck-Report.pdf.

the 2013 SAIC update to that study.[83] The 2013 Crossborder Energy study also used the long-term avoided cost approach[84] as did the updated study presented by TASC witness Thomas Beach in this proceeding.[85] I recommend that the Commission adopt the long-term avoided cost approach to the valuation of DG exports.

Q. Have parties provided arguments against the long-term avoided cost approach?

A. Yes. APS witness Brown devotes the majority of his testimony to a section entitled "what's wrong with a 'VOS' analysis?"[86] In this section he states that the VOS analysis "is inherently subjective, readily manipulated, and inherently skewed,"[87] and details a list of what he calls "[f]oundational problems that can throw off the whole framework of a study."[88] He additionally criticizes some of the categories of costs and benefits outlined in the Interstate Renewable Energy Council guidebook,[89] and examines the results of several VOS analyses that have been completed in Arizona and other states.[90]

Q. Do you agree with Mr. Brown's statements?

A. No. Mr. Brown claims that "[s]tudies of the 'VOS' are highly subjective and readily manipulated because there is no established methodology, and, furthermore, given the complexity of the analyses needed to assess all the various 'VOS' claims, no analysis can effectively avoid the need to make multiple subjective analytical judgments."[91] However, Mr. Brown's testimony goes on to make a number of specific

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[83] SAIC, *2013 Updated Solar PV Value Report*. SAIC, § 2.1 (May 10, 2013), https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf.

[84] R. Thomas Beach & Patrick G. McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, Crossborder Energy, 2 (May 8, 2013), https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.

[85] Beach Direct, Ex. 2.

[86] Direct Test. of Ashley Brown 12:18-57 ("Brown Direct").

[87] *Id.* 13:1

[88] *Id.* 18:15.

[89] *Id.* 24:13.

[90] *Id.* 47:4-57.

[91] *Id.* 13:4-7.

recommendations regarding the appropriate methodology for the calculation of many of the inputs to the valuation analysis.[92]

In addition, Mr. Brown cites to the results of a study completed in Maine and a study completed in Louisiana, pointing out that the resulting c/kWh values were very different in the two studies as apparent support for his claims that such studies may be biased.[93] In reality, it is not at all surprising that the c/kWh valuation of solar would differ dramatically in studies that looked at two very different states with different climates, different customer usage patterns, and different energy supply mixes.

Mr. Brown's criticisms essentially support the view that that the methodology for long-term valuation of solar DG would benefit from guidance from the Commission in order to ensure that the resulting analysis is reliable and unbiased. This is precisely what I have recommended in my direct testimony[94] and is the purpose of this proceeding, as indicated by Commissioner Little.[95]

6 Other Issues

6.1 Distribution of benefits from DG solar

Q. Have any parties in this proceeding made comments regarding the distribution of benefits from DG solar?

A. Yes. Mr. Brown makes the following claim in his testimony:

> A VOS analysis typically ignores the social impact of policies, such as net metering implemented to support distributed solar. Empirical studies on this subject have indicated that net metering pricing has a regressive social impact. It is, in fact, a wealth transfer from lower-

[92] *See, e.g., id.* 25:4 (discussing avoided energy costs), 27:1 (discussing generation capacity savings).
[93] Brown Direct 13:7-11.
[94] Kobor Direct 49:11-13.
[95] Guidance Letter 1.

income people to higher-income people.[96]

Q. Do you agree with this claim?

A. I do not. Studies on net metering do not show that there is a regressive social impact nor do they demonstrate a wealth transfer from lower-income people to higher-income people. In fact, the only empirical study Mr. Brown cites to in his testimony that includes data from Arizona is entitled "Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class."[97] The following statement appears on the very first page of this study:

> The question is: Who is buying up all of those solar power systems? Through our analysis of solar installation data from **Arizona**, California, and New Jersey, we found that these installations are overwhelmingly occurring in middle-class neighborhoods that have median incomes ranging from $40,000 to $90,000. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both **Arizona** and California and $30,000 to $40,000 in New Jersey. Additionally, the distribution of solar installations in these states aligns closely with the population distribution across income levels.[98]

That report additionally included a figure depicting the distribution of solar installations and households by income level for APS's territory. That figure is reproduced on the following page.

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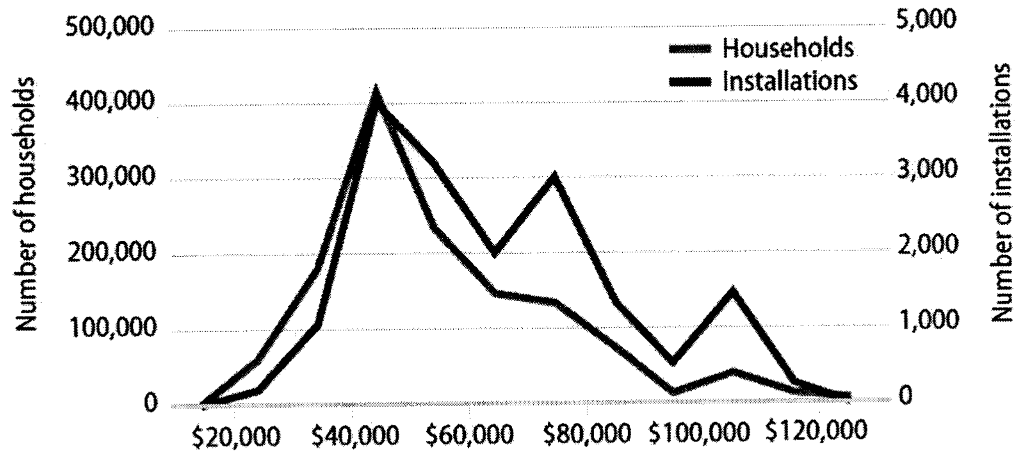
[96] Brown Direct 24:5-9.

[97] Brown Direct 24 n.26 (citing "Hernandez, Mari, *Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class*. Center for American Progress, October 21, 2013. https://cdn.americanprogress.org/wp-content/uploads/2013/10/RooftopSolarv2.pdf").

[98] Mari Hernandez, *Solar Power to the People*, Center for American Progress, 1 (Oct. 21, 2013), https://cdn.americanprogress.org/wp-content/uploads/2013/10/RooftopSolarv2.pdf (emphasis added).

Figure 4: APS Installations and Households by Income Level[99]



This analysis clearly indicates solar DG is being installed across the income spectrum in Arizona with a proportionate amount of solar installations at the lower ends of the income spectrum.

The other studies referenced by Mr. Brown include a study from California that found that while the average income of customers with solar was higher than the general population, that gap has been decreasing since 2007.[100] Mr. Brown also referenced a study that looked at Maryland, Massachusetts, and New York, and found that like Arizona, Massachusetts and New York saw the majority of solar installations in middle-income areas, while Maryland skewed slightly more towards higher-income areas.[101]

While distribution of solar installations across the income spectrum is one part of the picture, Mr. Brown's allegations ignore the fact that if a robust approach to the quantification of the costs and benefits associated with DG can be used to set a rate

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[99] *Id.* 3.
[100] Energy and Envtl. Econ., *California Net Energy Metering Ratepayer Impacts Evaluation,* 113 (Oct.28, 2013), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5724.
[101] Brown Direct 46-47 n.45 (citing Mari Hernandez, *Rooftop Solar Adoption in Emerging Residential Markets*, 1 (May 29, 2014), https://cdn.americanprogress.org/wp-content/uploads/2014/05/RooftopSolar-brief3.pdf).

for exports that allows a sharing of net benefits between customers that do and do not install DG, all customers will benefit, regardless of income level.

6.2 This docket is not the appropriate venue for determination of specific rate design measures

Q. Have any parties to this proceeding discussed specific rate design recommendations?

A. Yes. Several parties, including APS witness Mr. Snook, TEP/UNSE witness Dr. Overcast, and AIC witness Mr. O'Sheasy, include specific rate design recommendations in their direct testimonies, including an endorsement of three-part rates that include a demand charge and increasing fixed customer service charges through use of the minimum system method.[102]

Q. Do you have any comments on these recommendations?

A. I do not believe this docket is the appropriate venue for recommendations or determinations regarding specific rate design proposals. The scope of this docket should be limited to development of a robust, standardized methodology for valuation of DG that can be employed to develop specific findings for each Arizona utility. Specific rate design measures may indeed impact the magnitude of DG benefits and costs calculated using the methodology developed in this proceeding and are an important consideration in each utility's own rate case. Moreover, it would not be appropriate to consider specific rate design proposals absent a body of evidence to support those proposals, including utility cost of service studies and bill impact analyses, neither of which has been provided for the rate design recommendations discussed in this case.

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[102] Snook Direct 27:16-20; Overcast Direct 39:12-16; Direct Test. of Michael O'Sheasy 11:18-15:16.

7 Recommendations

Q. What are your recommendations for the Commission?

A. In addition to the recommendations summarized in my direct testimony, I recommend the following:

- The Commission should recognize that insufficient evidence has been provided to support the alleged cost shift calculations put forth by APS and TEP/UNSE in this docket and that the methodologies employed to develop these calculations overinflate the cost to serve NEM customers.
- The Commission should instruct the utilities to evaluate the cost to serve NEM customers in a fair and transparent way through standard utility cost-of-service analysis based on delivered load.
- The Commission should not make specific findings based on cost of service study evidence in this proceeding.
- The Commission should not endorse use of a counterfactual cost of service study as proposed by TEP/UNSE.
- The Commission should reject the short-term avoided cost approach to the valuation of DG.
- The Commission should reject the grid-scale benchmarking approach to the valuation of DG
- Valuation of DG exports should be considered separately from the cost to serve NEM customers, and the valuation should be based on a full assessment of the long-term costs and benefits associated with DG exports.
    - Detailed recommendations regarding the methodology for this valuation are provided in my direct testimony.[103]
- The Commission should recognize that the distribution of solar DG installations by income level reflects the income distribution of the state of Arizona.

[103] Kobor Direct 49-50.

- The Commission should recognize that this docket is not the appropriate venue for evaluation of specific rate design proposals. Rate design should be addressed in individual utility rate cases where the proposals can be fully evaluated.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Vote Solar-9

EXHIBIT ADMITTED

COS - Allocators	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	
ALL OTHER												
B:[Jurisdiction]												3628
C:[ALL OTHER Jurisdiction]												3628
D:[]												
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]												0.02
F:[DEMPROD1 Production Demand]												**2.07%**
G:[]												
H:[DEMPROD6 Specific Assignment]												100
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]												**100.00%**
J:[]												
K:[DEMTRAN1 Specific Assignment]												100
L:[DEMTRAN1 Transmission Substation]												100.00%
M:[]												
N:[DEMTRAN3 Specific Assignment]												100
O:[DEMTRAN3 Transmission Lines]												100.00%
P:[]												
Q:[DEMTRAN4 Specific Assignment]												100
R:[DEMTRAN4 SCE Specific]												100.00%
S:[]												
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]												
U:[DEMDIST1 Distribution Substation]												
V:[]												
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]												
X:[DEMDIST2 Distribution OH Primary Lines]												
Y:[]												
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]												
AA:[DEMDIST3 Distribution OH Secondary Lines]												
AB:[]												
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]												
AD:[DEMDIST4 Distribution UG Primary Lines]												
AE:[]												
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]												
AG:[DEMDIST5 Distribution UG Secondary Lines]												
AH:[]												
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]												
AJ:[DEMDIST6 Distribution OH Line Transformers]												
AK:[]												
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]												
AM:[DEMDIST7 Distribution UG Line Transformers]												
AN:[]												
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]												
AP:[CUSTOH1 Distribution OH Services]												
AQ:[]												
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]												
AS:[CUSTUG1 Distribution UG Services]												
AT:[]												
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]												
AV:[DEMDIST10 Distribution Rents]												
AW:[]												
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]												618,419
AY:[ENERGY1 Production - Energy]												2.17%
AZ:[]												
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]												0.02
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]												2.17%
BC:[]												
BD:[ENERGY2_A]												
BE:[ENERGY2_A Related Fuel (ACC)]												
BF:[]												
BG:[CUST370 Weighted Costs for Distribution Meters ($)]												9,140
BH:[CUST370 Distribution Meters]												0.70%
BI:[]												
BJ:[CUST371 Dusk to Dawn Customer Class Specific]												
BK:[CUST371 Dusk to Dawn]												
BL:[]												
BM:[CUST373 Street Lighting Customer Class Specific]												
BN:[CUST373 Street Lighting]												
BO:[]												
BP:[CUSTNUM Number of Customer Accounts]												1,469
BQ:[CUSTNUM Customer Accounts]												0.12%
BR:[]												
BS:[CUSTNUM_A Number of Customer Accounts ACC]												
BT:[CUSTNUM_A Customer Accounts ACC]												
BU:[]												
BV:[CUST910 Number of Customer Accounts]												
BW:[CUST910 Customer Service and Information]												
BX:[]												
BY:[CUST916 Number of Customer Accounts]												1,469
BZ:[CUST916 Sales Expense]												0.12%
CA:[]												
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]												3.40
CC:[DEMREGAST Regulatory Asset - Demand Related]												3.40%
CD:[]												
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]												729,140
CF:[ERGREGAST Regulatory Asset - Energy Related]												2.43%
CG:[]												
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]												618,419
CI:[ERGSYSBEN System Benefits - Energy Related]												2.17%
CJ:[]												
CK:[Retail ONLY versions of above allocators:]												
CL:[If]												
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]												
CN:[Retail DEMPROD1 Production Demand]												
CO:[]												
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]												
CQ:[Retail ENERGY1 Production - Energy]												
CR:[]												
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]												
CT:[Retail ERGSYSBEN System Benefits - Energy Related]												
CU:[end if]												
CV:[]												
CW:[Other Allocators]												
CX:[Demand Production (RES)]												
CY:[Ratio: Demand Production (RES)]												
CZ:[]												
DA:[Ancillary Services]												
DB:[Ratio: Ancillary Services]												

DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	
DH:[]	
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-221 (Water Pumping)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.01
F:[DEMPROD1 Production Demand]	**1.06%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	76,251
U:[DEMDIST1 Distribution Substation]	1.05%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	74,319
X:[DEMDIST2 Distribution OH Primary Lines]	1.05%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	
AD:[DEMDIST4 Distribution UG Primary Lines]	
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	123,951
AJ:[DEMDIST6 Distribution OH Line Transformers]	1.34%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AM:[DEMDIST7 Distribution UG Line Transformers]	
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	3,387
AP:[CUSTOH1 Distribution OH Services]	1.12%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	74,319
AV:[DEMDIST10 Distribution Rents]	1.05%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	369,052
AY:[ENERGY1 Production - Energy]	1.30%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.01
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	1.28%
BC:[]	
BD:[ENERGY2_A]	1.30
BE:[ENERGY2_A Related Fuel (ACC)]	1.33%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	7,620
BH:[CUST370 Distribution Meters]	0.59%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,467
BQ:[CUSTNUM Customer Accounts]	0.12%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1,376
BT:[CUSTNUM_A Customer Accounts ACC]	99.93%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,467
BW:[CUST910 Customer Service and Information]	0.12%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,467
BZ:[CUST916 Sales Expense]	0.12%

CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	1.23
CC:[DEMREGAST Regulatory Asset - Demand Related]	1.23%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	331,078
CF:[ERGREGAST Regulatory Asset - Energy Related]	1.10%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	369,052
CI:[ERGSYSBEN System Benefits - Energy Related]	1.30%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	1.08%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	369,052
CQ:[Retail ENERGY1 Production - Energy]	1.33%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	369,052
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	1.33%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancillary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(143,465)
DG:[CUSTADV Customer Advances]	0.14%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(739,563)
DJ:[CUSTDEP Customer Deposits]	1.02%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
STREET LIGHTING	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.00
F:[DEMPROD1 Production Demand]	**0.48%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	34,950
U:[DEMDIST1 Distribution Substation]	0.48%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	34,064
X:[DEMDIST2 Distribution OH Primary Lines]	0.48%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	33,000
AA:[DEMDIST3 Distribution OH Secondary Lines]	0.48%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	34,064
AD:[DEMDIST4 Distribution UG Primary Lines]	0.48%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	33,000
AG:[DEMDIST5 Distribution UG Secondary Lines]	0.48%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	33,627
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.36%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	33,627
AM:[DEMDIST7 Distribution UG Line Transformers]	0.34%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	34,064
AV:[DEMDIST10 Distribution Rents]	0.48%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	153,848

AY:[ENERGY1 Production - Energy]	0.54%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.49%
BC:[]	
BD:[ENERGY2_A]	0.50
BE:[ENERGY2_A Related Fuel (ACC)]	0.51%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	
BH:[CUST370 Distribution Meters]	
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	1
BN:[CUST373 Street Lighting]	100.00%
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,023
BQ:[CUSTNUM Customer Accounts]	0.09%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,023
BW:[CUST910 Customer Service and Information]	0.09%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,023
BZ:[CUST916 Sales Expense]	0.09%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	0.43
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.43%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	145,323
CF:[ERGREGAST Regulatory Asset - Energy Related]	0.48%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	153,848
CI:[ERGSYSBEN System Benefits - Energy Related]	0.54%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.49%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	153,848
CQ:[Retail ENERGY1 Production - Energy]	0.55%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	153,848
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.55%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(171,300)
DG:[CUSTADV Customer Advances]	0.17%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(498,448)
DJ:[CUSTDEP Customer Deposits]	0.69%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
DUSK TO DAWN	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.00
F:[DEMPROD1 Production Demand]	**0.08%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	5,613
U:[DEMDIST1 Distribution Substation]	0.08%
V:[]	

W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	5,471
X:[DEMDIST2 Distribution OH Primary Lines]	0.08%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	5,300
AA:[DEMDIST3 Distribution OH Secondary Lines]	0.08%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	5,471
AD:[DEMDIST4 Distribution UG Primary Lines]	0.08%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	5,300
AG:[DEMDIST5 Distribution UG Secondary Lines]	0.08%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	5,401
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.06%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	5,401
AM:[DEMDIST7 Distribution UG Line Transformers]	0.05%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	5,471
AV:[DEMDIST10 Distribution Rents]	0.08%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	24,770
AY:[ENERGY1 Production - Energy]	0.09%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.08%
BC:[]	
BD:[ENERGY2_A]	0.08
BE:[ENERGY2_A Related Fuel (ACC)]	0.08%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	
BH:[CUST370 Distribution Meters]	
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	1
BK:[CUST371 Dusk to Dawn]	100.00%
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	8,319
BQ:[CUSTNUM Customer Accounts]	0.70%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	8,319
BW:[CUST910 Customer Service and Information]	0.70%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	8,319
BZ:[CUST916 Sales Expense]	0.70%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	0.08
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.08%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	26,649
CF:[ERGREGAST Regulatory Asset - Energy Related]	0.09%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	24,770
CI:[ERGSYSBEN System Benefits - Energy Related]	0.09%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.08%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	24,770
CQ:[Retail ENERGY1 Production - Energy]	0.09%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	24,770
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.09%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	
DH:[]	
DI:[CUSTDEP Customer Deposits]	(211,388)
DJ:[CUSTDEP Customer Deposits]	0.29%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	

EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-20 (Church Rate)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.00
F:[DEMPROD1 Production Demand]	**0.30%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	23,845
U:[DEMDIST1 Distribution Substation]	0.33%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	23,241
X:[DEMDIST2 Distribution OH Primary Lines]	0.33%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	23,241
AD:[DEMDIST4 Distribution UG Primary Lines]	0.33%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	28,136
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.31%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	28,136
AM:[DEMDIST7 Distribution UG Line Transformers]	0.29%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	118
AP:[CUSTOH1 Distribution OH Services]	0.04%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	885
AS:[CUSTUG1 Distribution UG Services]	0.08%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	23,241
AV:[DEMDIST10 Distribution Rents]	0.33%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	41,349
AY:[ENERGY1 Production - Energy]	0.15%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.15%
BC:[]	
BD:[ENERGY2_A]	0.15
BE:[ENERGY2_A Related Fuel (ACC)]	0.15%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	2,600
BH:[CUST370 Distribution Meters]	0.20%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	409
BQ:[CUSTNUM Customer Accounts]	0.03%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	409
BW:[CUST910 Customer Service and Information]	0.03%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	409
BZ:[CUST916 Sales Expense]	0.03%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	0.19
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.19%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	36,862
CF:[ERGREGAST Regulatory Asset - Energy Related]	0.12%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	41,349
CI:[ERGSYSBEN System Benefits - Energy Related]	0.15%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.31%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	41,349
CQ:[Retail ENERGY1 Production - Energy]	0.15%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	41,349
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.15%
CU:[end If]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	

CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(122,682)
DG:[CUSTADV Customer Advances]	0.12%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(104,611)
DJ:[CUSTDEP Customer Deposits]	0.14%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32 TOU (0-20kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl (4CP Juris.]]	
F:[DEMPROD1 Production Demand]	
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	
U:[DEMDIST1 Distribution Substation]	
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	
X:[DEMDIST2 Distribution OH Primary Lines]	
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	
AD:[DEMDIST4 Distribution UG Primary Lines]	
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AJ:[DEMDIST6 Distribution OH Line Transformers]	
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AM:[DEMDIST7 Distribution UG Line Transformers]	
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	
AV:[DEMDIST10 Distribution Rents]	
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	
AY:[ENERGY1 Production - Energy]	
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	
BC:[]	
BD:[ENERGY2_A]	
BE:[ENERGY2_A Related Fuel (ACC)]	
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	
BH:[CUST370 Distribution Meters]	
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	
BQ:[CUSTNUM Customer Accounts]	
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	
BT:[CUSTNUM_A Customer Accounts ACC]	
BU:[]	
BV:[CUST910 Number of Customer Accounts]	
BW:[CUST910 Customer Service and Information]	

BX:[]	
BY:[CUST916 Number of Customer Accounts]	
BZ:[CUST916 Sales Expense]	
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CI:[ERGSYSBEN System Benefits - Energy Related]	
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	
CN:[Retail DEMPROD1 Production Demand]	
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	
CQ:[Retail ENERGY1 Production - Energy]	
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Anciliary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	
DH:[]	
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32 TOU (0-100kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.00
F:[DEMPROD1 Production Demand]	**0.09%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	6,886
U:[DEMDIST1 Distribution Substation]	0.09%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	6,711
X:[DEMDIST2 Distribution OH Primary Lines]	0.09%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	6,711
AD:[DEMDIST4 Distribution UG Primary Lines]	0.10%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	9,434
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.10%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	9,434
AM:[DEMDIST7 Distribution UG Line Transformers]	0.10%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	97
AP:[CUSTOH1 Distribution OH Services]	0.03%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	725
AS:[CUSTUG1 Distribution UG Services]	0.07%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	6,711

AV:[DEMDIST10 Distribution Rents]	0.09%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	40,726
AY:[ENERGY1 Production - Energy]	0.14%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.14%
BC:[]	
BD:[ENERGY2_A]	0.14
BE:[ENERGY2_A Related Fuel (ACC)]	0.14%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,172
BH:[CUST370 Distribution Meters]	0.09%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	336
BQ:[CUSTNUM Customer Accounts]	0.03%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	336
BW:[CUST910 Customer Service and Information]	0.03%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	336
BZ:[CUST916 Sales Expense]	0.03%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail (4CP Juris.)]	0.11
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.11%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	47,810
CF:[ERGREGAST Regulatory Asset - Energy Related]	0.16%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	40,726
CI:[ERGSYSBEN System Benefits - Energy Related]	0.14%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[if]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl (4CP Juris.)]	0
CN:[Retail DEMPROD1 Production Demand]	0.09%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	40,726
CQ:[Retail ENERGY1 Production - Energy]	0.15%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	40,726
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.15%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(122,788)
DG:[CUSTADV Customer Advances]	0.12%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(104,702)
DJ:[CUSTDEP Customer Deposits]	0.14%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32 TOU (101-400kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl (4CP Juris.)]	0.00
F:[DEMPROD1 Production Demand]	**0.18%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	

T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	12,097
U:[DEMDIST1 Distribution Substation]	0.17%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	11,791
X:[DEMDIST2 Distribution OH Primary Lines]	0.17%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	11,791
AD:[DEMDIST4 Distribution UG Primary Lines]	0.17%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	13,041
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.14%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	13,041
AM:[DEMDIST7 Distribution UG Line Transformers]	0.13%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	42
AP:[CUSTOH1 Distribution OH Services]	0.01%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	388
AS:[CUSTUG1 Distribution UG Services]	0.04%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	11,791
AV:[DEMDIST10 Distribution Rents]	0.17%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	75,181
AY:[ENERGY1 Production - Energy]	0.26%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.26%
BC:[]	
BD:[ENERGY2_A]	0.26
BE:[ENERGY2_A Related Fuel (ACC)]	0.27%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	404
BH:[CUST370 Distribution Meters]	0.03%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	73
BQ:[CUSTNUM Customer Accounts]	0.01%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	73
BW:[CUST910 Customer Service and Information]	0.01%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	73
BZ:[CUST916 Sales Expense]	0.01%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	0.16
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.16%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	73,603
CF:[ERGREGAST Regulatory Asset - Energy Related]	0.25%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	75,181
CI:[ERGSYSBEN System Benefits - Energy Related]	0.26%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	0
CO:[]	0.18%
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	75,181
CQ:[Retail ENERGY1 Production - Energy]	0.27%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	75,181
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.27%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	(192,118)
DH:[]	0.19%
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	(163,820)
DK:[]	0.23%
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	

DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32 TOU (401+ kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.01
F:[DEMPROD1 Production Demand]	**0.58%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	45,384
U:[DEMDIST1 Distribution Substation]	0.62%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	44,234
X:[DEMDIST2 Distribution OH Primary Lines]	0.62%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	44,234
AD:[DEMDIST4 Distribution UG Primary Lines]	0.63%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	45,764
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.50%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	45,764
AM:[DEMDIST7 Distribution UG Line Transformers]	0.46%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	873
AS:[CUSTUG1 Distribution UG Services]	0.08%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	44,234
AV:[DEMDIST10 Distribution Rents]	0.62%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	281,190
AY:[ENERGY1 Production - Energy]	0.99%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.01
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.97%
BC:[]	
BD:[ENERGY2_A]	0.98
BE:[ENERGY2_A Related Fuel (ACC)]	1.00%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	780
BH:[CUST370 Distribution Meters]	0.06%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	57
BQ:[CUSTNUM Customer Accounts]	0.00%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	57
BW:[CUST910 Customer Service and Information]	0.00%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	57
BZ:[CUST916 Sales Expense]	0.00%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	0.67
CC:[DEMREGAST Regulatory Asset - Demand Related]	0.67%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	311,326
CF:[ERGREGAST Regulatory Asset - Energy Related]	1.04%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	281,190
CI:[ERGSYSBEN System Benefits - Energy Related]	0.99%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[if]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.59%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	281,190
CQ:[Retail ENERGY1 Production - Energy]	1.01%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	281,190
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	1.01%
CU:[end if]	
CV:[]	

CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(644,638)
DG:[CUSTADV Customer Advances]	0.63%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(549,685)
DJ:[CUSTDEP Customer Deposits]	0.76%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
School TOU	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl (4CP Juris.)]	0.01
F:[DEMPROD1 Production Demand]	**0.51%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	38,392
U:[DEMDIST1 Distribution Substation]	0.53%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	37,419
X:[DEMDIST2 Distribution OH Primary Lines]	0.53%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	37,419
AD:[DEMDIST4 Distribution UG Primary Lines]	0.53%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	40,172
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.44%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	40,172
AM:[DEMDIST7 Distribution UG Line Transformers]	0.41%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	67
AP:[CUSTOH1 Distribution OH Services]	0.02%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	616
AS:[CUSTUG1 Distribution UG Services]	0.06%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	37,419
AV:[DEMDIST10 Distribution Rents]	0.53%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	117,838
AY:[ENERGY1 Production - Energy]	0.41%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.41%
BC:[]	
BD:[ENERGY2_A]	0.42
BE:[ENERGY2_A Related Fuel (ACC)]	0.43%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	755
BH:[CUST370 Distribution Meters]	0.06%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	116
BQ:[CUSTNUM Customer Accounts]	0.01%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%

BU:[]	
BV:[CUST910 Number of Customer Accounts]	116
BW:[CUST910 Customer Service and Information]	0.01%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	116
BZ:[CUST916 Sales Expense]	0.01%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	117,838
CI:[ERGSYSBEN System Benefits - Energy Related]	0.41%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.52%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	117,838
CQ:[Retail ENERGY1 Production - Energy]	0.42%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	117,838
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.42%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(325,232)
DG:[CUSTADV Customer Advances]	0.32%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(277,326)
DJ:[CUSTDEP Customer Deposits]	0.38%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-30, E-32 (0 - 100 kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.13
F:[DEMPROD1 Production Demand]	**12.83%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	1,016,993
U:[DEMDIST1 Distribution Substation]	13.95%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	991,221
X:[DEMDIST2 Distribution OH Primary Lines]	13.95%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	991,221
AD:[DEMDIST4 Distribution UG Primary Lines]	14.10%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	1,393,698
AJ:[DEMDIST6 Distribution OH Line Transformers]	15.11%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	1,393,698
AM:[DEMDIST7 Distribution UG Line Transformers]	14.14%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	35,108
AP:[CUSTOH1 Distribution OH Services]	11.65%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	262,281

AS:[CUSTUG1 Distribution UG Services]	23.85%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	991,221
AV:[DEMDIST10 Distribution Rents]	13.95%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	4,263,784
AY:[ENERGY1 Production - Energy]	14.99%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.15
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	15.11%
BC:[]	
BD:[ENERGY2_A]	15.28
BE:[ENERGY2_A Related Fuel (ACC)]	15.62%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	193,237
BH:[CUST370 Distribution Meters]	14.87%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	121,274
BQ:[CUSTNUM Customer Accounts]	10.24%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.01%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	121,274
BW:[CUST910 Customer Service and Information]	10.25%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	121,274
BZ:[CUST916 Sales Expense]	10.24%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	15.20
CC:[DEMREGAST Regulatory Asset - Demand Related]	15.20%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	4,129,250
CF:[ERGREGAST Regulatory Asset - Energy Related]	13.75%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	4,263,784
CI:[ERGSYSBEN System Benefits - Energy Related]	14.99%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	13.10%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	4,263,784
CQ:[Retail ENERGY1 Production - Energy]	15.33%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	4,263,784
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	15.33%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(14,695,797)
DG:[CUSTADV Customer Advances]	14.37%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(12,531,158)
DJ:[CUSTDEP Customer Deposits]	17.33%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	
F:[DEMPROD1 Production Demand]	
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	

Q:[DEMTRAN4 Specific Assignment]
R:[DEMTRAN4 SCE Specific]
S:[]
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]
U:[DEMDIST1 Distribution Substation]
V:[]
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]
X:[DEMDIST2 Distribution OH Primary Lines]
Y:[]
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]
AA:[DEMDIST3 Distribution OH Secondary Lines]
AB:[]
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]
AD:[DEMDIST4 Distribution UG Primary Lines]
AE:[]
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]
AG:[DEMDIST5 Distribution UG Secondary Lines]
AH:[]
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]
AJ:[DEMDIST6 Distribution OH Line Transformers]
AK:[]
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]
AM:[DEMDIST7 Distribution UG Line Transformers]
AN:[]
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]
AP:[CUSTOH1 Distribution OH Services]
AQ:[]
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]
AS:[CUSTUG1 Distribution UG Services]
AT:[]
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]
AV:[DEMDIST10 Distribution Rents]
AW:[]
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]
AY:[ENERGY1 Production - Energy]
AZ:[]
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]
BC:[]
BD:[ENERGY2_A]
BE:[ENERGY2_A Related Fuel (ACC)]
BF:[]
BG:[CUST370 Weighted Costs for Distribution Meters ($)]
BH:[CUST370 Distribution Meters]
BI:[]
BJ:[CUST371 Dusk to Dawn Customer Class Specific]
BK:[CUST371 Dusk to Dawn]
BL:[]
BM:[CUST373 Street Lighting Customer Class Specific]
BN:[CUST373 Street Lighting]
BO:[]
BP:[CUSTNUM Number of Customer Accounts]
BQ:[CUSTNUM Customer Accounts]
BR:[]
BS:[CUSTNUM_A Number of Customer Accounts ACC]
BT:[CUSTNUM_A Customer Accounts ACC]
BU:[]
BV:[CUST910 Number of Customer Accounts]
BW:[CUST910 Customer Service and Information]
BX:[]
BY:[CUST916 Number of Customer Accounts]
BZ:[CUST916 Sales Expense]
CA:[]
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]
CC:[DEMREGAST Regulatory Asset - Demand Related]
CD:[]
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]
CF:[ERGREGAST Regulatory Asset - Energy Related]
CG:[]
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]
CI:[ERGSYSBEN System Benefits - Energy Related]
CJ:[]
CK:[Retail ONLY versions of above allocators:]
CL:[If]
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]
CN:[Retail DEMPROD1 Production Demand]
CO:[]
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]
CQ:[Retail ENERGY1 Production - Energy]
CR:[]
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]
CT:[Retail ERGSYSBEN System Benefits - Energy Related]
CU:[end if]
CV:[]
CW:[Other Allocators]
CX:[Demand Production (RES)]
CY:[Ratio: Demand Production (RES)]
CZ:[]
DA:[Ancillary Services]
DB:[Ratio: Ancillary Services]
DC:[Sum: Ancillary Services]
DD:[Less: Ancillary Services]
DE:[]
DF:[CUSTADV Customer Advances]
DG:[CUSTADV Customer Advances]
DH:[]
DI:[CUSTDEP Customer Deposits]
DJ:[CUSTDEP Customer Deposits]
DK:[]
DL:[5]
DM:[5]
DN:[]
DO:[6]
DP:[6]
DQ:[]
DR:[7]
DS:[7]
DT:[]
DU:[8]

DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-32 (101 - 400 kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.09
F:[DEMPROD1 Production Demand]	**9.14%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	650,410
U:[DEMDIST1 Distribution Substation]	8.92%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	633,928
X:[DEMDIST2 Distribution OH Primary Lines]	8.92%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	633,928
AD:[DEMDIST4 Distribution UG Primary Lines]	9.02%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	491,526
AJ:[DEMDIST6 Distribution OH Line Transformers]	5.33%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	491,526
AM:[DEMDIST7 Distribution UG Line Transformers]	4.99%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	680
AP:[CUSTOH1 Distribution OH Services]	0.23%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	22,565
AS:[CUSTUG1 Distribution UG Services]	2.05%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	633,928
AV:[DEMDIST10 Distribution Rents]	8.92%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	3,352,488
AY:[ENERGY1 Production - Energy]	11.79%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.12
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	11.78%
BC:[]	
BD:[ENERGY2_A]	11.92
BE:[ENERGY2_A Related Fuel (ACC)]	12.19%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	25,147
BH:[CUST370 Distribution Meters]	1.94%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	4,252
BQ:[CUSTNUM Customer Accounts]	0.36%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	4,252
BW:[CUST910 Customer Service and Information]	0.36%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	4,252
BZ:[CUST916 Sales Expense]	0.36%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	10.43
CC:[DEMREGAST Regulatory Asset - Demand Related]	10.43%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	3,449,673
CF:[ERGREGAST Regulatory Asset - Energy Related]	11.48%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	3,352,488
CI:[ERGSYSBEN System Benefits - Energy Related]	11.79%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[ff]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	9.33%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	3,352,488
CQ:[Retail ENERGY1 Production - Energy]	12.05%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	3,352,488

CT:[Retail ERGSYSBEN System Benefits - Energy Related]	12.05%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	(10,020,970)
DH:[]	9.80%
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	(8,544,916)
DK:[]	11.82%
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	
EE:[]	100.00%
EF:[Zero Allocator]	
EG:[]	
E-32	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	
D:[]	3628
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	
F:[DEMPROD1 Production Demand]	
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	
U:[DEMDIST1 Distribution Substation]	
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	
X:[DEMDIST2 Distribution OH Primary Lines]	
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	
AD:[DEMDIST4 Distribution UG Primary Lines]	
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AJ:[DEMDIST6 Distribution OH Line Transformers]	
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AM:[DEMDIST7 Distribution UG Line Transformers]	
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	
AV:[DEMDIST10 Distribution Rents]	
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	
AY:[ENERGY1 Production - Energy]	
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	
BC:[]	
BD:[ENERGY2_A]	
BE:[ENERGY2_A Related Fuel (ACC)]	
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	
BH:[CUST370 Distribution Meters]	
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	
BQ:[CUSTNUM Customer Accounts]	

BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	
BT:[CUSTNUM_A Customer Accounts ACC]	
BU:[]	
BV:[CUST910 Number of Customer Accounts]	
BW:[CUST910 Customer Service and Information]	
BX:[]	
BY:[CUST916 Number of Customer Accounts]	
BZ:[CUST916 Sales Expense]	
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CI:[ERGSYSBEN System Benefits - Energy Related]	
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	
CQ:[Retail ENERGY1 Production - Energy]	
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	
DH:[]	
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	
EE:[]	100.00%
EF:[Zero Allocator]	
EG:[]	
E-32 (401+ kW)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	
D:[]	3628
E:[DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	0.07
F:[DEMPROD1 Production Demand]	**6.76%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	509,739
U:[DEMDIST1 Distribution Substation]	6.99%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	496,822
X:[DEMDIST2 Distribution OH Primary Lines]	6.99%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	496,822
AD:[DEMDIST4 Distribution UG Primary Lines]	7.07%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AJ:[DEMDIST6 Distribution OH Line Transformers]	
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	493,981
AM:[DEMDIST7 Distribution UG Line Transformers]	5.01%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	

AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	
AS:[CUSTUG1 Distribution UG Services]	21,815
AT:[]	1.98%
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	
AV:[DEMDIST10 Distribution Rents]	496,822
AW:[]	6.99%
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	
AY:[ENERGY1 Production - Energy]	2,622,747
AZ:[]	9.22%
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.09
BC:[]	9.15%
BD:[ENERGY2_A]	
BE:[ENERGY2_A Related Fuel (ACC)]	9.25
BF:[]	9.46%
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	
BH:[CUST370 Distribution Meters]	10,581
BI:[]	0.81%
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	
BQ:[CUSTNUM Customer Accounts]	795
BR:[]	0.07%
BS:[CUSTNUM_A Number of Customer Accounts ACC]	
BT:[CUSTNUM_A Customer Accounts ACC]	0
BU:[]	0.00%
BV:[CUST910 Number of Customer Accounts]	
BW:[CUST910 Customer Service and Information]	795
BX:[]	0.07%
BY:[CUST916 Number of Customer Accounts]	
BZ:[CUST916 Sales Expense]	795
CA:[]	0.07%
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	9.60
CD:[]	9.60%
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	3,732,824
CG:[]	12.43%
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CI:[ERGSYSBEN System Benefits - Energy Related]	2,622,747
CJ:[]	9.22%
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	0
CO:[]	6.90%
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	
CQ:[Retail ENERGY1 Production - Energy]	2,622,747
CR:[]	9.43%
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	2,622,747
CU:[end if]	9.43%
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	
DG:[CUSTADV Customer Advances]	(7,144,692)
DH:[]	6.98%
DI:[CUSTDEP Customer Deposits]	
DJ:[CUSTDEP Customer Deposits]	(6,092,303)
DK:[]	8.43%
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	
EE:[]	100.00%
EF:[Zero Allocator]	
EG:[]	
E-34	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	
D:[]	3628
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	
F:[DEMPROD1 Production Demand]	0.02
G:[]	**2.24%**
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	

N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	137,822
U:[DEMDIST1 Distribution Substation]	1.89%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	134,330
X:[DEMDIST2 Distribution OH Primary Lines]	1.89%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	134,330
AD:[DEMDIST4 Distribution UG Primary Lines]	1.91%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AJ:[DEMDIST6 Distribution OH Line Transformers]	
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	49,166
AM:[DEMDIST7 Distribution UG Line Transformers]	0.50%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	2,616
AS:[CUSTUG1 Distribution UG Services]	0.24%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	134,330
AV:[DEMDIST10 Distribution Rents]	1.89%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	801,426
AY:[ENERGY1 Production - Energy]	2.82%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.03
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	2.78%
BC:[]	
BD:[ENERGY2_A]	2.81
BE:[ENERGY2_A Related Fuel (ACC)]	2.87%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,529
BH:[CUST370 Distribution Meters]	0.12%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	30
BQ:[CUSTNUM Customer Accounts]	0.00%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	30
BW:[CUST910 Customer Service and Information]	0.00%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	30
BZ:[CUST916 Sales Expense]	0.00%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	2.55
CC:[DEMREGAST Regulatory Asset - Demand Related]	2.55%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	1,140,125
CF:[ERGREGAST Regulatory Asset - Energy Related]	3.80%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	801,426
CI:[ERGSYSBEN System Benefits - Energy Related]	2.82%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	2.29%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	801,426
CQ:[Retail ENERGY1 Production - Energy]	2.88%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	801,426
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	2.88%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(1,812,384)
DG:[CUSTADV Customer Advances]	1.77%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(1,545,426)
DJ:[CUSTDEP Customer Deposits]	2.14%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	

DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
E-35	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.04
F:[DEMPROD1 Production Demand]	**4.45%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	280,932
U:[DEMDIST1 Distribution Substation]	3.85%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	273,813
X:[DEMDIST2 Distribution OH Primary Lines]	3.85%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	273,813
AD:[DEMDIST4 Distribution UG Primary Lines]	3.89%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	
AJ:[DEMDIST6 Distribution OH Line Transformers]	
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	214,589
AM:[DEMDIST7 Distribution UG Line Transformers]	2.18%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	
AP:[CUSTOH1 Distribution OH Services]	
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	4,243
AS:[CUSTUG1 Distribution UG Services]	0.39%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	273,813
AV:[DEMDIST10 Distribution Rents]	3.85%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	1,570,709
AY:[ENERGY1 Production - Energy]	5.52%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.05
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	5.38%
BC:[]	
BD:[ENERGY2_A]	5.44
BE:[ENERGY2_A Related Fuel (ACC)]	5.56%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,720
BH:[CUST370 Distribution Meters]	0.13%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	37
BQ:[CUSTNUM Customer Accounts]	0.00%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	37
BW:[CUST910 Customer Service and Information]	0.00%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	37
BZ:[CUST916 Sales Expense]	0.00%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	3.42
CC:[DEMREGAST Regulatory Asset - Demand Related]	3.42%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	1,753,693
CF:[ERGREGAST Regulatory Asset - Energy Related]	5.84%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	1,570,709
CI:[ERGSYSBEN System Benefits - Energy Related]	5.52%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	4.54%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	1,570,709

CQ:[Retail ENERGY1 Production - Energy]	5.65%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	1,570,709
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	5.65%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(3,921,439)
DG:[CUSTADV Customer Advances]	3.83%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(3,343,825)
DJ:[CUSTDEP Customer Deposits]	4.62%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL SOLAR(ENERGY)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl (4CP Juris.)]	0.02
F:[DEMPROD1 Production Demand]	**1.72%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	130,073
U:[DEMDIST1 Distribution Substation]	1.78%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	126,777
X:[DEMDIST2 Distribution OH Primary Lines]	1.78%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	198,649
AA:[DEMDIST3 Distribution OH Secondary Lines]	2.86%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	126,777
AD:[DEMDIST4 Distribution UG Primary Lines]	1.80%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	198,649
AG:[DEMDIST5 Distribution UG Secondary Lines]	2.86%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	202,423
AJ:[DEMDIST6 Distribution OH Line Transformers]	2.19%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	202,423
AM:[DEMDIST7 Distribution UG Line Transformers]	2.05%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	6,788
AP:[CUSTOH1 Distribution OH Services]	2.25%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	20,290
AS:[CUSTUG1 Distribution UG Services]	1.84%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	126,777
AV:[DEMDIST10 Distribution Rents]	1.78%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	398,750
AY:[ENERGY1 Production - Energy]	1.40%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.01
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	1.41%
BC:[]	
BD:[ENERGY2_A]	0.34
BE:[ENERGY2_A Related Fuel (ACC)]	0.35%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	27,078
BH:[CUST370 Distribution Meters]	2.08%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	

BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	27,078
BQ:[CUSTNUM Customer Accounts]	2.29%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	
BT:[CUSTNUM_A Customer Accounts ACC]	
BU:[]	
BV:[CUST910 Number of Customer Accounts]	27,078
BW:[CUST910 Customer Service and Information]	2.29%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	27,078
BZ:[CUST916 Sales Expense]	2.29%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	398,750
CI:[ERGSYSBEN System Benefits - Energy Related]	1.40%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	1.76%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	398,750
CQ:[Retail ENERGY1 Production - Energy]	1.43%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	398,750
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	1.43%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(620,257)
DG:[CUSTADV Customer Advances]	0.61%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(370,358)
DJ:[CUSTDEP Customer Deposits]	0.51%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL SOLAR (DEMAND)	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.00
F:[DEMPROD1 Production Demand]	**0.11%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	8,015
U:[DEMDIST1 Distribution Substation]	0.11%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	7,812
X:[DEMDIST2 Distribution OH Primary Lines]	0.11%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	11,693
AA:[DEMDIST3 Distribution OH Secondary Lines]	0.17%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	7,812
AD:[DEMDIST4 Distribution UG Primary Lines]	0.11%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	11,693
AG:[DEMDIST5 Distribution UG Secondary Lines]	0.17%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	11,915
AJ:[DEMDIST6 Distribution OH Line Transformers]	0.13%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	11,915

AM:[DEMDIST7 Distribution UG Line Transformers]	0.12%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	295
AP:[CUSTOH1 Distribution OH Services]	0.10%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	881
AS:[CUSTUG1 Distribution UG Services]	0.08%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	7,812
AV:[DEMDIST10 Distribution Rents]	0.11%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	27,426
AY:[ENERGY1 Production - Energy]	0.10%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	0.10%
BC:[]	
BD:[ENERGY2_A]	0.05
BE:[ENERGY2_A Related Fuel (ACC)]	0.05%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,176
BH:[CUST370 Distribution Meters]	0.09%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,176
BQ:[CUSTNUM Customer Accounts]	0.10%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	
BT:[CUSTNUM_A Customer Accounts ACC]	
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,176
BW:[CUST910 Customer Service and Information]	0.10%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,176
BZ:[CUST916 Sales Expense]	0.10%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	
CC:[DEMREGAST Regulatory Asset - Demand Related]	
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	
CF:[ERGREGAST Regulatory Asset - Energy Related]	
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,426
CI:[ERGSYSBEN System Benefits - Energy Related]	0.10%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	0.11%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	27,426
CQ:[Retail ENERGY1 Production - Energy]	0.10%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,426
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	0.10%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(83,304)
DG:[CUSTADV Customer Advances]	0.08%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(49,741)
DJ:[CUSTDEP Customer Deposits]	0.07%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL E-12	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.16
F:[DEMPROD1 Production Demand]	**15.65%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	

K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	1,171,727
U:[DEMDIST1 Distribution Substation]	16.07%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	1,142,034
X:[DEMDIST2 Distribution OH Primary Lines]	16.07%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	2,137,411
AA:[DEMDIST3 Distribution OH Secondary Lines]	30.77%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	1,142,034
AD:[DEMDIST4 Distribution UG Primary Lines]	16.24%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	2,137,411
AG:[DEMDIST5 Distribution UG Secondary Lines]	30.77%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,178,022
AJ:[DEMDIST6 Distribution OH Line Transformers]	23.61%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,178,022
AM:[DEMDIST7 Distribution UG Line Transformers]	22.09%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	117,421
AP:[CUSTOH1 Distribution OH Services]	38.95%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	350,951
AS:[CUSTUG1 Distribution UG Services]	31.91%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	1,142,034
AV:[DEMDIST10 Distribution Rents]	16.07%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	3,860,095
AY:[ENERGY1 Production - Energy]	13.57%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.14
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	13.68%
BC:[]	
BD:[ENERGY2_A]	13.83
BE:[ENERGY2_A Related Fuel (ACC)]	14.14%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	468,372
BH:[CUST370 Distribution Meters]	36.04%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	468,372
BQ:[CUSTNUM Customer Accounts]	39.54%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.03%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	468,372
BW:[CUST910 Customer Service and Information]	39.59%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	468,372
BZ:[CUST916 Sales Expense]	39.54%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	14.91
CC:[DEMREGAST Regulatory Asset - Demand Related]	14.91%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	4,310,449
CF:[ERGREGAST Regulatory Asset - Energy Related]	14.35%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	3,860,095
CI:[ERGSYSBEN System Benefits - Energy Related]	13.57%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[if]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	15.98%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	3,860,095
CQ:[Retail ENERGY1 Production - Energy]	13.87%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	3,860,095
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	13.87%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(19,029,660)
DG:[CUSTADV Customer Advances]	18.60%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(11,362,681)
DJ:[CUSTDEP Customer Deposits]	15.71%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	

DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL ET-1 & ET-2	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.30
F:[DEMPROD1 Production Demand]	**30.11%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	2,271,340
U:[DEMDIST1 Distribution Substation]	31.16%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	2,213,782
X:[DEMDIST2 Distribution OH Primary Lines]	31.16%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	3,344,350
AA:[DEMDIST3 Distribution OH Secondary Lines]	48.14%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	2,213,782
AD:[DEMDIST4 Distribution UG Primary Lines]	31.49%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	3,344,350
AG:[DEMDIST5 Distribution UG Secondary Lines]	48.14%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	3,407,893
AJ:[DEMDIST6 Distribution OH Line Transformers]	36.94%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	3,407,893
AM:[DEMDIST7 Distribution UG Line Transformers]	34.57%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	107,657
AP:[CUSTOH1 Distribution OH Services]	35.72%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	321,770
AS:[CUSTUG1 Distribution UG Services]	29.26%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	2,213,782
AV:[DEMDIST10 Distribution Rents]	31.16%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	6,857,795
AY:[ENERGY1 Production - Energy]	24.11%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.24
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	24.25%
BC:[]	
BD:[ENERGY2_A]	24.52
BE:[ENERGY2_A Related Fuel (ACC)]	25.07%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	429,427
BH:[CUST370 Distribution Meters]	33.05%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	429,427
BQ:[CUSTNUM Customer Accounts]	36.26%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.03%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	429,427
BW:[CUST910 Customer Service and Information]	36.30%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	429,427
BZ:[CUST916 Sales Expense]	36.26%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	28.67
CC:[DEMREGAST Regulatory Asset - Demand Related]	28.67%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	7,352,176
CF:[ERGREGAST Regulatory Asset - Energy Related]	24.47%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	6,857,795
CI:[ERGSYSBEN System Benefits - Energy Related]	24.11%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0

CN:[Retail DEMPROD1 Production Demand]	30.75%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	6,857,795
CQ:[Retail ENERGY1 Production - Energy]	24.65%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	6,857,795
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	24.65%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(31,158,687)
DG:[CUSTADV Customer Advances]	30.46%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(18,604,968)
DJ:[CUSTDEP Customer Deposits]	25.73%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL ECT-1 & ECT-2	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	3628
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.12
F:[DEMPROD1 Production Demand]	**11.64%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	869,276
U:[DEMDIST1 Distribution Substation]	11.92%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	847,248
X:[DEMDIST2 Distribution OH Primary Lines]	11.92%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	1,216,451
AA:[DEMDIST3 Distribution OH Secondary Lines]	17.51%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	847,248
AD:[DEMDIST4 Distribution UG Primary Lines]	12.05%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	1,216,451
AG:[DEMDIST5 Distribution UG Secondary Lines]	17.51%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	1,239,564
AJ:[DEMDIST6 Distribution OH Line Transformers]	13.44%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	1,239,564
AM:[DEMDIST7 Distribution UG Line Transformers]	12.57%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	29,767
AP:[CUSTOH1 Distribution OH Services]	9.88%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	88,969
AS:[CUSTUG1 Distribution UG Services]	8.09%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	847,248
AV:[DEMDIST10 Distribution Rents]	11.92%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	2,962,224
AY:[ENERGY1 Production - Energy]	10.42%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.10
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	10.41%
BC:[]	
BD:[ENERGY2_A]	10.53
BE:[ENERGY2_A Related Fuel (ACC)]	10.77%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	118,736
BH:[CUST370 Distribution Meters]	9.14%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	

BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	118,736
BQ:[CUSTNUM Customer Accounts]	10.02%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.01%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	118,736
BW:[CUST910 Customer Service and Information]	10.04%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	118,736
BZ:[CUST916 Sales Expense]	10.02%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	8.95
CC:[DEMREGAST Regulatory Asset - Demand Related]	8.95%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	2,470,142
CF:[ERGREGAST Regulatory Asset - Energy Related]	8.22%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	2,962,224
CI:[ERGSYSBEN System Benefits - Energy Related]	10.42%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	1
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	11.89%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	2,962,224
CQ:[Retail ENERGY1 Production - Energy]	10.65%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	2,962,224
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	10.65%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(12,077,781)
DG:[CUSTADV Customer Advances]	11.81%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(7,211,688)
DJ:[CUSTDEP Customer Deposits]	9.97%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
TOTAL GENERAL SVC	
B:[Jurisdiction]	
C:[ALL OTHER Jurisdiction]	0
D:[]	47164
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.37
F:[DEMPROD1 Production Demand]	**37.08%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	2,722,500
U:[DEMDIST1 Distribution Substation]	37.35%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
X:[DEMDIST2 Distribution OH Primary Lines]	37.35%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
AD:[DEMDIST4 Distribution UG Primary Lines]	37.74%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,021,771

AJ:[DEMDIST6 Distribution OH Line Transformers]	21.92%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,779,507
AM:[DEMDIST7 Distribution UG Line Transformers]	28.19%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	36,113
AP:[CUSTOH1 Distribution OH Services]	11.98%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	317,007
AS:[CUSTUG1 Distribution UG Services]	28.82%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
AV:[DEMDIST10 Distribution Rents]	37.35%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	13,167,438
AY:[ENERGY1 Production - Energy]	46.30%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.46
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	46.13%
BC:[]	
BD:[ENERGY2_A]	46.65
BE:[ENERGY2_A Related Fuel (ACC)]	47.70%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	237,926
BH:[CUST370 Distribution Meters]	18.31%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	127,379
BQ:[CUSTNUM Customer Accounts]	10.75%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.01%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	127,379
BW:[CUST910 Customer Service and Information]	10.77%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	127,379
BZ:[CUST916 Sales Expense]	10.75%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	42.33
CC:[DEMREGAST Regulatory Asset - Demand Related]	42.33%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	14,675,166
CF:[ERGREGAST Regulatory Asset - Energy Related]	48.85%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	13,167,438
CI:[ERGSYSBEN System Benefits - Energy Related]	46.30%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	13
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	37.86%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	13,167,438
CQ:[Retail ENERGY1 Production - Energy]	47.33%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	13,167,438
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	47.33%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Anciliary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(39,002,740)
DG:[CUSTADV Customer Advances]	38.13%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(33,257,772)
DJ:[CUSTDEP Customer Deposits]	46.00%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	1,300.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
TOTAL RESIDENTIAL	
B:[Jurisdiction]	0
C:[ALL OTHER Jurisdiction]	18140
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.59
F:[DEMPROD1 Production Demand]	**59.23%**
G:[]	

H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	4,450,431
U:[DEMDIST1 Distribution Substation]	61.05%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
X:[DEMDIST2 Distribution OH Primary Lines]	61.05%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,908,554
AA:[DEMDIST3 Distribution OH Secondary Lines]	99.45%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
AD:[DEMDIST4 Distribution UG Primary Lines]	61.70%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,908,554
AG:[DEMDIST5 Distribution UG Secondary Lines]	99.45%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	7,039,817
AJ:[DEMDIST6 Distribution OH Line Transformers]	76.32%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	7,039,817
AM:[DEMDIST7 Distribution UG Line Transformers]	71.41%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	261,928
AP:[CUSTOH1 Distribution OH Services]	86.90%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	782,860
AS:[CUSTUG1 Distribution UG Services]	71.18%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
AV:[DEMDIST10 Distribution Rents]	61.05%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	14,106,290
AY:[ENERGY1 Production - Energy]	49.60%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.50
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	49.85%
BC:[]	
BD:[ENERGY2_A]	49.27
BE:[ENERGY2_A Related Fuel (ACC)]	50.38%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,044,789
BH:[CUST370 Distribution Meters]	80.40%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,044,789
BQ:[CUSTNUM Customer Accounts]	88.21%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1
BT:[CUSTNUM_A Customer Accounts ACC]	0.06%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,044,789
BW:[CUST910 Customer Service and Information]	88.32%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,044,789
BZ:[CUST916 Sales Expense]	88.21%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	52.53
CC:[DEMREGAST Regulatory Asset - Demand Related]	52.53%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	14,132,767
CF:[ERGREGAST Regulatory Asset - Energy Related]	47.05%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	14,106,290
CI:[ERGSYSBEN System Benefits - Energy Related]	49.60%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	5
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	60.48%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	14,106,290
CQ:[Retail ENERGY1 Production - Energy]	50.70%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	14,106,290
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	50.70%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(62,969,689)
DG:[CUSTADV Customer Advances]	61.56%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(37,599,435)
DJ:[CUSTDEP Customer Deposits]	52.00%
DK:[]	
DL:[5]	

DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	500.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
RESIDENTIAL	
B:[Jurisdiction]	0
C:[ALL OTHER Jurisdiction]	18140
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.59
F:[DEMPROD1 Production Demand]	**59.23%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	4,450,431
U:[DEMDIST1 Distribution Substation]	61.05%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
X:[DEMDIST2 Distribution OH Primary Lines]	61.05%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,908,554
AA:[DEMDIST3 Distribution OH Secondary Lines]	99.45%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
AD:[DEMDIST4 Distribution UG Primary Lines]	61.70%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,908,554
AG:[DEMDIST5 Distribution UG Secondary Lines]	99.45%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	7,039,817
AJ:[DEMDIST6 Distribution OH Line Transformers]	76.32%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	7,039,817
AM:[DEMDIST7 Distribution UG Line Transformers]	71.41%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	261,928
AP:[CUSTOH1 Distribution OH Services]	86.90%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	782,860
AS:[CUSTUG1 Distribution UG Services]	71.18%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	4,337,653
AV:[DEMDIST10 Distribution Rents]	61.05%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	14,106,290
AY:[ENERGY1 Production - Energy]	49.60%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.50
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	49.85%
BC:[]	
BD:[ENERGY2_A]	49.27
BE:[ENERGY2_A Related Fuel (ACC)]	50.38%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,044,789
BH:[CUST370 Distribution Meters]	80.40%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,044,789
BQ:[CUSTNUM Customer Accounts]	88.21%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1
BT:[CUSTNUM_A Customer Accounts ACC]	0.06%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,044,789
BW:[CUST910 Customer Service and Information]	88.32%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,044,789
BZ:[CUST916 Sales Expense]	88.21%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	52.53
CC:[DEMREGAST Regulatory Asset - Demand Related]	52.53%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	14,132,767
CF:[ERGREGAST Regulatory Asset - Energy Related]	47.05%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	14,106,290
CI:[ERGSYSBEN System Benefits - Energy Related]	49.60%
CJ:[]	

CK:[Retail ONLY versions of above allocators:]	
CL:[If]	5
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	60.48%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	14,106,290
CQ:[Retail ENERGY1 Production - Energy]	50.70%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	14,106,290
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	50.70%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(62,969,689)
DG:[CUSTADV Customer Advances]	61.56%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(37,599,435)
DJ:[CUSTDEP Customer Deposits]	52.00%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	500.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
GENERAL SERVICE	
B:[Jurisdiction]	0
C:[ALL OTHER Jurisdiction]	47164
D:[]	
E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	0.37
F:[DEMPROD1 Production Demand]	**37.08%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	2,722,500
U:[DEMDIST1 Distribution Substation]	37.35%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
X:[DEMDIST2 Distribution OH Primary Lines]	37.35%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AA:[DEMDIST3 Distribution OH Secondary Lines]	
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
AD:[DEMDIST4 Distribution UG Primary Lines]	37.74%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	
AG:[DEMDIST5 Distribution UG Secondary Lines]	
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,021,771
AJ:[DEMDIST6 Distribution OH Line Transformers]	21.92%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	2,779,507
AM:[DEMDIST7 Distribution UG Line Transformers]	28.19%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	36,113
AP:[CUSTOH1 Distribution OH Services]	11.98%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	317,007
AS:[CUSTUG1 Distribution UG Services]	28.82%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	2,653,510
AV:[DEMDIST10 Distribution Rents]	37.35%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	13,167,438
AY:[ENERGY1 Production - Energy]	46.30%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.46
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	46.13%
BC:[]	
BD:[ENERGY2_A]	46.65
BE:[ENERGY2_A Related Fuel (ACC)]	47.70%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	237,926
BH:[CUST370 Distribution Meters]	18.31%

BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	
BK:[CUST371 Dusk to Dawn]	
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	
BN:[CUST373 Street Lighting]	
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	127,379
BQ:[CUSTNUM Customer Accounts]	10.75%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	0
BT:[CUSTNUM_A Customer Accounts ACC]	0.01%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	127,379
BW:[CUST910 Customer Service and Information]	10.77%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	127,379
BZ:[CUST916 Sales Expense]	10.75%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	42.33
CC:[DEMREGAST Regulatory Asset - Demand Related]	42.33%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	14,675,166
CF:[ERGREGAST Regulatory Asset - Energy Related]	48.85%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	13,167,438
CI:[ERGSYSBEN System Benefits - Energy Related]	46.30%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	13
CM:[Retail DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	0
CN:[Retail DEMPROD1 Production Demand]	37.86%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	13,167,438
CQ:[Retail ENERGY1 Production - Energy]	47.33%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	13,167,438
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	47.33%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(39,002,740)
DG:[CUSTADV Customer Advances]	38.13%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(33,257,772)
DJ:[CUSTDEP Customer Deposits]	46.00%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	1,300.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
TOTAL RETAIL	
B:[Jurisdiction]	0
C:[ALL OTHER Jurisdiction]	76188
D:[]	
E:[DEMPROD1 Average & Excess @ GenerationI [4CP Juris.]]	0.98
F:[DEMPROD1 Production Demand]	**97.93%**
G:[]	
H:[DEMPROD6 Specific Assignment]	
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	
J:[]	
K:[DEMTRAN1 Specific Assignment]	
L:[DEMTRAN1 Transmission Substation]	
M:[]	
N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	7,289,745
U:[DEMDIST1 Distribution Substation]	100.00%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	7,105,017
X:[DEMDIST2 Distribution OH Primary Lines]	100.00%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,946,854
AA:[DEMDIST3 Distribution OH Secondary Lines]	100.00%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	7,030,698
AD:[DEMDIST4 Distribution UG Primary Lines]	100.00%
AE:[]	
AF:[DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,946,854

AG:[DEMDIST5 Distribution UG Secondary Lines]	100.00%
AH:[]	
AI:[DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	9,224,567
AJ:[DEMDIST6 Distribution OH Line Transformers]	100.00%
AK:[]	
AL:[DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)]	9,858,352
AM:[DEMDIST7 Distribution UG Line Transformers]	100.00%
AN:[]	
AO:[CUSTOH1 Weighted Customer Costs for Distribution Services ($)]	301,428
AP:[CUSTOH1 Distribution OH Services]	100.00%
AQ:[]	
AR:[CUSTUG1 Weighted Customer Costs for Distribution Services ($)]	1,099,867
AS:[CUSTUG1 Distribution UG Services]	100.00%
AT:[]	
AU:[DEMDIST10 NCP Demand @ Primary Line Level w/losses (KW)]	7,105,017
AV:[DEMDIST10 Distribution Rents]	100.00%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	27,821,398
AY:[ENERGY1 Production - Energy]	97.83%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	0.98
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	97.83%
BC:[]	
BD:[ENERGY2_A]	97.80
BE:[ENERGY2_A Related Fuel (ACC)]	100.00%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,290,334
BH:[CUST370 Distribution Meters]	99.30%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	1
BK:[CUST371 Dusk to Dawn]	100.00%
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	1
BN:[CUST373 Street Lighting]	100.00%
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,182,977
BQ:[CUSTNUM Customer Accounts]	99.88%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1,377
BT:[CUSTNUM_A Customer Accounts ACC]	100.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,182,977
BW:[CUST910 Customer Service and Information]	100.00%
BX:[]	
BY:[CUST916 Number of Customer Accounts]	1,182,977
BZ:[CUST916 Sales Expense]	99.88%
CA:[]	
CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	96.60
CC:[DEMREGAST Regulatory Asset - Demand Related]	96.60%
CD:[]	
CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	29,310,983
CF:[ERGREGAST Regulatory Asset - Energy Related]	97.57%
CG:[]	
CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,821,398
CI:[ERGSYSBEN System Benefits - Energy Related]	97.83%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	21
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	100.00%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	27,821,398
CQ:[Retail ENERGY1 Production - Energy]	100.00%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,821,398
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	100.00%
CU:[end if]	
CV:[]	
CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancillary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(102,287,194)
DG:[CUSTADV Customer Advances]	100.00%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(72,306,606)
DJ:[CUSTDEP Customer Deposits]	100.00%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
DX:[9]	
DY:[9]	
DZ:[]	
EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	2,100.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	
ACC JURISDICTION	
B:[Jurisdiction]	0
C:[ALL OTHER Jurisdiction]	76188
D:[]	

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G:[]	
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L:[DEMTRAN1 Transmission Substation]	
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N:[DEMTRAN3 Specific Assignment]	
O:[DEMTRAN3 Transmission Lines]	
P:[]	
Q:[DEMTRAN4 Specific Assignment]	
R:[DEMTRAN4 SCE Specific]	
S:[]	
T:[DEMDIST1 NCP Demand @ Substation Level w/losses (KW)]	7,289,745
U:[DEMDIST1 Distribution Substation]	100.00%
V:[]	
W:[DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)]	7,105,017
X:[DEMDIST2 Distribution OH Primary Lines]	100.00%
Y:[]	
Z:[DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)]	6,946,854
AA:[DEMDIST3 Distribution OH Secondary Lines]	100.00%
AB:[]	
AC:[DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)]	7,030,698
AD:[DEMDIST4 Distribution UG Primary Lines]	100.00%
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AJ:[DEMDIST6 Distribution OH Line Transformers]	100.00%
AK:[]	
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AV:[DEMDIST10 Distribution Rents]	100.00%
AW:[]	
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BN:[CUST373 Street Lighting]	100.00%
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BQ:[CUSTNUM Customer Accounts]	99.88%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1,377
BT:[CUSTNUM_A Customer Accounts ACC]	100.00%
BU:[]	
BV:[CUST910 Number of Customer Accounts]	1,182,977
BW:[CUST910 Customer Service and Information]	100.00%
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CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,821,398
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CL:[If]	21
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	1
CN:[Retail DEMPROD1 Production Demand]	100.00%
CO:[]	
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	27,821,398
CQ:[Retail ENERGY1 Production - Energy]	100.00%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,821,398
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	100.00%
CU:[end if]	
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CW:[Other Allocators]	
CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
CZ:[]	
DA:[Ancillary Services]	
DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancillary Services]	
DD:[Less: Ancillary Services]	
DE:[]	
DF:[CUSTADV Customer Advances]	(102,287,194)
DG:[CUSTADV Customer Advances]	100.00%
DH:[]	
DI:[CUSTDEP Customer Deposits]	(72,306,606)

DJ:[CUSTDEP Customer Deposits]	100.00%
DK:[]	
DL:[5]	
DM:[5]	
DN:[]	
DO:[6]	
DP:[6]	
DQ:[]	
DR:[7]	
DS:[7]	
DT:[]	
DU:[8]	
DV:[8]	
DW:[]	
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EA:[10]	
EB:[10]	
EC:[]	
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EE:[]	
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EG:[]	
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B:[Jurisdiction]	3628
C:[ALL OTHER Jurisdiction]	79816
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E:[DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	1.00
F:[DEMPROD1 Production Demand]	**100.00%**
G:[]	
H:[DEMPROD6 Specific Assignment]	100
I:[DEMPROD6 Ancillary Service - Scheduling & Dispatch]	**100.00%**
J:[]	
K:[DEMTRAN1 Specific Assignment]	100
L:[DEMTRAN1 Transmission Substation]	100.00%
M:[]	
N:[DEMTRAN3 Specific Assignment]	100
O:[DEMTRAN3 Transmission Lines]	100.00%
P:[]	
Q:[DEMTRAN4 Specific Assignment]	100
R:[DEMTRAN4 SCE Specific]	100.00%
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AV:[DEMDIST10 Distribution Rents]	100.00%
AW:[]	
AX:[ENERGY1 Customer Class Energy @ Generation (MWH)]	28,439,817
AY:[ENERGY1 Production - Energy]	100.00%
AZ:[]	
BA:[ENERGY2 Weighted Hourly Energy Allocator @ Generation]	1.00
BB:[ENERGY2 Production - Energy (Fuel and Purchased Power)]	100.00%
BC:[]	
BD:[ENERGY2_A]	97.80
BE:[ENERGY2_A Related Fuel (ACC)]	100.00%
BF:[]	
BG:[CUST370 Weighted Costs for Distribution Meters ($)]	1,299,475
BH:[CUST370 Distribution Meters]	100.00%
BI:[]	
BJ:[CUST371 Dusk to Dawn Customer Class Specific]	1
BK:[CUST371 Dusk to Dawn]	100.00%
BL:[]	
BM:[CUST373 Street Lighting Customer Class Specific]	1
BN:[CUST373 Street Lighting]	100.00%
BO:[]	
BP:[CUSTNUM Number of Customer Accounts]	1,184,446
BQ:[CUSTNUM Customer Accounts]	100.00%
BR:[]	
BS:[CUSTNUM_A Number of Customer Accounts ACC]	1,377
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BV:[CUST910 Number of Customer Accounts]	1,182,977
BW:[CUST910 Customer Service and Information]	100.00%
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CB:[DEMREGAST Average & Excess @ Generation - Retail [4CP Juris.]]	100.00
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CE:[ERGREGAST Customer Class Energy @ Generation (MWH)]	30,040,123
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CH:[ERGSYSBEN Customer Class Energy @ Generation (MWH)]	28,439,817
CI:[ERGSYSBEN System Benefits - Energy Related]	100.00%
CJ:[]	
CK:[Retail ONLY versions of above allocators:]	
CL:[If]	
CM:[Retail DEMPROD1 Average & Excess @ Generationl [4CP Juris.]]	21
CN:[Retail DEMPROD1 Production Demand]	1
CO:[]	100.00%
CP:[Retail ENERGY1 Customer Class Energy @ Generation (MWH)]	27,821,398
CQ:[Retail ENERGY1 Production - Energy]	100.00%
CR:[]	
CS:[Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)]	27,821,398
CT:[Retail ERGSYSBEN System Benefits - Energy Related]	100.00%
CU:[end if]	
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CX:[Demand Production (RES)]	
CY:[Ratio: Demand Production (RES)]	
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DB:[Ratio: Ancillary Services]	
DC:[Sum: Ancilary Services]	
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DG:[CUSTADV Customer Advances]	100.00%
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DK:[]	
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EA:[10]	
EB:[10]	
EC:[]	
ED:[100% Allocator]	2,200.00%
EE:[]	
EF:[Zero Allocator]	
EG:[]	

EXHIBIT
S-1
ADMITTED

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 COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	))))	DOCKET NO. E-00000J-14-0023

REBUTTAL TESTIMONY

OF

ZACHARY BRANUM

UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 7, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023

Zachary Branum's testimony addresses some of the questions raised by Commissioner Burns' in a letter he submitted on February 8, 2016, regarding a Colorado River shortage and power plant water requirements. Specifically, detail regarding the water consumption requirements of various power plants has been provided. Additionally, the effect of power plant retirement on water consumption has also been discussed. Lastly, a brief explanation of a Colorado River shortage has been given.

After reviewing data provided by Arizona Public Service, Tucson Electric Power, UNS Electric, and Arizona Electric Power Cooperative; it was determined that the largest source of water used in power plant cooling operations is treated effluent (51 percent), followed by ground water (28 percent), and surface water (21 percent). For the years of 2016-2020, it is anticipated that there will be a cumulative annual reduction in ground water and surface water consumption of 26.5 percent and 27.4 percent, respectively. Conversely, annual consumption of treated effluent will increase by roughly 7.2 percent. These changes are mainly due to power plant retirements and conversions, which is reflected in Tables 1 and 2.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Zachary Thomas Branum. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as a Utilities Division ("Staff") Engineer. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I received a Bachelor's degree in Aerospace Engineering (Astronautics) from Arizona State University in 2014 with a specialization in Applied Thermodynamics and Space Systems Design. I will receive my Masters of Science (M.S.) degree in Mechanical Engineering on May 9, 2016 with a specialization in Thermodynamics and Power Generation. Courses included in my graduate study were; Electrical Power Plants, Nuclear Power Engineering, Nuclear Reactor Theory and Design, Renewable Energy Engineering, Solar Thermal Engineering, Solar Commercialization, and Advanced Thermodynamics. Before joining the Commission in January 2016, I spent time conducting research at the National Energy Technology Laboratory for a period of three months, and I instructed undergraduate students at Arizona State University as a Graduate Teaching Assistant.

Q. Briefly describe your responsibilities as a Utilities Division Engineer.

A. In my capacity as a Utilities Division Engineer, I have been assigned to perform engineering analysis and provide recommendations to the Commission on assigned cases. This is my first proceeding as a Utilities Engineer with the Commission.

Q. Did you file Direct Testimony in this proceeding?

A. No.

PURPOSE OF TESTIMONY

Q. What is the scope of your testimony in this case?

A. The purpose of my testimony is to answer some of the questions raised by Commissioner Burns in his letter dated February 8, 2016, regarding the water-energy nexus.

Q. Which questions will you be addressing?

A. My testimony addresses the following:

1. Which power plants in the state of Arizona use surface[1] or ground water for the purposes of cooling?
2. Which power plants in the state of Arizona use treated effluent for the purposes of cooling?
3. What are the water requirements of power plants that are included in previous and future Integrated Resource Plans (IRP)?
4. Which power plants are retiring and how does that affect water consumption?
5. What is the situation with curtailing water in response to a Colorado River shortage?

Q. What resources were used to address these questions?

A. Staff requested power plant water consumption data from Arizona Public Service (APS), Tucson Electric Power (TEP), UNS Electric (UNSE), and Arizona Electric Power Cooperative (AEPCO). In the data requests, Staff also requested responses to questions concerning a Colorado River shortage. Staff also utilized information from the website of the Arizona Department of Water Resources ("ADWR") to address the issue of a Colorado River shortage.

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[1] Surface water refers to water provided by the Colorado River to the Central Arizona Project, along with other Rivers and lakes.

Q. Why was data only requested from APS, TEP, UNSE, and AEPCO?

A. The data was requested from APS, TEP, UNSE, and AEPCO because each are Load Serving Entities (LSE's), producing and supplying power. Other utilities and cooperatives purchase power from LSE's. Staff believes the power plant data from APS, TEP, UNSE, and AEPCO provides enough information to initially address the questions asked by Commissioner Burns. SRP is the only significant LSE that has been omitted.

CONCLUSIONS

Q. Which power plants of these LSE's use surface water for the purposes of cooling?

A. Four Corners[2], Sundance, Yucca, Navajo, and San Juan[3].

Q. Which rivers and/or lakes provide this surface water?

A. Four Corners Power Plant draws water from Morgan Lake, which receives water from the San Juan River. Prior to 2011, the Sundance Power Plant relied upon Colorado River Water. However, APS entered into an agreement with the Gila River Indian Community in 2011 that allows APS to receive GRIC CAP Indian Priority water, a high priority, low risk supply. Prior to 2015, the water supply to the Yucca Power Plant was drawn from the Colorado River. Yucca now uses groundwater for plant operations. Navajo Generating Station draws water for plant operations from Lake Powell. San Juan Generating Station draws water for plant operations from the San Juan River.

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[2] Four Corners Generating Station is located in Fruitland, New Mexico. APS owns Units 1, 2, and 3 (now shutdown) and operates Units 4 and 5.

[3] San Juan Generating Station is located in Farmington, New Mexico. TEP owns 50% interests in Units 1 and 2.

Q. Which power plants in the state of Arizona use ground water for the purposes of cooling?

A. Ocotillo, Red Hawk, Saguaro, West Phoenix, Cholla, Springerville, Sundt, Luna, Gila River, Black Mountain, Valencia, and Apache.

Q. Which power plants in the state of Arizona use treated effluent for the purposes of cooling?

A. Palo Verde[4] and Red Hawk. The source of effluent is the City of Tolleson.

Q. What are the water requirements of power plants serving these LSEs?

A. Table 1 lists the water consumptions requirements by source for each power plant for the year 2015. The table also provides the average yearly water consumption based on yearly data ranging from 2006 – 2015.

[4] Palo Verde and Red Hawk use a small amount of groundwater as indicated in Table 1.

	2015 Ground Water Consumed (Acre Feet)	Average Yearly Groundwater consumption (Acre Feet)	2015 Surface Water Consumed (Acre Feet)	Average Yearly Surface Water Consumption (Acre Feet)	2015 Effluent Consumed (Acre Feet)	Average Yearly Effluent Consumption (Acre Feet)
Four Corners	0	0	17,615	22,685	0	0
Ocotillo	353	382	0	0	0	0
Palo Verde	1,913	2,120	0	0	71,914	68,422
Red Hawk	346	248	0	0	3,470	3,486
Sundance	0	0	52	116	0	0
Saguaro	29	211	0	0	0	0
West Phoenix	2,184	2,403	0	0	0	0
Yucca	317	32	322	590	0	0
Cholla	13,009	15,253	0	0	0	0
Navajo	0	0	1,862	1,897	0	0
San Juan	0	0	4,621	4,408	0	0
Springerville	7,321	9,767	0	0	0	0
Sundt	1,346	1,849	0	0	0	0
Luna	440	672	0	0	56	98
Gila River	1,714	1,714	0	0	0	0
Black Mountain	7	29	0	0	0	0
Valencia	5	6	0	0	0	0
Apache	3,244	4,786	0	0	0	0
Total	**32,229**	**39,472**	**24,472**	**29,696**	**75,440**	**72,006**

Table 1: Water Consumption Requirements by Source[5].

On average; 72,006 acre-feet of treated effluent is consumed each year, 39,472 acre-feet of ground water is consumed each year, and 29,697 acre-feet of surface water is consumed each year (seen in Figure below). The largest source of water used in power plant operations is treated effluent, the second largest source is ground water, and the third is surface water. In fact, effluent makes up 51 percent of the total water usage while ground water represents 28 percent and surface water represents 21 percent.

[5] For power plants that serve AEPCO and APS, the water consumption requirements represent the entire water consumed by each plant, regardless of whether the plant is jointly owned. For power plants that serve TEP and UNSE, the water consumption requirements only represent the shares owned by each LSE.

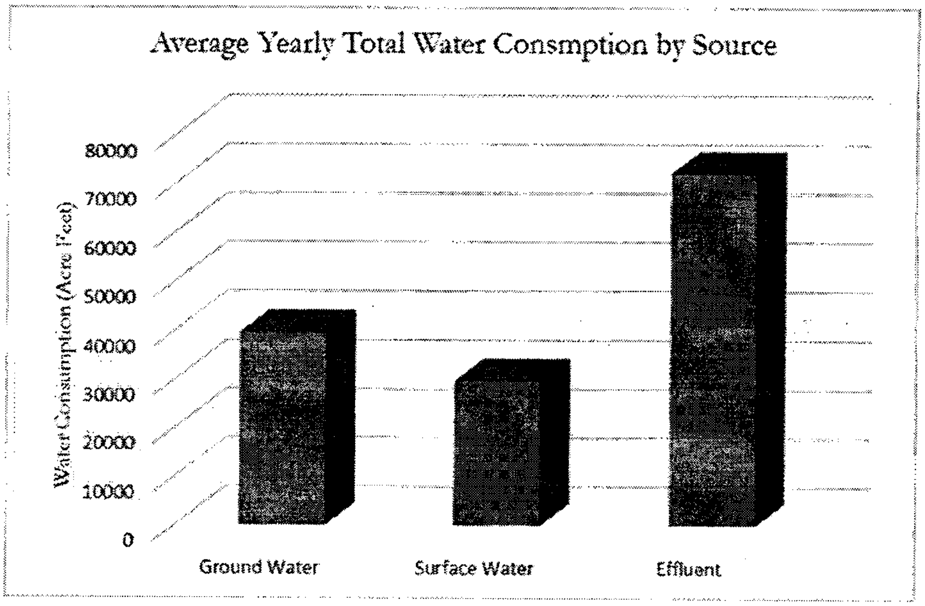

Figure 1: Average Yearly Total Water Consumption

Q. What are the future water consumption requirements for each power plant?

A. APS, TEP, UNSE, and AEPCO provided Staff with projected water consumption requirements for each power plant. Table 2 lists the yearly average water consumption from 2006 – 2015, the projected average yearly water consumption requirements for the upcoming years of 2016 – 2020, and the percent difference of the average yearly water consumption requirements.

	Current GW (AF)	Projected GW (AF)	GW Growth (%)	Current SW (AF)	Projected SW (AF)	SW Growth (%)	Current Eff (AF)	Projected Eff (AF)	Eff Growth (%)
Four Corners	0	0	0	22,685	15,883	-30	0	0	0
Ocotillo	382	12	-97	0	0	0	0	0	0
Palo Verde	2,120	2,149	1	0	0	0	68,422	71,631	5
Red Hawk	248	329	32	0	0	0	3,486	5,478	57
Sundance	0	0	0	116	204	77	0	0	0
Saguaro	211	16	-92	0	0	0	0	0	0
West Phoenix	2,403	3,077	28	0	0	0	0	0	0
Yucca	32	323	918	590	0	-100	0	0	0
Cholla	15,253	8,030	-47	0	0	0	0	0	0
Navajo	0	0	0	1,897	2,145	13	0	0	0
San Juan	0	0	0	4,408	3,314	-25	0	0	0
Springerville	9,767	7,967	-18	0	0	0	0	0	0
Sundt	1,849	1,475	-20	0	0	0	0	0	0
Luna	672	700	4	0	0	0	98	99	1
Gila River	1,714	1,732	1	0	0	0	0	0	0
Black Mountain	29	16	-45	0	0	0	0	0	0
Valencia	6	7	10	0	0	0	0	0	0
Apache	4,786	3,200	-33	0	0	0	0	0	0
Total	39,472	29,032	-26	29,696	21,546	-27	72,006	77,209	7

Table 2: Current, Projected, and Percent Difference of Water Consumption.

As seen in Table 2, it is anticipated that there will be a 27 percent reduction in the average yearly consumption of ground water along with a 27 percent reduction in average yearly consumption of surface water. The average yearly consumption of treated effluent will increase by roughly 7 percent. These changes are mainly caused by power plant retirements and conversions.

Q. Which power plants are retiring/converting and how does that affect water consumption?

A. In 2019, one unit at the Navajo Power Plant will cease operation, thereby reducing water demand for the plant. However, this reduction in water consumption is not reflected in the projected yearly data provided to Staff by TEP because the unit that is being shut down is owned by SRP.[6] At the end of 2017, units 2 and 3 at San Juan Generating Station will cease operation, thereby reducing water demand for the plant by one-half. At the end of 2013, units 1-3 at the Four Corners Power Plant ceased operation, thereby reducing water demand for the plant by over one-quarter. The planned retirement of Unit 2 at Cholla Power Plant in 2016 will reduce water demand for the plant by roughly one-half.

Additionally, some coal power plants will be reducing capacity and/or making the conversion to natural gas. The water demand for Springerville Generating Station will be reduced by roughly 20 percent due to a reduction in coal capacity. The elimination of coal on Unit 4 and the conversion to natural gas will reduce the water demand for the Sundt Generating Station by 20 percent. It can be seen from the data that Saguaro's average yearly water consumption has been reduced by 92 percent which is a result of the retirement of two steam units in June 2013. There is a 97 percent reduction in water demand for Ocotillo due to the modernization project of the plant. Two steam units are being removed from the plant while five new combustion turbines will be added by 2018.

It is important to note that the water reductions seen at some power plants are countered with increased consumption at other facilities. This is primarily a result of more natural gas being used in place of the retiring coal units. For example, Redhawk which uses natural gas will see a 32 percent increase in its average annual groundwater consumption and a 57 percent increase in its average yearly effluent consumption. West Phoenix, which also uses natural gas, will see a 28 percent increase in its average yearly ground water consumption and Sundance is anticipated to consume 77 percent more surface water on average per year. However, the net result is a reduction in yearly average water consumption for both ground water and surface water due to the fact that natural gas plants are typically more efficient than

[6] Refer to footnote 5

their coal counterparts. Additionally, as more modern natural gas plants are used to meet load, it is possible that in some instances their cooling systems are superior to those found in the power plants that are retiring. The increased efficiency and improved cooling systems both factor into the overall anticipated reduction in water consumption.

Q. What is the situation with curtailing water in response to a Colorado River shortage?

A. According to the ADWR, "A shortage is an annual reduction in the amount of Colorado River water available to Arizona, Nevada and Mexico and is determined primarily by the volume of water in Lake Mead. If the water falls below an elevation of 1075', a shortage would be declared. A near-term shortage will not impact water supplies for Arizona's cities, towns, industries, mines or tribes using CAP water. It would, however, eliminate Central Arizona Project (CAP) water supplies to the Arizona Water Banking Authority.[7] It would also reduce a portion of the CAP water supply identified for groundwater replenishment, which would impact agricultural users in central Arizona and may cause an increase in CAP water rates. In the face of potential shortage, farmers in central Arizona may choose to offset supply reductions in their CAP supply by using local supplies including pumping groundwater. Arizona has been planning for a potential shortage for decades. Since 1996, CAP has worked with the Arizona Water Banking Authority ("AWBA") to store excess CAP water underground to provide back-up supplies for municipal, industrial and Native American water users. More than twice the amount (3.2 million acre-feet, which exceeds a trillion gallons) of the Colorado River water that is delivered to central Arizona annually has been stored to date. CAP, the ADWR and the AWBA have planned to recover and deliver these supplies should the need arise."[8]

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[7]The Arizona Water Banking Authority was established to increase utilization of the state's Colorado River entitlement and develop long-term storage credits for the state. AWBA stores or "banks" unused Colorado River water to be used in times of shortage. http://www.azwaterbank.gov/

[8] *Colorado River Shortage Impacts on Arizona.* Arizona Department of Water Resources. April 2015

Staff requested a response to the following question from APS, TEP, UNSE, and AEPCO; if a shortage on the Colorado River or Lake Mead is declared, what will be the impact on your existing or planned generation units? The following statements are the responses from each;

APS:

"In the event of a shortage on the Colorado River or Lake Mead, no impact is anticipated on existing or planned generation units operated and owned by APS. Prior to 2015, the water supply to the Yucca Power Plant was identified by the USBR as reliant upon Colorado River water, and subject to curtailment in a declared shortage. APS drilled a new well in 2015 that withdraws groundwater, eliminating this risk. Prior to 2011, the Sundance Power Plant relied upon low priority Colorado River water, subject to curtailment in a declared shortage. APS entered into an agreement with the Gila River Indian Community in 2011 that allows APS to receive GRIC CAP Indian Priority water, a high priority, low risk supply."[9]

TEP:

"To the extent there is any impact to TEP generating units from the declaration of a shortage on the Colorado River or Lake Mead, it would be with respect to Navajo Generating Station, Four Corners Power Plant, and/or San Juan Generating Station as each of these facilities use surface waters that are within the Colorado River drainage area. Navajo Generating Station draws water for plant operations from Lake Powell and holds senior water rights as part of Arizona's Upper Colorado River apportionment. Several years ago the intake for the plant was lowered to within the "dead pool" of Lake Powell. In 2019, one unit at the plant will cease operation, thereby reducing water demand for the plant by one-third. San Juan Generating Station draws water for plant operations from the San Juan River, and also holds senior water rights. In addition to these water rights, a water hazard sharing

[9] APS' response to Staff's data request

agreement with the Jicoria Nation is in place, which can provide for additional water rights in the case of an extreme water shortage. Finally, at the end of 2017, units 2 and 3 at San Juan Generating Station will cease operation, thereby reducing water demand for the plant by one-half. Four Corners Power Plant draws water from Morgan Lake, which receives water from the San Juan River under senior water rights. At the end of 2013, units 1-3 at the plant ceased operation, thereby reducing water demand for the plant by over one-quarter. Based on the senior water rights in place and the decrease in water demand at each of these plants, TEP does not anticipate a significant impact from the declaration of a shortage on the Colorado River or Lake Mead. If there was an impact at one of these plants that resulted in the need to curtail generation, we anticipate that TEP would either have sufficient capacity through other resources within its system, or could find sufficient capacity in the wholesale market, specifically due to the large amount of available merchant generation located around the Palo Verde hub."[10]

UNSE:

"UNS Electric's fossil-fired generating units use groundwater for cooling and other process needs. Therefore, we do not anticipate any impact from the declaration of a shortage on the Colorado River or Lake Mead."[11]

AEPCO:

"The operation of Apache Generating Station is not dependent on Colorado River water supply and thus the water source of AEPCO's existing units would be unaffected in the event of a water shortage on the Colorado River or at Lake Mead. AEPCO and its Distribution Cooperative Members have capacity under contract with the Western Area Power Administration for the delivery of hydroelectric generation which is served via these sources. If a shortage were to be declared upstream of these

[10] TEP's response to Staff's data request
[11] UNSE's response to Staff's data request

facilities, the energy available to AEPCO under these contracts may be curtailed depending on the length and severity of the potential shortage. Under such conditions, AEPCO would procure additional energy via generation or purchases from the electric market to fulfill its energy service obligation to its Members."[12]

Q. What are your initial conclusions after reviewing the utility provided data and their responses?

A. Agriculture is the largest use of water in Arizona, followed by residential use. The least demanding are commercial, industrial, and institutional uses. "In Arizona, approximately 15 percent of the water supply is for commercial, industrial, and institutional uses. This includes water used by commercial buildings, hospitals, schools, golf courses, parks, *power plants*, and other industries."[13] It appears that a Colorado River shortage would affect power plants that use surface water as their source for cooling and the LSEs noted that they have prepared for this. As previously mentioned, the largest source of water used in power plant operations is treated effluent (51 percent), the second largest source is ground water (28 percent), and the third is surface water (21 percent). As a result, it does not appear a shortage would severely affect power plant operations, especially with current water rights agreements in place. In the event of a shortage, several utilities intend to rely upon unspecified wholesale purchases which may or may not depend on surface water as a resource.

[12] APECO's response to Staff's data request
[13] http://www.azwater.gov/azdwr/StatewidePlanning/Conservation2/CommercialIndustrial/default.htm

EXHIBIT
S-2
~~ADMITTED~~

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 COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	)	DOCKET NO. E-00000J-14-0023

DIRECT TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 25, 2016

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EXHIBITS

EXECUTIVE SUMMARY
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023

Mr. Solganick's direct testimony provides Staff's perspective of the relative value and cost of various forms of distributed generation and highlights the drivers to determine value and cost.

The testimony discusses distributed generation and compares it to other forms of generation.

Staff's perspective highlights the obligation of the utility to obtain goods and services at a reasonable cost and the Commission's responsibility to ensure that potential suppliers are not impacted by the utility's monopsony power.

The testimony does not set or calculate the value of solar but highlights through the use of a comparative matrix the similarities and differences between solar distributed generation and other forms of generation, distributed generation, load shifting, storage, wind, conservation and efficient appliances and HVAC.

Staff recommends moving over the long-term from net metering and banking to setting a price for excess distributed energy in the utility's rate case based upon the principles determined in this proceeding. The recommendations consider adders for transmission and distribution impacts where appropriate and proven.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning sub-metering and billing. I previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 40 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony on utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand-side management, capacity and system planning, and regulatory issues.

I have also been engaged (as a subcontractor) to review utility performance before, during, and after outages resulting from major storms in the state of Washington (major windstorm), Missouri (summer storms and ice storm), Texas (Hurricane Ike), Jamaica West Indies (Hurricane Ivan), the two 2011 storms (tropical storm Irene and a major snow storm) that affected New Jersey, and to review the emergency plan of a New England utility. Some of these assignments were at the request of the utility and others at the request of a state utility regulator. Testimony, if prepared and filed, is listed in Exhibit HS-1.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and I have advised the Board of Directors of a public power utility consortium. For a period of four years, I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and ratebase audits for the Public Utilities Commission of Ohio and the Oregon Public Utility Commission. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale, and delivery of retail energy, energy-related products and services, and support services provided to utilities and retailers.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998 I was a Managing Consultant for AT&T Solutions. From 1990 to 1994 I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held positions of progressively increasing responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute, and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice, and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission

- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. What is the purpose of your testimony?

A. My testimony provides Staff's perspective of the relative value and cost of various forms of distributed generation and highlights the drivers to determine value and cost. This testimony draws contrasts between various types of distributed generation and defines various drivers of value and cost.

Staff is not recommending a specific price for purchases of excess energy from any form of distributed generation or from photovoltaic systems in particular, but is highlighting those factors that apply, those that do not and those that may be so small that the value (or cost) is de minimis.

Staff recommends that the price for the purchase of excess energy by a utility should be set within the context of a utility specific proceeding such as a rate case and depends on the situation and conditions specific to that utility, along with consideration of the factors/methodology set out in Exhibit HS-3 and discussed below.

DIRECT TESTIMONY

Q. Please define distributed generation.

A. For the purposes of this proceeding Staff defines distributed generation ("DG") as on-site generation produced or stored by a variety of small, grid-connected (typically at the distribution level) devices using a variety of fuels (typically natural gas, distillate oil or feedstocks), or renewable sources (such as solar, wind, hydro, biomass, geothermal). DG may be controlled by the grid operator, thorough an aggregator or uncontrolled and either be capable of independent operation (microgrid) or dependent on the grid to operate.

Q. Please provide some examples of distributed generation.

A. Some examples of distributed generation are the following:

- Combined Heat and Power ("CHP") or "Cogeneration" using combustion turbines; diesel or spark ignition engines; boiler and steam turbine configurations; or fuel cell. Fuels commonly used include coal, heavy oil, distillate oil, natural gas, hydrogen and other feedstocks.
- On-site electrical generation uses similar technologies and fuels as CHP but does not use or export heat.
- Emergency generation generally employs combustion turbines; diesel or spark ignition engines; or fuel cells. Fuels commonly used may include distillate oil or natural gas.
- Wind Power
- Solar PV
- Tidal
- Geothermal

Q. Please describe other distinguishing characteristics.

A. DG would be expected to be smaller in size than classic utility central station generation, closer to, if not inside, load centers and more numerous.

Q. Please describe some of the potential positive attributes of distributed generation.

A. DG is alleged to have potential positive attributes (compared to utility central station generation) due to:

- Size
- Dispersed location
- Ability to operate on a smaller grid
- Potentially less transmission required
- Potential to support load during transmission and/or distribution outages
- Lower environmental impact
- Disparate ownership and financing

Q. Please describe some of the potential negative attributes of distributed generation.

A. DG is alleged to have potential negative attributes (compared to utility central station generation) due to:

- Size – higher cost per kilowatt
- Efficiency – higher cost per kilowatt hour
- Financing – higher costs per kilowatt
- Interconnection costs
- Lack of control and coordination
- Impact on grid control – voltage, reactive, etc.
- Greater and local environmental impact (closer to public and/or noise issues)
- Lack of fuel supply flexibility

Q. What value can a utility operated generating unit provide that DG does not?

A. Utility operated generation typically would have dual fuel capabilities (in some areas), maximum emergency generation and rapid return from unit outages. These capabilities allegedly result from the difference between the obligation to serve and meeting contractual requirements.

Q. Please explain Staff's perspective as you developed this testimony.

A. Staff's perspective is based on the concept that what happens behind the meter is the customer's business. Whether load is reduced by conservation, insulation, high efficiency appliances, storage or the installation of a DG system that is solely the customer's right and decision and a proper rate structure will offer accurate price signals to assist a customer making a decision. Any excess energy not needed by the customer can then be delivered to the utility and purchased at its value at the time and location of delivery.

Staff's perspective also assumes residential and small general service rates will transition to a Three-Part Time of Use ("TOU") structure which offers customers the opportunity to decide when and how much energy to consume and when and how much demand to impose on the system. (Larger customers have been served on three part rates for many years).

Staff recognizes that utilities, utility shareholders, solar vendors, regulators, C&I customers and residential customers all have different perspectives and value propositions. Staff's perspective or viewpoint is to look at costs and values from the perspective of all of the utility's customers. This perspective is derived from Staff's role in the regulatory process to assist the Commission in ensuring that rates are based on reasonable costs. Utilities have a responsibility, and the Commission acts as an enforcement mechanism, to provide service at the lowest reasonable cost. Examples include reviewing procurement results, policies and process, considering the effectiveness of the utility's operations and reviewing the utility's participation in its service territory.

Q. Please define reasonable cost.

A. The utility has an obligation to spend no more than what is necessary to provide any element of service. The "reasonable" standard does not imply that the utility should ignore laws or regulations to obtain a rock bottom price nor does it permit that any and all expenditures made by the utility to be part of the cost of service. The standard is not a requirement to pay the least but to pay based on an evaluation of cost and other relevant parameters at the time the decision was made by the utility. In certain circumstances, reasonable cost may be tempered by other regulatory directives such as purchases within the utility's service territory or meeting fuel diversity goals.

Q. What is a monopsony?

A. A monopsony is one buyer and many competing sellers, which (absent regulation) may allow the buyer to drive down (or dictate) the price paid for the seller's output. In some ways the classic utility regulatory model demands that the utility act as a monopsony in procuring inputs such as fuel and purchased power in order to provide energy to retail customers at the lowest reasonable costs. The Commission assumes a role to ensure that the utility's purchasing power does not unreasonably affect competitors such as energy service companies of all types.

Q. Are consumers and businesses capable of making investments without an assured cost or value stream?

A. Yes. Life is inherently uncertain yet most people manage to make long-term financial decisions such as purchasing a home, a vehicle or higher education without guarantees by the vendor, a third party or the government as to financial success. Businesses do have partial governmental support from the tax code's applicable loss provisions, while individuals have less protection.

Energy efficiency measures do not receive a fixed or guaranteed future price for the energy (that will no longer be purchased) and energy efficiency ("EE") has some of the attributes and characteristics of DG.

When a consumer or business purchases a hybrid, electric, diesel or high mileage automobile the purchaser isn't promised a fixed price for fuel to ensure long-term savings. There is an economic risk associated with those decisions and yet high efficiency vehicles get purchased. DG solar systems and efficient autos are in a similar price range.

Q. Please compare and contrast the purchase of excess energy from DG as compared to a full buy and full sell pricing regime.

A. Staff's perspective assumes that what happens behind the meter is the customer's business and excess energy (if any) is sold to the utility at some regulated price. This is conceptually different than having the customer purchase all of his/her energy consumption from the utility and sell all of the production from a DG installation to the utility. Changing the "regime" from Staff's excess energy view to a buy all/sell all view will change the calculation of values and costs.

The buy all/sell all view inherently treats EE measures differently than DG. Staff's perspective treats the DG energy used by the customer behind the meter as a reduction in costs to the customer at the retail tariff rate just as energy efficiency is a reduction in cost to the customer at the retail tariff rate.

Q. Please describe Exhibit HS-2.

A. Exhibit HS-2 is a five-page excerpt (pages 13 to 17) of a report prepared by the Rocky Mountain Institute ("RMI") Electricity Innovation Lab titled "A Review of Solar PV Benefit & Cost Studies, 2nd Edition". Staff attached these pages as an exhibit because Staff considers the definitions used in the document to be clear and useful for the discussion of Staff's matrix (Exhibit HS-3). The use of these definitions is not all inclusive, as the RMI report does not include the emergency conditions discussed below. Also as evident in Staff's matrix, certain items are not assigned values (or costs) by Staff, such as capacity-generation (short term), capacity-scheduling/forecasting, risk-fuel price hedging and social.

Q. Is Staff introducing and supporting the complete RMI report?

A. No. Staff is only using the definitions contained in the RMI Report and thus has attached only those pages to my testimony. Staff's use of RMI's definitions should not be viewed by parties to be an endorsement by Staff of the RMI Report itself and/or its findings or conclusions.

Q. Please define the terms used in Staff's matrix (Exhibit HS-3).

A. The definitions of the terms used are the following:

- <u>Avoided Cost</u> – The costs of energy that would have been produced or purchased but for the existence of the DG. These costs may be hourly or may be aggregated based on a delivery profile for convenience or better understanding. If the avoided costs are based on generating facilities meeting environmental requirements then the costs of environmental compliance are included within the avoided cost. The losses to the point of delivery should also be included. [On-Peak, Off-Peak, Losses-Energy]

- Cost and Value – The cost of energy being stored or shifted, which at a later point will be used to deliver value. Value occurs when the DG is used to support loads and cost is incurred in preparation for action. [Load Shifting, Storage-Energy]
- Increased Cost – Increased costs such as additional meters to be read, more complex billing, and incremental customer contact before DG installation or during DG operation.
- One Time Cost – Incremental costs for installation of metering arrangements and communications protocols to connect DG to the grid.
- Value – The provision of services delivered to the grid such as reactive power or frequency control. This value maybe limited due to the amount of storage, when load can be shifted or when the DG is in operation. [Load shifting, Storage-Energy, Solar, Wind] The value may not be limited if the DG can be dispatched at any time and run for indefinite intervals. [Responsive Generation]
- Time Specific Avoided Cost – The costs of emergency generation or other efforts to carry load. [Emergency (shortage)]
- Time Specific Payment – The value created by the ability to absorb energy when requested. [Low Load (Excess generation)]
- Outage Prevention Value – The ability to deliver energy during emergencies at the transmission or distribution level including maintaining service for long periods.
- Limited Outage Prevention Value – The ability to deliver energy during emergencies at the transmission or distribution level including maintaining service for limited periods or when DG is in operation.
- ELCC – Equivalent Load Carrying Capability is the value of DG based upon its performance including its dispatchability, the length of time the capacity is available and the coincidence between the capacity available and peak loads.

- Specific Location Only – Value available due to geographic location, such as the ability to eliminate or defer additional assets on specific distribution feeders, substations or transmission lines.
- Maybe if Aggregated – Value can be delivered if enough DG can be aggregated and controlled to deliver a meaningful response or service.

Q. Please explain the term "Responsive" as used in Exhibit HS-3.

A. DG that can be controlled by an entity that is not the owner and/or user (host) of the DG equipment/facility is considered "Responsive". A grid operator or the local load-serving utility may handle control. A third party may aggregate multiple smaller responsive DG units. The intent of control is to allow DG to be dispatched to meet common or emergency operating conditions.

Q. Does Staff recommend increasing the value of energy by considering extra or incremental environmental costs?

A. No. Avoided cost values the kWh provided at the costs the utility does not incur (energy if short term and capacity (or some portion) in the longer term). If a generating unit must meet specific environmental standards (NOx, SOx, water usage, maybe carbon) those costs are already included the costs to construct and/or operate the plant.

Q. Please describe common emergency operating conditions that are considered in Exhibit HS-3.

A. I envision at least two emergency conditions:

- A period of time when there is potentially not enough energy and capacity to support the expected load. In this situation a utility or grid operator might disconnect interruptible load, move all available generation to maximum capability (max emergency), issue requests for customers to reduce or shed load and if necessary involuntarily curtail loads based on a predetermined load shedding plan. The intent of the utility or grid operator is to maintain the stability of the system for the maximum number of customers or load. This situation may be caused by fuel shortages, adverse weather (storms), temperature and/or humidity exceeding design conditions, insufficient reserve margins, loss of generating units, loss of transmission lines and on a more local basis insufficient distribution capability.

- A period of time when there is potentially too much energy as compared to the expected load on the system. In this situation a utility or grid operator might back down generating units below economic costs, shutdown units without regard to recommended operating protocols and/or pay other systems to take the unneeded energy. The intent of the utility or grid operator is to maintain the stability of the system. This situation may occur during periods of low loads (commonly at night with little or no space conditioning load – spring or fall) combined with generating units that are defined as "must run" or with specific minimum generation.

Q. Please describe the distinction between long-term and short-term as used in Exhibit HS-3.

A. A long-term impact is sufficient in timing and magnitude to change the utility's system plan and eliminate or significantly defer the purchase or construction of generation, transmission and/or distribution facilities.

Q. Please explain Staff's matrix, Exhibit HS-3.

A. Exhibit HS-3 was developed to demonstrate the range of capabilities of various forms or types of DG (and other comparable alternatives) and then relate those capabilities to the value that DG may provide the utility (and its customers) or impose on the utility and its customers.

The exhibit is not designed to detail or list all types of DG or differentiate by fuel type or environmental impact but rather to focus the discussion on the capabilities and the related value and costs and portions thereof.

Q. How does Staff envision using Exhibit HS-3?

A. Staff recommends that Exhibit HS-3 be used to develop the value and cost for various forms of distributed generation during a utility's rate case or other proceeding. Staff does not suggest that a value (and cost) must be developed for every category of DG listed in Exhibit HS-3 at this time but only for technologies in use in Arizona or expected to be available in the marketplace in the near future.

Q. What conclusions does Staff draw from Exhibit HS-3?

A. After developing Exhibit HS-3 and considering appropriate methodologies to develop value and cost, Staff determined that there is a range of value that can be applied to DG and that it is inappropriate to use the same value for all types of DG. Specifically:

- DG that is "Responsive" is more valuable to the utility than DG that is not responsive due to the ability to react to emergency conditions on the utility system or provide reactive power.
- Energy provided to the utility by DG has a time dependent value such as avoided energy costs (including variable operations & maintenance ("O&M")).
- Generation capacity provided to the utility by DG has full value only if it is provided coincident to peak load conditions.

- Transmission needs can only be offset over a long-term horizon or when specific geographical areas can be targeted to avoid or delay new transmission construction, but transmission charges may be reduced in the short-term.
- Distribution capacity is only reduced when the utility's engineering design standards (to meet customer requirements) can be reduced or when specific geographical areas can be targeted to avoid or delay new distribution construction.
- System losses can vary due to electrical properties and timing, therefore loss factors for capacity and energy are different.
- Interconnection costs exist and some (such as metering and protection) are due only to the existence of DG.
- Some values and costs are small and incremental and thus not worth developing and including:
    - Billing costs (calculation and processing) of excess energy credits
    - On-going customer service
- Some values are inherent in the avoided cost methodology including:
    - Environmental costs (air, water and solid waste) are inherent in the fixed and variable costs of avoided capacity and energy, as the avoided facility must meet applicable regulations.
- There may be mismatches between avoided utility facilities and DG such as:
    - Dual (backup) fuel capabilities
    - Must run requirements of CHP to meet thermal loads
    - Renewable Energy Certificates ("REC")

Q. How should Staff's matrix be used?

A. Staff's matrix should be used to evaluate specific eligible costs and value of energy, capacity and other services delivered to the grid by DG (of all types) during each utility's rate case and/or integrated resource planning processes.

Q. How has electric metering changed recently?

A. For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively. Interval data has been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes and a small number of large customers, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak periods and did not offer much information to the customer, such as when the energy was used on an interval basis.

Advanced Metering Infrastructure ("AMI") has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. AMI installations can provide near real time information but are limited by data transmission speeds and processing raw data efficiently.

Q. What impact does AMI have on DG?

A. AMI can be used not only to measure the energy consumed (and the associated demand) by a customer but can also detail the excess energy provided by a customer and when that energy is delivered to the utility.

Q. Why is AMI relevant in the context of DG and net metering?

A. Net metering was useful and appropriate when the costs of metering excess energy on a time of delivery basis using older interval metering probably exceeded the value of the excess energy delivered by a DG system.

Q. Does the Commission have rules on net metering?

A. I have been informed that the Commission's current net metering rules are contained in Title 14, Chapter 2, Article 23 of the Arizona Administrative Code ("A.A.C.") (A.A.C. Section 14-2-2301 et seq.).

Q. What were the advantages of net metering?

A. Net metering:

- Acted as an incentive to encourage DG
- Was easily understood by customers
- Caused little or no cost increases in the metering and billing process
- Was an acceptable starting point for the net value of DG

Q. What were the disadvantages of net metering?

A. Net metering:

- Failed to educate customers about the time varying value and cost of energy
- Equated the value of excess energy to retail energy without adequate foundation

- Allowed a customer to bank energy (i.e., store energy on the utility and withdraw it later without any cost for that storage function)

Q. What is Staff's recommendation for net metering?

A. Staff recommends that over the long-term net metering and the banking of excess energy associated with net metering be eliminated and replaced with a direct mechanism for purchasing excess DG energy that reflects the concepts discussed in Exhibit HS-3.

Q. Why should energy banking be eliminated?

A. Energy banking distorts the costs and value of DG because it does not recognize the time varying value of energy and does not recognize the impact on the utility system. DG solar may be exported during the winter and during mid-day, yet may offset energy purchases that would otherwise occur in the summer. Other, relatively minor considerations include, for example, when excess DG energy is fed back into the utility system it most likely passes through the customer's distribution transformer where some of that energy is lost as heat. If the energy is delivered to a nearby customer it also most likely will pass through another distribution transformer incurring further losses. However "banked" energy is not reduced by the possible losses but "returned" to the customer when needed to meet load. The concept of banking excess energy treats DG differently that emerging storage devices, which if located on the customer's side of the meter will have losses (into and out of storage) that storage customers will pay for.

Q. What would be an ideal price mechanism for excess DG energy?

A. In a perfect world excess DG energy would be priced at real time avoided costs, with capacity compensated separately based upon effective load carrying capabilities and various peak conditions. However, presently the costs of tracking hourly delivery of excess DG energy, billing and informing customers in order to properly price the excess DG energy for small installations would be significant compared to the amounts involved and therefore a seasonal or time period average price for excess DG may be cost effective.

Q. How does Staff recommend setting a price for excess DG energy?

A. Staff recommends that DG customers be offered a price that is understandable, easy to administer, is consistent with the utility's other opportunities to purchase energy with similar characteristics and comports with the utility's responsibility to procure energy at a reasonable price. Since the utility has market power as a purchaser, it is appropriate that the price be examined by the Commission and set in a rate proceeding.

The price offered should begin with avoided energy costs along with appropriate losses specific to that utility and/or its interconnected systems. The price may be further increased if there is demonstrated or forecast capacity value for generation.

If the Commission determines a particular value formula, in this proceeding, then follow-on proceedings such as rate cases and/or integrated resource planning processes are opportunities for specific utilities to quantify the value of DG.

Q. Should the price of excess DG energy include a transmission component?

A. If the deferral or elimination of transmission assets and/or costs can be demonstrated. This situation may occur when enough DG can be aggregated in a specific geographic location to make an incremental difference. This value component should be an adder.

Q. Should the price of excess DG energy include a distribution component?

A. If the deferral or elimination of distribution assets and/or costs can be demonstrated. This situation may occur when enough DG can be aggregated in a specific distribution area (feeder or substation) to make an incremental difference. A feeder focused RFP process could be used. This value component should be an adder.

Q. Should the price of excess DG energy recognize environmental effects?

A. As discussed above, the avoided energy value includes an environmental component that reflects the fixed and variable costs necessary for a generating unit to meet environmental standards, therefore no adder is needed. Payment for the value of the RECs should be an adder only if the utility purchasing the DG energy also receives the REC; otherwise society will pay for the REC twice. This value component should be an adder.

Q. How often should the price of excess DG energy be reset?

A. For the time being, Staff recommends that the price of various components be reset in the context of regulatory proceedings such as rate cases and be presumed to be in effect until the next case.

Q. Should the price of excess DG energy aggregate various periods or vary with time of delivery?

A. For the administrative convenience of the utility and the DG customer, one or more prices can be set for homogeneous types of DG with similar delivery patterns that reflect a weighted average of cost and delivery periods.

Q. In the UNS Electric rate case, Staff has provided a model to determine the impact of various rate design changes on solar DG customers. How do you view the use of the model in valuing DG?

A. The model Staff has developed is useful in examining "value" of solar DG only from the perspective of the solar DG customer. It only adds another dimension to the analysis as the value of solar differs from the perspective of each stakeholder. Utilities, utility shareholders, solar vendors, regulators, non-residential customers and residential customers will all have different perspectives and value propositions. However, it is important to note that the model does not estimate the profitability of solar vendors and their impact on solar DG customers.

Q. Are you sponsoring the model in this case?

A. No. Staff intends to utilize the model as another tool in upcoming rate cases looking at this issue in attempting to determine the impact of various proposals on existing and future DG customers. I am simply bringing this to parties' attention in this docket to demonstrate that we need to consider new tools to look at the value concept in a comprehensive fashion and from different perspectives.

Q. Is it your intent to address the issues raised by the Commissioners letters to this docket?

A Yes. Below Staff addresses many of the issues raised by the Chairman in his December 22, 2015 letter. Staff will attempt to address the issues raised by the other Commissioners' letters in rebuttal or during the hearing in this case.

Q. What issues did Chairman Little ask parties to address in this proceeding?

A. Chairman Little posed many questions for the parties to this docket to address in order to provide a better record for consideration. Staff addresses a number of his questions:

2. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?
   - The declining cost of PV panels (and balance of system) should, all other parameters held constant, increase the profitably of a customer's PV system

investment. Declining costs of PV panels also reduces the cost of utility developed and third party developed large scale PV installations, which should be considered competition for distributed PV installations.

3. Is it appropriate to factor the cost of panels into the reimbursement rate for net metering? If so, how?

   o More expensive panels (per se) do not create any greater value. There should be no need to consider the cost of panels (or the resultant system cost) when considering net metering. Each decision-maker decides whether the benefit received is adequate for undertaking the cost of panels.

4. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?

   o The costs of DG solar may vary due to customer specific conditions such as roof orientation and tree shading. A locational variation in value (treated as an adder) may occur if the DG solar is located on a distribution feeder that can benefit from the mass installation of systems and offset distribution investment. Above the distribution level the value of DG solar is not significantly affected by location within a compact service territory.

6. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?

   o With a versatile rate design such as a Three Part-TOU rate, the value of behind the meter storage will increase due to the ability to both reduce demand and shift energy consumption and export of DG energy. Adding storage to a DG solar installation may effectively allow shifting of DG solar production closer to load peaks to increase ELCC.

7. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and cost of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?

- Due to economies of scale, community and utility solar may provide lower costs compared to DG solar while providing most or all of the value. Energy efficiency can provide similar distributed "effects" along with local employment and spending impacts.

8. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should these additional costs result in changes to the value and the cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

- As discussed above, dispatchable generation (distributed or utility owned) offers the flexibility to provide system support at any hour of the year; DG solar or wind is inferior in that regard. Storage could be used to mitigate some of the limitations of DG solar or wind. When a price is set for the purpose of delivered excess energy, intermittency must be taken into account unless a varying real time price is used as a component of the net value formula.

9. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

   - Peak demand (and its timing) can vary among utility systems depending on the mix of load and therefore a blanket statement cannot be made. The value of DG does vary with time and can affect both the avoided cost of energy and the customers demand. ELCC is a method to reflect the capacity value of an intermittent technology. Staff notes that most utilities planning processes are well able to address the issue of any resource's relationship to coincident peak demand and, thus, this can be assessed by each utility in a relevant proceeding.

10. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

   - At present DG solar as commonly installed is not dispatchable. If advanced inverters are installed along with a centralized dispatch function then the output of a DG solar system can be reduced due to system or feeder congestion. As discussed above, dispatchable generation that can be increased and made available is more valuable than generation that follows weather and daylight. Absent the use of storage Staff is not aware of a method (except storage) to substantially increase the output of DG solar on command. Tracking is expected to be used to maximize production, but not for dispatchability.

12. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments and other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

- Staff recommends that secondary economics should not be considered in value and cost considerations of any resource choice because they are not rewarded in the other cases of customer inspired conservation, insulation, high efficiency appliances and storage. Comparisons of local job content can vary between technologies and whether jobs are construction, operations or maintenance, sales and finance. Comparisons of local equipment content can vary between technologies and whether equipment is manufactured locally or produced in the United States or imported. These variations preclude valuing secondary economic impacts easily or accurately, except in very rare circumstances.

13. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

- As the penetration of DG solar increases there may be positive and negative impacts at the distribution level. The positive impact of DG solar may mitigate a future distribution investment. At the generation level, DG solar may provide no savings for other customers if the avoided costs all flow to the DG solar customer. As penetration increases, intermittency may require increased dispatch and control activities and costs. If the production of DG on a feeder becomes significant (higher penetration) the negative impacts on a feeder can be mitigated through interconnection (and other equipment) and potentially smart inverters. Staff recommends this consideration be deferred until DG solar penetration exceeds 15 percent and the issue becomes more relevant.

14. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

- Yes, fuel and other operational saving form the bulk of the avoided costs that establish the value of excess energy delivered to the utility. Fuel forecast variability is a significant problem that capacity planners treat by using a variety of forecasts and scenarios to make decisions probabilistically. As discussed above other technologies such as energy efficiency and fuel-efficient vehicles are not promised a fixed price for the life of the asset. Staff recommends each utility use the same fuel price forecast for each potential resource in its planning process so that DG is considered on the same bases as, say, a natural gas plant. Staff recommends dealing with fuel forecast variability by not setting too long of a term of prices for excess energy and instead use a mechanism to recalibrate periodically.

17. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?

- Yes, DG solar as generally installed requires connection to the utility grid to operate and to sell excess DG energy. Most inverters will not operate without voltage and frequency from the grid. With a Three Part-TOU rate, the costs of the grid connection will be paid for by most DG solar customers.

18. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?

   - Yes, if water is consumed in electric generation (such as cooling, steam cycle blowdown, NOx control or power augmentation); but that cost difference should already be accounted for in the fixed and variable O&M costs that are included in avoided costs. Therefore, no value adder is needed for water unless it has been inadvertently overlooked in the avoided cost comparison.

19. Are there disaster recovery or backup benefits associated with the development of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?

   - No, for single installations that include inverters that shut down energy production when the grid is unavailable, DG solar offers no benefits and a slight increase in the time for restoration (due to safety measures that must be taken to protect line personnel). Yes, if DG solar installations are aggregated and fitted with smart inverters and controls to allow "island" operation, only those customers within the island will have service during mass outages. However, the presence of islanded load pockets will complicate restoration and increase the time to return non-islanded customers due to the need to obtain distribution dispatch clearances and resynchronize the islanded load.

20 What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

   - If the impact of providing voltage support and/or frequency support or other ancillary services are identified and become significant, they should be taken into consideration. Also see the response to # 17.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.
Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)

Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.
New Jersey Board of Public Utilities

Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

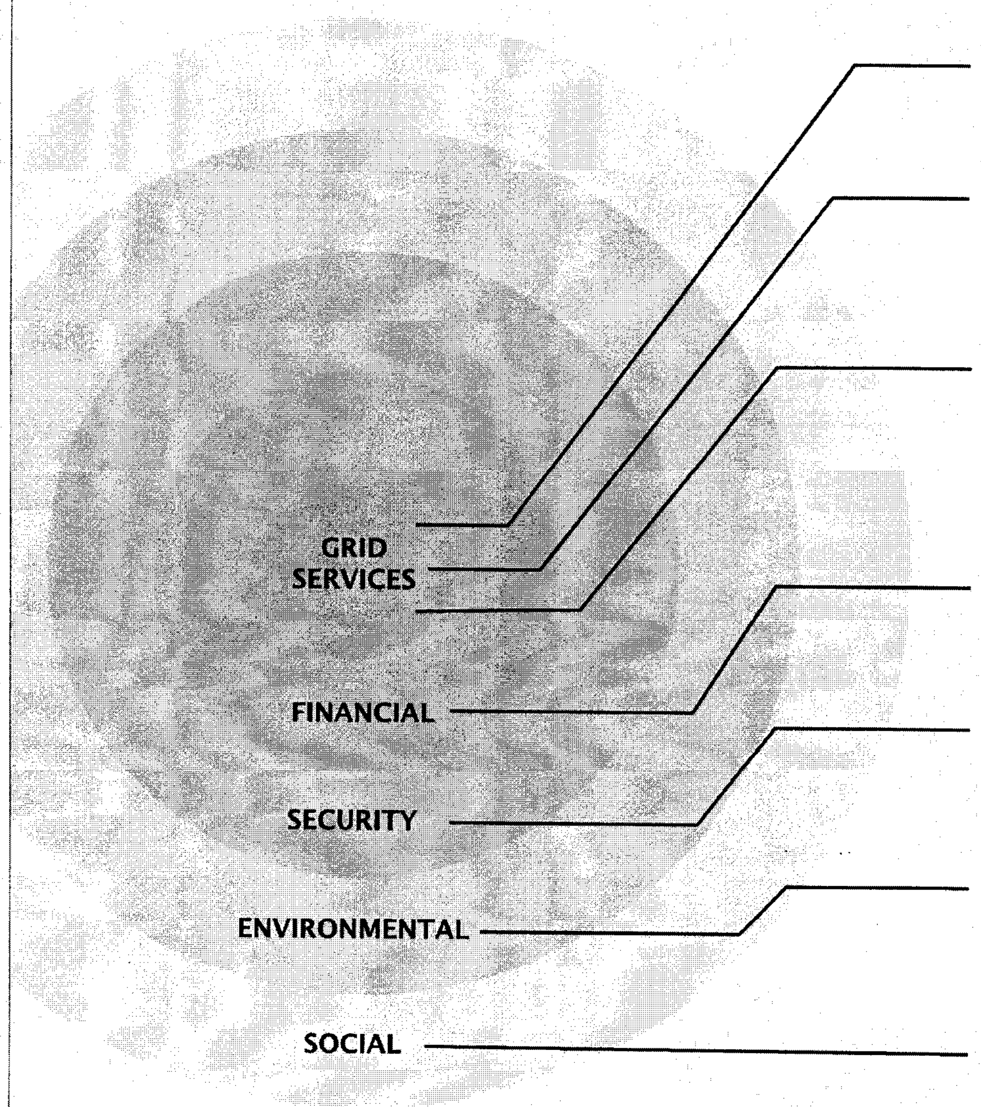
Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

BENEFIT & COST CATEGORIES

For the purposes of this report, **value is defined as net value, i.e. benefits minus costs.** Depending upon the size of the benefit and the size of the cost, value can be positive or negative. A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are:



ENERGY
- energy
- system losses

CAPACITY
- generation capacity
- transmission & distribution capacity
- DPV installed capacity

GRID SUPPORT SERVICES
- reactive supply & voltage control
- regulation & frequency response
- energy & generator imbalance
- synchronized & supplemental operating reserves
- scheduling, forecasting, and system control & dispatch

FINANCIAL RISK
- fuel price hedge
- market price response

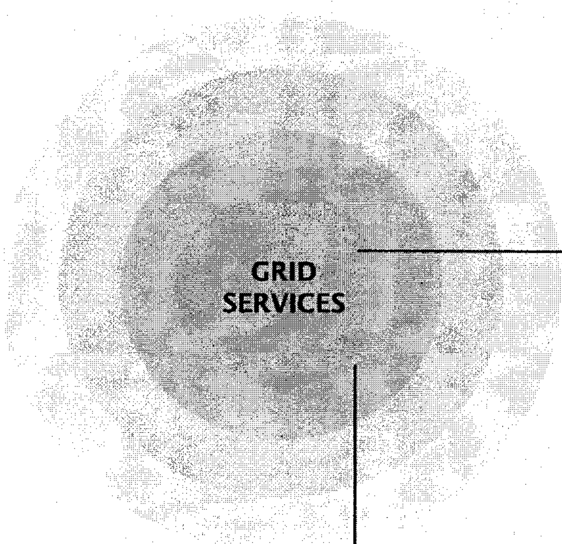
SECURITY RISK
- reliability & resilience

ENVIRONMENTAL
- carbon emissions (CO_2)
- criteria air pollutants (SO_2, NO_x, PM)
- water
- land

SOCIAL
- economic development (jobs and tax revenues)

BENEFIT & COST CATEGORIES DEFINED

e- Lab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE



ENERGY

Energy value of DPV is positive when the solar energy generated displaces the need to produce energy from another resource at a net savings. There are two primary components:

- **Avoided Energy** - The cost and amount of energy that would have otherwise been generated to meet customer needs, largely driven by the variable costs of the marginal resource that is displaced. In addition to the coincidence of solar generation with demand and generation, key drivers of avoided energy cost include (1) fuel price forecast, (2) variable operation & maintenance costs, and (3) heat rate.

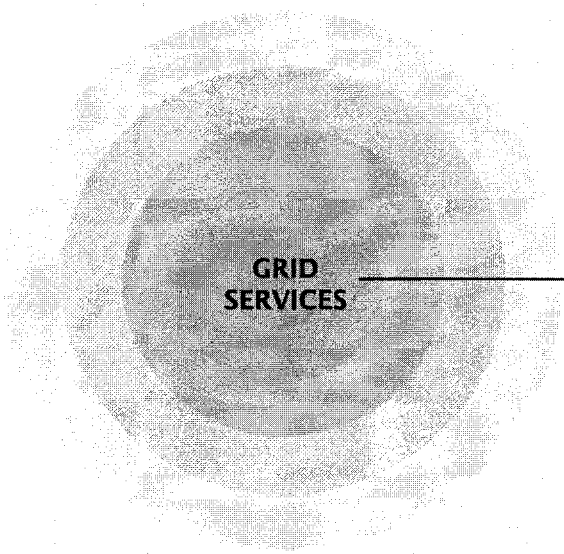
- **System Losses** - The compounded value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, those losses are avoided. Losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

CAPACITY

Capacity value of DPV is positive when the addition of DPV defers or avoids more investment in generation, transmission, and distribution assets than it incurs. There are two primary components:

- **Generation Capacity** - The cost of the amount of central generation capacity that can be deferred or avoided due to the addition of DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

- **Transmission & Distribution Capacity** - The value of the net change in T&D infrastructure investment due to DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding T&D upgrades. Costs occur when additional T&D investment is needed to support the addition of DPV.



GRID SUPPORT SERVICES

Grid support value of DPV is positive when the net amount and cost of grid support services required to balance supply and demand is less than would otherwise have been required. Grid support services, which encompass more narrowly defined ancillary services (AS), are those services required to enable the reliable operation of interconnected electric grid systems. Grid support services include:

- **Reactive Supply and Voltage Control**— Generation facilities used to supply reactive power and voltage control.

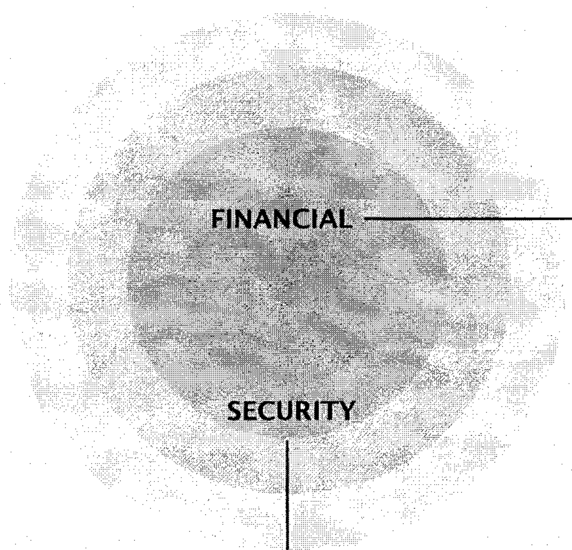
- **Frequency Regulation**—Control equipment and extra generating capacity necessary to (1) maintain frequency by following the moment-to-moment variations in control area load (supplying power to meet any difference in actual and scheduled generation), and (2) to respond automatically to frequency deviations in their networks. While the services provided by regulation service and frequency response service are different, they are complementary services made available using the same equipment and are offered as part of one service.

- **Energy Imbalance**—This service supplies any hourly net mismatch between scheduled energy supply and the actual load served.

- **Operating Reserves**—Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output, and should be located near the load (typically in the same control area). They are available to serve load immediately in an unexpected contingency. Supplemental reserve is generating capacity used to respond to contingency situations that is not available instantaneously, but rather within a short period, and should be located near the load (typically in the same control area).

- **Scheduling/Forecasting**—Interchange schedule confirmation and implementation with other control areas, and actions to ensure operational security during the transaction.

BENEFIT & COST CATEGORIES DEFINED



FINANCIAL RISK

Financial value of DPV is positive when financial risk or overall market price is reduced due to the addition of DPV. Two components considered in the studies reviewed are:

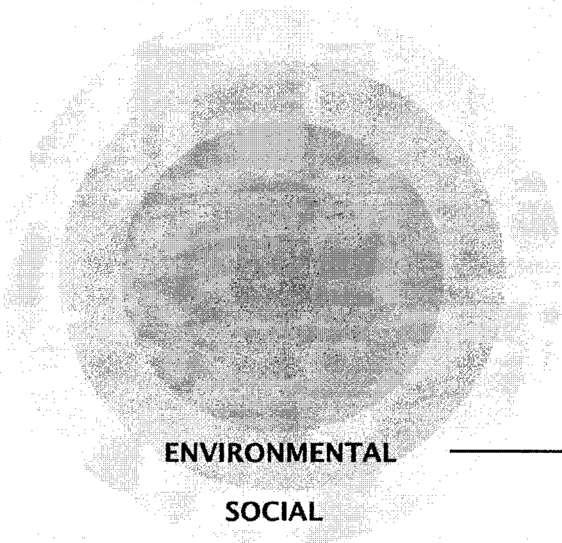
- **Fuel Price Hedge** - The cost that a utility would otherwise incur to guarantee that a portion of electricity supply costs are fixed.

- **Market Price Response** - The price impact as a result of DPV's reducing demand for centrally-supplied electricity and the fuel that powers those generators, thereby lowering electricity prices and potentially commodity prices.

SECURITY RISK

Security value of DPV is positive when grid reliability and resiliency are increased by (1) reducing outages by reducing congestion along the T&D network, (2) reducing large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed, and (3) providing back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

BENEFIT & COST CATEGORIES DEFINED



ENVIRONMENTAL

Environmental value of DPV is positive when DPV results in the reduction of environmental or health impacts that would otherwise have been created. Key drivers include primarily the environmental impacts of the marginal resource being displaced. There are four components of environmental value:

- **Carbon** - The value from reducing carbon emissions is driven by the emission intensity of displaced marginal resource and the price of emissions.

- **Criteria Air Pollutants** - The value from reducing criteria air pollutant emissions—NO_x, SO_2, and particulate matter—is driven by the cost of abatement technologies, the market value of pollutant reductions, and/or the cost of human health damages.

- **Water** - The value from reducing water use is driven by the differing water consumption patterns associated with different generation technologies, and is sometimes measured by the price paid for water in competing sectors.

- **Land** - The value associated with land is driven by the difference in the land footprint required for energy generation and any change in property value driven by the addition of DPV.

- **Avoided Renewable Portfolio Standard costs (RPS)** - The value derived from meeting electricity demand through DPV, which reduces total demand that would otherwise have to be met and the associated renewable energy that would have to be procured as mandated by an RPS.

SOCIAL

The studies reviewed in this report defined social value in economic terms. The social value of DPV was positive when DPV resulted in a net increase in jobs and local economic development. Key drivers include the number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

Value of Distributed Generation				
DG Type	Generation			
DG Characteristics & Capabilities	Off Grid	No Export	Responsive	Non-Responsive
Energy				
On-Peak	Not Applicable	Not Applicable	Avoided Cost	Avoided Cost
Off-Peak			Avoided Cost	Avoided Cost
Losses-Energy			Avoided Cost	Avoided Cost
Emergency (shortage)			Time Specific Avoided Cost	
Low Load (Excess generation)			Time Specific Payment	
Capacity				
Generation				
Emergency			Outage Prevention Value	
Long-term			ELCC	ELCC
Short-term				
Losses			Proportional to ELCC	Proportional to ELCC
Transmission				
Emergency			Outage Prevention Value	
Long-term			Proportional to ELCC	Proportional to ELCC
Short-term			Specific Location Only	Specific Location Only
Losses			Proportional to ELCC	Proportional to ELCC
Distribution				
Emergency			Outage Prevention Value	
Long-term			Proportional to ELCC	Proportional to ELCC
Short-term			Specific Location Only	Specific Location Only
Losses			Proportional to ELCC	Proportional to ELCC
Reactive			Value	
Frequency Regulation			Value	
Energy Imbalance			Maybe if Aggregated	
Operating Reserves			Maybe if Aggregated	
Scheduling/Forecasting				
Risk				
Fuel Price Hedge				
Market Price Response			Yes	Yes
Environmental				
Carbon			Maybe in Avoided Cost	Maybe in Avoided Cost
NOX SOX			In Avoided Cost	In Avoided Cost
Water			In Avoided Cost	In Avoided Cost
Land			In Avoided Cost	In Avoided Cost
Social				
Customer				
Meter & Reading	100%		Increased Cost	Increased Cost
Service Drop	100%			
Billing	100%		Increased Cost	Increased Cost
Customer Service	100%		Increased Cost	Increased Cost
Interconnection	No Cost	No Cost	One Time Cost	One Time Cost

Value of Distributed Generation	Load Shifting		Storage-Energy	
DG Type				
DG Characteristics & Capabilities	Responsive	Non-Responsive	Responsive	Non-Responsive
Energy				
On-Peak	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Off-Peak	Cost or Value	Cost	Both	Retail Purchase
Losses-Energy	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Emergency (shortage)	Time Specific Avoided Cost		Time Specific Avoided Cost	
Low Load (Excess generation)	Time Specific Payment		Time Specific Payment	
Capacity				
Generation				
Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
Long-term	ELCC	ELCC	ELCC	ELCC
Short-term				
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Transmission				
Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Distribution				
Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Reactive	Ltd Value		Ltd Value	
Frequency Regulation				
Energy Imbalance				
Operating Reserves				
Scheduling/Forecasting				
Risk				
Fuel Price Hedge				
Market Price Response	Yes	Yes	Yes	Yes
Environmental				
Carbon	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Water	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Land	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social				
Customer				
Meter & Reading	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Service Drop				
Billing	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Customer Service	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Interconnection	One Time Cost	One Time Cost	One Time Cost	One Time Cost

Value of Distributed Generation		Solar				
DG Type		Fixed Axis			Tracking	
DG Characteristics & Capabilities		South	West	Responsive	Responsive	Non-Responsive
Energy						
On-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Emergency (shortage)						
Low Load (Excess generation)						
Capacity						
Generation						
	Emergency					
	Long-term	ELCC	ELCC	ELCC	ELCC	ELCC
	Short-term					
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Transmission						
	Emergency			Outage Prevention Value	Outage Prevention Value	
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Distribution						
	Emergency			Outage Prevention Value	Outage Prevention Value	
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Reactive				Value	Value	
Frequency Regulation				Maybe if Aggregated	Maybe if Aggregated	
Energy Imbalance				Maybe if Aggregated	Maybe if Aggregated	
Operating Reserves						
Scheduling/Forecasting						
Risk						
Fuel Price Hedge		Yes	Yes	Yes	Yes	Yes
Market Price Response		Yes	Yes	Yes	Yes	Yes
Environmental						
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social						
Customer						
Meter & Reading		Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Service Drop						
Billing		Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Customer Service		Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Interconnection		One Time Cost	One Time Cost	One Time Cost	One Time Cost	One Time Cost

Value of Distributed Generation		Wind	
DG Type			
DG Characteristics & Capabilities		Responsive	Non-Responsive
Energy			
On-Peak		Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost
Emergency (shortage)			
Low Load (Excess generation)		Time Specific Payment	
Capacity			
Generation			
	Emergency		
	Long-term	ELCC	ELCC
	Short-term		
	Losses	Proportional to ELCC	Proportional to ELCC
Transmission			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Distribution			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Reactive		Value	
Frequency Regulation		Maybe If Aggregated	
Energy Imbalance			
Operating Reserves			
Scheduling/Forecasting			
Risk			
Fuel Price Hedge		Yes	Yes
Market Price Response		Yes	Yes
Environmental			
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost
Social			
Customer			
Meter & Reading		Increased Cost	Increased Cost
Service Drop			
Billing		Increased Cost	Increased Cost
Customer Service		Increased Cost	Increased Cost
Interconnection		One Time Cost	One Time Cost

Value of Distributed Generation		Increased Conservation	Increased Insulation
DG Type			
DG Characteristics & Capabilities			
Energy			
On-Peak		Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost
Emergency (shortage)			
Low Load (Excess generation)			
Capacity			
Generation			
	Emergency		
	Long-term	ELCC	ELCC
	Short-term		
	Losses	Proportional to ELCC	Proportional to ELCC
Transmission			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Distribution			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Reactive			
Frequency Regulation			
Energy Imbalance			
Operating Reserves			
Scheduling/Forecasting			
Risk			
Fuel Price Hedge		Yes	Yes
Market Price Response		Yes	Yes
Environmental			
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost
Social			
Customer			
Meter & Reading			
Service Drop			
Billing			
Customer Service			
Interconnection		No Cost	No Cost

Value of Distributed Generation / DG Type / DG Characteristics & Capabilities		Efficent Appliances		Efficient HVAC	
		Responsive	Non-Responsive	Responsive	Non-Responsive
Energy					
On-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Emergency (shortage)					
Low Load (Excess generation)		Time Specific Payment		Time Specific Payment	
Capacity					
Generation					
	Emergency				
	Long-term	ELCC	ELCC	ELCC	ELCC
	Short-term				
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Transmission					
	Emergency				
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Distribution					
	Emergency				
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Reactive					
Frequency Regulation					
Energy Imbalance					
Operating Reserves					
Scheduling/Forecasting					
Risk					
Fuel Price Hedge		Yes	Yes	Yes	Yes
Market Price Response		Yes	Yes	Yes	Yes
Environmental					
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social					
Customer					
Meter & Reading					
Service Drop					
Billing					
Customer Service					
Interconnection		No Cost	No Cost	No Cost	No Cost

EXHIBIT
S-3
ADMITTED

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 COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	))))	DOCKET NO. E-00000J-14-0023

REBUTTAL TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 7, 2016

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EXECUTIVE SUMMARY
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023

Mr. Solganick's rebuttal testimony details Staff's recommendations for the attributes needed to derive the value and costs of DG in general and DG solar in particular.

Staff offers its perspective of the positions of various parties and analyzes the suggested methodologies in the context of utility planning, operations and cost recovery. Staff also responds to the positions of the various parties.

Staff also responds to some of the questions posed by Commissioners Forese, Burns and Stump.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided direct testimony relating to value and cost of solar and addressed some of Commissioner Little's questions.

Q. What is the purpose of your rebuttal testimony?

A. This testimony provides Staff's response to the direct testimony filed by some of the interveners and also responds to questions from Commissioners Forese, Burns and Stump.

REBUTTAL TESTIMONY

Q. What conclusions and recommendations did Staff draw in its direct testimony?

A. Staff provided its perspective of the relative value and cost of various forms of distributed generation "(DG") including drawing contrasts between various types of generation and defining various drivers of value and cost.

Staff's perspective is based on specific concepts:[1]

- What happens behind the meter is the customer's business.
- The proper rate structure will offer accurate price signals to assist customers to make decisions between, for example, conservation, insulation, high efficiency appliances, storage or DG.
- Rates for residential and small general service customers will transition to Three-Part Time of Use ("TOU").
- Costs and values are to be viewed from the perspective of all customers.
- Utilities have a responsibility (enforced by the Commission) to provide service at the lowest reasonable cost.

[1] Solganick Direct 7:7

Q. Did Staff define DG and a number of terms that are relevant for the value and cost determination?

A. Yes. Staff developed its matrix[2] that compared and contrasted various forms of DG including generation, load shifting, storage, multiple forms of DG solar, wind, conservation, insulation, efficient appliances and efficient HVAC. The purpose of the Staff's matrix is to highlight that solar DG and many other alternatives offer similar attributes (to different degrees). Based on the matrix Staff drew many conclusions that are important when determining value and cost.[3]

Q. What elements did Staff recommend to set the price for excess DG energy?

A. The price offered should begin with avoided energy costs along with appropriate losses specific to that utility and/or its interconnected systems. The price should be further increased for the demonstrated or forecast capacity value for generation.[4]

If the deferral or elimination of transmission or distribution assets and/or costs is applicable then these value components should be geographic adders.[5] Geographic values should be treated as distinct adders and not accrue to all energy delivered because the deferral of transmission and/or distribution assets (or operational savings) is dependent on location.[6] Staff suggested that the utility should consider a feeder focused adder to attract DG in certain distribution locations, however there may be a threshold amount of demand that the DG should offset for the adder to apply.[7]

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[2] Solganick Direct Exhibit HS-3
[3] Solganick Direct 14:15
[4] Solganick Direct 19:12
[5] Solganick Direct 19:19 and 19:24
[6] Solganick Direct 12:1, 15:1 and 15:4
[7] Solganick Direct 19:24

Environmental costs are included in the avoided cost value and therefore no additional value is needed. If an emerging environmental cost will affect future energy and capacity then that information should be made available from the Integrated Resource Plan ("IRP") process.[8]

Q. Which components of Staff's matrix are recommended for inclusion in the development of values and costs?

A. The following elements from the Staff matrix should be included to develop the base value of DG. Staff's matrix should be used to define what each form of DG provides value, as each type of DG has a different value proposition.

- Energy
  - (On & Off Peak) based on avoided cost including time dependency (recognizing the value based on when the energy is delivered)
- Capacity
  - Long-term based on ELCC when capacity is needed
- Environmental
  - Presently included in avoided cost (SOX, NOX, water, land use, etc.) therefore no additional value is needed
  - Potentially a carbon component based on the IRP process and emerging regulation

The addition of losses is appropriate but they should be applied based on a specific study (utilities generally have an energy loss study (and many have a demand loss study) that is used in the cost of service process).

- Energy
  - Losses adjusted for geographic location using the energy loss study

[8] Solganick Direct 20:4

- Capacity
  - Losses adjusted for geographic location using the demand loss study.

There are a number of geographic adders that may be effective in specific demonstrated locations.

- Transmission
  - Long-term based on ELCC when capacity is needed and can be offset if there is a true reduction in transmission costs and not a reallocation due to lower energy sales.
- Distribution
  - Long-term based on ELCC when capacity is needed and can be offset.

There are a number of emergency capabilities that could also apply to some forms of DG that can be controlled by the utility (see Staff's matrix for applicability guidance and Staff's discussion of "responsive"[9]).

- Energy
  - Positive (value) if output can be increased under utility control.
  - Negative (cost) if output cannot be decreased under utility control.
- Capacity
  - Positive (value) if output can be increased under utility control.
- Transmission
  - Positive (value) if output can be increased under utility control.
- Distribution
  - Positive (value) if output can be increased under utility control.

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[9] Solganick Direct 12:7

There are grid support services that could also apply to some forms of DG that can be controlled by the utility (see Staff's matrix for applicability guidance). Some of these capabilities are included in the avoided cost of a utility generation facility; therefore the absence of these may be a cost to deduct. As the Commission evaluates whether these items have value when provided by the alternate technology, it should look to the present state to see if this value is being delivered now rather than presupposing that the market will evolve and deliver these capabilities.

- Reactive if available under utility control and needed geographically.
- Frequency Regulation if available under utility control.
- Operating (spinning) reserves if available under utility control.
- Market price response if measureable and not already within the avoided cost (short term effects).

There are customer costs to recognize as either per customer (unless judged to be very minor) or for connection of the DG facility.

- Metering & Reading
- Billing (costs of applying bill credits and software changes to accomplish)
- Customer Service
- Interconnection (based on geographic location with recognition of congestion costs or needed investments)

Staff does not recommend providing a value for social costs such as local economic development as these items are difficult to quantify and not included in the ratemaking formula for existing generation and other facilities and not unique or incremental in DG.

Q. What is the impact of RECs?

A. The compensation for energy should reflect whether RECs are delivered to the utility or retained by the customer.[10]

Q. Are there any reliability or resiliency benefits to DG solar as presently configured?

A. Staff addressed this issue in its response to Chairman Little's question.[11] At present few, if any, DG solar installations offer reliability and resiliency benefits and the technology if developed in the future will primarily benefit the DG customer, therefore there is no basis to pay for a value that does not provide a benefit to non-participating customers. Customers that are concerned about reliability beyond that provided by their utility often purchase at their own expense backup sources of electricity or make appropriate plans to deal with the emergency, therefore adding a value component is inappropriate. The presence of non-utility generation on the grid complicates (and slows down) restoration due to requirements for clearances to maintain safety of line workers.

Q. Does Staff's recommended values and costs impact the value of DG used behind the meter?

A. No. The value of any DG used behind the meter is determined by the customer and the rate schedule the customer purchases energy and capacity on.

Q. Are there other mechanical and/or rate setting issues involved?

A. Yes. Staff's direct testimony addresses a number of procedural issues.[12]

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[10] Solganick Direct 20:7
[11] Solganick Direct 27:9
[12] Solganick Direct 18:23 through 19:10

Q. Are all utilities alike?

A. Staff recognizes that each utility operates under different circumstances and challenges. The customer density of various utilities varies and leads to different transmission and distribution configurations that will have an impact on geographic based costs including interconnection. The utility's metering capabilities will also determine how detailed costs can be defined and the corresponding rate design in place.

Q. Are all DG resources alike?

A. Staff's matrix demonstrates that there are a large number of types of DG with varying characteristics, capabilities and attributes. Additionally, there can be geographical differences among DG types that further affect performance. For DG solar there can be utility-scale, community scale, residential and commercial and industrial ("C&I").

Utility-scale would generally be connected at a substation and depending on size would support loads at that substation or connected substations. Due to the economies of scale and location, the utility-scale solar can utilize tracking to maximize production and produce energy earlier in the morning and later in the afternoon thus offering both energy and better support of the utility's peak demand.

Community-scale solar may be located closer to the load and may be smaller than utility-scale but can have similar attributes including increased production and better contribution to peak demand due to tracking. Community-scale solar would typically use less of the transmission system and have lower losses to the load.

Utility-scale and community-scale solar benefit from economies of scale, which lowers costs and allows the use of smart inverters and other controls to tailor performance to the needs of the distribution system such as providing voltage control and reacting to emergency conditions.

Solar behind a customer's meter is generally smaller in size and more costly per kW. Tracking is usually not used and in many areas the orientation of the panels has focused on maximum energy production (south) rather that meeting demand (west). Losses due to distribution feeder conductors are reduced compared to community-scale solar but distribution transformation losses may be double (out then in) depending on customer density. Notably behind the meter customer systems provide excess energy as the net of solar production less the customer's internal load. Due to differences in load profile it is inappropriate to aggregate residential and C&I systems within the same price structure as that will shift benefits between two distinct customer classes.

Q. What are the points of agreement among the parties in this case?

A. The parties to this case, in general, agree that the price for excess energy delivered to the grid should include:

- Avoided energy costs and appropriate losses.
- Deferrable capacity costs including losses (based on ELCC).

Q. What are the points of partial agreement among the parties in this case?

A. The parties to this case, in general, accept the concept, but do not agree on significant issues, relating to the price for excess energy delivered to the utility grid that might include:

- Transmission capacity costs including losses but the methodology for computing the value differs based on
    - Lumpiness of assets versus continuous value
    - Valuing deferral before need

- Level of penetration

- Distribution capacity costs including losses but the methodology for computing the value differs based on
  - Lumpiness of assets versus continuous value
  - Valuing deferral before need
  - Level of penetration

Q. What are the points of disagreement among the parties in this case?

A. There is a dichotomy among the parties to this case, in general, with only TASC and VS suggesting the inclusion of values such as:

- Additional environmental benefits above regulations in place (such as SOX/NOX and proposed carbon costs)
- Improved electric reliability
- Improved system operations
- Economic development benefits
- Using near term DG penetration

Q. Why do your reviews not include rate design, net metering and associated items?

A. Staff has held the position that the specific value of DG and the associated rate design should be approved in the context of a rate case.[13] Staff has provided its rate design and net metering positions in the on-going UNS Electric rate case (15-0142), the Sulphur Springs Valley Electric Cooperative rate case (15-0312) and will be providing its position in the Tucson Electric Power rate case (15-0322). Arizona Public Service is due to file its rate case in June 2016 and Staff expects to provide its position in that upcoming rate case.

[13] Solganick Direct 4:22

Q. What is resource lumpiness?

A. Utility scale resources often come in discrete sizes leading to lumpiness in the planning process. For example, gas turbines come in discrete MW sizes, as do combined cycle plants and some baseload generation. Transmission capability is often determined by voltage and conductor size again resulting in discrete sizes.

Q. Why is resource lumpiness problematic?

A. In order for a technology to reliably replace the utility resource the technology must demonstrate the certainty that the alternate technology will reach the needed penetration to displace the utility resource. If the alternate technology does not ultimately reach the needed size then it only delays the resource but does not eliminate it.

Q. Are there timing constraints associated with resource development?

A. Yes. The development of a major resource may require siting, permitting, engineering and construction before the resource can be placed into service. Therefore the valuation process should consider that the initial steps in resource development may occur and then a sufficient volume of alternate resources might supplant the construction of the resource. In this situation the costs of siting, permitting and engineering may not be avoidable but may need to be performed as a contingent expenditure to allow the utility to be ready should the distributed resources not materialize in time to meet customer needs. Staff recommends that if these costs are not avoidable then they should not be included in the value proposition.

Q. Does the suggested use of long-term forecasts generate concern about their application?

A. Yes. RUCO, TASC and VS recommend the use of a 20 to 30 year horizon[14] and RUCO[15] and VS[16] suggest that the value of avoided energy be levelized for excess energy supplied by DG solar.

Q. **Does Staff agree?**

A. This suggestion brings several concerns into focus.

Unlike utility or community-scale DG solar, the output of rooftop DG solar is the net of the production less customer usage. There is no requirement that the DG solar customer deliver a specified portion of the production over the life of the installation. There is the potential for the DG customer to respond with a "snapback" effect, which is when a customer sees how much they are saving they use some incremental energy as compensation for their efforts. The increased "compensation" might be lowering the thermostat by one or more degrees during the summer season and thus reducing the excess energy delivered to the utility grid. In the future a solar DG customer may decide to switch to an electric vehicle and reduce the excess energy delivered to the utility grid. Advocates of levelizing energy savings may not recognize that these later events distort the levelization of value.

Although RUCO supports a twenty-year horizon it takes a less expansive view of costs and benefits and proposes to include only easily quantifiable costs and benefits and focus on categories related to the energy system.[17]

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[14] Huber Direct 13:7, Beach Direct 18:12 and Kobor Direct 23:1
[15] Huber Direct 12:26
[16] Kobor Direct 22:24
[17] Huber Direct 13:7

Before any long-term view is taken, the life of the alternate technology should be explored to ensure it matches the term used in the analyses.

Staff recommends that a long-term analysis be undertaken with great care because of the potential for overpayment. The use of too low or too high of a discount rate should be avoided as this tilts the valuation higher. By revisiting the valuation in the utility's rate case, values can be increased if avoided costs rise in the future beyond the forecast used in the previous case.

Q. TASC and VS recognize that the analysis they are recommending may require additional data that utilities are not presently using. Does this create a concern?

A. Yes. Moving the level of analysis that utilities perform forward is a reasonable consideration but the cost, pace and usefulness for utility customers must be considered. TASC acknowledges that some of the data needed to bolster or raise the value of DG solar is not presently available in utility planning.[18] VS wants third party review and funding for that additional review.[19]

Staff recommends that any discussion of enhanced analysis take place within the IRP process.

Q. Both TASC and VS envision the use of smart inverters and storage as solutions to various issues.[20] Should these solutions be used to recognize value now?

A. This issue is better addressed in rate cases wherein the value of DG solar or other technologies are quantified and approved. Staff's recommended Three-Part TOU rate design and net metering price the value of both demand and energy to allow all customers to make

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[18] Beach Direct 22:1
[19] Kobor Direct 5:13
[20] Beach Direct 31:1 and Volkmann Direct 13:3

choices in their usage, time of usage and intensity of usage. Storage technology is one way for all customers to make economic decisions that are rewarded by this rate design.

Staff[21] and APS[22] have recognized that there are emergency conditions such as Low Load (excess generation) that may be partially alleviated by coordinated actions from smart inverters. However, until the solar DG industry demonstrates that the technology can be controlled and includes smart inverters as standard equipment, Staff recommends that it may be more appropriate to subtract value from DG solar for its inability to react to this emergency condition unlike some other forms of generation and storage.

Q. TASC suggests that there is a fuel hedge value to DG solar[23] that should be measured and used to increase the price of excess energy. Does Staff agree?

A. I have seen little evidence that electric utility customers are demanding more reduction in long-term pricing volatility. In competitive supply states residential contracts appear to extend out a few years at most. Utility energy adjustment programs are generally annual or even shorter durations. Staff suggests electric customers do not value a partial fuel price hedge and one should not be applied.

Q. TASC suggests that there is a market price mitigation value of DG solar[24] that should be used to increase the price of excess energy. Is this function unique to DG solar or measurable?

A. The suggestion appears to be that DG solar reduces the load on the grid and therefore reduces the energy price level for all customers. This economic concept is hard to measure and confirm. DG solar is inferior in this respect compared to other forms of DG as shown

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[21] Solganick Direct 13:9 and Exhibit HS-3
[22] Albert Direct 14:8
[23] Beach Direct 20-21 Table 2
[24] Beach Direct 20-21 Table 2

in Staff's matrix. Increased insulation, efficient appliance and efficient HVAC provide this response on a more certain basis as the load reduction effects of these measures are more predictable and less subject to customer's future actions. Responsive DG when called on also could provide this effect. DG solar may provide this effect subject to the DG customer's usage. On hotter days the amount of excess energy may be reduced to serve the increased needs of the DG customer. Based on the limited estimation of the effect and the likely more predictable response of other forms of DG compared to DG solar, Staff recommends this concept should not be used to increase the value of DG solar excess energy.

Q. VS suggests analyzing the value of DG solar using current penetration but then asserts that the analysis be over a long-term. Does this create a dichotomy?

A. Yes. VS focuses on the present for the estimation of solar DG penetration.[25] It also suggests that the analysis be over a twenty to thirty year term.[26] TEP suggests that as penetration of DG solar rises the peak may shift later into the evening.[27] If this is the case then the ELCC of DG solar will decrease (potentially to zero) and reduce the capacity value.

VS' suggestion to use current penetration levels also removes from the analysis the costs of congestion on feeders and impacts on system operations due to higher penetration of DG production and excess energy. This suggestion will cause the costs due to DG solar to be understated. Staff recommends that the level of penetration be synchronized with the period of analysis to properly match value and costs so that analyses are internally consistent.

[25] Kobor Direct 24:7
[26] Kobor 23:1
[27] Tilghman 21:10

Q. Please provide a review of Arizona Public Service ("APS") witness Leland R. Snook's direct testimony.

A. APS witness Snook states the Cost of Service Study ("COSS") "does not consider environmental or economic development benefits because they are not part of the cost to serve customers. They are intangible and unquantifiable values. If they are to be considered at all, they are more appropriately considered in a resource planning context when comparing resource alternatives."[28] He also provides an estimate of the percentage of a DG solar installation's capacity that offset's generation requirements as "at most 19 percent".[29]

Q. Please provide a review of APS witness Bradley J. Albert's direct testimony.

A. APS witness Albert recognizes that energy losses are reduced when energy is consumed at the same site because this power does not have to travel across the grid.[30] His short-term estimate is 7 percent over a year and 12 percent at the time of peak demand.[31] He reminds us some other generation sources do not emit CO2 or other types of emissions. These generating sources include solar, wind and nuclear.[32] He also discusses the need to curtail energy production[33] a condition that Staff discussed in its direct testimony[34]. He suggests three potential ways to estimate the value of rooftop solar based on short-term avoided costs (time varying energy market costs), long-term avoided costs (resource planning) and grid-scale adjusted cost (market competitive).[35]

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[28] Snook Direct 18:7
[29] Snook Direct 18:19
[30] Albert Direct 8:25
[31] Albert Direct 24:1
[32] Albert Direct 13:23
[33] Albert Direct 14:8
[34] Solganick Direct 13:9
[35] Albert Direct 16:18

Staff's initial testimony recommended the recognition of losses and its matrix highlighted the differences and similarities of various alternatives. Staff is willing to consider the use of a comparative resource to benchmark the value of DG.

Q. Please provide a review of APS witness John Stirling's direct testimony.

A. APS witness Stirling describes the process used by a Tennessee Valley Authority ("TVA") working group to evaluate the value of solar and the determination that six "value streams" should be included (generation deferral, avoided energy, environmental, transmission, distribution and losses) as these are currently quantifiable value streams that impact TVA.[36] The first three items are estimated within TVA's Integrated Resource Planning process[37], transmission was valued based on point to point service rates[38], distribution was estimated at zero[39] and losses were considered at both the transmission and distribution levels[40].

Q. Please provide a review of Grand Canyon State Electric Cooperative Association ("GCSECA") witness David W. Hedrick direct testimony.

A. GCSECA witness Hedrick highlights the position of cooperatives including those that purchase energy and capacity from entities such as Arizona Electric Power Cooperative, which contracts do not provide for a capacity cost reduction opportunity due to DG.[41] He also explores the impact of DG on the distribution system and argues that costs are not reduced and that additional equipment may be needed.[42] He highlights that rates are set based on expenses that are known, measureable and continuing.[43]

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[36] Stirling Direct 5:11 and 6:8
[37] Stirling Direct 6:24
[38] Stirling Direct 8:7
[39] Stirling Direct 8:18
[40] Stirling Direct 9:20
[41] Hedrick Direct 10:15
[42] Hedrick Direct 11:8
[43] Hedrick Direct 13:11

Staff notes GCSECA's cooperative distribution utilities have a different cost structure that must be given due recognition. Also, GCSECA also advocates, as Staff does for the inclusion of expenses that are known, measureable and continuing, the present ratemaking formula.

Q. Please provide a review of Residential Utility Consumer Office ("RUCO") witness Lon Huber's direct testimony.

A. RUCO witness Huber highlights RUCO's focus on the 97 percent of residential customers that are non-solar and the costs to serve DG customers that are paid by non-DG customers.[44] He highlights "Value should be a consideration but the amount one pays should be as cost based as possible."[45] "Additionally, RUCO believes that nearly all of the benefits that DG solar could provide to utility customers can also be provided by utility-scale or community-scale solar."[46] He asserts that DG solar is less accessible to customers in contrast to energy efficiency ("EE")[47], that EE offers more diverse grid impacts[48], that PV systems mask but do not reduce a customer's load[49], solar can increase utility system costs[50] and the benefits are concentrated among a smaller group of customers compared to EE[51]. All of these items suggest (to RUCO) that impacts should be evaluated from the perspective of non-DG customers.[52] He asserts that a twenty-year horizon be used and only easily quantified costs and benefits be included.[53] Further, lost revenue and intermittency (resulting in potential additional operating reserves) should be determined.[54] Benefits of solar are considered to include fuel cost savings[55], deferred capacity costs based on coincidence with peak demand

[44] Huber Direct 1:13
[45] Huber Direct 2:17
[46] Huber Direct 4:2
[47] Huber Direct 10:22
[48] Huber Direct 11:7
[49] Huber Direct 11:18
[50] Huber Direct 12:1
[51] Huber Direct 12:10
[52] Huber Direct 12:19
[53] Huber Direct 13:7
[54] Huber Direct 14:2
[55] Huber Direct 18:19

using Effective Load Carrying Capability ("ELCC")[56] and the impact of solar penetration[57]. He estimates that DG could "possibly" result in changes in distribution and transmission capacity needs.[58] RUCO asserts "Generally speaking, community and utility scale solar located within the distribution system have been shown to be more cost-effective (lower $/MW) than DG solar."[59]

Q. Please provide a review of The Alliance for Solar Choice ("TASC") witness B. Thomas Beach's direct testimony.

A. TASC witness Beach argues "DG located behind the meter will both reduce demand for power from the utility, and, at times, will supply power to the utility."[60] "… a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day."[61] He argues that benefits and costs should be analyzed from multiple perspectives of the utility system, participating NEW customers, and other ratepayers – so the regulator can balance all those important interests."[62], use a broader set of benefits and costs including transmission and distribution capacity and losses[63], calculate the benefits and costs over a 20 to 30 year lifetime (corresponding to a DG system)[64] and focus on exports[65]. TASC highlights "avoided cost savings" and includes avoided energy (and losses), avoided generating capacity (and losses), suggests that marginal line losses are double the system average, avoided ancillary services, avoided T&D capacity (location specific), avoided environmental costs (can be included in avoided energy costs), avoided carbon emissions, fuel hedge (forward cost plus hedging

[56] Huber Direct 17:9
[57] Huber Direct 18:1
[58] Huber Direct 19:1 and 19:11
[59] Huber Direct 23:15
[60] Beach Direct 10:21
[61] Beach Direct 12:26
[62] Beach Direct 17:20
[63] Beach Direct 17:29
[64] Beach Direct 18:12
[65] Beach Direct 18:22

costs), market price mitigation, avoided renewables (avoided utility owned or contracted, societal benefits (climate change damages, scarce water resources, lower air emissions, fewer power outages, greater local economic activity), less costs for integration, administrative and interconnection and possibly lost revenues.[66] He argues that all of the categories are quantifiable and the quantification may require data and/or calculations that utilities may not produce today in the normal course of business.[67] TASC focuses on "... DG will remain a viable economic proposition for participating ratepayers.[68] TASC highlights that rooftop or other renewable distributed energy technologies provide greater choice and new capital, new competition, grid services (if smart inverters are employed), enhanced reliability and resiliency (when paired with storage), high tech synergies, customer engagement and self-reliance, but recognizes that these benefits of choice are "difficult to express in dollar terms".[69]

Q. Please provide a review of Tucson Electric Power ("TEP") witness Carmine Tilghman's direct testimony.

A. TEP witness Tilghman highlights "... the Company believes that it is no longer appropriate to pay full retail credit for DG solar when a utility-scale solar facility on the same distribution system can be built or purchased for approximately half the cost and that provides the same green energy with the same environmental attributes."[70] He poses a significant question relating to solar panel orientation "A western facing panel provides greater production during summer peaking hours, but at an economic impact to the customer based on current rates and NEM policies. The Commission must determine whose value they're going to consider – the individual customer who purchased the system, the utility looking to reduce their overall system cost, or society in general who wants to lower rate impacts with increasing renewable

[66] Beach Direct 20-21 Table 2
[67] Beach Direct 22:1
[68] Beach Direct 25:6
[69] Beach Direct 31:1
[70] Tilghman Direct 4:13

energy?"[71] He replaces the concept of intermittency with a requirement for appropriate values and costs including demand rates and ancillary charges.[72] Coincidence between the utilities annual system peak and DG solar is approximately 30 percent, but solar production is effectively zero two hours after the peak when the utility load is still 90-93 percent of the system peak.[73] He asserts that bi-directional flow on the distribution system will require modifications and upgrades.[74] Tilghman raises the questions as to whether providing compensation for societal benefits, secondary economic impacts and other subjective benefits, if the Commission determines some value for them, should be compensated through utility rate design or by state or local government.[75] He highlights that with increasing penetration of solar systems the utility must take into consideration the right combination of resources to respond to the daily timing (compared to load) along with variability and intermittency.[76] He acknowledges the potential for transmission capacity deferral but notes that a long-term peak shift may reduce this with increased solar penetration.[77] He also recognizes the potential for distribution capacity deferrals.[78] He raises an interesting question relating to the value the utility grid provides to DG solar by providing a sink or storage for excess production and asks whether the utility should be compensated for this value based on the cost of storage.[79] He acknowledges that water savings exist and are included in the avoided energy cost.[80]

Staff agrees with TEP that the values and costs of solar can be benchmarked with utility-scale and community-scale solar, that there may be a deferral value for transmission and

[71] Tilghman Direct 11:14
[72] Tilghman Direct 13:7
[73] Tilghman Direct 14:10
[74] Tilghman Direct 16:4
[75] Tilghman Direct 17:20
[76] Tilghman Direct 20:7
[77] Tilghman Direct 21:1
[78] Tilghman Direct 22:1
[79] Tilghman Direct 23:16
[80] Tilghman Direct 24:4

distribution at certain geographic locations, that water costs are included in the avoided energy cost and raises the question of quasi-storage due to banking that Staff has recommended should be considered for elimination from net metering depending on circumstances[81].

Q. Please provide a review of TEP witness H. Edwin Overcast's direct testimony.

A. TEP witness Overcast argues "With regard to solar DG the proliferation of rooftop solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as utility cost benefit from scale economies."[82] He characterizes a rate case as a near term analysis and an IRP analysis as long term.[83] He argues that long term energy forecasts should not be used and levelized but rather based on the short term marginal costs and that the capacity avoided costs are by their nature long-term costs.[84] He suggests that avoided capacity costs be established by the vintage of the installation and also by a market process such as competitive bidding.[85] He asserts that energy payments based on short run costs is the exact same way that utility generation recovers energy costs and that there is no economic reason that solar DG should be any different than a competitive power plant that bears the fuel cost risk in the short term.[86]

Q. Please provide a review of Vote Solar ("VS") witness Kurt Volkmann's direct testimony.

A. VS witness Volkmann suggests that DG can add significant value by deferring capital investment[87] and can have zero costs or require additional measures to accommodate the

[81] Solganick Direct 18:9
[82] Overcast Direct 8:19
[83] Overcast Direct 44:16
[84] Overcast Direct 45:1
[85] Overcast Direct 46:4
[86] Overcast Direct 47:2
[87] Volkmann Direct 6:3

increased load on a feeder[88]. He suggests that utilities disclose the capabilities of feeders to accept DG in order to reduce costs and enable providers to offer innovative alternatives to traditional utility solutions.[89] He recommends the Commission adopt a smart inverter requirement for DG solar and storage installations and opines that this will be an additional input into the DG solar valuation methodology.[90] He discusses the coincidence of DG solar and utility residential and commercial local peaks and suggests that storage may improve the coincidence with local peaks.[91] He recommends that the Commission adopt a detailed marginal cost of service methodology for valuing both transmission and distribution capacity, which he recognizes as data-intensive. He also suggests that where DG makes small, incremental contributions to increase transmission capacity in areas where no immediate capacity upgrade is planned, that this relief has value and should be recognized.[92] He suggests similar treatment for distribution capacity.[93] He provides information on water usage and references a 2011 WRA report and computes the water value for APS as $0.00018 per kWh and for TEP at $0.00028 per kWh.[94] He suggests imputing reductions in service interruptions or reduced duration if the DG can operate without the grid.[95] He suggests that distribution planning processes consider the impact of DG as coordinated alternatives.[96]

VS's proposal to require advanced inverters should be considered by the Commission. Staff has provided additional information about water consumption at generating plants and VS has contributed to this discussion with additional information. Staff suggests that rather than requiring utilities to disclose the capabilities of all feeders that Staff's suggestion that utilities

[88] Volkmann Direct 6:10
[89] Volkmann Direct 7:8
[90] Volkmann Direct 13:3
[91] Volkmann Direct 14:3
[92] Volkmann Direct 18:11
[93] Volkmann Direct 21:4
[94] Volkmann Direct 24:18
[95] Volkmann Direct 26:8
[96] Volkmann Direct 301:12

use an RFP process when feeder capacity is needed would offer a similar result at lower cost.[97] Staff also does not agree that enhanced reliability and resiliency occur with DG solar alone or provide benefits to non-participants.[98]

Q. Please provide a review of VS witness Briana Kobor's direct testimony.

A. VS witness Kobor recommends that the focus be on the energy exported to the utility grid[99], examine cost effectiveness from the perspective of non-participating customers and include impact on utility rates, incorporation of environmental impacts, improved electric reliability, improved system operations and economic development benefits.[100] She recommends focusing on near term levels of DG penetration.[101] She requests funding for third party analysis of a utility's proposal to reform the rate structure and that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.[102] She opines that DG valuation must include the full range of long-term benefits and costs and are utility specific.[103] She recognizes that utility ratemaking is based on a one-year test year focused on current utility costs[104] and that environmental and economic development benefits should not be ignored because they do not fit the historical mold of cost-of-service ratemaking[105]. She suggests analyzing all DG solar (residential and commercial/industrial), analyze value over the life of a DG system (20 to 30 years[106]), use an appropriate discount rate (inflation, not WACC[107]); use a near-term forecast of DG penetration (1-3 years[108]) and analyze capacity on a continuous basis (recognize the modularity

[97] Solganick Direct 19:24
[98] Solganick Direct 27:9
[99] Kobor Direct 8:18
[100] Kobor Direct 4:14 and 4:20 and 19:21
[101] Kobor Direct 5:1
[102] Kobor Direct 5:13
[103] Kobor Direct 8:1
[104] Kobor Direct 10:3
[105] Kobor Direct 12:22
[106] Kobor Direct 22:22
[107] Kobor Direct 23:5
[108] Kobor Direct 24:1

of DG additions[109]).[110] She asks for the use of scenarios to address uncertainty of future rate design.[111] She suggests using long-term Energy Information Administration (25 year) fuel projections and sensitivity analyses.[112] She supports the addition of line losses and ELCC for capacity.[113] However, she requests recognition of capacity reserves for utility generation but may imply that similar reserves are not needed for DG solar.[114] She argues that rooftop DG solar requires a robust local workforce that includes installers, manufacturers, sales associates, and distribution workers along with a multiplier analysis.[115]

Staff agrees with VS that the focus is the energy exported to the grid and that the perspective be that of non-participants and line loss and ELCC have a place in the analysis. Staff does not support limiting the longer-term analysis to near term levels of penetration as this induces a mismatch. Staff has concerns about using long-term fuel forecasts due to past performance. Staff suggests that there is a mismatch when rooftop DG solar's economic impact considers labor force while the economic impact of utility generation is not considered within the ratemaking process.

Q. Is there a Commission process in place that provides information to establish the value of DG in a rate case?

A. The major Arizona utilities file biannual Integrated Resource Plans ("IRP"), which detail the generation and transmission options that the utility is and has considered during its process to develop a long-term resource plan. The basis for the long-term resource plan starts with a

[109] Kobor Direct 25:1
[110] Kobor Direct 17:13
[111] Kobor Direct 27:11
[112] Kobor Direct 28:5
[113] Kobor Direct 31:6
[114] Kobor Direct 31:21
[115] Kobor Direct 35:5

defined load forecast commonly called the base case. Robust IRP include several sensitivity cases around the base case load forecast to account for variations in the load forecast drivers.

Once a series of load forecasts are developed then the utility can move to capacity planning with the impacts of customer-side effects such as energy efficiency ("EE"), appliance efficiency, demand side management ("DSM") and DG woven into the capacity planning process. In certain cases these "subtractors" may leave the required peak capacity needs static but the capacity planner may consider retirements, fuel conversions and emerging or potential emissions requirements. Generation also has the capability to stand in for some level of transmission and capacity planners consider this function in parallel with supply requirements at specific locations on the grid. Conversely purchases supported by a robust transmission grid can offer alternatives to construction of new capacity.

Q. What issues did Commissioner Forese ask parties to address in this proceeding?

A. Commissioner Forese expressed his concern that the parties may move to positions that are rigid rather than searching for "win-win" scenario. Staff supports the Commissioner's more optimistic viewpoint and notes that its position allows for evolution over time. Although Staff adopted its long-term rate design proposal for Three-Part TOU rates in the on-going UNSE case (15-0142)[116] that position did not call for the immediate suspension of net metering[117] and also supported partial "grandfathering"[118] to recognize that certain customers had been "early adopters" at the urging of many constituencies and thus deserved consideration as the rate design and/or net metering evolved. Further supporting the Commissioner's concern, Staff has recommended that there be an adder to reflect geographic differentials depending on the specific distribution infrastructure if DG can replace or

[116] Solganick Direct (15-0142) 10:5
[117] Solganick Direct (15-0142) 45:20 and Broderick Direct (15-0142) 11:9 and Solganick Rebuttal (15-0142) 12:25 and Broderick Rebuttal 8:10
[118] Broderick Rebuttal (15-0142) 5:14 and 6:1, 6:18

significantly delay needed upgrades or expansion.[119] Staff also notes that its Three-Part TOU proposal does not specifically single out any customer subclass including DG.[120] To address the initial post transition impact of Staff's recommended Three-Part TOU rates Staff proposed a 15 percent cost per kW incentive for DG solar installations for the six months after the completion of the full transition.[121] Taken together Staff's proposals in the UNSE case form a foundation suitable for that utility for a win-win approach to the various issues involved.

Q. Commissioner Burns expressed his concerns over the interrelationship of energy and water as it specifically relates to Arizona.

A. Staff recognizes the nexus between energy and water, as many of the existing generation technologies require water as the "working fluid", for power augmentation and also for cooling. Staff witness Zachary Branum has filed rebuttal testimony detailing the use of water for Arizona power generation.

The use of water for the working fluid within Rankine cycle steam power plants (fueled by nuclear, coal or gas) accounts for limited water consumption as the water is recirculated between the boiler and steam condenser and requires limited water blowdown and makeup to maintain the quality of the working fluid. The operating costs for a power plant include the cost of such water usage.

Water can also be used to augment power production in combined cycle or combustion turbine power plants by cooling the inlet air and/or steam injection. This tradeoff of

[119] Solganick Direct 12:1 and 19:24
[120] Solganick Direct (15-0142) 32:11
[121] Broderick Rebuttal (15-0142) 13:20

increased production through increased water usage is included in the operating costs for such power plants.

Water has been historically used as a cooling medium for many power plants, initially in once through cooling and more recently through the use of cooling towers. Power plants have been developed that use air-cooling in place of water-cooling but there can be performance impacts. Staff notes positively that Vote Solar witness Volkmann has raised this issue and has provided some initial information to evaluate the impact of water on power generation. The typical utility IRP would also use these types of evaluation methods to consider the water energy nexus.

The quantification of the amount of water used in various forms of power generation ranging from once through cooling to technologies that do not require water including air cooled units and certain forms of DG (wind, large scale and rooftop solar) is a reasonably accomplished engineering function. What is challenging is the pricing of the cost of the water consumed. The price of water can range from present average costs, recognize the estimated increased future cost of water or consider the use of reclaimed water. Staff supports the use of analyses that include a focus on the cost of water or the value of the avoidance of the use of water.

Q. Commissioner Burns also highlighted the potential advantages of combined heat and power including its use in the agricultural sector.

A. Staff's direct testimony specifically recognizes the potential value of combined heat and power.[122] Staff also has recommended that behind the meter[123] DG be considered in a

[122] Solganick Direct (15-0142) 5:12
[123] Solganick Direct (15-0142) 7:7

broader sense than DG solar, as there are many alternatives[124] with various positive attributes[125] that should be considered within the IRP process. The production of energy through the use of agricultural waste can and should be evaluated within the IRP process where such potential opportunities exist in Arizona.

Q. What issues did Commissioner Stump ask parties to address in this proceeding?

A. Commissioner Stump posed many questions for the parties to this docket to address in order to provide a better record for consideration. Staff addresses a number of his questions:

1. The Commission's May 7, 2014 workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

- A remote solar generation station (often called utility-scale) is different from rooftop solar due to the economies of scale (usually lower costs) and differential losses between rooftop solar located nearer to load and utility-scale solar located at or near a transmission or distributions substation. At present utility-scale solar could be more easily controlled in response to system (grid) needs, while in the future wide spread use of smart inverters combined with some centralized control may allow rooftop solar to provide similar control capabilities.
- Staff's direct testimony addressed the cost differential between the two types of DG solar and the utility's requirement to procure resources at the lowest reasonable cost.[126]

[124] Solganick Direct (15-0142) 5:10
[125] Solganick Direct (15-0142) 6:5
[126] Solganick Direct 8:4 and 8:14

2. Why argue that a value of solar proceeding is important only for the resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG.

- While the discussions about cost-shift can be informed by the value of solar, the value of solar should not be used to allow the continuation of cost-shifts. Staff has recommended the mandatory transition to a Three-Part TOU rate design as it properly prices the discrete elements of demand, energy and customer for all customers when fully implemented.[127] Staff also supports that what happens behind the meter is the customer's business and that views all technologies on an equal basis.[128] The purchase of energy from other utilities or a customer should be driven by a reasonable cost standard.[129] If the Commission then determines that DG solar (or any other technology) can add value to Arizona and that value should be compensated through the utility regulatory policy, then that incremental compensation should be identified and separately paid for. Examples might include a distribution adder if substation enhancements can be eliminated that would be paid only to those customers that made the elimination possible.[130]

3. In 2014, lost fixed cost associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's

[127] Solganick Direct (15-0142) 30:11
[128] Solganick Direct 7:7
[129] Solganick Direct 8:4
[130] Solganick Direct 19:24 and 22:14

demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

- The relative magnitude of EE compared to solar DG will change based upon the penetrations of each of these programs and therefore is an evolving situation.
- As Staff has shown in its matrix[131] there are multiple technologies that may provide the attributes of DG solar and DG solar may lack other attributes.
- Staff has recommended the mandatory transition to Three-Part TOU rates[132] to eliminate (after full implementation) the cost shift attributed to DG solar and place all technologies on an equal footing.
- EE and DG solar have different customer accessibility due to financing, orientation, home ownership versus rental property and other requirements. Staff suggests that the inherent value of each (EE or DG) does not affect the other, although the customer should implement lower cost alternatives first.
- Staff suggests that both engineering simulations and load research can demonstrate that EE will reduce both peak demand (coincident and non-coincident) and energy while solar DG will reduce energy consumption and may (or may not) reduce peak demand. Further if DG solar is delivering energy to the grid, flows are reversed (at least through the customer's transformer and potentially into the distribution system).

4. How do we calculate regressive social costs into the value of solar, given that non-solar customers subsidized solar customers?

- Staff has recommended the mandatory transition to Three-Part TOU rates[133] to eliminate (after full implementation) the cost shift attributed to DG solar and place all technologies on an equal footing.

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[131] Solganick Direct Exhibit HS-3
[132] Solganick Direct (15-0142) 30:11
[133] Solganick Direct (15-0142) 30:11

7. How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U. S. installation cost into a value on solar determination?

- Productivity increases and/or decreases in inputs such as panels have no direct relationship to the value of solar and do not need to be considered except as a means to estimate market penetration.

8. In value of solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower installation costs? How does the cost and value of DG compare with the alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that utility scale and community scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility scale or community scale solar?

- As Staff has shown in its matrix[134] there are multiple technologies that may provide the attributes of DG solar and DG solar may lack other attributes.
- The appropriate place to compare the value of different alternatives both renewable and more traditional sources of energy is within the IRP process.
- The relative value of solar as DG, utility or community can be evaluated within the IRP process. Due to economies of scale that are slightly offset by reduced losses it is likely that rooftop DG solar is less efficient than community or utility scale solar.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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[134] Solganick Direct Exhibit HS-3

EXHIBIT
S-4
~~ADMITTED~~

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ARIZONA CORPORATION COMMISSION

April 22, 2016

Thomas A. Loquvam
Pinnacle West Capital Corporation
P.O. Box 53999, MS 8695
Phoenix, Arizona 85072-3999

Via E-mail and United States Mail
thomas.loquvam@pinnaclewest.com

Re: Staff's **Third** Set of Data Requests to Arizona Public Service Company
Docket No. E-00000J-14-0023

Dear Mr. Loquvam:

Please treat this as Staff's **Third** Set of Data Requests to Arizona Public Service Company in the above matter.

For purposes of this data request set, the words "Arizona Public Service Company," "Company," "you," and "your" refer to Arizona Public Service Company and any representative, including every person and/or entity acting with, under the control of, or on behalf of Arizona Public Service Company. For each answer, please identify by name, title, and address each person providing information that forms the basis for the response provided.

These data requests are continuing, and your answers or any documents supplied in response to these data requests should be supplemented with any additional information or documents that come to your attention after you have provided your initial responses.

Please respond within **FIVE (5)** calendar days of your receipt of the copy of this letter. However, if you require additional time, please let us know.

Please provide one hard copy as well as searchable PDF, DOC or EXCEL files (via email or electronic media) of the requested data directly to each of the following addressees via overnight delivery services to:

(1) Tom Broderick, Director, Utilities Division, Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona 85007, tbroderick@azcc.gov.

(2) Constance Fitzsimmons, Legal Division, Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona 85007, cfitzsimmons@azcc.gov.

Sincerely,

Maureen A. Scott, Senior Staff Counsel
Matthew Laudone
Legal Division
(602) 542-3402

MAS;ML:klc:mam
Enclosure

ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000J-14-0023
APRIL 22, 2016

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.
***For all data requests for which you do not have the information requested, please state such and skip to the next data request. Also, for responses to data requests that may be voluminous or overly burdensome, please contact Tom Broderick at 602-542-4251 to discuss.

STF 3. 1 Please provide information on all utility-scale solar renewable PPAs, with an effective date on or after January 1, 2008, including:

a. The effective date

b. Term of the PPA

c. Actual price per kWh to the utility and any other charges, by year for the life of the contract, and

d. Type(s) of renewable technology for each PPA.

e. Please also provide a copy of each PPA, including term sheet.

STF 3. 2 Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g. The cost per kWh generated over the life of the facility.

ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-00000J-14-0023
APRIL 22, 2016

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.
***For all data requests for which you do not have the information requested, please state such and skip to the next data request. Also, for responses to data requests that may be voluminous or overly burdensome, please contact Tom Broderick at 602-542-4251 to discuss.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

STF 3. 3 Please explain the decision criteria you have and will rely upon for deciding whether to rely on a PPA or utility ownership for utility scale solar. If one decision criteria includes cost comparisons, please provide an explanation, formula and example of comparison between PPA and utility ownership. If that formula is from a perspective other than the customers' revenue requirements, please explain why.

STF 3. 4 Given the utilities' support for reliance upon PPA data for utility scale solar as a basis for pricing export for rooftop DG solar, please explain whether the utility is willing to apply the same criteria to its utility ownership decision process for utility scale solar. If not, why not apply the same criteria? Is the utility supportive of applying this criteria uniformly if the PPA concept is embraced as the benchmark for solar evaluation?

STF 3. 5 As regards the specific points of comparison between PPA's and utility ownership of utility scale solar which do or may lead to differences in cost comparisons, please address:

(To the extent these questions are general, please answer from the perspective of your utility's actual experience and practices.)

a) Any differences in amount and timing of revenue requirements to customers given PPA's recovery in PPFAC's and utility ownership following a revenue requirements formula? For the same resource, is the PPA less costly initially due to typical reliance upon levelized pricing; whereas utility ownership prices are initially higher and subsequently lower under the revenue requirements formula?

b) Please explain the differences between tax efficiency of utilization of related investment tax credits between PPA vendors and utility ownership?

Public Documents
No Confidential Documents
Included

EXHIBIT
S-5
Public Docs
ADMITTED

aps

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Kerri.Carnes@aps.com

May 26, 2016

Maureen A. Scott
Senior Staff Counsel
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

RE: Value and Cost of Distributed Generation Generic Docket
Docket No. E-00000J-14-0023

Dear Ms. Scott:

Enclosed, please find Arizona Public Service Company's response to Staff's Fourth Set of Data Requests in the above-referenced matter. The response to Staff 4.2 contains confidential information and is provided pursuant to the protective order.

If you have any questions, please contact me at (602)250-3341.

Sincerely,

Kerri A. Carnes

KC/kr
Attachment

cc: Matthew Laudone
Rick Lloyd

ARIZONA CORPORATION COMMISSION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
May 24, 2016

Staff 4.1: Please provide cost and revenue requirement data for the Red Rock solar facility scheduled to go on line in late 2016 or early 2017.

Response: The estimated cost for Red Rock is $94.7 million. Annual revenue requirements are provided below based on 1/1/2017 operation date. Note that these amounts are estimates and are subject to change until the project is placed in service.

Revenue Requirement				
Year	**$Thousands**		**Year**	**$Thousands**
2017	12,147		2032	7,009
2018	11,267		2033	6,901
2019	10,314		2034	6,795
2020	9,457		2035	6,689
2021	8,898		2036	6,584
2022	8,339		2037	6,480
2023	8,003		2038	6,377
2024	7,890		2039	6,274
2025	7,778		2040	6,172
2026	7,666		2041	6,071
2027	7,555		2042	5,971
2028	7,444		2043	5,872
2029	7,334		2044	5,774
2030	7,225		2045	5,677
2031	7,117		2046	5,581

ARIZONA CORPORATION COMMISSION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
May 24, 2016

Staff 4.2: Please provide the inputs and assumptions used in calculating the revenue requirements for all utility owned grid scale solar facilities.

Response: Please see attached **confidential** Excel spreadsheet APS15914.

	Paloma	Cotton Center	Hyder I	Chino Valley	Foothills 1	Foothills 2
In-Service Date	9/12/2011	10/24/2011	10/24/2011, 2/3/2012	11/26/2012	3/19/2013	10/15/2013
% of First Year After COD	30.1%	18.6%		9.3%	78.6%	21.1%
System Size (MW ac)	17	17	16	19	17	18
Plant In Service	65,990	82,272	75,837	90,569	78,387	61,229
Book Life (years)	30.0	30.0	30.0	30.0	30.0	30.0
O&M per kW	$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25
O&M Escalation %	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Property Tax Rate	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
Renewable Prop Tax Assess Ratio	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Prop Tax Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Composite Income Tax Rate	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
Fed Tax Basis Red	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
ITC	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Tax Depreciation	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS
Debt % of Capitalization	46.06%	46.06%	46.06%	46.06%	46.06%	46.06%
Equity % of Capitalization	53.94%	53.94%	53.94%	53.94%	53.94%	53.94%
LT Cost of Debt	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
Authorized ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Hyder II	Gila Bend	Luke AFB	Desert Star	Red Rock
11/1/2013	6/30/2014	6/29/2015	7/22/2015	1/1/2017
16.4%	50.4%	50.7%	44.4%	100.0%

14	32	10	10	40
60,892	107,086	35,103	31,534	94,700

30.0	30.0	30.0	30.0	30.0

$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25
3.0%	3.0%	3.0%	3.0%	3.0%

10.3%	10.3%	10.3%	10.3%	10.3%
20.0%	20.0%	20.0%	20.0%	20.0%
2.0%	2.0%	2.0%	2.0%	2.0%

39.22%	39.22%	39.22%	39.22%	39.22%
50.00%	50.00%	50.00%	50.00%	50.00%
30.00%	30.00%	30.00%	30.00%	30.00%
5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS

46.06%	46.06%	46.06%	46.06%	46.06%
53.94%	53.94%	53.94%	53.94%	53.94%
6.38%	6.38%	6.38%	6.38%	6.50%
10.00%	10.00%	10.00%	10.00%	10.00%

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DOCKET NO. E-00000J-14-0023
May 24, 2016

Staff 4.3: Please provide the weighted average for all existing PPAs, 2015-2025, for utility scale solar on a levelized and non-levelized basis.

Response: The below values are weighted by expected energy production for all of APS's existing solar photovoltaic PPAs for the years 2015-2025, and are derived from confidential data that is provided in Amended Staff Data Request 3.6. Please note that the below costs are not weighted based on in-service dates.

PPA levelized cost is 119.5 $/MWH

Non-levelized (annual) cost of PPAs

Year	$/MWH
2015	111.6
2016	113.4
2017	115.1
2018	116.9
2019	118.8
2020	120.7
2021	122.7
2022	124.8
2023	126.9
2024	129.1
2025	131.4

ARIZONA CORPORATION COMMISSION'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023

May 24, 2016

Staff 4.4: Please provide the weighted average for all existing utility owned grid scale solar facilities, 2015-2025, on a levelized and non-levelized basis.

Response: The below values are weighted by expected energy production for all of APS's utility owned grid scale solar photovolatic facilities for the years 2015-2025 including Red Rock, and are derived from the confidential data that is provided in Amended Staff Data Request 3.6. Please note that the below costs are not weighted based on in-service dates and are provided with and without the Arizona Production Tax Credit (PTC).

Levelized cost with PTC is 102.1 $/MWH, and without PTC is 109.9 $/MWH

Non-levelized (average) cost of APS Owned Solar

Year	w/ AZ PTC ($/MWH)	w/o AZ PTC ($/MWH)
2015	105.8	123.4
2016	107.7	123.5
2017	103.9	115.5
2018	101.3	112.1
2019	99.7	109.1
2020	99.3	106.3
2021	101.9	104.6
2022	102.5	102.5
2023	100.9	100.9
2024	99.3	99.3
2025	98.2	98.2

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DOCKET NO. E-00000J-14-0023
May 24, 2016

Staff 4.5: Please provide the combined weighted average for all existing PPAs for utility scale solar and grid scale solar facilities, 2015-2025, on a levelized and non-levelized basis.

Response: Using the information provided in Staff 4.3 and 4.4, below are the combined weighted average costs of APS's existing PPAs and APS owned utility scale solar photovoltaic facilities for the years 2015-2025. Costs are provided with and without the Arizona Production Tax Credit (PTC) for APS owned solar facilities.

Levelized cost of PPAs + APS Owned Solar is 106.2 $/MWH with PTC, and 112.1 $/MWH without PTC.

Non-levelized (annual) cost of PPAs + APS Owned Solar:

Year	w/ AZ PTC ($/MWH)	w/o AZ PTC ($/MWH)
2015	107.4	120.0
2016	109.2	120.8
2017	106.4	115.4
2018	104.8	113.2
2019	104.0	111.3
2020	104.1	109.5
2021	106.5	108.6
2022	107.5	107.5
2023	106.7	106.7
2024	105.9	105.9
2025	105.6	105.6

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Staff 4.6: Please indicate whether any utility owned facilities or PPAs for grid scale solar prior to 2010 were excluded from the calculation and why?

Response: APS did not exclude any grid-scale facilities, whether utility owned or third-party owned, prior to 2010 in its calculations.

5-5

aps

Kerri A. Carnes
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May 27, 2016

Maureen A. Scott
Senior Staff Counsel
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

RE: Value and Cost of Distributed Generation Generic Docket
Docket No. E-00000J-14-0023

Dear Ms. Scott:

Enclosed, please find Arizona Public Service Company's Amended Responses to 3.2(e) and 3.6 of Staff's Third Set of Data Requests, originally sent on May 12, 2016. Both Amended Responses contain highly confidential information and are being provided pursuant to a protective order in this matter.

If you have any questions, please contact me at (602)250-3341.

Sincerely,

Kerri A. Carnes

KC/ks
Attachment

cc: Matthew Laudone
Rick Lloyd

ARIZONA CORPORATION COMMISSION'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023
APRIL 22, 2016

Staff 3.2: Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g. The cost of kWh generated over the life of the facility.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

Response: This information is **highly confidential** and is being provided pursuant to an executed Protective Agreement.

a.- d., f., g. Please see attached document labeled APS15911 – Highly Confidential

e. Please see attached table labeled APS15899- Highly Confidential

h. Please see the attached PDF Agreements for AZ Sun

APS15909 Paloma – Highly Confidential
APS15902 Cotton Center- Highly Confidential
APS15906 Hyder 1- Highly Confidential
APS15900 Chino Valley- Highly Confidential
APS15903 Foothills- Highly Confidential
APS15907 Hyder II- Highly Confidential
APS15904 Gila Bend- Highly Confidential
APS 15901Desert Star- Highly Confidential
APS15908 Luke AFB- Highly Confidential

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Amended Response: This is an amended response to 3.2(e). Attached please find the **highly confidential** Excel spreadsheet APS15912, which is being provided to replace the previously provided APS15899. APS15912 has corrected the inadvertent use of an incorrect value and doubling counting of the production tax credit (PTC) for certain facilities.

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Staff 3.6: To the extent that cost differences exist between PPA's and utility ownership of utility scale solar, should the formula for export pricing of rooftop DG solar, be based on a combination of the costs to customers of PPA's and utility ownership and not solely on PPA's? Why not? Could that formula be based on a weighted average of the percentage of your utilities reliance upon PPA or ownership either historically or as per IRP or both?

Response: There are several ways in which the grid-scale adjusted methodology can be implemented. The discussion in APS witness Albert's testimony was based upon a prospective analysis and relied upon current pricing information publicly available in the market. This has the advantage of utilizing the most current market information and is likely to be the best way to estimate the current cost of implementing grid-scale solar PV. The methodology can also be based upon historical costs of grid-scale solar PV. This could include both PPAs and utility-owned systems. While this approach is based upon actual cost information, these historical costs are not indicative of the current cost of implementing grid-scale solar PV.

Nonetheless, a weighted average of grid-scale costs for third-party and utility owned projects could be used to establish a price for energy exported to the grid from rooftop solar facilities. To be comprehensive, a methodology using this approach could reasonably include several factors, including:

i. a graduated weighting system that places a greater emphasis on more recent announced or executed grid-scale solar prices;
ii. a rolling blended average of no more than five years, where in each subsequent year, the oldest year of data in that period would roll out of the calculation;
iii. refreshing the analysis each year to capture the most current available data and ensure that the price used in the calculation reflects current market conditions;
iv. utilizing data and pricing for photovoltaic solar panels, and excludes other types of solar technologies (e.g., concentrated solar or solar thermal projects);

v. in the event that the utility does not have any projects of recent vintage (for example – within the previous year), the methodology could consider utilizing pricing data from available industry sources for grid-scale solar PV projects with priority placed on projects within the state of Arizona to the extent available; and

vi. adjusting to recognize the value differences between grid-scale and the export portion of rooftop solar. This adjustment to recognize valuation differences such as generation capacity value and energy losses is more fully discussed in the direct testimony of Mr. Albert.

The attached **highly confidential** spreadsheet, labeled APS15910 – highly confidential, contains a "grid-scale weighted average" methodology that blends actual third-party and utility-owned grid-scale solar facilities. That provide solar energy to APS's customers. Depending on how each of the factors described above are addressed in establishing the methodology, APS would expect a range of results that could vary from approximately 7 to 12 cents/kWH based upon APS's current portfolio of grid-scale solar facilities.

The attached spreadsheet is set up to include several factors upon which the calculation methodology can be adjusted. For example, the spreadsheet has the capability to more heavily weigh the impact of recent projects, and limit the impact of projects installed further in the past. Similarly, the spreadsheet permits varying (i) the base year considered; (ii) the number of years included in the calculation; (iii) whether the Arizona Production Tax Credit (AZ PTC) is included in the calculations for APS-owned facilities; (iv) whether PPAs are levelized; (v) whether utility-owned projects are levelized or appear as they appear in revenue requirements; and (vi) whether to apply a 20% adjustment factor to account for the operational differences between grid-scale and rooftop solar, as described by Brad Albert.

Although APS prepared the attached spreadsheet at the request of Commission Staff, it does not necessarily endorse the outcome. APS continues to support the methodologies described in the filed testimony of Brad Albert.

Please note, APS is producing the attached spreadsheet electronically with all cells fully operational.

Amended Response: Attached please find the **highly confidential** Excel spreadsheet APS15913, which is being provided to replace the previously provided APS15910. APS15913 has been revised to include information on Red Rock in the calculation, and to correct an error in the revenue requirements for APS owned solar facilities with the AZ PTC.

ARIZONA CORPORATION COMMISSION'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
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APRIL 22, 2016

Staff 3.1: Please provide information on all utility-scale solar renewable PP As, with an effective date on or after January 1, 2008, including:

a. The effective date

b. Term of the PPA

c. Actual price per kWh to the utility and any other charges, by year for the life of the contract, and

d. Type(s) of renewable technology for each PPA.

e. Please also provide a copy of each PPA, including term sheet.

Response: This information is **highly confidential** and is being provided pursuant to an executed Protective Agreement.

a. – d. See attached tables labeled APS15898 – Highly Confidential

e. See attached PPAs – Highly Confidential
APS15891 Ajo– Highly Confidential
APS15892 Badger– Highly Confidential
APS15893 Bagdad – Highly Confidential
APS15894 Gillespie– Highly Confidential
APS15895 Prescott– Highly Confidential
APS15896 Saddle Mountain– Highly Confidential
APS15897 Solana– Highly Confidential

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Staff 3.2: Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g. The cost of kWh generated over the life of the facility.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

Response: This information is **highly confidential** and is being provided pursuant to an executed Protective Agreement.

a.- d., f., g. Please see attached document labeled APS15911 - Highly Confidential

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APS 15901Desert Star- Highly Confidential
APS15908 Luke AFB- Highly Confidential

not subject to cost overruns for costs associated with the development of projects under either structure. Regarding cost recovery, APS believes that utilities are appropriately limited to recovering only prudently incurred costs.

d. All of the PV solar PPAs APS has entered into have contract terms of 25 or 30 years. After that time, APS no longer has any rights to their output. At that time, the third-party can remarket the facility. And if APS must replace the gap left in its generation portfolio at that time, either to comply with the renewable energy standard or otherwise, APS will need to incur additional costs.

   By contrast, APS can continue to operate utility-owned facilities after their depreciable life. Indeed, during the depreciable lives, APS will be actively maintaining its facilities, which will increase the likelihood that they continue to produce energy after 30 years. After 30 years, the facilities will produce energy less efficiently, but the facilities will be fully depreciated and no longer be in customers' rates.

e. APS does not directly procure solar panels in either the PPA or utility ownership modes. APS does not perceive any significant difference between solar panels offered through a PPA structure versus solar panels included in a developer's proposal to APS through a utility ownership model. In each structure, the solar developer works directly with solar panel manufacturers.

f. APS does not have directly comparable PPA costs for any of its most recent utility-owned grid-scale projects. Recent utility-owned grid-scale projects have been competitively bid for selection of an EPC contractor to construct the project on sites that APS has already procured.

   For APS's first set of AZ Sun projects, which were bid approximately six years ago, PPA bids were also accepted. APS did not retain any formal benchmarking data. An evaluation of those bids confirmed that the lifetime costs of utility-owned grid-scale projects were modestly lower than the PPA options available at the time.

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Staff 3.3: Please explain the decision criteria you have and will rely upon for deciding whether to rely on a PPA or utility ownership for utility scale solar. If one decision criteria includes cost comparisons, please provide an explanation, formula and example of comparison between PPA and utility ownership. If that formula is from a perspective other than the customers' revenue requirements, please explain why.

Response: The decision of whether to procure third-party owned, or utility-owned, grid-scale solar generation has not been driven by a head-to-head comparison, but more by the advisability of relying on a balanced portfolio to meet resource needs. Under both, projects are only selected after a competitive bidding process that ensures the lowest available cost at the time of the project. Further, given that the grid-scale solar developers building both third-party and utility-owned projects have similar cost structures, and utilities often have relatively inexpensive financing costs, utility-owned projects are cost-competitive with third-party owned projects.

Finally, utility-owned projects offer additional advantages beyond third-party owned projects, including: (i) PPAs are treated as imputed debt on utility balance sheets, increasing utilities' FFO to debt ratio and potentially requiring additional equity; and (ii) after the typical PPA term of 25-30 years, APS no longer has any rights to the energy produced, whereas utility-owned projects continue to produce energy for the benefit of customers even after they are fully depreciated.

Neither third-party nor utility-owned projects are demonstrably better than the other. Instead, it is appropriate to obtain a balanced portfolio of both. Currently, APS has 324.5 MWs of third-party owned and 170 MWs of utility-owned grid-scale solar facilities.

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Staff 3.4: Given the utilities' support for reliance upon PPA data for utility scale solar as a basis for pricing export for rooftop DG solar, please explain whether the utility is willing to apply the same criteria to its utility ownership decision process for utility scale solar. If not, why not apply the same criteria? Is the utility supportive of applying this criteria uniformly if the PPA concept is embraced as the benchmark for solar evaluation?

Response: Please see the response to Staff 3.3. Paraphrasing the testimony of Staff witness Howard Solganick, many factors drive resource procurement decisions, including simple cost comparisons. Other factors include those identified in APS's response to Staff 3.3

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Staff 3.5: As regards the specific points of comparison between PPA's and utility ownership of utility scale solar which do or may lead to differences in cost comparisons, please address:

(To the extent these questions are general, please answer from the perspective of your utility's actual experience and practices.)

a. Any differences in amount and timing of revenue requirements to customers given PPA's recovery in PPFAC's and utility ownership following a revenue requirements formula? For the same resource, is the PPA less costly initially due to typical reliance upon levelized pricing; whereas utility ownership prices are initially higher and subsequently lower under the revenue requirements formula?

b. Please explain the differences between tax efficiency of utilization of related investment tax credits between PPA vendors and utility ownership?

c. Please explain the differences between treatment of cost overruns, if any, between PPA's and utility ownership? Are PPA's typically not compensated for actual costs in excess of contract, but utilities typically request recovery of costs over budget in rate cases? Do utilities support limiting cost recovery in rate cases to budgets?

d. Please explain differences between duration of PPA's versus useful life depreciation for owned assets? Are PPA's typically for less than the useful asset life such that vendors do not include all costs in the initial contract but plan on cost recovery in follow-on contracts?

e. Please explain whether the procurement of panels from suppliers is different in PPA's versus utility ownership? Are PPA's typically sourced from vendors purchasing solar panels in high volumes at greater economies of scale than from a utility?

f. To the extent available and for each existing utility owned utility scale solar, please provide the contemporaneous comparable PPA benchmarks known to the utility.

Response: a. The revenue requirements pattern over the life of a utility-owned PV solar facility is highest in the early years of the facility's life before the facility has incurred much depreciation. The revenue requirements decline to much lower levels in the later years of the facility's life as the investment in plant and equipment gets fully depreciated. In contrast, the typical PPA procured by APS exhibits a constant fixed price for the life of the contract or an initial price with an annual escalation feature resembling a general inflation rate. In either case, the net present value of the annual revenue requirements for utility-owned facilities has been comparable to or modestly lower than 3rd-party PPAs.

b. APS can claim a federal investment tax credit ("ITC") of 30% of the tax basis of the associated facility on its income tax return. This ITC is subject to the normalization rules of the Internal Revenue Code and related regulations, which provide the utility and its ratepayers a levelized sharing of the benefits of the investment tax credit as either:
    a. a rate base reduction, which must be restored no less rapidly than ratably, based upon the regulatory depreciable life of the associated facility; or
    b. a cost of service reduction (through ratemaking income tax expense), which amortizes the benefit of the investment tax credit no more rapidly than ratably, over the depreciable life of the property.

   Through this levelized sharing, the benefits of the investment tax credit are realized by both current and future ratepayers.

   PPA vendors are not subject to the normalization rules. APS cannot discuss, however, whether or how ITC benefits received by third-party PPA developers flow through to customers. Furthermore, when considering solar ownership versus a PPA, APS has found that any net present value benefit that may result from a lower PPA price in initial years is generally offset by the value that a utility owned solar project is expected to have after the term of a 25-30 year PPA expires. As discussed in Staff 3.3 and 3.5 (d), the utility-owned project continues to produce energy for the benefit of customers even after fully depreciated versus the replacement cost of power necessary when a 25-30 year PPA arrangement terminates.

c. APS procures power based upon fixed price commitments from utility scale solar developers for both the PPA structure and under the utility ownership model. As a result, APS is

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Staff 3.6: To the extent that cost differences exist between PPA's and utility ownership of utility scale solar, should the formula for export pricing of rooftop DG solar, be based on a combination of the costs to customers of PPA's and utility ownership and not solely on PPA's? Why not? Could that formula be based on a weighted average of the percentage of your utilities reliance upon PPA or ownership either historically or as per IRP or both?

Response: There are several ways in which the grid-scale adjusted methodology can be implemented. The discussion in APS witness Albert's testimony was based upon a prospective analysis and relied upon current pricing information publicly available in the market. This has the advantage of utilizing the most current market information and is likely to be the best way to estimate the current cost of implementing grid-scale solar PV. The methodology can also be based upon historical costs of grid-scale solar PV. This could include both PPAs and utility-owned systems. While this approach is based upon actual cost information, these historical costs are not indicative of the current cost of implementing grid-scale solar PV.

Nonetheless, a weighted average of grid-scale costs for third-party and utility owned projects could be used to establish a price for energy exported to the grid from rooftop solar facilities. To be comprehensive, a methodology using this approach could reasonably include several factors, including:

i. a graduated weighting system that places a greater emphasis on more recent announced or executed grid-scale solar prices;
ii. a rolling blended average of no more than five years, where in each subsequent year, the oldest year of data in that period would roll out of the calculation;
iii. refreshing the analysis each year to capture the most current available data and ensure that the price used in the calculation reflects current market conditions;
iv. utilizing data and pricing for photovoltaic solar panels, and excludes other types of solar technologies (e.g., concentrated solar or solar thermal projects);

v. in the event that the utility does not have any projects of recent vintage (for example – within the previous year), the methodology could consider utilizing pricing data from available industry sources for grid-scale solar PV projects with priority placed on projects within the state of Arizona to the extent available; and

vi. adjusting to recognize the value differences between grid-scale and the export portion of rooftop solar. This adjustment to recognize valuation differences such as generation capacity value and energy losses is more fully discussed in the direct testimony of Mr. Albert.

The attached **highly confidential** spreadsheet, labeled APS15910 – highly confidential, contains a "grid-scale weighted average" methodology that blends actual third-party and utility-owned grid-scale solar facilities. That provide solar energy to APS's customers. Depending on how each of the factors described above are addressed in establishing the methodology, APS would expect a range of results that could vary from approximately 7 to 12 cents/kWH based upon APS's current portfolio of grid-scale solar facilities.

The attached spreadsheet is set up to include several factors upon which the calculation methodology can be adjusted. For example, the spreadsheet has the capability to more heavily weigh the impact of recent projects, and limit the impact of projects installed further in the past. Similarly, the spreadsheet permits varying (i) the base year considered; (ii) the number of years included in the calculation; (iii) whether the Arizona Production Tax Credit (AZ PTC) is included in the calculations for APS-owned facilities; (iv) whether PPAs are levelized; (v) whether utility-owned projects are levelized or appear as they appear in revenue requirements; and (vi) whether to apply a 20% adjustment factor to account for the operational differences between grid-scale and rooftop solar, as described by Brad Albert.

Although APS prepared the attached spreadsheet at the request of Commission Staff, it does not necessarily endorse the outcome. APS continues to support the methodologies described in the filed testimony of Brad Albert.

Please note, APS is producing the attached spreadsheet electronically with all cells fully operational.

Highly Confidential

Facility	(a) Date Construction Began	(b) Date Facility Began Generating Electricity (Commercial Operation Date)	(c) Life Expectancy of Facility	(d) Type(s) of Renewable Technology at Facility	(e) Total Revenue Requirement by year for Depreciable life	(f) Total Cost of Facility ($000)	(g) Cost of kWh Generated Over Life of Facility ($/kWh)
Paloma	5/16/2011	9/21/2011	30 years[1]	Photovoltaic	Please See Attached APS15899	Total Cost: $68,620 Capacity (MW): 17 Cost per MW: $4.04	Levelized Cost: $0.118
Cotton Center	12/30/2010	10/23/2011	30 years[1]	Photovoltaic	Please See Attached APS15899	Total Cost: $83,858 Capacity (MW): 17 Cost per MW: $4.93	Levelized Cost: $0.127
Hyder I	6/1/2011	PH1 11/11/2011 PH2 2/3/2012	30 years[1]	Photovoltaic	Please See Attached APS15899	Total Cost: $76,025 Capacity (MW): 16 Cost per MW: $4.75	Levelized Cost: $0.114
Chino Valley	2/10/2012	10/26/2012	30 years[1]	Photovoltaic	Please See Attached APS15899	Total Cost: $90,863 Capacity (MW): 19 Cost per MW: $4.78	Levelized Cost: $0.129
Foothills	8/2/2012	PH1 3/18/2013 PH2 11/8/2013	30 years[1]	Photovoltaic	Please See Attached APS15899	Total Cost: $139,916 Capacity (MW): 35 Cost per MW: $4.00	Levelized Cost: $0.094

[1] *See responses to* Staff 3.3 and 3.5 (d)

					Highly Confidential		
Facility	**(a) Date Construction Began**	**(b) Date Facility Began Generating Electricity (Commercial Operation Date)**	**(c) Life Expectancy of Facility**	**(d) Type(s) of Renewable Technology at Facility**	**(e) Total Revenue Requirement by year for Depreciable life**	**(f) Total Cost of Facility ($000)**	**(g) Cost of kWh Generated Over Life of Facility ($/kWh)**
Hyder II	4/1/2013	11/3/2013	30 years[2]	Photovoltaic	Please See Attached APS15899	Total Cost: $55,804 Capacity (MW): 14 Cost per MW: 3.99	Levelized Cost: $0.110
Gila Bend	8/26/2013	6/2/2014	30 years[2]	Photovoltaic	Please See Attached APS15899	Total Cost: $110,648 Capacity (MW): 32 Cost per MW: $3.46	Levelized Cost: $0.089
Desert Star	1/9/2015	7/28/2015	30 years[2]	Photovoltaic	Please See Attached APS15899	Total Cost: $31,940 Capacity (MW): 10 Cost per MW: $3.19	Levelized Cost: $0.075
Luke AFB	1/16/2015	6/30/2015	30 years[2]	Photovoltaic	Please See Attached APS15899	Total Cost: $32,349 Capacity (MW): 10 Cost per MW: $3.23	Levelized Cost: $0.087

[2] *See responses to* Staff 3.3 and 3.5 (d)

Amended Response to Staff Data Request 3.2 (e)

Annual Revenue Requirement ($000)

					Highly Confidential			
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Paloma	2,550.2	8,141.9	4,901.8	4,271.3	4,274.3	4,842.7	4,827.0	4,799.1
Cotton Center	1,706.0	9,940.3	6,008.3	5,170.1	5,183.3	5,995.3	5,960.2	5,911.6
Hyder I	1,174.8	8,364.9	5,334.9	3,801.6	3,752.0	4,207.8	4,251.2	4,284.3
Chino Valley	-	1,078.2	9,500.8	6,108.4	6,656.8	6,161.2	6,061.9	6,043.5
Foothills	-	-	7,286.6	12,772.4	11,030.8	10,668.5	10,316.0	10,100.5
Hyder II	-	-	843.2	5,482.2	4,987.4	5,721.2	5,495.2	5,336.5
Gila Bend	-	-	-	7,510.0	10,157.5	10,795.7	10,404.2	10,013.4
Luke AFB	-	-	-	-	1,894.6	3,493.8	3,474.3	3,344.0
Desert Star	-	-	-	-	1,689.2	2,996.4	2,976.8	2,861.0

Annual Production (MWH)

					Highly Confidential			
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Paloma	13,577	42,843	41,614	41,177	40,889	40,734	40,318	40,036
Cotton Center	13,447	46,172	43,658	45,485	45,394	45,442	45,213	45,122
Hyder I	3,111	39,252	41,701	40,466	40,264	40,181	39,862	39,663
Chino Valley	-	6,292	49,479	47,983	47,743	47,504	47,267	47,030
Foothills	-	-	61,094	112,041	111,480	111,272	110,368	109,816
Hyder II	-	-	5,299	45,941	45,941	45,619	45,255	45,029
Gila Bend	-	-	-	50,448	108,426	108,225	107,344	106,808
Luke AFB	-	-	-	-	16,527	34,879	34,603	34,430
Desert Star	-	-	-	-	13,110	35,562	35,283	35,106

Amended Response to Staff Data Request 3.

Annual Revenue Requirement ($000)

	2019	2020	2021	2022	2023	2024	Highly Confidentional 2025	2026
Paloma	4,819.5	4,918.2	5,157.3	5,271.5	5,177.6	5,084.1	4,991.1	4,898.6
Cotton Center	5,916.2	6,006.8	6,251.9	6,359.6	6,238.2	6,117.2	5,996.7	5,876.7
Hyder I	4,418.7	4,716.7	5,309.2	5,639.0	5,531.1	5,423.6	5,316.5	5,209.9
Chino Valley	6,107.5	6,304.8	6,741.8	6,965.1	6,832.7	6,700.7	6,569.2	6,438.3
Foothills	10,135.4	10,334.4	10,828.1	11,059.4	10,860.8	10,655.6	10,451.2	10,247.6
Hyder II	5,245.2	5,154.2	5,063.5	4,973.2	4,883.2	4,793.5	4,704.2	4,615.3
Gila Bend	9,738.9	9,580.7	9,423.1	9,266.4	9,110.3	8,955.1	8,800.6	8,647.0
Luke AFB	3,214.0	3,121.7	3,067.2	3,012.8	2,958.7	2,904.8	2,851.1	2,797.7
Desert Star	2,745.4	2,666.1	2,623.1	2,580.4	2,537.9	2,495.7	2,453.7	2,411.9

Annual Production (MWH)

	2019	2020	2021	2022	2023	2024	Highly Confidentional 2025	2026
Paloma	39,756	39,606	39,201	38,927	38,654	38,508	38,115	37,848
Cotton Center	45,032	45,080	44,852	44,762	44,673	44,720	44,494	44,405
Hyder I	39,464	39,383	39,071	38,875	38,681	38,602	38,295	38,104
Chino Valley	46,795	46,561	46,328	46,097	45,866	45,637	45,409	45,182
Foothills	109,267	109,064	108,177	107,637	107,098	106,899	106,030	105,500
Hyder II	44,804	44,713	44,357	44,135	43,914	43,825	43,476	43,259
Gila Bend	106,274	106,076	105,214	104,688	104,164	103,971	103,125	102,609
Luke AFB	34,258	34,187	33,916	33,747	33,578	33,508	33,243	33,077
Desert Star	34,931	34,856	34,582	34,409	34,237	34,164	33,896	33,726

Amended Response to Staff Data Request 3.

Annual Revenue Requirement ($000)

	2027	2028	2029	2030	2031	2032	2033	2034
Paloma	4,806.6	4,715.1	4,624.1	4,533.6	4,443.7	4,354.4	4,265.6	4,177.5
Cotton Center	5,757.2	5,638.1	5,519.6	5,401.7	5,284.3	5,167.4	5,051.2	4,935.5
Hyder I	5,103.8	4,998.1	4,892.9	4,788.3	4,684.1	4,580.5	4,477.4	4,374.8
Chino Valley	6,307.9	6,178.0	6,048.7	5,920.0	5,791.9	5,664.4	5,537.6	5,411.4
Foothills	10,044.9	9,850.8	9,649.8	9,449.9	9,250.8	9,052.8	8,863.8	8,667.9
Hyder II	4,526.7	4,438.6	4,350.8	4,263.5	4,176.6	4,090.1	4,004.1	3,918.6
Gila Bend	8,494.2	8,342.3	8,191.3	8,041.2	7,892.1	7,744.0	7,596.8	7,450.7
Luke AFB	2,744.6	2,691.7	2,639.1	2,586.8	2,534.7	2,483.0	2,431.6	2,380.5
Desert Star	2,370.4	2,329.1	2,288.2	2,247.5	2,207.1	2,167.0	2,127.2	2,087.7

Annual Production (MWH)

	2027	2028	2029	2030	2031	2032	2033	2034
Paloma	37,583	37,441	37,059	36,799	36,542	36,404	36,032	35,780
Cotton Center	44,316	44,364	44,139	44,051	43,963	44,010	43,787	43,700
Hyder I	37,913	37,835	37,535	37,347	37,160	37,084	36,790	36,606
Chino Valley	44,956	44,731	44,507	44,285	44,063	43,843	43,624	43,406
Foothills	104,972	104,777	103,925	103,406	102,889	102,697	101,862	101,353
Hyder II	43,043	42,956	42,613	42,400	42,188	42,103	41,767	41,559
Gila Bend	102,096	101,907	101,078	100,573	100,070	99,884	99,072	98,576
Luke AFB	32,911	32,843	32,583	32,420	32,258	32,191	31,936	31,777
Desert Star	33,558	33,486	33,223	33,057	32,821	32,821	32,563	32,401

Amended Response to Staff Data Request 3.

Annual Revenue Requirement ($000)	Highly Confidential							
	2035	2036	2037	2038	2039	2040	2041	2042
Paloma	4,090.0	4,003.1	3,916.9	3,831.4	3,746.5	3,662.4	2,538.5	-
Cotton Center	4,820.5	4,706.1	4,592.4	4,479.4	4,367.0	4,255.4	3,350.0	-
Hyder I	4,272.9	4,171.6	4,070.8	3,970.7	3,871.3	3,772.5	3,158.2	71.3
Chino Valley	5,285.9	5,161.0	5,036.9	4,913.6	4,791.0	4,669.1	4,548.1	3,679.9
Foothills	8,473.0	8,279.3	8,086.7	7,903.7	7,713.5	7,524.5	7,336.9	7,150.6
Hyder II	3,833.6	3,749.0	3,665.0	3,581.5	3,498.5	3,416.1	3,334.3	3,253.0
Gila Bend	7,305.7	7,161.8	7,019.0	6,877.4	6,737.0	6,597.9	6,460.0	6,323.4
Luke AFB	2,329.7	2,279.2	2,229.1	2,179.4	2,130.0	2,081.0	2,032.3	1,984.1
Desert Star	2,048.6	2,009.8	1,971.3	1,933.2	1,895.4	1,858.1	1,821.1	1,784.5

Annual Production (MWH)	Highly Confidential							
	2035	2036	2037	2038	2039	2040	2041	2042
Paloma	35,529	35,351	35,175	34,999	34,824	34,650	22,984	-
Cotton Center	43,612	43,394	43,177	42,961	42,746	42,533	31,740	-
Hyder I	36,423	36,241	36,060	35,879	35,700	35,521	35,344	2,931
Chino Valley	43,189	42,973	42,758	42,544	42,332	42,120	41,909	34,750
Foothills	100,846	100,342	99,840	99,341	98,844	98,350	97,858	97,369
Hyder II	41,351	41,144	40,939	40,734	40,530	40,328	40,126	39,925
Gila Bend	98,083	97,593	97,105	96,619	96,136	95,655	95,177	94,701
Luke AFB	31,618	31,460	31,303	31,146	30,990	30,835	30,681	30,528
Desert Star	32,239	32,078	31,917	31,758	31,599	31,441	31,284	31,127

Amended Response to Staff Data Request 3.

Annual Revenue Requirement ($000)	Highly Confidential 2043	2044	2045	2046
Paloma	-	-	-	-
Cotton Center	-	-	-	-
Hyder I	-	-	-	-
Chino Valley	-	-	-	-
Foothills	4,234.4	-	-	-
Hyder II	2,632.2	-	-	-
Gila Bend	6,188.2	2,983.8	-	-
Luke AFB	1,936.3	1,888.9	912.6	-
Desert Star	1,748.3	1,712.6	932.1	-

Annual Production (MWH)	Highly Confidential 2043	2044	2045	2046
Paloma	-	-	-	-
Cotton Center	-	-	-	-
Hyder I	-	-	-	-
Chino Valley	-	-	-	-
Foothills	16,147	-	-	-
Hyder II	33,105	-	-	-
Gila Bend	94,228	39,065	-	-
Luke AFB	30,375	30,223	12,530	-
Desert Star	30,972	30,817	15,331	-

AZ Sun Revenue Requirements Detail by Proj
($000)

Confidential

Line		Actual 2011	2012	2013	2014	2015
	Revenue recognized for AZ Sun - Paloma					
	Return on rate base:					
6	Plant in service	68,571	68,031	66,617	66,617	66,617
7	Accumulated depr	537	2,686	4,815	6,943	9,072
8	Net plant in service (line 6 - line7)	68,034	65,345	61,802	59,674	57,545
9	Accumulated def inc tax - depr	(20,586)	(20,365)	(19,109)	(19,116)	(18,771)
10	Accumulated def ITC	(18,456)	(19,275)	(19,275)	(17,133)	(16,545)
11	Deferred inc tax carryforward - depr	13,849	-	-	-	-
12	Deferred ITC carryforward	18,456	7,452	-	-	-
13	Net rate base (sum of lines 8 through 12)	61,296	33,157	23,418	23,424	22,230
14	Embedded cost of equity capital rate (10% * .5394)	5.92%	5.39%	5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)	852	2,907	1,391	1,209	1,216
16	Embedded cost of debt rate (6.38% * .4606)	2.67%	2.94%	2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)	384	1,414	758	659	663
18	Total return (line 15 + line 17)	1,236	4,321	2,149	1,868	1,879
19	Depreciation expense	537	2,149	2,128	2,128	2,128
20	O&M	34	352	307	160	149
21	Property taxes	-	-	159	162	161
	Income tax expense					
22	Equity return (equity return * .395)	336	1,148	550	478	480

23	Production tax credit net of federal tax	43	(619)	(619)	(619)	(619)
24	Depr - ITC basis reduction and AFUDC	71	270	165	112	112
25	Total (sum of lines 22 through 24)	450	799	95	(29)	(26)
26	Gross up factor (1/.605)	1.653	1.653	1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)	744	1,320	157	(48)	(43)
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21	2,550	8,142	4,902	4,271	4,274

Confidential

Revenue recognized for AZ Sun - Cotton Center

		Actual				
		2011	**2012**	**2013**	**2014**	**2015**
	Return on rate base:					
6	Plant in service	83,166	81,627	81,377	81,377	81,377
7	Accumulated depr	458	3,094	5,728	8,362	10,995
8	Net plant in service (line 6 - line7)	82,708	78,533	75,649	73,016	70,382
9	Accumulated def inc tax - depr	(24,837)	(24,827)	(23,832)	(23,828)	(23,376)
10	Accumulated def ITC	(23,824)	(23,720)	(23,720)	(21,216)	(20,425)
11	Deferred inc tax carryforward - depr	16,941	-	-	-	-
12	Deferred ITC carryforward	23,824	9,170	-	-	-
13	Net rate base (sum of lines 8 through 12)	74,812	39,156	28,098	27,971	26,580
14	Embedded cost of equity capital rate (10% * .5394)	5.92%	5.39%	5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)	775	3,547	1,673	1,448	1,454
16	Embedded cost of debt rate (6.38% * .4606)	2.67%	2.94%	2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)	349	1,725	911	789	792
18	Total return (line 15 + line 17)	1,125	5,272	2,584	2,237	2,246
19	Depreciation expense	458	2,636	2,634	2,634	2,634
20	O&M	13	275	287	50	48
21	Property taxes	-	-	202	201	205

	Income tax expense					
22	Equity return (equity return * .395)	306	1,401	661	572	574
23	Production tax credit net of federal tax	(300)	(681)	(681)	(681)	(681)
24	Depr - ITC basis reduction and AFUDC	61	343	203	138	138
25	Total (sum of lines 22 through 24)	67	1,063	182	29	31
26	Gross up factor (1/.605)	1.653	1.653	1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)	111	1,757	301	48	52
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21	1,706	9,940	6,008	5,170	5,183

Confidential

Revenue recognized for AZ Sun - Hyder I

		Actual				
		2011	**2012**	**2013**	**2014**	**2015**
	Return on rate base:					
6	Plant in service	61,499	76,009	74,178	74,178	74,178
7	Accumulated depr	234	2,584	4,978	7,372	9,770
8	Net plant in service (line 6 - line7)	61,265	73,426	69,200	66,806	64,408
9	Accumulated def inc tax - depr	(18,748)	(18,851)	(20,940)	(21,222)	(21,040)
10	Accumulated def ITC	(15,073)	(17,598)	(21,270)	(19,056)	(18,357)
11	Deferred inc tax carryforward - depr	12,789	-	-	-	-
12	Deferred ITC carryforward	15,073	6,803	264	-	-
13	Net rate base (sum of lines 8 through 12)	55,305	43,780	27,254	26,529	25,012
14	Embedded cost of equity capital rate (10% * .5394)	5.92%	5.39%	5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)	480	3,339	1,781	1,387	1,370
16	Embedded cost of debt rate (6.38% * .4606)	2.67%	2.94%	2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)	216	1,633	970	756	746
18	Total return (line 15 + line 17)	696	4,972	2,751	2,143	2,116
19	Depreciation expense	234	2,350	2,394	2,394	2,398

20	O&M	-	204	241	57	55
21	Property taxes	-	-	275	284	270
	Income tax expense					
22	Equity return (equity return * .395)	189	1,319	703	548	541
23	Production tax credit net of federal tax	(80)	(1,039)	(1,082)	(1,323)	(1,323)
24	Depr - ITC basis reduction and AFUDC	39	228	182	124	124
25	Total (sum of lines 22 through 24)	148	508	(197)	(651)	(658)
26	Gross up factor (1/.605)	1.653	1.653	1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)	245	840	(325)	(1,076)	(1,087)
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21	1,175	8,365	5,335	3,802	3,752

Confidential

Revenue recognized for AZ Sun - Chino Valley

		Actual				
		2011	2012	2013	2014	2015
	Return on rate base:					
6	Plant in service		90,710	90,659	90,657	90,657
7	Accumulated depr		251	3,123	5,953	8,783
8	Net plant in service (line 6 - line7)		90,458	87,536	84,703	81,874
9	Accumulated def inc tax - depr		(18,721)	(22,154)	(24,238)	(25,003)
10	Accumulated def ITC		-	(25,293)	(23,537)	(22,694)
11	Deferred inc tax carryforward - depr		-	-	-	-
12	Deferred ITC carryforward		-	25,293	-	-
13	Net rate base (sum of lines 8 through 12)		71,737	65,382	36,928	34,177
14	Embedded cost of equity capital rate (10% * .5394)		5.39%	5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)		376	3,704	2,031	1,876
16	Embedded cost of debt rate (6.38% * .4606)		2.94%	2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)		205	2,018	1,106	1,022
18	Total return (line 15 + line 17)		581	5,722	3,137	2,899

		2012	2013	2014	2015
19	Depreciation expense	251	2,872	2,830	2,830
20	O&M	-	339	342	449
21	Property taxes	-	-	-	777
	Income tax expense				
22	Equity return (equity return * .395)	149	1,463	802	741
23	Production tax credit net of federal tax	-	(1,286)	(1,071)	(1,069)
24	Depr - ITC basis reduction and AFUDC	-	166	148	148
25	Total (sum of lines 22 through 24)	149	343	(122)	(180)
26	Gross up factor (1/.605)	1.653	1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)	246	567	(201)	(298)
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)	1,078	9,501	6,108	6,657

Confidential

Revenue recognized for AZ Sun - Foothills I

		Actual				
	Return on rate base:	2011	2012	2013	2014	2015
6	Plant in service			78,510	78,378	78,378
7	Accumulated depr			1,928	4,476	7,023
8	Net plant in service (line 6 - line7)			76,582	73,902	71,355
9	Accumulated def inc tax - depr			(15,440)	(18,494)	(20,226)
10	Accumulated def ITC			(21,673)	(20,435)	(19,687)
11	Deferred inc tax carryforward - depr			-	-	-
12	Deferred ITC carryforward			21,673	-	-
13	Net rate base (sum of lines 8 through 12)			61,142	34,973	31,442
14	Embedded cost of equity capital rate (10% * .5394)			5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)			2,841	2,323	1,735

16	Embedded cost of debt rate (6.38% * .4606)	2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)	1,548	1,265	945
18	Total return (line 15 + line 17)	4,389	3,588	2,680
19	Depreciation expense	1,928	2,548	2,547
20	O&M	250	867	810
21	Property taxes	-	-	296
	Income tax expense			
22	Equity return (equity return * .395)	1,122	917	685
23	Production tax credit net of federal tax	(1,300)	(1,300)	(1,300)
24	Depr - ITC basis reduction and AFUDC	107	124	127
25	Total (sum of lines 22 through 24)	(71)	(258)	(488)
26	Gross up factor (1/.605)	1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)	(117)	(427)	(807)
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)	6,450	6,576	5,526

Confidential

Revenue recognized for AZ Sun - Foothills II

		Actual				
		2011	2012	2013	2014	2015
	Return on rate base:					
6	Plant in service			59,828	61,326	61,343
7	Accumulated depr			164	2,182	4,205
8	Net plant in service (line 6 - line7)			59,663	59,143	57,138
9	Accumulated def inc tax - depr			(12,357)	(14,970)	(16,393)
10	Accumulated def ITC			(15,247)	(15,940)	(14,927)
11	Deferred inc tax carryforward - depr			-	-	-
12	Deferred ITC carryforward			-	-	-

Line	Description	2011	2012	2013	2014	2015
13	Net rate base (sum of lines 8 through 12)			32,060	28,233	25,819
14	Embedded cost of equity capital rate (10% * .5394)			5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)			300	1,830	1,405
16	Embedded cost of debt rate (6.38% * .4606)			2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)			164	997	766
18	Total return (line 15 + line 17)			464	2,827	2,171
19	Depreciation expense			164	2,018	2,023
20	O&M			-	-	-
21	Property taxes			-	-	234
	Income tax expense					
22	Equity return (equity return * .395)			119	723	555
23	Production tax credit net of federal tax			-	-	-
24	Depr - ITC basis reduction and AFUDC			7	95	96
25	Total (sum of lines 22 through 24)			126	817	651
26	Gross up factor (1/.605)			1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)			208	1,351	1,077
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)			837	6,196	5,504

Confidential

Revenue recognized for AZ Sun - Hyder II

Line	Description	2011	2012	2013	2014	2015
		Actual				
	Return on rate base:					
6	Plant in service			55,804	54,820	54,820
7	Accumulated depr			161	1,862	3,557
8	Net plant in service (line 6 - line7)			55,642	52,959	51,263
9	Accumulated def inc tax - depr			(11,352)	(13,369)	(14,633)

		2011	2012	2013	2014	2015
10	Accumulated def ITC			(15,886)	(14,273)	(13,780)
11	Deferred inc tax carryforward - depr			-	-	-
12	Deferred ITC carryforward			-	-	-
13	Net rate base (sum of lines 8 through 12)			28,404	25,317	22,850
14	Embedded cost of equity capital rate (10% * .5394)			5.39%	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)			304	1,634	1,260
16	Embedded cost of debt rate (6.38% * .4606)			2.94%	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)			166	890	686
18	Total return (line 15 + line 17)			470	2,524	1,946
19	Depreciation expense			161	1,700	1,695
20	O&M			-	44	151
21	Property taxes			-	-	230
	Income tax expense					
22	Equity return (equity return * .395)			120	645	498
23	Production tax credit net of federal tax			-	-	-
24	Depr - ITC basis reduction and AFUDC			8	89	86
25	Total (sum of lines 22 through 24)			128	734	584
26	Gross up factor (1/.605)			1.653	1.653	1.653
27	Total income tax expense (line 25 * line 26)			212	1,214	965
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21	-	-	843	5,482	4,987

Confidential

Revenue recognized for AZ Sun - Gila Bend

		Actual				
		2011	**2012**	**2013**	**2014**	**2015**
	Return on rate base:					
6	Plant in service				110,387	110,404

7	Accumulated depr	2,062	5,571
8	Net plant in service (line 6 - line7)	108,325	104,833
9	Accumulated def inc tax - depr	(20,292)	(22,817)
10	Accumulated def ITC	(30,464)	(29,231)
11	Deferred inc tax carryforward - depr	-	-
12	Deferred ITC carryforward	-	-
13	Net rate base (sum of lines 8 through 12)	57,569	52,786
14	Embedded cost of equity capital rate (10% * .5394)	5.39%	5.39%
15	Equity return (line 13 * line 14 / 12)	2,396	2,741
16	Embedded cost of debt rate (6.38% * .4606)	2.94%	2.94%
17	Debt return (line 13 * line 16 / 12)	1,306	1,493
18	Total return (line 15 + line 17)	3,702	4,234
19	Depreciation expense	2,062	3,509
20	O&M	7	320
21	Property taxes	-	-
	Income tax expense		
22	Equity return (equity return * .395)	947	1,083
23	Production tax credit net of federal tax	-	-
24	Depr - ITC basis reduction and AFUDC	106	184
25	Total (sum of lines 22 through 24)	1,052	1,267
26	Gross up factor (1/.605)	1.653	1.653
27	Total income tax expense (line 25 * line 26)	1,739	2,094
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)	7,510	10,158

Revenue recognized for AZ Sun - Luke AFB

		Actual				
		2011	2012	2013	2014	2015
	Return on rate base:					
6	Plant in service					32,349
7	Accumulated depr					400
8	Net plant in service (line 6 - line7)					31,949
9	Accumulated def inc tax - depr					(6,199)
10	Accumulated def ITC					(9,211)
11	Deferred inc tax carryforward - depr					-
12	Deferred ITC carryforward					-
13	Net rate base (sum of lines 8 through 12)					16,539
14	Embedded cost of equity capital rate (10% * .5394)					5.39%
15	Equity return (line 13 * line 14 / 12)					643
16	Embedded cost of debt rate (6.38% * .4606)					2.94%
17	Debt return (line 13 * line 16 / 12)					350
18	Total return (line 15 + line 17)					993
19	Depreciation expense					400
20	O&M					51
21	Property taxes					-
	Income tax expense					
22	Equity return (equity return * .395)					254
23	Production tax credit net of federal tax					-
24	Depr - ITC basis reduction and AFUDC					18
25	Total (sum of lines 22 through 24)					272
26	Gross up factor (1/.605)					1.653
27	Total income tax expense (line 25 * line 26)					450

28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)					1,895

Confidential

	Revenue recognized for AZ Sun - Desert Star	Actual				
	Return on rate base:	**2011**	**2012**	**2013**	**2014**	**2015**
6	Plant in service					31,837
7	Accumulated depr					436
8	Net plant in service (line 6 - line7)					31,401
9	Accumulated def inc tax - depr					(6,105)
10	Accumulated def ITC					(8,808)
11	Deferred inc tax carryforward - depr					-
12	Deferred ITC carryforward					-
13	Net rate base (sum of lines 8 through 12)					16,488
14	Embedded cost of equity capital rate (10% * .5394)					5.39%
15	Equity return (line 13 * line 14 / 12)					536
16	Embedded cost of debt rate (6.38% * .4606)					2.94%
17	Debt return (line 13 * line 16 / 12)					292
18	Total return (line 15 + line 17)					828
19	Depreciation expense					436
20	O&M					47
21	Property taxes					-
	Income tax expense					
22	Equity return (equity return * .395)					212
23	Production tax credit net of federal tax					-
24	Depr - ITC basis reduction and AFUDC					17
25	Total (sum of lines 22 through 24)					229

26	Gross up factor (1/.605)	1.653
27	Total income tax expense (line 25 * line 26)	378
28	Total revenue (negative rev) recognized (sum of lines 18, 19, 20, 21, 27)	1,689

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Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031
11,661	13,861	16,061	18,260	20,460	22,660	24,859	27,059	29,259	31,458	33,658	35,858
56,370	54,170	51,971	49,771	47,571	45,372	43,172	40,972	38,773	36,573	34,373	32,174
(17,364)	(16,661)	(15,958)	(15,255)	(14,552)	(13,849)	(13,146)	(12,443)	(11,740)	(11,037)	(10,334)	(9,631)
(15,674)	(15,021)	(14,368)	(13,715)	(13,061)	(12,408)	(11,755)	(11,102)	(10,449)	(9,796)	(9,143)	(8,490)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
23,332	22,489	21,645	20,802	19,958	19,114	18,271	17,427	16,584	15,740	14,897	14,053
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,259	1,213	1,168	1,122	1,077	1,031	986	940	895	849	804	758
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
686	661	636	611	586	562	537	512	487	463	438	413
1,944	1,874	1,804	1,733	1,663	1,593	1,522	1,452	1,382	1,312	1,241	1,171
2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
419	431	444	458	471	485	500	515	531	546	563	580
240	232	223	214	205	196	187	178	169	160	151	143
497	479	461	443	425	407	389	371	353	335	317	299

(606)	(557)	(516)	(445)	(328)	(126)	-	-	-	-	-	-
132	132	132	132	132	132	132	132	132	132	132	132
24	55	78	130	229	413	522	504	486	468	450	432
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
40	90	129	215	379	683	862	833	803	773	743	714
4,843	4,827	4,799	4,820	4,918	5,157	5,271	5,178	5,084	4,991	4,899	4,807

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584
14,223	16,965	19,708	22,450	25,193	27,935	30,677	33,420	36,162	38,905	41,647	44,390
69,361	66,618	63,876	61,134	58,391	55,649	52,906	50,164	47,421	44,679	41,937	39,194
(21,840)	(20,960)	(20,080)	(19,200)	(18,320)	(17,439)	(16,559)	(15,679)	(14,799)	(13,919)	(13,039)	(12,158)
(19,324)	(18,519)	(17,714)	(16,909)	(16,104)	(15,298)	(14,493)	(13,688)	(12,883)	(12,078)	(11,273)	(10,467)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
28,196	27,139	26,082	25,025	23,968	22,911	21,854	20,797	19,740	18,683	17,626	16,568
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,521	1,464	1,407	1,350	1,293	1,236	1,179	1,122	1,065	1,008	951	894
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
829	798	766	735	704	673	642	611	580	549	518	487
2,349	2,261	2,173	2,085	1,997	1,909	1,821	1,733	1,645	1,557	1,469	1,381
2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742
419	431	444	458	471	485	500	515	531	546	563	580
300	289	278	267	255	244	233	222	211	200	189	178

601	578	556	533	511	488	466	443	421	398	376	353
(666)	(613)	(567)	(490)	(361)	(139)	-	-	-	-	-	-
177	177	177	177	177	177	177	177	177	177	177	177
112	143	166	220	327	527	643	621	598	575	553	530
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
185	236	274	364	540	871	1,063	1,026	988	951	914	877
5,995	5,960	5,912	5,916	6,007	6,252	6,360	6,238	6,117	5,997	5,877	5,757

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837
12,936	15,464	17,992	20,520	23,048	25,576	28,104	30,632	33,160	35,687	38,215	40,743
62,901	60,373	57,845	55,317	52,789	50,261	47,733	45,206	42,678	40,150	37,622	35,094
(20,644)	(19,941)	(19,107)	(18,272)	(17,437)	(16,602)	(15,768)	(14,933)	(14,098)	(13,263)	(12,428)	(11,594)
(18,166)	(17,415)	(16,664)	(15,913)	(15,162)	(14,410)	(13,659)	(12,908)	(12,157)	(11,405)	(10,654)	(9,903)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
24,091	23,016	22,074	21,132	20,191	19,249	18,307	17,365	16,423	15,481	14,539	13,597
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,299	1,241	1,191	1,140	1,089	1,038	987	937	886	835	784	733
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
708	676	649	621	593	566	538	510	483	455	427	400
2,007	1,918	1,839	1,761	1,682	1,604	1,525	1,447	1,368	1,290	1,211	1,133
2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528

391	402	414	427	440	453	466	480	495	510	525	541
278	268	258	248	237	227	217	207	196	186	176	166
513	490	470	450	430	410	390	370	350	330	310	290
(1,272)	(1,170)	(1,083)	(936)	(689)	(265)	-	-	-	-	-	-
156	156	156	156	156	156	156	156	156	156	156	156
(603)	(523)	(457)	(329)	(103)	301	546	526	506	486	466	446
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
(996)	(865)	(755)	(544)	(170)	498	902	869	836	803	770	737
4,208	4,251	4,284	4,419	4,717	5,309	5,639	5,531	5,424	5,317	5,210	5,104

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569
12,357	15,376	18,395	21,414	24,433	27,452	30,471	33,490	36,509	39,528	42,547	45,566
78,212	75,193	72,174	69,155	66,136	63,117	60,098	57,079	54,060	51,041	48,022	45,003
(24,761)	(24,632)	(23,644)	(22,657)	(21,669)	(20,681)	(19,693)	(18,706)	(17,718)	(16,730)	(15,742)	(14,754)
(22,223)	(21,334)	(20,445)	(19,556)	(18,667)	(17,778)	(16,889)	(16,000)	(15,111)	(14,223)	(13,334)	(12,445)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
31,228	29,227	28,084	26,942	25,800	24,658	23,515	22,373	21,231	20,089	18,946	17,804
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,684	1,576	1,515	1,453	1,392	1,330	1,268	1,207	1,145	1,084	1,022	960
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
918	859	825	792	758	725	691	657	624	590	557	523
2,602	2,435	2,340	2,245	2,150	2,055	1,959	1,864	1,769	1,674	1,579	1,484

3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019
454	468	482	497	511	527	543	559	576	593	611	629
373	360	346	333	320	306	293	280	266	253	240	226
665	623	598	574	550	525	501	477	452	428	404	379
(1,035)	(951)	(881)	(761)	(561)	(216)	-	-	-	-	-	-
195	195	195	195	195	195	195	195	195	195	195	195
(174)	(133)	(87)	8	184	505	696	672	648	623	599	575
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
(287)	(220)	(144)	14	305	835	1,151	1,111	1,071	1,030	990	950
6,161	6,062	6,043	6,108	6,305	6,742	6,965	6,833	6,701	6,569	6,438	6,308

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391
9,893	12,506	15,119	17,732	20,345	22,958	25,571	28,184	30,797	33,409	36,022	38,635
68,498	65,885	63,272	60,659	58,046	55,433	52,820	50,207	47,594	44,982	42,369	39,756
(20,177)	(20,809)	(20,698)	(19,844)	(18,990)	(18,137)	(17,283)	(16,429)	(15,575)	(14,722)	(13,868)	(13,014)
(19,976)	(19,208)	(18,440)	(17,671)	(16,903)	(16,135)	(15,366)	(14,598)	(13,830)	(13,061)	(12,293)	(11,525)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
28,344	25,868	24,134	23,143	22,153	21,162	20,171	19,180	18,189	17,198	16,208	15,217
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,529	1,395	1,302	1,248	1,195	1,141	1,088	1,035	981	928	874	821

2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
833	760	709	680	651	622	593	564	535	505	476	447
2,362	2,155	2,011	1,928	1,846	1,763	1,681	1,598	1,516	1,433	1,351	1,268
2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613
380	389	402	412	422	433	443	458	470	481	494	506
334	323	311	300	288	277	265	254	242	231	219	208
604	551	514	493	472	451	430	409	388	366	345	324
(1,272)	(1,170)	(1,083)	(936)	(689)	(265)	-	-	-	-	-	-
170	170	170	170	170	170	170	170	170	170	170	170
(498)	(448)	(399)	(272)	(47)	356	600	579	558	537	516	494
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
(823)	(741)	(659)	(450)	(78)	589	992	957	922	887	852	817
4,866	4,739	4,678	4,803	5,091	5,674	5,994	5,880	5,762	5,645	5,528	5,412

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229
6,554	8,594	10,635	12,676	14,717	16,758	18,799	20,840	22,881	24,922	26,963	29,004
54,676	52,635	50,594	48,553	46,512	44,471	42,430	40,389	38,348	36,307	34,266	32,225
(15,895)	(16,381)	(16,295)	(15,639)	(14,982)	(14,326)	(13,669)	(13,012)	(12,356)	(11,699)	(11,043)	(10,386)
(15,362)	(14,771)	(14,180)	(13,589)	(12,998)	(12,408)	(11,817)	(11,226)	(10,635)	(10,044)	(9,453)	(8,863)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-

23,419	21,483	20,119	19,325	18,531	17,738	16,944	16,151	15,357	14,564	13,770	12,976
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,263	1,159	1,085	1,042	1,000	957	914	871	828	786	743	700
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
688	631	591	568	545	521	498	475	451	428	405	381
1,951	1,790	1,676	1,610	1,544	1,478	1,412	1,346	1,280	1,214	1,147	1,081
2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041
487	500	516	530	543	557	572	591	606	622	638	655
261	252	243	234	225	216	207	198	189	180	171	162
499	458	429	412	395	378	361	344	327	310	293	276
-	-	-	-	-	-	-	-	-	-	-	-
143	143	143	143	143	143	143	143	143	143	143	143
642	601	572	555	538	521	504	487	470	454	437	420
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
1,062	993	945	917	889	861	834	806	778	750	722	694
5,802	5,577	5,422	5,332	5,243	5,154	5,065	4,981	4,893	4,806	4,719	4,633

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139
6,423	8,453	10,482	12,512	14,542	16,572	18,601	20,631	22,661	24,690	26,720	28,750
55,716	53,686	51,657	49,627	47,597	45,568	43,538	41,508	39,478	37,449	35,419	33,389
(15,771)	(16,252)	(16,167)	(15,517)	(14,867)	(14,217)	(13,567)	(12,916)	(12,266)	(11,616)	(10,966)	(10,316)

(15,537)	(14,939)	(14,342)	(13,744)	(13,147)	(12,549)	(11,952)	(11,354)	(10,756)	(10,159)	(9,561)	(8,964)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
24,408	22,495	21,148	20,366	19,584	18,802	18,020	17,238	16,456	15,674	14,892	14,110
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,317	1,213	1,141	1,099	1,056	1,014	972	930	888	845	803	761
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
717	661	621	598	575	553	530	507	484	461	438	415
2,034	1,874	1,762	1,697	1,632	1,567	1,502	1,436	1,371	1,306	1,241	1,176
2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
325	335	345	355	366	377	388	400	412	424	437	450
260	251	242	233	224	215	206	197	188	179	170	161
520	479	451	434	417	401	384	367	351	334	317	301
-	-	-	-	-	-	-	-	-	-	-	-
129	129	129	129	129	129	129	129	129	129	129	129
649	608	580	563	546	530	513	496	480	463	446	430
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
1,073	1,005	958	930	903	875	848	820	793	765	738	710
5,721	5,495	5,337	5,245	5,154	5,064	4,973	4,883	4,794	4,704	4,615	4,527

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902

8,938	12,508	16,078	19,647	23,217	26,786	30,356	33,925	37,495	41,064	44,634	48,203
101,964	98,394	94,825	91,255	87,686	84,116	80,547	76,977	73,407	69,838	66,268	62,699
(25,984)	(26,813)	(27,643)	(27,497)	(26,376)	(25,255)	(24,134)	(23,012)	(21,891)	(20,770)	(19,649)	(18,528)
(28,271)	(27,224)	(26,177)	(25,130)	(24,083)	(23,036)	(21,989)	(20,942)	(19,895)	(18,847)	(17,800)	(16,753)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
47,709	44,357	41,005	38,628	37,227	35,826	34,424	33,023	31,622	30,220	28,819	27,418
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
2,573	2,393	2,212	2,084	2,008	1,932	1,857	1,781	1,706	1,630	1,554	1,479
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
1,402	1,303	1,205	1,135	1,094	1,053	1,012	970	929	888	847	806
3,975	3,696	3,417	3,219	3,102	2,985	2,868	2,752	2,635	2,518	2,401	2,285
3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570
721	743	765	788	812	836	861	887	914	941	970	999
473	457	441	425	410	394	378	362	347	331	315	299
1,017	945	874	823	793	763	733	704	674	644	614	584
-	-	-	-	-	-	-	-	-	-	-	-
228	228	228	228	228	228	228	228	228	228	228	228
1,244	1,173	1,102	1,051	1,021	991	961	931	902	872	842	812
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
2,057	1,939	1,821	1,737	1,688	1,638	1,589	1,540	1,490	1,441	1,392	1,342
10,796	10,404	10,013	9,739	9,581	9,423	9,266	9,110	8,955	8,801	8,647	8,494

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103
1,763	2,933	4,103	5,273	6,444	7,614	8,784	9,954	11,124	12,294	13,464	14,634
33,340	32,169	30,999	29,829	28,659	27,489	26,319	25,149	23,979	22,809	21,639	20,469
(7,743)	(8,427)	(8,696)	(8,965)	(8,918)	(8,554)	(8,191)	(7,827)	(7,463)	(7,100)	(6,736)	(6,372)
(9,163)	(8,836)	(8,508)	(8,181)	(7,854)	(7,527)	(7,199)	(6,872)	(6,545)	(6,218)	(5,890)	(5,563)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
16,433	14,907	13,795	12,683	11,887	11,408	10,929	10,450	9,971	9,491	9,012	8,533
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
886	804	744	684	641	615	590	564	538	512	486	460
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
483	438	405	373	349	335	321	307	293	279	265	251
1,369	1,242	1,149	1,057	991	951	911	871	831	791	751	711
1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170
219	225	232	239	246	254	261	269	277	286	294	303
-	155	150	145	139	134	129	124	119	114	108	103
350	318	294	270	253	243	233	223	212	202	192	182
-	-	-	-	-	-	-	-	-	-	-	-
95	95	95	95	95	95	95	95	95	95	95	95
445	412	389	365	348	338	328	317	307	297	287	277
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
735	682	643	603	575	558	542	525	508	491	474	457

3,494	3,474	3,344	3,214	3,122	3,067	3,013	2,959	2,905	2,851	2,798	2,745

Confidential

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534
1,518	2,569	3,620	4,671	5,722	6,773	7,825	8,876	9,927	10,978	12,029	13,080
30,017	28,966	27,914	26,863	25,812	24,761	23,710	22,659	21,608	20,556	19,505	18,454
(7,483)	(8,142)	(8,401)	(8,660)	(8,615)	(8,264)	(7,914)	(7,564)	(7,213)	(6,863)	(6,512)	(6,162)
(8,829)	(8,513)	(8,198)	(7,883)	(7,568)	(7,252)	(6,937)	(6,622)	(6,306)	(5,991)	(5,676)	(5,360)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
13,705	12,310	11,315	10,320	9,630	9,244	8,859	8,474	8,088	7,703	7,317	6,932
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
739	664	610	557	519	499	478	457	436	415	395	374
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
403	362	333	303	283	272	260	249	238	226	215	204
1,142	1,026	943	860	802	770	738	706	674	642	610	578
1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051
219	225	232	239	246	254	261	269	277	286	294	303
-	139	135	130	125	121	116	111	107	102	97	93
292	262	241	220	205	197	189	181	172	164	156	148
-	-	-	-	-	-	-	-	-	-	-	-
62	62	62	62	62	62	62	62	62	62	62	62
354	324	303	281	267	259	250	242	234	226	217	209

1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
584	535	500	465	441	427	414	400	387	373	359	346
2,996	2,977	2,861	2,745	2,666	2,623	2,580	2,538	2,496	2,454	2,412	2,370

Confidential

Confidential

Forecast

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031	68,031
38,057	40,257	42,457	44,656	46,856	49,056	51,255	53,455	55,655	57,854	60,054	62,254
29,974	27,774	25,575	23,375	21,175	18,976	16,776	14,576	12,377	10,177	7,977	5,778
(8,928)	(8,225)	(7,521)	(6,818)	(6,115)	(5,412)	(4,709)	(4,006)	(3,303)	(2,600)	(1,897)	(1,194)
(7,837)	(7,184)	(6,531)	(5,878)	(5,225)	(4,572)	(3,918)	(3,265)	(2,612)	(1,959)	(1,306)	(653)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
13,209	12,366	11,522	10,679	9,835	8,992	8,148	7,305	6,461	5,617	4,774	3,930
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
713	667	622	576	531	485	440	394	349	303	258	212
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
388	363	339	314	289	264	239	215	190	165	140	115
1,101	1,030	960	890	820	749	679	609	538	468	398	327
2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
597	615	633	652	672	692	713	734	756	779	802	827
134	125	116	107	98	89	80	71	62	53	45	36
281	263	245	228	210	192	174	156	138	120	102	84

-	-	-	-	-	-	-	-	-	-	-	-
132	132	132	132	132	132	132	132	132	132	132	132
414	396	378	360	342	324	306	288	270	252	234	216
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
684	654	625	595	565	535	506	476	446	417	387	357
4,715	4,624	4,534	4,444	4,354	4,266	4,178	4,090	4,003	3,917	3,831	3,747

Confidential

Confidential

Forecast											
2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584	83,584
47,132	49,874	52,617	55,359	58,102	60,844	63,586	66,329	69,071	71,814	74,556	77,299
36,452	33,709	30,967	28,225	25,482	22,740	19,997	17,255	14,512	11,770	9,028	6,285
(11,278)	(10,398)	(9,518)	(8,638)	(7,758)	(6,877)	(5,997)	(5,117)	(4,237)	(3,357)	(2,477)	(1,596)
(9,662)	(8,857)	(8,052)	(7,247)	(6,441)	(5,636)	(4,831)	(4,026)	(3,221)	(2,416)	(1,610)	(805)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
15,511	14,454	13,397	12,340	11,283	10,226	9,169	8,112	7,055	5,998	4,941	3,884
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
837	780	723	666	609	552	495	438	381	324	267	209
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
456	425	394	363	332	301	269	238	207	176	145	114
1,293	1,204	1,116	1,028	940	852	764	676	588	500	412	324
2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742
597	615	633	652	672	692	713	734	756	779	802	827
167	155	144	133	122	111	100	89	78	67	56	44

330	308	285	263	240	218	195	173	150	128	105	83
-	-	-	-	-	-	-	-	-	-	-	-
177	177	177	177	177	177	177	177	177	177	177	177
508	485	463	440	418	395	373	350	328	305	283	260
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
840	802	765	728	691	653	616	579	542	505	467	430
5,638	5,520	5,402	5,284	5,167	5,051	4,936	4,821	4,706	4,592	4,479	4,367

Confidential

Confidential

Forecast

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837	75,837
43,271	45,799	48,327	50,855	53,383	55,911	58,439	60,967	63,494	66,022	68,550	71,078
32,566	30,038	27,510	24,982	22,454	19,926	17,399	14,871	12,343	9,815	7,287	4,759
(10,759)	(9,924)	(9,089)	(8,254)	(7,420)	(6,585)	(5,750)	(4,915)	(4,081)	(3,246)	(2,411)	(1,576)
(9,152)	(8,401)	(7,649)	(6,898)	(6,147)	(5,396)	(4,644)	(3,893)	(3,142)	(2,391)	(1,639)	(888)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
12,655	11,714	10,772	9,830	8,888	7,946	7,004	6,062	5,120	4,178	3,237	2,295
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
683	632	581	530	479	429	378	327	276	225	175	124
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
372	344	317	289	261	234	206	178	150	123	95	67
1,055	976	898	819	741	662	584	505	427	348	270	191
2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528	2,528

557	574	591	608	627	646	665	685	705	727	748	771
155	145	135	125	114	104	94	84	74	63	53	43
270	250	230	209	189	169	149	129	109	89	69	49
-	-	-	-	-	-	-	-	-	-	-	-
156	156	156	156	156	156	156	156	156	156	156	156
426	406	385	365	345	325	305	285	265	245	225	205
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
703	670	637	604	571	538	504	471	438	405	372	339
4,998	4,893	4,788	4,684	4,580	4,477	4,375	4,273	4,172	4,071	3,971	3,871

Confidential

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Forecast											
2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569	90,569
48,585	51,604	54,623	57,641	60,660	63,679	66,698	69,717	72,736	75,755	78,774	81,793
41,984	38,965	35,946	32,927	29,908	26,889	23,870	20,852	17,833	14,814	11,795	8,776
(13,767)	(12,779)	(11,791)	(10,803)	(9,815)	(8,828)	(7,840)	(6,852)	(5,864)	(4,877)	(3,889)	(2,901)
(11,556)	(10,667)	(9,778)	(8,889)	(8,000)	(7,111)	(6,222)	(5,333)	(4,445)	(3,556)	(2,667)	(1,778)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
16,662	15,520	14,377	13,235	12,093	10,950	9,808	8,666	7,524	6,381	5,239	4,097
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
899	837	776	714	652	591	529	467	406	344	283	221
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
490	456	422	389	355	322	288	255	221	188	154	120
1,388	1,293	1,198	1,103	1,008	912	817	722	627	532	437	341

3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019	3,019
648	667	687	708	729	751	774	797	821	845	871	897
213	200	186	173	160	147	133	120	107	93	80	67
355	331	306	282	258	233	209	185	160	136	112	87
-	-	-	-	-	-	-	-	-	-	-	-
195	195	195	195	195	195	195	195	195	195	195	195
550	526	502	477	453	429	404	380	356	331	307	283
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
910	869	829	789	749	709	668	628	588	548	507	467
6,178	6,049	5,920	5,792	5,664	5,538	5,411	5,286	5,161	5,037	4,914	4,791

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Forecast

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391	78,391
41,248	43,861	46,474	49,087	51,700	54,313	56,926	59,539	62,151	64,764	67,377	69,990
37,143	34,530	31,917	29,304	26,691	24,078	21,465	18,852	16,240	13,627	11,014	8,401
(12,160)	(11,307)	(10,453)	(9,599)	(8,745)	(7,892)	(7,038)	(6,184)	(5,331)	(4,477)	(3,623)	(2,769)
(10,757)	(9,988)	(9,220)	(8,452)	(7,683)	(6,915)	(6,147)	(5,378)	(4,610)	(3,842)	(3,073)	(2,305)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
14,226	13,235	12,244	11,253	10,262	9,272	8,281	7,290	6,299	5,308	4,317	3,327
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
767	714	660	607	554	500	447	393	340	286	233	179

2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
418	389	360	331	302	272	243	214	185	156	127	98
1,185	1,103	1,020	938	855	773	690	607	525	442	360	277
2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613	2,613
523	536	550	564	578	597	613	629	645	662	683	701
196	184	173	161	150	138	127	115	104	92	81	69
303	282	261	240	219	198	176	155	134	113	92	71
-	-	-	-	-	-	-	-	-	-	-	-
170	170	170	170	170	170	170	170	170	170	170	170
473	452	431	410	389	368	347	326	304	283	262	241
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
782	747	713	678	643	608	573	538	503	468	433	398
5,299	5,184	5,068	4,954	4,839	4,729	4,615	4,502	4,390	4,277	4,170	4,059

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Forecast

2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229	61,229
31,045	33,086	35,127	37,168	39,209	41,250	43,291	45,332	47,373	49,414	51,455	53,496
30,184	28,143	26,102	24,061	22,020	19,979	17,938	15,897	13,856	11,815	9,774	7,733
(9,730)	(9,073)	(8,416)	(7,760)	(7,103)	(6,447)	(5,790)	(5,134)	(4,477)	(3,821)	(3,164)	(2,507)
(8,272)	(7,681)	(7,090)	(6,499)	(5,908)	(5,318)	(4,727)	(4,136)	(3,545)	(2,954)	(2,363)	(1,773)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-

12,183	11,389	10,596	9,802	9,008	8,215	7,421	6,628	5,834	5,041	4,247	3,453
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
657	614	572	529	486	443	400	358	315	272	229	186
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
358	335	311	288	265	241	218	195	171	148	125	101
1,015	949	883	817	751	685	618	552	486	420	354	288
2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041	2,041
676	694	713	731	751	775	796	817	839	862	889	913
153	144	135	126	117	108	99	90	81	72	63	54
260	243	226	209	192	175	158	141	124	107	90	74
-	-	-	-	-	-	-	-	-	-	-	-
143	143	143	143	143	143	143	143	143	143	143	143
403	386	369	352	335	318	301	284	268	251	234	217
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
666	638	610	582	554	526	498	470	442	414	386	358
4,551	4,466	4,381	4,297	4,214	4,135	4,052	3,971	3,890	3,809	3,734	3,655

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Forecast

2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139	62,139
30,780	32,809	34,839	36,869	38,899	40,928	42,958	44,988	47,018	49,047	51,077	53,107
31,359	29,330	27,300	25,270	23,240	21,211	19,181	17,151	15,122	13,092	11,062	9,032
(9,665)	(9,015)	(8,365)	(7,715)	(7,065)	(6,415)	(5,764)	(5,114)	(4,464)	(3,814)	(3,164)	(2,513)

(8,366)	(7,768)	(7,171)	(6,573)	(5,976)	(5,378)	(4,781)	(4,183)	(3,585)	(2,988)	(2,390)	(1,793)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
13,328	12,546	11,764	10,982	10,200	9,418	8,636	7,854	7,072	6,290	5,508	4,726
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
719	677	635	592	550	508	466	424	381	339	297	255
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
392	369	346	323	300	277	254	231	208	185	162	139
1,111	1,045	980	915	850	785	720	654	589	524	459	394
2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
463	477	492	506	522	537	553	570	587	605	623	642
152	143	134	125	116	107	99	90	81	72	63	54
284	267	251	234	217	201	184	167	151	134	117	101
-	-	-	-	-	-	-	-	-	-	-	-
129	129	129	129	129	129	129	129	129	129	129	129
413	396	380	363	346	330	313	296	280	263	246	230
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
683	655	627	600	572	545	517	490	462	435	407	380
4,439	4,351	4,264	4,177	4,090	4,004	3,919	3,834	3,749	3,665	3,581	3,498

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Forecast

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902	110,902

51,773	55,342	58,912	62,481	66,051	69,621	73,190	76,760	80,329	83,899	87,468	91,038
59,129	55,560	51,990	48,421	44,851	41,282	37,712	34,143	30,573	27,004	23,434	19,864
(17,407)	(16,286)	(15,164)	(14,043)	(12,922)	(11,801)	(10,680)	(9,559)	(8,438)	(7,316)	(6,195)	(5,074)
(15,706)	(14,659)	(13,612)	(12,565)	(11,518)	(10,471)	(9,424)	(8,377)	(7,330)	(6,282)	(5,235)	(4,188)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
26,016	24,615	23,214	21,812	20,411	19,010	17,609	16,207	14,806	13,405	12,003	10,602
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
1,403	1,328	1,252	1,177	1,101	1,025	950	874	799	723	647	572
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
765	723	682	641	600	559	517	476	435	394	353	312
2,168	2,051	1,934	1,818	1,701	1,584	1,467	1,350	1,234	1,117	1,000	883
3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570	3,570
1,029	1,059	1,091	1,124	1,158	1,192	1,228	1,265	1,303	1,342	1,382	1,424
284	268	252	236	221	205	189	173	158	142	126	110
554	524	495	465	435	405	375	345	315	286	256	226
-	-	-	-	-	-	-	-	-	-	-	-
228	228	228	228	228	228	228	228	228	228	228	228
782	752	722	693	663	633	603	573	543	513	484	454
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
1,293	1,244	1,194	1,145	1,095	1,046	997	947	898	849	799	750
8,342	8,191	8,041	7,892	7,744	7,597	7,451	7,306	7,162	7,019	6,877	6,737

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Forecast

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103	35,103
15,804	16,974	18,144	19,314	20,485	21,655	22,825	23,995	25,165	26,335	27,505	28,675
19,298	18,128	16,958	15,788	14,618	13,448	12,278	11,108	9,938	8,768	7,598	6,427
(6,009)	(5,645)	(5,281)	(4,918)	(4,554)	(4,190)	(3,827)	(3,463)	(3,099)	(2,736)	(2,372)	(2,008)
(5,236)	(4,909)	(4,581)	(4,254)	(3,927)	(3,600)	(3,272)	(2,945)	(2,618)	(2,291)	(1,963)	(1,636)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
8,054	7,575	7,095	6,616	6,137	5,658	5,179	4,700	4,220	3,741	3,262	2,783
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
434	409	383	357	331	305	279	253	228	202	176	150
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
237	223	209	194	180	166	152	138	124	110	96	82
671	631	591	551	511	471	432	392	352	312	272	232
1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170
312	321	331	341	351	362	373	384	395	407	419	432
98	93	88	83	77	72	67	62	57	52	46	41
172	161	151	141	131	121	110	100	90	80	69	59
-	-	-	-	-	-	-	-	-	-	-	-
95	95	95	95	95	95	95	95	95	95	95	95
266	256	246	236	226	215	205	195	185	175	164	154
1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
440	423	407	390	373	356	339	322	305	288	272	255

2,692	2,639	2,587	2,535	2,483	2,432	2,380	2,330	2,279	2,229	2,179	2,130

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Forecast											
2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534	31,534
14,131	15,183	16,234	17,285	18,336	19,387	20,438	21,489	22,541	23,592	24,643	25,694
17,403	16,352	15,301	14,249	13,198	12,147	11,096	10,045	8,994	7,943	6,891	5,840
(5,812)	(5,461)	(5,111)	(4,760)	(4,410)	(4,060)	(3,709)	(3,359)	(3,008)	(2,658)	(2,308)	(1,957)
(5,045)	(4,730)	(4,414)	(4,099)	(3,784)	(3,468)	(3,153)	(2,838)	(2,523)	(2,207)	(1,892)	(1,577)
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
6,546	6,161	5,775	5,390	5,005	4,619	4,234	3,848	3,463	3,077	2,692	2,306
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
353	332	312	291	270	249	228	208	187	166	145	124
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
192	181	170	158	147	136	124	113	102	90	79	68
545	513	481	449	417	385	353	321	289	256	224	192
1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051
312	321	331	341	351	362	373	384	395	407	419	432
88	83	79	74	70	65	60	56	51	46	42	37
139	131	123	115	107	98	90	82	74	66	57	49
-	-	-	-	-	-	-	-	-	-	-	-
62	62	62	62	62	62	62	62	62	62	62	62
201	193	185	176	168	160	152	144	135	127	119	111

1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653	1.653
332	319	305	292	278	264	251	237	224	210	197	183
2,329	2,288	2,247	2,207	2,167	2,127	2,088	2,049	2,010	1,971	1,933	1,895

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
68,031	68,031									
64,453	65,990									
3,578	2,041									
(491)	(0)									
0	0									
-	-									
-	-									
3,087	2,041									
5.39%	5.39%									
166	110									
2.94%	2.94%									
91	42									
257	152									
2,200	1,537									
851	613									
27	12									
66	43									

-	-
132	92
198	136
1.653	1.653
328	225
3,662	2,539

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
83,584	83,584									
80,041	82,272									
3,543	1,311									
(716)	(0)									
(0)	(0)									
-	-									
-	-									
2,827	1,311									
5.39%	5.39%									
152	71									
2.94%	2.94%									
83	31									
236	102									
2,742	2,232									
851	713									
33	18									

60	28
-	-
177	144
238	172
1.653	1.653
393	285
4,255	3,350

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
75,837	75,837	13,833								
73,606	75,794	13,833								
2,231	43	-								
(741)	(19)	(5)								
(137)	(0)	0								
-	-	-								
-	-	-								
1,353	24	(5)								
5.39%	5.39%	5.39%								
73	1	(0)								
2.94%	2.94%	2.94%								
40	1	(0)								
113	2	(0)								
2,528	2,188	43								

794	724	24
33	20	0
29	1	(0)
-	-	-
156	135	3
185	135	3
1.653	1.653	1.653
305	224	4
3,773	3,158	71

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
90,569	90,569	90,569								
84,812	87,831	90,569								
5,757	2,738	-								
(1,913)	(925)	(30)								
(889)	-	-								
-	-	-								
-	-	-								
2,955	1,812	(30)								
5.39%	5.39%	5.39%								
159	98	(2)								
2.94%	2.94%	2.94%								
87	53	(1)								
246	151	(2)								

3,019	3,019	2,738
924	951	889
53	40	24
63	39	(1)
-	-	-
195	195	20
258	234	19
1.653	1.653	1.653
427	387	32
4,669	4,548	3,680

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
78,391	78,391	78,391	78,391							
72,603	75,216	77,829	78,387							
5,788	3,175	562	4							
(1,916)	(1,062)	(208)	(26)							
(1,537)	(768)	(0)	(0)							
-	-	-	-							
-	-	-	-							
2,336	1,345	354	(22)							
5.39%	5.39%	5.39%	5.39%							
126	73	19	(1)							

2.94%	2.94%	2.94%	2.94%
69	40	10	(0)
195	112	30	(1)
2,613	2,613	2,613	558
720	738	758	782
58	46	35	5
50	29	8	(0)
-	-	-	-
170	170	170	36
220	199	178	36
1.653	1.653	1.653	1.653
364	329	294	59
3,948	3,838	3,729	1,404

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
61,229	61,229	61,229	61,229							
55,537	57,578	59,619	61,229							
5,692	3,651	1,610	-							
(1,851)	(1,194)	(538)	(20)							
(1,182)	(591)	0	0							
-	-	-	-							
-	-	-	-							

2,660	1,866	1,073	(20)
5.39%	5.39%	5.39%	5.39%
143	101	58	(1)
2.94%	2.94%	2.94%	2.94%
78	55	32	(0)
222	156	89	(2)
2,041	2,041	2,041	1,610
938	964	990	1,021
45	36	27	14
57	40	23	(0)
-	-	-	-
143	143	143	113
200	183	166	113
1.653	1.653	1.653	1.653
330	302	275	186
3,576	3,499	3,422	2,831

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
62,139	62,139	62,139	62,139							
55,136	57,166	59,196	60,892							
7,003	4,973	2,943	1,247							
(1,863)	(1,213)	(563)	(20)							

(1,195)	(598)	(0)	(0)
-	-	-	-
-	-	-	-
3,944	3,162	2,380	1,228
5.39%	5.39%	5.39%	5.39%
213	171	128	66
2.94%	2.94%	2.94%	2.94%
116	93	70	30
329	264	198	96
2,030	2,030	2,030	1,696
661	681	701	603
45	36	27	15
84	67	51	26
-	-	-	-
129	129	129	108
213	196	180	134
1.653	1.653	1.653	1.653
352	325	297	221
3,416	3,334	3,253	2,632

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
110,902	110,902	110,902	110,902	108,978						

94,607	98,177	101,746	105,316	107,086
16,295	12,725	9,156	5,586	1,892
(3,953)	(2,832)	(1,711)	(590)	(34)
(3,141)	(2,094)	(1,047)	0	0
-	-	-	-	-
-	-	-	-	-
9,201	7,799	6,398	4,997	1,859
5.39%	5.39%	5.39%	5.39%	5.39%
496	421	345	270	100
2.94%	2.94%	2.94%	2.94%	2.94%
270	229	188	147	27
767	650	533	416	127
3,570	3,570	3,570	3,570	1,770
1,466	1,510	1,556	1,602	818
95	79	63	47	16
196	166	136	106	40
-	-	-	-	-
228	228	228	228	113
424	394	364	334	153
1.653	1.653	1.653	1.653	1.653
701	651	602	553	252
6,598	6,460	6,323	6,188	2,984

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
35,103	35,103	35,103	35,103	35,103	35,103					
29,845	31,015	32,185	33,356	34,526	35,103					
5,257	4,087	2,917	1,747	577	-					
(1,645)	(1,281)	(918)	(554)	(190)	(11)					
(1,309)	(982)	(654)	(327)	0	0					
-	-	-	-	-	-					
-	-	-	-	-	-					
2,304	1,824	1,345	866	387	(11)					
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%					
124	98	73	47	21	(1)					
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%					
68	54	40	25	11	(0)					
192	152	112	72	32	(1)					
1,170	1,170	1,170	1,170	1,170	577					
445	458	472	486	501	254					
36	31	26	21	15	5					
49	39	29	18	8	(0)					
-	-	-	-	-	-					
95	95	95	95	95	47					
144	134	123	113	103	47					
1.653	1.653	1.653	1.653	1.653	1.653					
238	221	204	187	170	77					

2,081	2,032	1,984	1,936	1,889	913					

2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
31,534	31,534	31,534	31,534	31,534	31,534					
26,745	27,796	28,847	29,899	30,950	31,534					
4,789	3,738	2,687	1,636	585	-					
(1,607)	(1,257)	(906)	(556)	(205)	(11)					
(1,261)	(946)	(631)	(315)	(0)	(0)					
-	-	-	-	-	-					
-	-	-	-	-	-					
1,921	1,536	1,150	765	379	(11)					
5.39%	5.39%	5.39%	5.39%	5.39%	5.39%					
104	83	62	41	20	(1)					
2.94%	2.94%	2.94%	2.94%	2.94%	2.94%					
56	45	34	22	11	(0)					
160	128	96	64	32	(1)					
1,051	1,051	1,051	1,051	1,051	585					
445	458	472	486	501	287					
32	28	23	19	14	5					
41	33	25	16	8	(0)					
-	-	-	-	-	-					
62	62	62	62	62	34					
103	94	86	78	70	34					

1.653	1.653	1.653	1.653	1.653	1.653
169	156	142	129	115	56
1,858	1,821	1,784	1,748	1,713	932

	Paloma	Cotton Center	Hyder I	Chino Valley	Foothills 1	Foothills 2
In-Service Date	9/12/2011	10/24/2011	10/24/2011, 2/3/2012	11/26/2012	3/19/2013	10/15/2013
% of First Year After COD	30.1%	18.6%		9.3%	78.6%	21.1%
System Size (MW ac)	17	17	16	19	17	18
Plant In Service	65,990	82,272	75,837	90,569	78,387	61,229
Book Life (years)	30.0	30.0	30.0	30.0	30.0	30.0
O&M per kW	$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25
O&M Escalation %	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Property Tax Rate	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
Renewable Prop Tax Assess Ratio	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Prop Tax Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Composite Income Tax Rate	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
Fed Tax Basis Red	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
ITC	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Tax Depreciation	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS
Debt % of Capitalization	46.06%	46.06%	46.06%	46.06%	46.06%	46.06%
Equity % of Capitalization	53.94%	53.94%	53.94%	53.94%	53.94%	53.94%
LT Cost of Debt	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
Authorized ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Hyder II	Gila Bend	Luke AFB	Desert Star	Red Rock
11/1/2013	6/30/2014	6/29/2015	7/22/2015	1/1/2017
16.4%	50.4%	50.7%	44.4%	100.0%
14	32	10	10	40
60,892	107,086	35,103	31,534	94,700
30.0	30.0	30.0	30.0	30.0
$ 21.25	$ 21.25	$ 21.25	$ 21.25	$ 21.25
3.0%	3.0%	3.0%	3.0%	3.0%
10.3%	10.3%	10.3%	10.3%	10.3%
20.0%	20.0%	20.0%	20.0%	20.0%
2.0%	2.0%	2.0%	2.0%	2.0%
39.22%	39.22%	39.22%	39.22%	39.22%
50.00%	50.00%	50.00%	50.00%	50.00%
30.00%	30.00%	30.00%	30.00%	30.00%
5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS	5 yr MACRS
46.06%	46.06%	46.06%	46.06%	46.06%
53.94%	53.94%	53.94%	53.94%	53.94%
6.38%	6.38%	6.38%	6.38%	6.50%
10.00%	10.00%	10.00%	10.00%	10.00%

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

E-00000J-14-0023

EXHIBIT

S-9

ADMITTED

STAFF'S EXHIBITS

FOR

HEARING JUNE 9, 1016

TEP/UNSE

PUBLIC INFORMATION

Staff Data Requests to TEP and UNSE

TEP and UNSE Responses to Staff Data Requests

La Senita Single –Azis System-UNSE

La Senita Estimated kWh

Weighted Average $/kWh by Facility

Weighted Average $/kWh by Facility-PPA

Hypothetical 10MW SAT PV

Fort Hauchuca Fixed PV System Levelized Cost of Energy

White Mountain Fixed/LCPV System Levelized Cost of Energy

White Mountain Solar Estimated kWh

Rio Rico PV System-UNSE Levelized Cost of Energy

Rio Rico Estimated kWh

Areva-Thermal Levelized Cost of Energy

Areva Estimated kWh

Prarie Fire Fixed PV

Prarie Fire Estimated kWh

Equivalent and Non-Equivalent Technologies

UASTP I Single Axis PV Levelized Cost of Energy

UASTP II Fixed PV Levelized Cost of Energy

UASTP Estimated kWh

Springerville 4.6 Fixed PV Levelized Cost of Energy

Springerville 4.6 Estimated kWh

Springerville 1.0 Fixed PV Levelized Cost of Energy

Springerville 1.0 Estimated kWh

UNS ELECTRIC, IN…'S RESPONSE TO STAFF'S FIRST S… OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023

March 16, 2016

STF 1.1

Please provide the following information going back ten years for all your generation plants: type of plant, total annual volume of water used for cooling separated by **amount consumed, amount withdrawn**, and water source (surface water, ground water, treated effluent). **Finally, please indicate which plants will be retiring within the next 10 years.**

RESPONSE:

Please see STF 1.1-1.2 UNS Electric Water Usage VofDG.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan

WITNESS:

Carmine Tilghman

STF 1.2

Please provide the following information for all your generation plants: type of plant, five-year projected total annual volume of water for cooling separated by **amount consumed, amount withdrawn** and water source (surface water, ground water, treated effluent).

RESPONSE:

Please see STF 1.1-1.2 UNS Electric Water Usage VofDG.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan

WITNESS:

Carmine Tilghman

STF 1.3

If a shortage is on the Colorado River or Lake Mead is declared, what will be the impact on your existing or planned generation units?

RESPONSE:

UNS Electric's fossil-fired generating units use groundwater for cooling and other process needs. Therefore, we do not anticipate any impact from the declaration of a shortage on the Colorado River or Lake Mead.

RESPONDENT:

Mark Mansfield / Jeff Yockey

WITNESS:

Carmine Tilghman

UNS ELECTRIC, INC.'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
March 16, 2016

STF 1.4

What does your Company believe the impact of rooftop solar and other distributed generation in your service territory will be on water use? Please supply any data you may have to support your conclusions.

RESPONSE:

As UNS Electric expands the use of renewable energy, including distributed generation, and that renewable energy displaces generation from fossil resources, we expect to see a decrease in the water used to serve customer load relative to what would have occurred without the expanded renewable generation. UNS Electric estimates that a total of 580 acre feet of water use could be avoided from 2015 through 2025 by realizing the amount of distributed generation needed to meet Renewable Energy Standard ("RES") requirements. To be clear, this water reduction would occur with any solar or wind technology, regardless of whether or not it is distributed. In 2025, the water use avoided would represent nearly 17% of the total annual water usage. Please see STF 1.4 UNS Electric DG Water VofDG.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan / Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS Electric

Annual Water Usage Data

Acre Feet	Plant Type	Actual 2006
Black Mountain Generating Station (1)	Combustion Turbine	-
Valencia Generating Station	Combustion Turbine	1
Gila River Power Station (2)	Natural Gas Combined Cycle	
Annual Water Usage		1

Data reflects UNS Electric's share of water consumption at each of its owned and jointly owned fa

Water withdrawal is equal to consumption for all facilities

All facilities utilize ground water as their water source. Valencia Generating Station is supplied wa

(1) The Company purchased Black Mountain Generating Station in 2008.

(2) UNS Electric's acquisition of Gila River Unit 3 in January 2015

Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
-	46	47	40	10	35	24	24	7	11
1	7	8	11	9	9	11	0	5	6
								362	383
1	53	55	51	19	43	35	24	375	400

acilities

ater by the City of Nogales.

Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
12	17	19	20	23	24
5	7	8	8	9	9
365	383	372	373	371	372
383	407	398	401	402	406

UNS Electric
Annual Water Usage Data

Acre Feet	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Black Mountain Generating Station	7	11	12	17	19	20	23	24	27	28	30
Valencia Generating Station	5	6	5	7	8	8	9	9	10	11	12
Gila River Power Station	362	383	365	383	372	373	371	372	445	451	455
Annual Water Usage	375	400	383	407	398	401	402	406	482	490	496

Distributed Generation Reductions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Arizona REST Targets	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%
% Distributed Generation	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Retail Sales Prior to DG Reductions, GWh	1,646.6	1,619.8	1,613.5	1,622.5	1,636.6	1,652.6	1,672.5	1,698.9	1,725.0	1,751.7	1,777.9
Distributed Generation, GWh	24.3	28.6	33.2	38.0	43.0	48.1	53.4	59.0	64.8	70.6	76.6
Net Retail Sales, GWh	1,622.3	1,591.1	1,580.3	1,584.5	1,593.5	1,604.5	1,619.1	1,639.9	1,660.3	1,681.0	1,701.3
Estimated Water Reductions from DG, Acre Feet	26	31	36	41	46	52	57	63	70	76	82
Percent of Annual Water Usage	7.0%	7.7%	9.3%	10.0%	11.6%	12.9%	14.3%	15.6%	14.4%	15.5%	16.6%

Reductions from distributed generation are based on avoided water usage from natural gas combined cycle resources at 350 gallons / MWh

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
March 16, 2016

STF 1.1

Please provide the following information going back ten years for all your generation plants: type of plant, total annual volume of water used for cooling separated by **amount consumed, amount withdrawn**, and water source (surface water, ground water, treated effluent). **Finally, please indicate which plants will be retiring within the next 10 years.**

RESPONSE:

Please see STF 1.1-1.2 TEP Water Usage VofDG.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
March 16, 2016

STF 1.2

Please provide the following information for all your generation plants: type of plant, five-year projected total annual volume of water for cooling separated by **amount consumed, amount withdrawn** and water source (surface water, ground water, treated effluent).

RESPONSE:

Please see STF 1.1-1.2 TEP Water Usage VofDG.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan

WITNESS:

Carmine Tilghman

STF 1.3

If a shortage is on the Colorado River or Lake Mead is declared, what will be the impact on your existing or planned generation units?

RESPONSE:

To the extent there is any impact to TEP generating units from the declaration of a shortage on the Colorado River or Lake Mead, it would be with respect to Navajo Generating Station, Four Corners Power Plant, and/or San Juan Generating Station as each of these facilities use surface waters that are within the Colorado River drainage area.

Navajo Generating Station draws water for plant operations from Lake Powell and holds senior water rights as part of Arizona's Upper Colorado River apportionment. Several years ago the intake for the plant was lowered to within the "dead pool" of Lake Powell. In 2019, one unit at the plant will cease operation, thereby reducing water demand for the plant by one-third.

San Juan Generating Station draws water for plant operations from the San Juan River, and also holds senior water rights. In addition to these water rights, a water hazard sharing agreement with the Jicoria Nation is in place, which can provide for additional water rights in the case of an extreme water shortage. Finally, at the end of 2017, units 2 and 3 at San Juan Generating Station will cease operation, thereby reducing water demand for the plant by one-half.

Four Corners Power Plant draws water from Morgan Lake, which receives water from the San Juan River under senior water rights. At the end of 2013, units 1-3 at the plant ceased operation, thereby reducing water demand for the plant by over one-quarter.

Based on the senior water rights in place and the decrease in water demand at each of these plants, TEP does not anticipate a significant impact from the declaration of a shortage on the Colorado River or Lake Mead. If there was an impact at one of these plants that resulted in the need to curtail generation, we anticipate that TEP would either have sufficient capacity through other resources within its system, or could find sufficient capacity in the wholesale market, specifically due to the large amount of available merchant generation located around the Palo Verde hub.

RESPONDENT:

Mark Mansfield / Jeff Yockey

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 March 16, 2016

STF 1.4

What does your Company believe the impact of rooftop solar and other distributed generation in your service territory will be on water use? Please supply any data you may have to support your conclusions.

RESPONSE:

As TEP expands the use of renewable energy, including distributed generation, and that renewable energy displaces generation from fossil resources, we expect to see a decrease in the water used to serve customer load relative to what would have occurred without the expanded renewable generation. TEP estimates that a total of 3,432 acre feet of water use could be avoided from 2015 through 2025 by realizing the amount of distributed generation needed to meet Renewable Energy Standard ("RES") requirements. To be clear, this water reduction would occur with any solar or wind technology, regardless of whether or not it is distributed. In 2025, the water use avoided would represent nearly 3% of the total annual water usage. Please see STF 1.4 TEP DG Water VofDG.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Jeff Yockey / Mike Sheehan / Carmine Tilghman

WITNESS:

Carmine Tilghman

Tucson Electric Power

Annual Water Usage Data

Water Use (Consumption) Acre Feet	Plant Type	Actual 2006	Actual 2007	Actual 2008	Actual 2009
Four Corners Power Plant	Pulverized Coal	1,160	1,096	1,273	1,387
Navajo Generation Station	Pulverized Coal	2,000	2,070	2,050	1,947
San Juan Generating Station (1)	Pulverized Coal	4,822	4,681	4,489	4,843
Springerville Generating Station (2)	Pulverized Coal	10,350	10,664	10,722	10,252
Sundt Generating Station (3)	see Note 3	2,391	2,442	2,078	1,300
Luna Energy Facility	Natural Gas Combined Cycle	802	703	585	517
Gila River Power Station (4)	Natural Gas Combined Cycle				
Annual Water Usage		21,524	21,657	21,197	20,246

Water Source	2006	2007	2008	2009
Surface Water	7,981	7,847	7,812	8,177
Groundwater	13,501	13,781	13,310	12,027
Treated Effluent	42	29	75	42

Water Withdrawal (5)	2006	2007	2008	2009
Four Corners Power Plant (6)	1,379	1,245	1,447	1,652
Luna Energy Facility (7)	761	675	509	475

Data reflects TEP's share of total water consumption at each of its owned and jointly owned facilities.

(1) Planned retirement of San Unit 2 by December 31, 2017

(2) Reduction in coal capacity on Springerville Unit 1 on January 1, 2015

(3) TEP's elimination of coal on Sundt Unit 4 in August 2015. Data includes Unit 4 (pulverized coal), Units 1-3 (natural gas steam), ai

(4) TEP's acquisition of Gila River Unit 3 in January 2015

(5) Water withdrawal is equal to consumption for all other facilities

(6) A small amount of water withdrawal is returned to surface water

(7) Total amount of water consumed is equal to wather withdrawn from groundwater plus treated effluent

Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1,078	1,070	1,091	969	1,095	1,155	1,183	1,279	1,264	1,224	1,145	1,282	1,166
1,825	1,817	1,620	2,068	1,715	1,862	1,974	2,156	2,203	2,196	2,194	2,090	2,101
4,483	4,325	3,961	4,415	3,439	4,621	4,944	4,956	2,373	2,163	2,135	2,183	2,128
9,593	9,677	10,360	9,875	8,860	7,321	7,531	7,486	8,241	8,045	8,533	8,152	8,090
1,826	2,027	1,795	1,482	1,803	1,346	1,336	1,370	1,516	1,481	1,669	1,537	1,551
793	696	932	519	734	440	464	527	767	865	878	873	804
					1,351	1,192	1,200	1,417	1,501	1,474	1,489	1,511
19,598	19,613	19,758	19,328	17,646	18,096	18,625	18,975	17,781	17,475	18,028	17,605	17,351

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
7,386	7,212	6,672	7,452	6,249	7,638	8,101	8,392	5,840	5,583	5,474	5,555	5,396
12,079	12,242	12,890	11,807	11,214	10,402	10,458	10,508	11,832	11,769	12,430	11,927	11,842
133	159	196	69	183	56	66	75	109	123	125	124	114

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1,297	1,269	1,382	1,188	1,408	1,306	1,411	1,526	1,508	1,460	1,366	1,529	1,391
660	537	735	450	551	384	399	452	658	742	753	749	690

nd TEP's local area combustion turbines sited at DeMoss Pietre, North Loop and Sundt

Tucson Electric Power

Annual Water Usage Data

Water Usage, Acre Feet	2015	2016	2017	2018
Four Corners	1,155	1,183	1,279	1,264
Navajo	1,862	1,974	2,156	2,203
San Juan	4,621	4,944	4,956	2,373
Springerville	7,321	7,531	7,486	8,241
Sundt	1,344	1,334	1,366	1,510
Luna	384	399	452	658
Gila River	1,351	1,192	1,200	1,417
Combustion Turbines	2	3	3	6
Annual Water Usage	18,040	18,559	18,900	17,672

Distributed Generation Reductions	2015	2016	2017	2018
Arizona REST Targets	5.0%	6.0%	7.0%	8.0%
% Distributed Generation	30.0%	30.0%	30.0%	30.0%
Retail Sales Prior to DG Reductions, GWh	9,160.6	8,629.7	8,601.6	8,833.5
Distributed Generation, GWh	135.4	152.6	176.9	207.0
Net Retail Sales, GWh	9,025.2	8,477.2	8,424.6	8,626.5
Estimated Water Reductions from DG, Acre Feet	145	164	190	222
Percent of Annual Water Usage	0.8%	0.9%	1.0%	1.3%

Reductions from distributed generation are based on avoided water usage from natural gas combined cycle resources at 350 g

2019	2020	2021	2022	2023	2024	2025
1,224	1,145	1,282	1,166	1,247	1,269	1,224
2,196	2,194	2,090	2,101	2,086	2,166	2,159
2,163	2,135	2,183	2,128	2,150	2,183	2,125
8,045	8,533	8,152	8,090	8,371	8,151	8,038
1,474	1,663	1,532	1,545	1,471	1,476	1,395
742	753	749	690	697	734	722
1,501	1,474	1,489	1,511	1,490	1,517	1,523
7	6	5	6	95	99	103
17,353	17,903	17,482	17,237	17,609	17,595	17,289

2019	2020	2021	2022	2023	2024	2025
9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%
30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
9,541.3	10,179.9	10,273.7	10,397.2	10,515.0	10,637.9	10,741.4
250.8	296.5	328.2	361.3	394.7	428.8	462.5
9,290.5	9,883.4	9,945.5	10,035.9	10,120.3	10,209.1	10,278.8
269	318	353	388	424	461	497
1.6%	1.8%	2.0%	2.3%	2.4%	2.6%	2.9%

gallons / MWh

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
May 13, 2016

STF 2.1

Please provide information on all utility-scale solar renewable PPAs, with an effective date on or after January 1, 2008, including:

a. The effective date

b. Term of the PPA

c. Actual price per kWh to the utility and any other charges, by year for the life of the contract, and

d. Type(s) of renewable technology for each PPA.

e. Please also provide a copy of each PPA, including term sheet.

RESPONSE:

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

a. Please see **STF 2.1 TEP UNSE PPA Pricing-Highly Confidential.xlsx** for specific contract and amendment dates. The Excel file is <u>not</u> identified by Bates numbers.

b.,d. Please see **STF 2.1 Renewable Energy Data.xlsx.**

c. Please see **STF 2.1 TEP UNSE PPA Pricing-Highly Confidential.xlsx**. The Excel file is <u>not</u> identified by Bates numbers.

e. TEP is not able to provide the requested PPAs without counterparty permissions. Accordingly, the Company is in the process of seeking counterparty authorizations and anticipates providing the PPAs where approvals were not denied on Monday, May 16, 2016.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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STF 2.2

Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity.

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g, The cost per kWh generated over the life of the facility.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

RESPONSE:

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

a. The Company does not retain start of construction data.

b. Please see **STF 2.1 Renewable Energy Data.xlsx** for project COD dates.

c. Company owned facilities' life expectancy is 30 years. PPA's are 20 years.

d. Please see **STF 2.1 Renewable Energy Data.xlsx** for project technologies.

e. Please see **STF 2.2 Value of Solar 05-2016-Highly Confidential.xlsx**.

f. Please see **STF 2.2 Utility Owned Project Costs-Highly Confidential.xlsx**. The Excel file is not identified by Bates numbers.

g. Please see **STF 2.2 Utility Owned Project Costs-Highly Confidential.xlsx**.

h. The responsive contract to this request is the E.On Tech Park PPA. Once permission has been obtained from the counterparty, the Company will provide the contract to the requesting party in response to STF 2.1e.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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STF 2.3

Please explain the decision criteria you have and will rely upon for deciding whether to rely on a PPA or utility ownership for utility scale solar. If one decision criteria includes cost comparisons, please provide an explanation, formula and example of comparison between PPA and utility ownership. If that formula is from a perspective other than the customers' revenue requirements, please explain why.

RESPONSE:

The decision criteria to determine whether or not a facility is to be Company-owned or procured through a PPA is primarily based on operational strategy, prudent utility practice for asset management, and RPS compliance.

It is impractical for the Company to assume it could build, own and operate sufficient utility scale facilities to meet the Arizona RPS. However, it is equally impractical to assume that the Company should be required to procure all of the needed resources necessary for compliance through a third-party PPA. There are distinct operational advantages of utility-owned facilities over production-based third-party owned contract facilities. These advantages include the ability to control dispatch and output as necessary (regulation down), the ability to control and provide reactive power versus real power when necessary (volt/VAR support), utility controlled low voltage ride-through, and over/under frequency control at the dispatch request of the balancing authority, among others. Finally, at the end of a PPA, the Company may no longer have access to the operating facility even though it is still functioning; whereas, a utility-owned project will continue to produce energy for the benefit of customers even after being fully depreciated.

As such, the Company has been on a planned trajectory of approximately 25% utility-ownership for solar resources and a 75% third-party ownership model. This is consistent with Commission order 71702 (March 17, 2010) that both discusses and determines the benefits of a procurement model that allows for both utility-owned facilities and third-part owned facilities.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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STF 2.4

Given the utilities' support for reliance upon PPA data for utility scale solar as a basis for pricing export for rooftop DG solar, please explain whether the utility is willing to apply the same criteria to its utility ownership decision process for utility scale solar. If not, why not apply the same criteria? Is the utility supportive of applying this criteria uniformly if the PPA concept is embraced as the benchmark for solar evaluation?

RESPONSE:

The Company does NOT support this particular methodology, as the comparison between a utility-owned facility and a third-party facility are treated differently from an accounting perspective, tax perspective, and an operational perspective. To ignore these differences and simply apply the "price" of the PPA to a utility-owned model would severely discount the operational advantages discussed in STF 2.3, while at the same time unfairly comparing the utility-owned facility to a project that is not subject to the same rules, regulations, and requirements as the utility.

In order to utilize the "apples to apples" comparison that has been discussed throughout this proceeding, there must be some form of discount applied to the PPA value to account for this difference.

Additionally, it must be acknowledged that a utility's obligation to serve, while still meeting the RPS, will include multiple forms of renewable resources that will have different prices and value. While the Company has supported the use of solar energy for meeting the RPS, it has not been in the past, nor is it now, the most-cost-effective renewable energy. However, as a matter of policy, the stakeholders involved have supported the use of higher priced solar energy over other forms of renewable energy for a number of non-value based reasons.

This same logic should be applied to the comparison between the distinctly different utility-scale solar ownership models of utility-owned versus third-party owned.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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STF 2.5

As regards the specific points of comparison between PPA's and utility ownership of utility scale solar which do or may lead to differences in cost comparisons, please address:

(To the extent these questions are general, please answer from the perspective of your utility's actual experience and practices.)

a. Any differences in amount and timing of revenue requirements to customers given PPA's recovery in PPFAC's and utility ownership following a revenue requirements formula? For the same resource, is the PPA less costly initially due to typical reliance upon levelized pricing; whereas utility ownership prices are initially higher and subsequently lower under the revenue requirements formula?

b. Please explain the differences between tax efficiency of utilization of related investment tax credits between PPA vendors and utility ownership?

c. Please explain the differences between treatment of cost overruns, if any, between PPA's and utility ownership? Are PPA's typically not compensated for actual costs in excess of contract, but utilities typically request recovery of costs over budget in rate cases? Do utilities support limiting cost recovery in rate cases to budgets?

d. Please explain differences between duration of PPA's versus useful life depreciation for owned assets? Are PPA's typically for less than the useful asset life such that vendors do not include all costs in the initial contract but plan on cost recovery in follow-on contracts?

e. Please explain whether the procurement of panels from suppliers is different in PPA's versus utility ownership? Are PPA's typically sourced from vendors purchasing solar panels in high volumes at greater economies of scale than from a utility?

f. To the extent available and for each existing utility owned utility scale solar, please provide the contemporaneous comparable PPA benchmarks known to the utility.

RESPONSE:

a. In general, the entire PPA cost is recovered through the PPFAC and the REST surcharge (Market Cost of Comparable Conventional Generation, MCCCG and the Above Market Cost of Comparable Conventional Generation, AMCCCG, respectively). Each mechanism has a true up component associated with it to ensure full and accurate recovery. The utility model, while typically higher in the early years due to the straight-line depreciation method, is more difficult to quantify. Previously, the Commission has authorized the Company to recover certain ownership expenses associated with its investments in renewable energy in between rate cases through the annual REST surcharge, which included carrying costs, book depreciation, property taxes, and O&M. However, the net present value of the annual revenue requirement of the two options is relatively comparable, if not slightly in favor of utility-owned projects.

As of today, TEP no longer asks for recovery of expenses through the annual REST surcharges, which is an advantage to the ratepayer as they do not have to pay for these costs associated with the Company's capital investments in renewable energy between rate cases. The actual amount of savings to the ratepayers varies depending on the time in between the investment and the inclusion in rates.

b. PPA vendors will often use an ownership structure that allows them to market the investment tax credit benefits associated with a renewable energy project to an entity that has a Federal income tax liability ("Tax Equity Investor"). The Tax Equity Investor typically has a near-term tax liability that can be offset with investment tax credits. For a utility owned project, the utility itself must have a Federal income tax liability to use the investment tax credits. Whether a utility has enough Federal income tax liability to use the investment tax credits will depend on the particular facts and circumstances in the tax year. If either the Tax Equity Investor or the utility does not have a near-term tax liability the investment tax credits are carried forward and the benefit will be realized in a subsequent year.

c. Cost overruns associated with a PPA are typically borne by the developer. However, every developer includes a contingency factor in their PPA price to account for potential overruns. The amount of the contingency is dependent upon their risk tolerance and confidence in construction. Utilizing a competitive solicitation DOES NOT guarantee that the ratepayer is receiving the renewable energy at the most prudently incurred least cost, only that the utility will select the least cost option available through the market. Since these models ARE NOT based on the "cost plus" model of utility, there is no prudency determination on the actual costs.

Cost overruns for the utility, on the other hand, are subject to reasonableness and prudency reviews through the Company's general rate cases. It has been regularly recommended by Staff, and ordered by the Commission, in the Company's requests for approval of its Buildout plans that "any costs determined not to be reasonable and prudent be refunded by the Company".

d. The Company's typical PPA's are for a term of 20 years, while it is widely believed that the useful life of a solar facility is between 30-35 years. While this question should be directed to traditional developers regarding actual costs recovered through the PPA, it is the Company's understanding that many PPA's do assume some form of residual value at the end of the PPA. However, the Company cannot confirm what this value is or what impact it has on the initial contract. Regardless, the Company would need to replace the energy source upon expiration of the PPA, even if the PPA facility is still operating. For a utility-owned facility, the Company will continue to obtain energy from the facility even after it is fully depreciated, which benefits customers.

e. Due to the Company's relatively extensive utility-scale Buildout plan over the last several years, there has been no noticeable difference on the reported price of panels that Company procures versus those procured by solar developers.

f. The Company is providing a series of worksheets in order for Staff to determine some form of contemporaneous comparable or equivalent PPA price, with the understanding that there a numerous variables that can affect the equivalent outcome. These spreadsheets are as follows:

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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1. Please see **STF 2.2 UTILITY OWNED PROJECT COSTS-Highly Confidential.xlsx**, which lists the Company's total project cost for each facility. The Excel file is not identified by Bates numbers.
2. Please see **STF 2.1 Renewable Energy Data.xlsx** provided in response to STF 2.1(a), which lists expected annual production and AC system sizes.
3. Please see **STF 2.2 Value of Solar 05-2016-Highly Confidential.xls**, which provides the equivalent LCOE PPA price determination for Company-owned facilities. The Excel file is not identified by Bates numbers.
4. Please see **STF 2.1 TEP UNSE PPA Pricing-Highly Confidential.xlsx** provided in STF 2.1c, which provides PPA contract prices.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
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STF 2.6

To the extent that cost differences exist between PPA's and utility ownership of utility scale solar, should the formula for export pricing of rooftop DG solar, be based on a combination of the costs to customers of PPA's and utility ownership and not solely on PPA's? Why not? Could that formula be based on a weighted average of the percentage of your utilities reliance upon PPA or ownership either historically or as per IRP or both?

RESPONSE:

Under certain conditions, the Company can be supportive of a formulaic approach to calculation of the export rate. Specifically, the Company would be supportive if the following conditions were addressed:

1. A weighted average of all facilities, based on their AC capacity value.
2. Weighting factors that provided greater emphasis on more recent PPA's, which would be more indicative of the current market and *value*, which is what this docket was meant to determine. As such, the Company cannot reasonably support any contractual PPA prices that were entered into more than 5 years prior to the effective date of the calculated price (ie: If the calculated price is for 2017, then the prices for 2016, 2015, 2014, 2013, and 2012 would be included with the appropriate weighting factors.)
3. As has been discussed in the Company's filed testimony and during verbal testimony, the Company continues to believe that there are numerous advantages to a well-planned, grid-operator controlled, three-phase utility scale facility over the random, single-phase distributed generation resources. These advantages have been enumerated by multiple witnesses. As such, the Company would recommend some form of discount to the calculated PPA price if is to be applied to a DG export rate.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

[redacted]

Project Name	Project Owner	AKA	Technology
> Community Solar 5 MW	TEP		Fixed PV
> Fort Huachuca Phase II	TEP	Fort Huachuca Phase II	Fixed PV
> Rehnu Solar	Rehnu, Inc.		Single-Axis CPV
Aminox UASTP Solar Power Generation Station	FRB Solar LLC	Amonix	CPV Dual A
Avalon Solar	Coronal Management, LLC	Avalon Phase I	Single-Axis PV
Avalon Solar II	Centaurus Renewable Energy	Avalon Phase II	Single-Axis PV
Avra Valley	NRG Solar Avra Valley LLC	NRG Avra Valley	Single-Axis PV
Cogenera	WGL Energy	Cogenra	CPV
DeMoss Petrie	Tep	TEP	Fixed
E.On Tech Park	Tech Park Solar, LLC	E.On UASTP	Single-Axis PV
Fort Huachuca Phase I	TEP	Fort Huachuca Phase I	Fixed PV
Gato Montes Solar	Gato Montes Solar, LLC	AstroSol/Astronergy	Fixed PV
Macho Springs	Capital Power	Macho Springs	Wind
Picture Rocks	Picture Rocks Solar, LLC	FRV Marana	Single-Axis PV
Red Horse Solar	Red Horse Wind 2, LLC	Red Horse Solar	Single-Axis PV
Red Horse Wind	Red Horse Wind 2, LLC	Red Horse Wind	Wind
Solon Prairie Fire	TEP	DM Air Corridor project	Fixed PV
Springerville .81 expansion	TEP	Springerville	Fixed PV
Springerville 1.0 expansion	TEP	Springerville	Fixed PV
Springerville 4.6	TEP	Springerville	Fixed PV
Sundt - Los Reales	TEP	Sundt - Los Reales	Biogas
Sundt Augmentation	TEP	Areva Solar Thermal	Thermal

SunPower HQ	TEP	Rooftop	Fixed PV
SunPower OH	TEP	Rooftop	Fixed PV
UASTP I	TEP	UASTP 1.6 Solon	Single-Axis PV
UASTP II	TEP	Solon 5 UASTP TEP Owned	Fixed PV
Valencia Solar	Valencia Solar, LLC	E. On Valencia	Single-Axis PV
White Mountain Solar	TEP	Springerville 10 - SunPower	Fixed / LCPV

Totals

> Project is still under construction/in development

Project Name	Project Owner	AKA	Technology
> GrayHawk Solar (PURPA)	LS-Cliffrose, LLC		Single-Axis PV
> Jacobson 5 MW	UNSE		Fixed PV
> Red Horse Expansion	Red Horse Wind 2, LLC	Red Horse Solar	Single-Axis PV
Black Mountain Solar	Black Mountain, LLC	Black Mountain Solar Facility (BMSF)	Single-Axis PV
Kingman Wind Farm	Brookfield Renewable Energy Group	Western Wind/Kingman	Wind
Kingman Wind Farm (Solar)	Brookfield Renewable Energy Group	Western Wind/Kingman	Solar
La Senita	UNSE	La Senita	Single-Axis PV
Rio Rico	UNSE	UNSE	Santa Cruz Valley Project	Fixed PV

	Totals

> Project is still under construction/in development	**Totals**

Utility Scale Renewable Portfolio

TEP

DC MW Capacity	AC MW Capacity	Estimated Annual Energy, GWh	COD	FERC Dockets	Site Location	County
5.00	4.00	8.76			Tucson, Az	Pima County
5.00	4.00	8.76			Fort Huachuca, Sierra Vista, AZ	Cochise County
0.05	0.04	0.1			UA Tech Park	Cochise County
2.00	1.20	2.63	3/31/2011	QF11-30	UA Tech Park	Pima County
35.00	28.34	62.06	12/23/2014	QR14-737	Sahuarita	Pima County
21.53	17.22	37.71	3/2/2016		Sahuarita	Pima County
34.41	25.00	54.75	12/14/2012	ER12-2019 MBR	Marana, Az	Pima County
1.38	1.10	2.42	7/1/2014	N/A	UA Tech Park	Pima County
0.22	0.18	0.39	6/6/2001		DeMoss Petrie Sub Station	Pima County
6.60	4.80	10.51	12/28/2012	QF13-540	UA Tech Park	Pima County
17.20	13.60	29.78	12/9/2014		Fort Huachuca, Sierra Vista, AZ	Cochise County
6.00	4.92	10.77	12/19/2012	QF12-478	Tech Park	Pima County
[redacted]	50.40	110.38	11/15/2011	ER11-3051 MBR Dkt	Deming, NM	Luna County
25.00	20.00	43.80	12/5/2012	QF13-22	Marana, Az	Pima County
51.25	41.00	89.8	08/31/2015		Wilcox, Az	Cochise County
[redacted]	30.00	65.70	08/31/2015		Wilcox, Az	Cochise County
5.00	4.00	8.76	12/28/2012		Old Vail & Valencia	Pima County
0.81	0.65	1.42	12/30/2010		Springerville, Az	Apache County
1.00	0.80	1.75	12/30/2010		Springerville, Az	Apache County
4.60	3.68	8.06	6/6/2004		Springerville, Az	Apache County
[redacted]	4.00	8.76	1/20/1998		Los Reales Landfill	Pima County
[redacted]	5.00	10.95	12/30/2014		Sundt #4	Pima County

0.05	0.04	0.088	6/7/2012		HQ	Pima County
0.50	0.40	0.88	6/6/2012		OH	Pima County
1.60	1.28	2.80	12/31/2010		UA Tech Park	Pima County
5.00	4.00	8.76	12/29/2011		UA Tech Park	Pima County
13.20	10.00	21.90	6/28/2013	QF13-59	Valencia & I-10	Pima County
10.00	8.25	18.07	12/12/2014		Springerville	Apache County

DC MW Capacity	AC MW Capacity	Annual Energy, GWh	Total DC + AC only units MW	
242.35	**279.86**	**612.89**	**331.75**	Current
247.40	**283.90**	**621.75**	**336.80**	By End of 2016
252.40	**287.90**	**630.51**	**341.80**	By End of 2017

UNSE

DC MW Capacity	AC MW Capacity	Annual Energy, GWh	COD		Site	County
57.50	46.00	100.74			Kingman, Az	Mohave County
5.00	4.00	8.76			Kingman, Az	Mohave County
37.50	30.00	65.7			Wilcox, Az	Cochise County
9.87	8.90	19.49	12/1/2012	QF13-24	Kingman, Az	Mohave County
	10.00	21.90	9/16/2011	QF11-5	Kingman, Az	Mohave County
0.30	0.24	0.53	9/16/2011		Kingman, Az	Mohave County
1.22	0.98	2.14	11/4/2011		Kingman, Az	Mohave County
7.20	5.76	12.61	3/1/2014		Rio Rico, Az	Santa Cruz County

DC MW Capacity	AC MW Capacity	Annual Energy, GWh		Total DC + AC only units MW	
18.59	25.88	56.67		28.59	Current
61.09	59.88	131.13		71.09	By End of 2016
118.59	105.88	231.87		128.59	By End of 2017

TOTAL UNS PORTFOLIO

DC MW Capacity	AC MW Capacity	Annual Energy, GWh		Total DC + AC only units MW	
260.94	305.73	669.56		360.34	Current
308.49	343.78	752.87		407.89	By End of 2016
370.99	393.78	862.37		470.39	By End of 2017

Revised 04-25-2016 JK

[redacted]

Term	Comments
Own	Estimated COD 08/15/2017
Own	Esimated COD 10/05/2016
20	Esimated COD 6/01/2016
20	
20	
20	
20	
20	
Own	
20	
Own	
20	
20	
20	
20	
20	
Own	
Own	
Own	
Own	
Through 2017	
Own	

Own		
Own		
Own		
Own		
20		
Own		

RESIDENTIAL	NON RESIDENTIAL	Total TEP Portfolio MW Utility+Resi+Non Resi
76	78	485.75

Term	Comments
20	Esimated COD Q2 2017
Own	Esimated COD 12/2/2016
20	Esimated COD 05/18/2016
20	
20	Project is broken out from wind and solar to differentiate AC to DC values
20	
Own	
Own	

RESIDENTIAL	NON RESIDENTIAL	Total TEP Portfolio MW Utility+Resi+Non Resi
16.15	9.07	53.81

RESIDENTIAL	NON RESIDENTIAL	Total TEP Portfolio MW Utility+Resi+Non Resi
92.15	87.07	539.56

(*From left to right: most recent entity to oldest entity)

Name of System	AKA (Tags)	**Current Owner**	Previous Entitiy I	Previous Entitiy II	Previous Entitiy III
Black Solar Facility	Black Mountain Solar Facility (BMSF)	Black Mountain, LLC	Duke Energy		
Kingman Wind Farm	Western Wind/Kingman	Brookfield Renewable Energy Group	Kingman Energy Corp.	Western Wind Energy Corp	
Macho Springs	Macho Springs	Capital Power	Element Power US, LLC	Macho Springs Power	
Avalon Solar	Avalon Phase I	Coronal Management, LLC	Centaurus Renewable Energy LLC	Avalon Solar Partners LLC	Equator Solar LLC
Aminox UASTP Solar Power Generation Station 1 LLC	Aminox, UASTP	FRB Solar LLC	Amonix		
Gato Montes Solar, LLC	Astrosol, Astronergy	Gato Montes Solar, LLC	Duke Energy	First Light LLC	Astronergy
Avra Valley	NRG, Avra Valley	NRG Solar Avra Valley, LLC			
Picture Rocks	FRV, Marana	Picture Rocks Solar LLC	SunEdison	Fotowataio	MMA Renewables
E.On Tech Park	E.On UASTP	Tech Park Solar, LLC	E.On	FSP Solar II (Foresight)	
Valencia Solar, LLC	E.On Valencia	Valencia Solar, LLC	EC&R NA Solar PV, LLC	FSP Solar I (Foresight)	
Cogenera	Cogenera	Washington Gas	Emcore Solar Arizona	Green Volts	

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 May 26, 2016

STF 2.2

Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity.

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g, The cost per kWh generated over the life of the facility.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

RESPONSE: May 13, 2016

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

a. The Company does not retain start of construction data.

b. Please see **STF 2.1 Renewable Energy Data.xlsx** for project COD dates.

c. Company owned facilities' life expectancy is 30 years. PPA's are 20 years.

d. Please see **STF 2.1 Renewable Energy Data.xlsx** for project technologies.

e. Please see **STF 2.2 Value of Solar 05-2016-Highly Confidential.xlsx**.

f. Please see **STF 2.2 Utility Owned Project Costs-Highly Confidential.xlsx**. The Excel file is <u>not</u> identified by Bates numbers.

g. Please see **STF 2.2 Utility Owned Project Costs-Highly Confidential.xlsx.**

h. The responsive contract to this request is the E.On Tech Park PPA. Once permission has been obtained from the counterparty, the Company will provide the contract to the requesting party in response to STF 2.1e.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 May 26, 2016

SUPPLEMENTAL RESPONSE: May 24, 2016

Nine additional subparts have been added to STF 2.2, based on a call from the ACC. The following responses are provided.

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

1. **Update utility owned spreadsheet to show the annual cost per kWh for each project**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

2. **Attach to spreadsheet a graph showing the declining costs over life for utility owned projects, including a weighted average cost (will use a capacity based weighted average cost and use weather-normalized production values on a forward looking basis).**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx.

3. **Attach a graph showing the weighted average of all relevant technologies (utility-owned and PPA's – do not use 2004 Springerville project or Areva Steam Augmentation project)**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx.

4. **Provide copies of the Red Horse PPA (missing from attached PPA's)**

   Response: TEP received correspondence from Red Horse notifying the Company that Red Horse is unable to grant consent for the Company to provide their agreements until they have completed their due diligence, which may also include consent from their financing parties, as required by their financing agreements. TEP will provide these agreements as soon as consent has been obtained.

   Additionally, the Company is providing a copy of the Cliffrose Solar PPA solar PPA that was entered into under PURPA, and filed with the Commission. Please refer to Docket No. E-04204A-15-0314, dated August 31, 2015. See document titled STF 2.2 Cliffrose Solar PPA_PURPA.pdf, Bates Nos. TEP\007445-007493.

5. **Provide copies of the Solon E&D and P&C agreements (standardized)**

   Response: The Company is providing more recent standardized E&D and P&C documents that were utilized for the Rio Rico facility. Please see Competitively Sensitive and Highly Confidential documents titled:

File Name	Bates Numbers
STF 2.2 UNSE Gehrlicher P&C Agreement (Rio Rico) 12-21-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007609-007673
STF 2.2 UNSE Gehrlicher E&D Agreement (Rio Rico) 12-21-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007674-007752

6. **Provide copies of the E.On E&D and P&C agreements (non-standardized used at Fort Huachuca).**

   Response: Please see the following files for the E.On E&D and P&C agreements.

File Name	Bates Numbers
STF 2.2 TEP EON Ft Huachuca E&D Agmt 01-14-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007494-007546
STF 2.2 TEP EON Ft Huachuca P&C Agrmrt EXECUTION VERSION 3-5-14-HIGHLY CONFIDENTIAL.pdf	TEP\007547-007608

7. **Provide a copy of TEP's response to RUCO DR that provided a timeline for renewables to meet the proposed 30% by 2030**

   Response: Please see STF 2.1 Projected Renewables through 2025-HIGHLY CONFIDENTIAL.xlsx. The Excel file is not identified by Bates numbers.

8. **30 year comparison of utility owned versus a PPA LCOE PPA**

   Response: Please see STF 2.2 Ownership model-Tracking PV-HIGHLY CONFIDENTIAL.xls

9. **Total PPA contract costs through 2025 by year**

   Response: Please see STF 2.2 TEP & UNSE PPA's estimated obligations 2016-05-20-HIGHLY CONFIDENTIAL.xlsx.

RESPONDENT:

Carmine Tilghman / David Lewis

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 May 26, 2016

SUPPLEMENTAL RESPONSE: May 26, 2016

THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

TEP received permission to release the Red Horse PPAs as highly confidential documents pursuant to the terms of the Protective Order dated May 10, 2016, which are listed below:

File Name	Bates Numbers
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 1st Amendment Signed 2-12-2014-HIGHLY CONFIDENTIAL.pdf	TEP\007753-007760
STF 2.2 TEP Red Horse Wind 2 RH3 (Torch) PPA 3rd Amendment signed 08-05-2015-HIGHLY CONFIDENTIAL.pdf	TEP\007761-007807
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 2nd Amendment 02-12-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007808-007812
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 2-20-13 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007813-007823

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 May 16, 2016

STF 2.1

Please provide information on all utility-scale solar renewable PPAs, with an effective date on or after January 1, 2008, including:

a. The effective date

b. Term of the PPA

c. Actual price per kWh to the utility and any other charges, by year for the life of the contract, and

d. Type(s) of renewable technology for each PPA.

e. Please also provide a copy of each PPA, including term sheet.

RESPONSE: May 13, 2016

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

a. Please see **STF 2.1 TEP UNSE PPA Pricing-Highly Confidential.xlsx** for specific contract and amendment dates. The Excel file is <u>not</u> identified by Bates numbers.

b., d. Please see **STF 2.1 Renewable Energy Data.xlsx.**

c. Please see **STF 2.1 TEP UNSE PPA Pricing-Highly Confidential.xlsx**. The Excel file is <u>not</u> identified by Bates numbers.

e. TEP is not able to provide the requested PPAs without counterparty permissions. Accordingly, the Company is in the process of seeking counterparty authorizations and anticipates providing the PPAs where approvals were not denied on Monday, May 16, 2016.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: May 16, 2016

THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

e. The Company provided the counterparties to the PPAs until May 16, 2016 to object to the Company providing their PPA(s) in response to this data request pursuant to the Protective

Order in this docket. Attached are the PPAs for the following counterparties that did not object and that are being provided. The following counterparty did not provide consent and the Company is, therefore, unable to provide it.

File Name	Bates Numbers
STF 2.1 TEP Amonix UASTP Solar PPA 2 MW 4-19-2010 Signed-1-HIGHLY CONFIDENTIAL.pdf	TEP\006628-006671
STF 2.1 TEP Amonix UASTP Solar PPA Amendment No 1 8-22-2011 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006672-006674
STF 2.1 TEP Amonix UASTP Solar PPA Amendment No 2 7-30-2013 Signed-1-HIGHLY CONFIDENTIAL.pdf	TEP\006675-006679
STF 2.1 TEP Avalon Solar II Phase II PPA 12-17-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006680-006736
STF 2.1 TEP Avalon Solar PPA 35MW 4-19-10 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006737-006781
STF 2.1 TEP Avalon Solar PPA Amendment No. 1 35 MW 7-21-11 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006782-006784
STF 2.1 TEP Avalon Solar PPA Amendment No. 2 35 MW 9-27-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006785-006788
STF 2.1 TEP Avalon Solar PPA Amendment No. 3 35 MW 12-20-13 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006789-006795
STF 2.1 TEP Avalon Solar PPA Amendment No. 4 35 MW 1-17-14 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006796-006799
STF 2.1 TEP Avalon Solar PPA Consent to Assignment 35MW 9-27-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006800-006803
STF 2.1 TEP Avalon Solar PPA Exhibit E 1-17-14 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006804-006805
STF 2.1 TEP Avalon Solar PPA Exhibit G 1-17-14 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006806-006807
STF 2.1 TEP Cogenra (Washington Gas) PPA 3-21-13 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006808-006850
STF 2.1 TEP Cogenra (Washington Gas) PPA Amendment No 1 9-19-13 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006851-006853
STF 2.1 TEP Cogenra (Washington Gas) PPA Amendment No 2 10-13-15-HIGHLY CONFIDENTIAL.pdf	TEP\006854-006860
STF 2.1 TEP Cogenra (Washington Gas) PPA Assignment 09-24-13 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006861-006865
STF 2.1 TEP Cogenra (Washington Gas) PPA Exhibit B 8-28-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006866-006867

STF 2.1 TEP FRV (Picture Rocks Solar) PPA 9-1-09 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006868-006912
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Amendment No 1 6-3-10 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006913-006922
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Amendment No 2 5-23-11 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006923-006925
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Amendment No 3 3-12-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\006926-006930
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Amendment No 4 11-16-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006931-006933
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Exhibit B 11-5-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006934-006936
STF 2.1 TEP FRV (Picture Rocks Solar) PPA Letter Agreement Sect 4.10 11-2-2012 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006937-006939
STF 2.1 TEP FSP Solar I (E.On Valencia) PPA 12 MW 04-16-10 signed-1-HIGHLY CONFIDENTIAL.pdf	TEP\006940-006986
STF 2.1 TEP FSP Solar I (E.On Valencia) PPA 12 MW Exhibit B 6-26-13 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006987-006988
STF 2.1 TEP FSP Solar I (E.On Valencia) PPA 12 MW Exhibit E 6-27-13 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006989-006990
STF 2.1 TEP FSP Solar I (E.On Valencia) PPA 12 MW Revised Exhibits B-C 9-24-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\006991-006993
STF 2.1 TEP FSP Solar II (E.On Valencia) PPA 4 MW 04-16-10 signed-1-HIGHLY CONFIDENTIAL.pdf	TEP\006994-007040
STF 2.1 TEP FSP Solar II (E.On) PPA 4 MW 04-16-12 signed conformed-HIGHLY CONFIDENTIAL.pdf	TEP\007041-007088
STF 2.1 TEP Gatos (Astrosol First Light) PPA (EXIBITS B E and G) 8-28-2012 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007089-007093
STF 2.1 TEP Gatos (Astrosol First Light) PPA 5 MW 4-19-10 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007094-007140
STF 2.1 TEP Gatos (Astrosol First Light) PPA Amendment No 1 3-22-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007141-007144
STF 2.1 TEP Gatos (AstroSol First Light) PPA Amendment No 2 12-10-12 Signed-1-HIGHLY CONFIDENTIAL.pdf	TEP\007145-007150
STF 2.1 TEP Gatos (Astrosol First Light) PPA Assignment 12-5-11 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007151-007153
STF 2.1 TEP Macho Springs -Capital Power Letter of Entity Change 1-5-15 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007154-007156
STF 2.1 TEP Macho Springs Power 1 (Torch Energy) PPA 50MW wind 4-19-10 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007157-007202

STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA 25MW 4-29-10 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007203-007249
STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA Amendment No 1 8-10-11-HIGHLY CONFIDENTIAL.pdf	TEP\007250-007256
STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA Amendment No 2 8-23-11 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007257-007260
STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA Amendment No 3 9-2011 Signed only by TEP-HIGHLY CONFIDENTIAL.pdf	TEP\007261-007264
STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA Amendment No 4 1-19-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007265-007268
STF 2.1 TEP NRG SOLAR AVRA VALLEY PPA Amendment No. 5 9-16-13 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007269-007274
STF 2.1 TEP REHNU PPA 3-08-16 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007275-007322
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA 9-23-10 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007323-007365
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA Amendment 1 10-11-11 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007366-007376
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA Amendment 2 9-28-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007377-007381
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA Assignment 10-13-11 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007382-007385
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA Exhibit E 3-5-12 Signed-HIGHLY CONFIDENTIAL.pdf	TEP\007386-007387
STF 2.1 UNSE Black Mountain (Solon UNSE1) PPA Letter Agreement 5-26-11 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007388-007398
STF 2.1 UNSE Western Wind (Kingman Energy) PPA 1st Amend 12-02-11 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007399-007401
STF 2.1 UNSE Western Wind PPA Wind and Solar 10-16-09 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007402-007444

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023
May 26, 2016

STF 2.2

Please provide the following information on any utility-scale solar renewable generation built and owned by the utility with a date construction began after January 1, 2008, including:

a. Date construction began

b. Date the facility began generating electricity.

c. Life expectancy of facility

d. Type(s) of renewable technology at each facility

e. Total revenue requirement resulting from each facility by year for depreciable life

f. Total cost of the facility, and

g, The cost per kWh generated over the life of the facility.

h. If the utility contracted with a developer to build the facility and the utility subsequently bought the plant, please provide a copy of the relevant contracts.

RESPONSE: May 13, 2016

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a. The Company does not retain start of construction data.

b. Please see **STF 2.1 Renewable Energy Data.xlsx** for project COD dates.

c. Company owned facilities' life expectancy is 30 years. PPA's are 20 years.

d. Please see **STF 2.1 Renewable Energy Data.xlsx** for project technologies.

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h. The responsive contract to this request is the E.On Tech Park PPA. Once permission has been obtained from the counterparty, the Company will provide the contract to the requesting party in response to STF 2.1e.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023

May 26, 2016

SUPPLEMENTAL RESPONSE: May 24, 2016

Nine additional subparts have been added to STF 2.2, based on a call from the ACC. The following responses are provided.

SOME OF THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

1. **Update utility owned spreadsheet to show the annual cost per kWh for each project**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx. The Excel file is not identified by Bates numbers.

2. **Attach to spreadsheet a graph showing the declining costs over life for utility owned projects, including a weighted average cost (will use a capacity based weighted average cost and use weather-normalized production values on a forward looking basis).**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx.

3. **Attach a graph showing the weighted average of all relevant technologies (utility-owned and PPA's – do not use 2004 Springerville project or Areva Steam Augmentation project)**

   Response: Please see STF 2.2 Value of Solar 05-2016 w-PPA-Highly Confidential.xlsx.

4. **Provide copies of the Red Horse PPA (missing from attached PPA's)**

   Response: TEP received correspondence from Red Horse notifying the Company that Red Horse is unable to grant consent for the Company to provide their agreements until they have completed their due diligence, which may also include consent from their financing parties, as required by their financing agreements. TEP will provide these agreements as soon as consent has been obtained.

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STF 2.2 UNSE Gehrlicher E&D Agreement (Rio Rico) 12-21-12 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007674-007752

6. **Provide copies of the E.On E&D and P&C agreements (non-standardized used at Fort Huachuca).**

Response: Please see the following files for the E.On E&D and P&C agreements.

File Name	Bates Numbers
STF 2.2 TEP EON Ft Huachuca E&D Agmt 01-14-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007494-007546
STF 2.2 TEP EON Ft Huachuca P&C Agrmrt EXECUTION VERSION 3-5-14-HIGHLY CONFIDENTIAL.pdf	TEP\007547-007608

7. **Provide a copy of TEP's response to RUCO DR that provided a timeline for renewables to meet the proposed 30% by 2030**

Response: Please see STF 2.1 Projected Renewables through 2025-HIGHLY CONFIDENTIAL.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

8. **30 year comparison of utility owned versus a PPA LCOE PPA**

Response: Please see STF 2.2 Ownership model-Tracking PV-HIGHLY CONFIDENTIAL.xls

9. **Total PPA contract costs through 2025 by year**

Response: Please see STF 2.2 TEP & UNSE PPA's estimated obligations 2016-05-20-HIGHLY CONFIDENTIAL.xlsx.

RESPONDENT:

Carmine Tilghman / David Lewis

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 May 26, 2016

SUPPLEMENTAL RESPONSE: May 26, 2016

THE FILES LISTED BELOW CONTAIN "HIGHLY CONFIDENTIAL" INFORMATION PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (DATED MAY 10, 2016) WHICH ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY WHO HAVE SIGNED THE PROTECTIVE ORDER. ALL OTHER PARTIES WHO WANT THIS INFORMATION SHOULD CONTACT THE COMPANY.

TEP received permission to release the Red Horse PPAs as highly confidential documents pursuant to the terms of the Protective Order dated May 10, 2016, which are listed below:

File Name	Bates Numbers
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 1st Amendment Signed 2-12-2014-HIGHLY CONFIDENTIAL.pdf	TEP\007753-007760
STF 2.2 TEP Red Horse Wind 2 RH3 (Torch) PPA 3rd Amendment signed 08-05-2015-HIGHLY CONFIDENTIAL.pdf	TEP\007761-007807
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 2nd Amendment 02-12-14 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007808-007812
STF 2.2 TEP Red Horse Wind 2 (Torch) PPA 2-20-13 signed-HIGHLY CONFIDENTIAL.pdf	TEP\007813-007823

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

La Senita Single-Axis System - UNSE

1 MW HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/KWh)

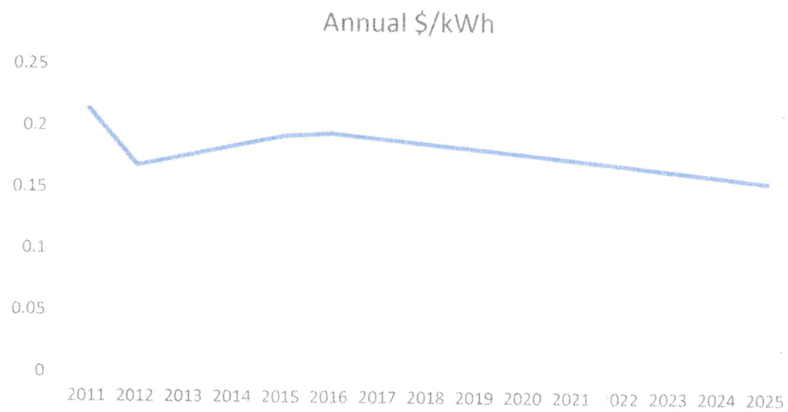
Assumptions		DPIS - 2011
Original Cost	$ 5,308,701	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.95%	
Debt Return (wtd cost)	2.83%	
Equity Return (wtd cost)	5.00%	
Tax Depreciation (Yrs)	6	
ITC Claimed	1,592,610	796305.15

Original Cost	$ 5,308,701
ITC @ 30%	$ 1,592,610.30
Depeciable Tax Basis	$ 4,512,395.85
Tax Basis After 50% Bonus	$ 2,256,197.93

	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8
Property Tax Rate	11.237%	11.462%	11.691%	11.925%	12.163%	12.407%	12.655%	12.908%
	1	2	3	4	5	6	7	8
Year	2011	2012	2013	2014	2015	2016	2017	2018
Tax Depreciation	$ 4,512,396							
Tax Depreciation included in Rate Base	$ 161,157	$ 4,351,239	$ -	$ -	$ -	$ -	$ -	$ -
Book Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Less: Book Depr on ITC Adj	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
Timing Difference	(0)	4,190,082	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
Def. Tax @ 38.95%	(0)	1,632,037	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
A.D.I.T.	(0)	1,632,037	1,569,266	1,506,496	1,443,725	1,380,954	1,318,184	1,255,413
Plant in Service	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
Accum. Depreciation	(189,596)	(379,193)	(568,789)	(758,386)	(947,982)	(1,137,579)	(1,327,175)	(1,516,772)
Net Plant in Service	5,119,105	4,929,508	4,739,912	4,550,315	4,360,719	4,171,122	3,981,526	3,791,929
Unamortized ITC	(1,433,349)	(1,114,827)	(796,305)	(477,783)	(159,261)			
Unamortized ITC included in Rate Base	$ (1,433,349)	$ (1,114,827)	$ (796,305)	$ (477,783)	$ (159,261)			
A.D.I.T.	0	(1,632,037)	(1,569,266)	(1,506,496)	(1,443,725)	(1,380,954)	(1,318,184)	(1,255,413)
Net Rate Base	3,685,755	2,182,644	2,374,340	2,566,036	2,757,733	2,790,168	2,663,342	2,536,516
Return on Rate Base:								
Debt Return	184,177	109,067	118,646	128,225	137,804	139,425	133,087	126,750
Equity Return	104,299	61,764	67,189	72,613	78,038	78,956	75,367	71,778
Total	288,476	170,831	185,834	200,838	215,842	218,380	208,454	198,528
Operating Expenses & Taxes:								
Operations and Maintenance	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743
Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Property Taxes(1)	21,475	21,175	20,853	20,511	20,146	19,759	19,348	18,912
Total	216,072	215,871	215,652	215,413	215,155	214,876	214,575	214,252
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate	66,543	39,406	42,866	46,327	49,788	50,374	48,084	45,794
Revenue Requirement	$ 571,091	$ 426,107	$ 444,353	$ 462,579	$ 480,785	$ 483,630	$ 471,113	$ 458,574
NPV Cost	$ 4,696,059							
Estimated Output (KWh)	2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917	2,464,532
NPV Output	27,557,562							
LCOE ($/KWh)	$ 0.17							

(1) Property taxes are the product of net book value x assesment rate x property tax rate x a 18% valuation factor - then increase the tax rate annually by the escalation factor

2011	2012	2013	2014	2015	2016	2017	2018
0.21374751	0.167773387	0.175836373	0.183968526	0.19216993	0.194278456	0.190201417	0.186069532



$ -

13.166%	13.429%	13.698%	13.972%	14.251%	14.536%	14.827%	15.124%	15.426%	15.735%
Yr.9	Yr. 10	Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18
9	10	11	12	13	14	15	16	17	18
2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
1,192,642	1,129,872	1,067,101	1,004,330	941,560	878,789	816,018	753,248	690,477	627,706
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(1,706,368)	(1,895,965)	(2,085,561)	(2,275,158)	(2,464,754)	(2,654,351)	(2,843,947)	(3,033,543)	(3,223,140)	(3,412,736)
3,602,333	3,412,736	3,223,140	3,033,543	2,843,947	2,654,351	2,464,754	2,275,158	2,085,561	1,895,965
(1,192,642)	(1,129,872)	(1,067,101)	(1,004,330)	(941,560)	(878,789)	(816,018)	(753,248)	(690,477)	(627,706)
2,409,690	2,282,865	2,156,039	2,029,213	1,902,387	1,775,561	1,648,736	1,521,910	1,395,084	1,268,258
120,412	114,075	107,737	101,400	95,062	88,725	82,387	76,050	69,712	63,375
68,189	64,600	61,011	57,422	53,833	50,244	46,656	43,067	39,478	35,889
188,601	178,675	168,748	158,822	148,896	138,969	129,043	119,117	109,190	99,264
5,858	5,975	6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
18,452	17,966	17,452	16,911	16,342	15,742	15,113	14,452	13,758	13,031
213,907	213,537	213,144	212,725	212,279	211,807	211,307	210,777	210,218	209,628
43,505	41,215	38,925	36,635	34,346	32,056	29,766	27,477	25,187	22,897
$ 446,013	$ 433,427	$ 420,817	$ 408,182	$ 395,521	$ 382,832	$ 370,116	$ 357,370	$ 344,595	$ 331,789
2,452,210	2,439,949	2,427,749	2,415,610	2,403,532	2,391,514	2,379,557	2,367,659	2,355,821	2,344,042

2019	2020	2021	2022	2023	2024	2025
0.181881898	0.177637818	0.173336424	0.168976827	0.164558122	0.160079451	0.155539798

16.049%	16.370%	16.698%	17.032%	17.372%	17.720%	18.074%	18.435%	18.804%	19.180%
Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23	Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28
19	20	21	22	23	24	25	26	27	28
2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
564,936	502,165	439,395	376,624	313,853	251,083	188,312	125,541	62,771	(0)
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(3,602,333)	(3,791,929)	(3,981,526)	(4,171,122)	(4,360,719)	(4,550,315)	(4,739,912)	(4,929,508)	(5,119,105)	(5,308,701)
1,706,368	1,516,772	1,327,175	1,137,579	947,982	758,386	568,789	379,193	189,596	0
(564,936)	(502,165)	(439,395)	(376,624)	(313,853)	(251,083)	(188,312)	(125,541)	(62,771)	0
1,141,432	1,014,607	887,781	760,955	634,129	507,303	380,477	253,652	126,826	0
57,037	50,700	44,362	38,025	31,687	25,350	19,012	12,675	6,337	0
32,300	28,711	25,122	21,533	17,944	14,356	10,767	7,178	3,589	0
89,337	79,411	69,485	59,558	49,632	39,706	29,779	19,853	9,926	0
7,141	7,284	7,430	7,578	7,730	7,884	8,042	8,203	8,367	8,534
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
12,269	11,471	10,637	9,765	8,853	7,902	6,908	5,872	4,792	3,666
209,007	208,352	207,663	206,940	206,180	205,383	204,547	203,672	202,755	201,797
20,607	18,318	16,028	13,738	11,449	9,159	6,869	4,579	2,290	0
$ 318,951	$ 306,081	$ 293,176	$ 280,236	$ 267,260	$ 254,247	$ 241,195	$ 228,104	$ 214,971	$ 201,797
2,332,321	2,320,660	2,309,057	2,297,511	2,286,024	2,274,594	2,263,221	2,308,999	2,297,338	2,285,851

HIGHLY CONFIDENTIAL

	La Senita Esimated KWh	
COD:11/4/2011	Contract Year	Estimated Power Production (KWh)
2012	1	2,671,800
2013	2	2,539,780
2014	3	2,527,081
2015	4	2,514,445
2016	5	2,501,873
2017	6	2,489,364
2018	7	2,476,917
2019	8	2,464,532
2020	9	2,452,210
2021	10	2,439,949
2022	11	2,427,749
2023	12	2,415,610
2024	13	2,403,532
2025	14	2,391,514
2026	15	2,379,557
2027	16	2,367,659
2028	17	2,355,821
2029	18	2,344,042
2030	19	2,332,321
2031	20	2,320,660
2032	21	2,309,057
2033	22	2,297,511
2034	23	2,286,024
2035	24	2,274,594
2036	25	2,263,221
2037	26	2,308,999
2038	27	2,297,338
2039	28	2,285,851
		67,139,011

Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
Fort Huahuca	TEP	Fixed PV	$ 0.07	2014
Rio Rico	UNSE	Fixed PV	$ 0.09	2014
Prairie Fire	TEP	Fixed PV	$ 0.13	2012
La Senita	UNSE	Single Axix PV	$ 0.17	2011
UASTP II	TEP	Fixed PV	$ 0.14	2011
UASTP I	TEP	Single Axix PV	$ 0.12	2010
Springerville 1.8	TEP	Fixed PV	$ 0.15	2010
Springerville 4.6	TEP	Fixed PV	$ 0.30	2004

Non-Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
White Mtn	TEP	Low Concentrating PV	$ 0.17	2014
Areva	TEP	Solar Thermal Steam Augmentation	$ 0.06	2014

HIGHLY CONFIDENT

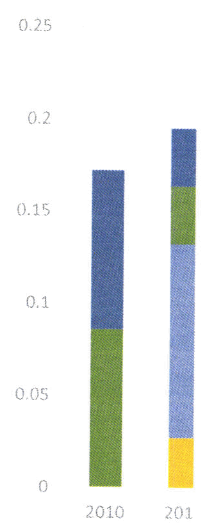
Cost

Fort Huahuca
Rio Rico
Prairie Fire
La Senita
UASTP II
UASTP I
Springerville 1.8
White Mtn

Output

Fort Huahuca
Rio Rico
Prairie Fire
La Senita
UASTP II
UASTP I
Springerville 1.8
White Mtn

Fort Huahuca
Rio Rico
Prairie Fire
La Senita
UASTP II
UASTP I
Springerville 1.8
White Mtn
$/kWh



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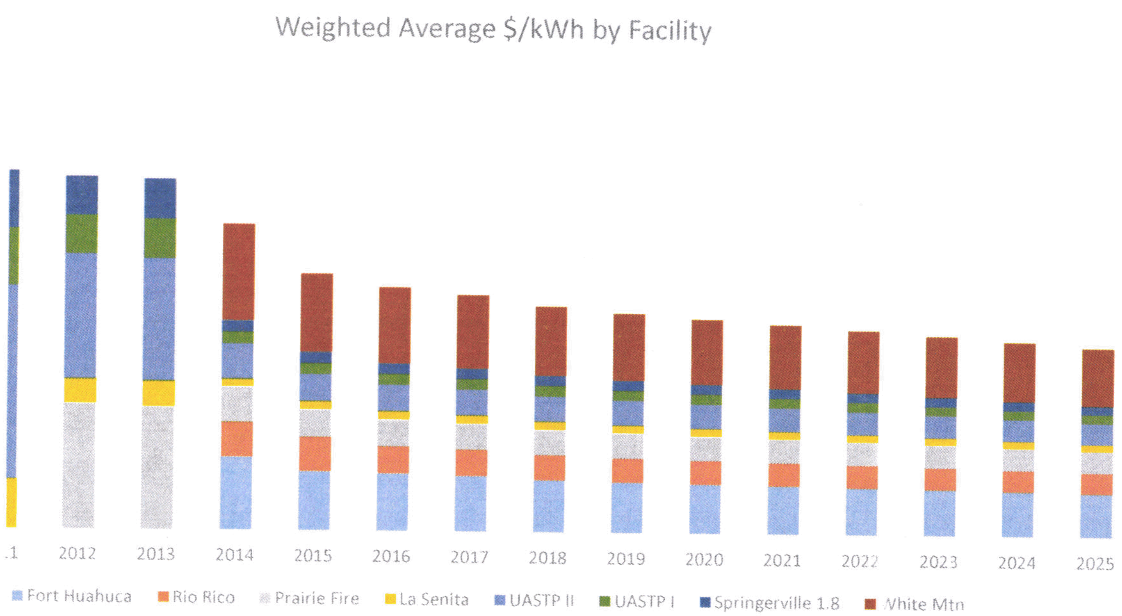
2010	2011	2012	2013	2014	2015	2016	2017	2018
				$ 4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558	$ 3,024,956
				2,044,267	1,990,607	1,569,739	1,505,232	1,440,663
		2,168,426	2,112,189	2,055,913	1,608,682	1,552,322	1,495,919	1,457,584
	571,091	426,107	444,353	462,579	480,785	483,630	471,113	458,574
	2,211,064	2,153,718	2,096,331	2,038,902	1,556,596	1,517,550	1,478,457	1,439,316
640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798	603,077
640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798	603,077
				5,639,668	4,554,957	4,404,485	4,253,913	3,962,039
$ 1,281,833	$ 4,096,761	$ 6,095,598	$ 6,032,926	$ 17,958,572	$ 14,975,097	$ 14,163,096	$ 13,691,789	$ 12,989,287

2010	2011	2012	2013	2014	2015	2016	2017	2018
				38,635,000	38,441,825	38,249,616	38,058,368	37,868,076
				15,768,000	15,689,160	15,610,714	15,532,661	15,454,997
		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579
	2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917	2,464,532
	10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451
3,504,000	3,486,480	3,469,048	3,451,702	3,434,444	3,417,272	3,400,185	3,383,184	3,366,268
3,942,000	3,922,290	3,902,679	3,883,165	3,863,749	3,844,431	3,825,208	3,806,082	3,787,052
				21,900,000	21,790,500	21,681,548	21,573,140	21,465,274
7,446,000	21,030,570	31,756,756	31,597,972	107,742,982	107,204,267	106,668,246	106,134,905	105,604,230

2010	2011	2012	2013	2014	2015	2016	2017	2018
				0.04	0.03	0.03	0.03	0.03
				0.02	0.02	0.01	0.01	0.01
		0.07	0.07	0.02	0.02	0.01	0.01	0.01
	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.00
	0.11	0.07	0.07	0.02	0.01	0.01	0.01	0.01
0.09	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01
0.09	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01
				0.05	0.04	0.04	0.04	0.04
0.17	0.19	0.19	0.19	0.17	0.14	0.13	0.13	0.12

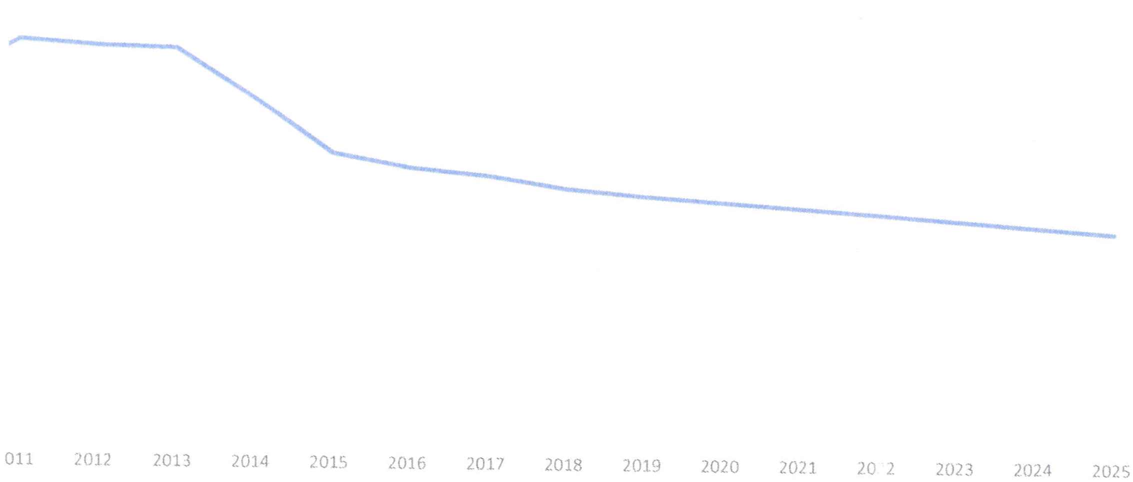


2019	2020	2021	2022	2023	2024	2025
$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242
1,390,151	1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330
1,419,202	1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830
446,013	433,427	420,817	408,182	395,521	382,832	370,116
1,400,126	1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846
586,335	569,572	552,787	535,979	519,148	502,292	485,410
586,335	569,572	552,787	535,979	519,148	502,292	485,410
3,820,636	3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216
$ 12,565,939	$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401

2019	2020	2021	2022	2023	2024	2025
37,678,736	37,490,342	37,302,890	37,116,376	36,930,794	36,746,140	36,562,409
15,377,722	15,300,834	15,224,330	15,148,208	15,072,467	14,997,105	14,922,119
10,572,451	10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216
2,452,210	2,439,949	2,427,749	2,415,610	2,403,532	2,391,514	2,379,557
10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216	10,207,920
3,349,437	3,332,690	3,316,026	3,299,446	3,282,949	3,266,534	3,250,202
3,768,117	3,749,276	3,730,530	3,711,877	3,693,318	3,674,851	3,656,477
21,357,948	21,251,158	21,144,902	21,039,178	20,933,982	20,829,312	20,725,165
105,076,209	104,550,828	104,028,074	103,507,933	102,990,394	102,475,441	101,963,065

2019	2020	2021	2022	2023	2024	2025
0.03	0.03	0.03	0.03	0.03	0.02	0.02
0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.01	0.01	0.01	0.01	0.01	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.00	0.00
0.04	0.04	0.03	0.03	0.03	0.03	0.03
0.12	0.12	0.11	0.11	0.11	0.11	0.10

Weighted Average $/kWh for Total System



Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
Fort Huahuca	TEP	Fixed PV	$ 0.07	2014
Rio Rico	UNSE	Fixed PV	$ 0.09	2014
Prairie Fire	TEP	Fixed PV	$ 0.13	2012
La Senita	UNSE	Single Axix PV	$ 0.17	2011
UASTP II	TEP	Fixed PV	$ 0.14	2011
UASTP I	TEP	Single Axix PV	$ 0.12	2010
Springerville 1.8	TEP	Fixed PV	$ 0.15	2010
Springerville 4.6	TEP	Fixed PV	$ 0.30	2004

Non-Equivalent Technologies

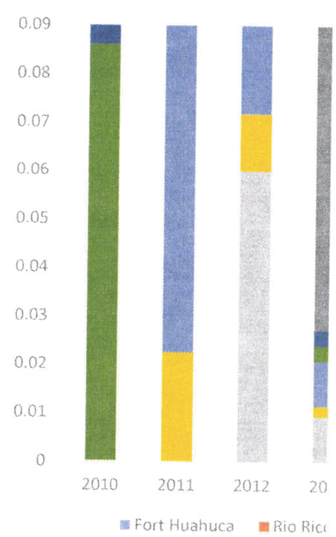
Project Name	Company	Technology	LCOE	COD
White Mtn	TEP	Low Concentrating PV	$ 0.17	2014
Areva	TEP	Solar Thermal Steam Augmentation	$ 0.06	2014

HIGHLY CONFIDENTIAL

Cost	2010
Fort Huahuca	
Rio Rico	
Prairie Fire	
La Senita	
UASTP II	
UASTP I	640,917
Springerville 1.8	640,917
White Mtn	
Aggregate PPA	-
	$ 1,281,833

Output	2010
Fort Huahuca	
Rio Rico	
Prairie Fire	
La Senita	
UASTP II	
UASTP I	3,504,000
Springerville 1.8	3,942,000
White Mtn	
Aggregate PPA	-
	7,446,000

	2010
Fort Huahuca	
Rio Rico	
Prairie Fire	
La Senita	
UASTP II	
UASTP I	0.09
Springerville 1.8	0.09
White Mtn	
Aggregate PPA	-
$/kWh	0.17

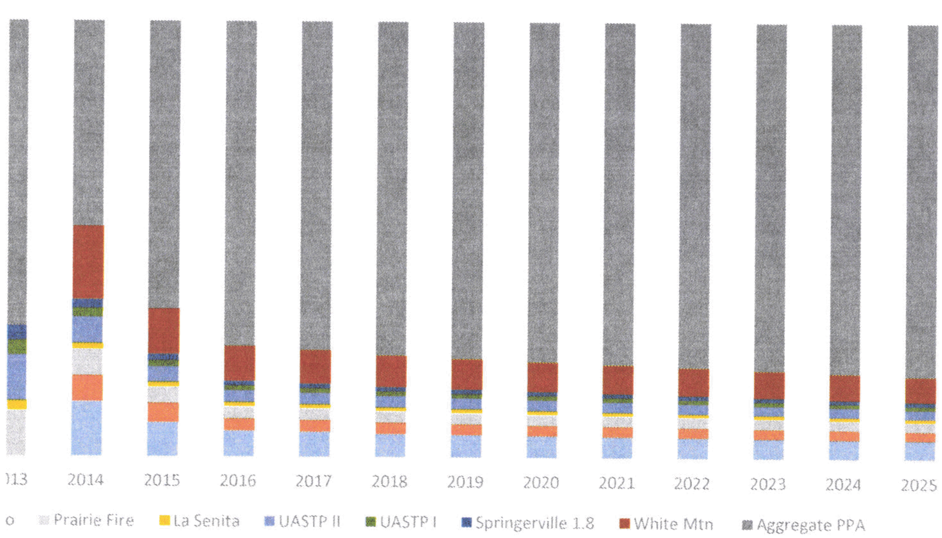


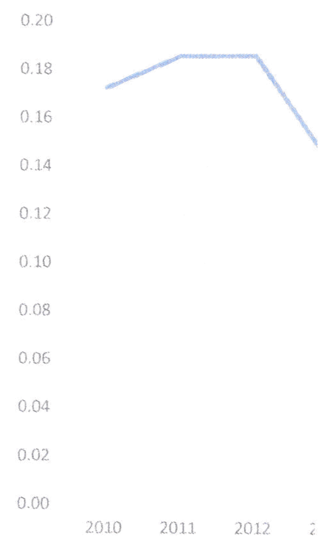
2011	2012	2013	2014	2015	2016	2017	2018	2019
			$ 4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558	$ 3,024,956	$ 2,917,140
			2,044,267	1,990,607	1,569,739	1,505,232	1,440,663	1,390,151
	2,168,426	2,112,189	2,055,913	1,608,682	1,552,322	1,495,919	1,457,584	1,419,202
571,091	426,107	444,353	462,579	480,785	483,630	471,113	458,574	446,013
2,211,064	2,153,718	2,096,331	2,038,902	1,556,596	1,517,550	1,478,457	1,439,316	1,400,126
657,303	673,673	690,027	706,363	653,181	636,499	619,798	603,077	586,335
657,303	673,673	690,027	706,363	653,181	636,499	619,798	603,077	586,335
			5,639,668	4,554,957	4,404,485	4,253,913	3,962,039	3,820,636
617,011	617,011	25,574,585	34,524,821	42,190,642	44,876,458	44,876,458	44,876,458	44,876,458
$ 4,096,761	$ 6,095,598	$ 6,032,926	$ 17,958,572	$ 14,975,097	$ 14,163,096	$ 13,691,789	$ 12,989,287	$ 12,565,939

2011	2012	2013	2014	2015	2016	2017	2018	2019
			38,635,000	38,441,825	38,249,616	38,058,368	37,868,076	37,678,736
			15,768,000	15,689,160	15,610,714	15,532,661	15,454,997	15,377,722
	10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451
2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917	2,464,532	2,452,210
10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451	10,519,589
3,486,480	3,469,048	3,451,702	3,434,444	3,417,272	3,400,185	3,383,184	3,366,268	3,349,437
3,922,290	3,902,679	3,883,165	3,863,749	3,844,431	3,825,208	3,806,082	3,787,052	3,768,117
			21,900,000	21,790,500	21,681,548	21,573,140	21,465,274	21,357,948
4,380,000	4,380,000	190,989,900	270,662,100	382,899,600	511,014,600	511,014,600	511,014,600	511,014,600
25,410,570	36,136,756	222,587,872	378,405,082	490,103,867	617,682,846	617,149,505	616,618,830	616,090,809

2011	2012	2013	2014	2015	2016	2017	2018	2019
			0.01	0.01	0.01	0.01	0.00	0.00
			0.01	0.00	0.00	0.00	0.00	0.00
	0.06	0.01	0.01	0.00	0.00	0.00	0.00	0.00
0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.09	0.06	0.01	0.01	0.00	0.00	0.00	0.00	0.00
0.03	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.03	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
			0.01	0.01	0.01	0.01	0.01	0.01
0.02	0.02	0.11	0.09	0.09	0.07	0.07	0.07	0.07
0.19	0.19	0.14	0.14	0.12	0.10	0.09	0.09	0.09

Weighted Average $/kWh by Facility - PPA



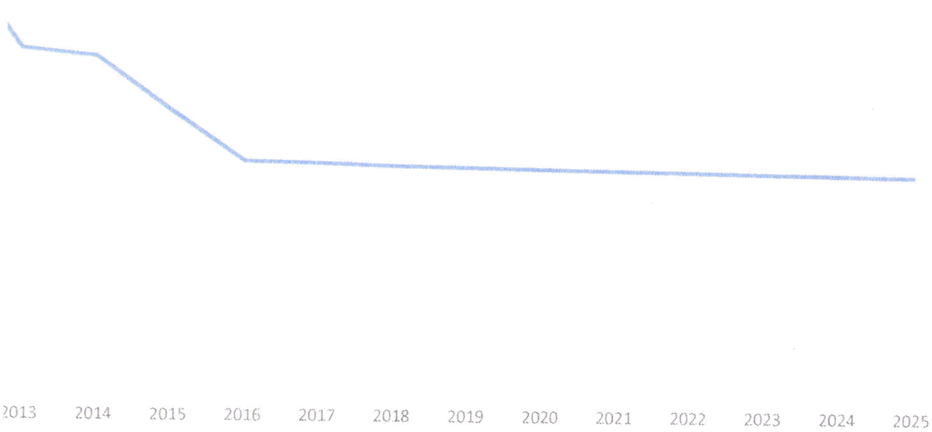


2020	2021	2022	2023	2024	2025
$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242
1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330
1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830
433,427	420,817	408,182	395,521	382,832	370,116
1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846
569,572	552,787	535,979	519,148	502,292	485,410
569,572	552,787	535,979	519,148	502,292	485,410
3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216
44,876,458	44,876,458	44,876,458	44,876,458	44,876,458	44,876,458
$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401

2020	2021	2022	2023	2024	2025
37,490,342	37,302,890	37,116,376	36,930,794	36,746,140	36,562,409
15,300,834	15,224,330	15,148,208	15,072,467	14,997,105	14,922,119
10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216
2,439,949	2,427,749	2,415,610	2,403,532	2,391,514	2,379,557
10,466,991	10,414,656	10,362,583	10,310,770	10,259,216	10,207,920
3,332,690	3,316,026	3,299,446	3,282,949	3,266,534	3,250,202
3,749,276	3,730,530	3,711,877	3,693,318	3,674,851	3,656,477
21,251,158	21,144,902	21,039,178	20,933,982	20,829,312	20,725,165
511,014,600	511,014,600	511,014,600	511,014,600	511,014,600	511,014,600
615,565,428	615,042,674	614,522,533	614,004,994	613,490,041	612,977,665

2020	2021	2022	2023	2024	2025
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01
0.07	0.07	0.07	0.07	0.07	0.07
0.09	0.09	0.09	0.09	0.09	0.09

Weighted Average $/kWh for Total System



Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
Fort Huahuca	TEP	Fixed PV	$ 0.07	2014
Rio Rico	UNSE	Fixed PV	$ 0.09	2014
Prairie Fire	TEP	Fixed PV	$ 0.13	2012
La Senita	UNSE	Single Axix PV	$ 0.17	2011
UASTP II	TEP	Fixed PV	$ 0.14	2011
UASTP I	TEP	Single Axix PV	$ 0.12	2010
Springerville 1.8	TEP	Fixed PV	$ 0.15	2010
Springerville 4.6	TEP	Fixed PV	$ 0.30	2004

Non-Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
White Mtn	TEP	Low Concentrating PV	$ 0.17	2014
Areva	TEP	Solar Thermal Steam Augmentation	$ 0.06	2014

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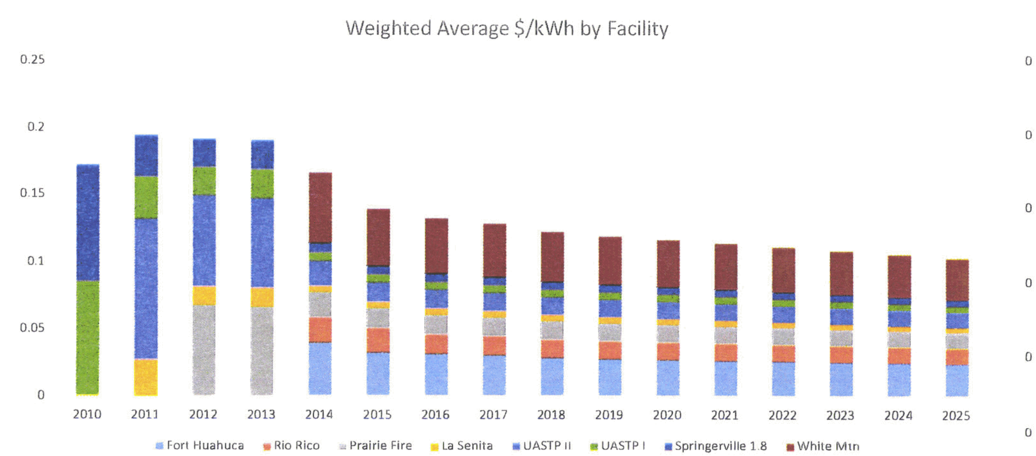
Cost	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					$ 4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558
Rio Rico					2,044,267	1,990,607	1,569,739	1,505,232
Prairie Fire			2,168,426	2,112,189	2,055,913	1,608,682	1,552,322	1,495,919
La Senita		571,091	426,107	444,353	462,579	480,785	483,630	471,113
UASTP II		2,211,064	2,153,718	2,096,331	2,038,902	1,556,596	1,517,550	1,478,457
UASTP I	640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798
Springerville 1.8	640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798
White Mtn					5,639,668	4,554,957	4,404,485	4,253,913
	$ 1,281,833	$ 4,096,761	$ 6,095,598	$ 6,032,926	$ 17,958,572	$ 14,975,097	$ 14,163,096	$ 13,691,789

Output	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					38,635,000	38,441,825	38,249,616	38,058,368
Rio Rico					15,768,000	15,689,160	15,610,714	15,532,661
Prairie Fire			10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974
La Senita		2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917
UASTP II		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579
UASTP I	3,504,000	3,486,480	3,469,048	3,451,702	3,434,444	3,417,272	3,400,185	3,383,184
Springerville 1.8	3,942,000	3,922,290	3,902,679	3,883,165	3,863,749	3,844,431	3,825,208	3,806,082
White Mtn					21,900,000	21,790,500	21,681,548	21,573,140
	7,446,000	21,030,570	31,756,756	31,597,972	107,742,982	107,204,267	106,668,246	106,134,905

	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					0.04	0.03	0.03	0.03
Rio Rico					0.02	0.02	0.01	0.01
Prairie Fire			0.07	0.07	0.02	0.02	0.01	0.01
La Senita		0.03	0.01	0.01	0.00	0.00	0.00	0.00
UASTP II		0.11	0.07	0.07	0.02	0.01	0.01	0.01
UASTP I	0.09	0.03	0.02	0.02	0.01	0.01	0.01	0.01
Springerville 1.8	0.09	0.03	0.02	0.02	0.01	0.01	0.01	0.01
White Mtn					0.05	0.04	0.04	0.04
$/kWh	0.17	0.19	0.19	0.19	0.17	0.14	0.13	0.13

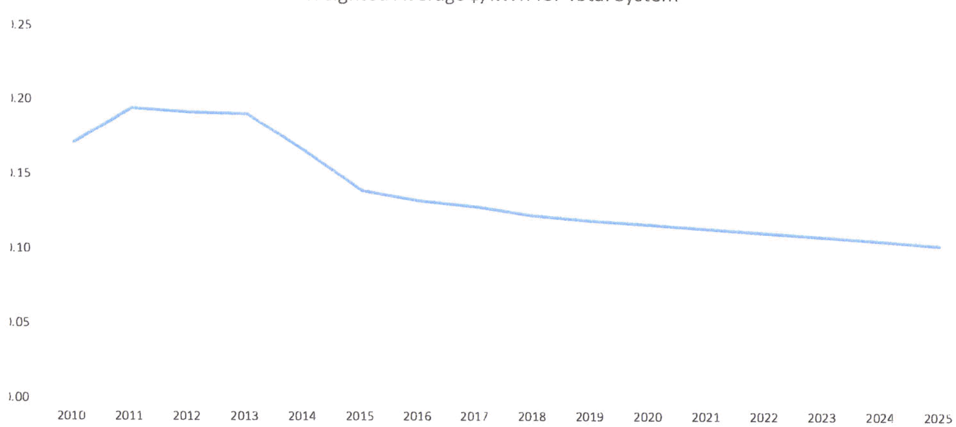


2018	2019	2020	2021	2022	2023	2024	2025
$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242
1,440,663	1,390,151	1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330
1,457,584	1,419,202	1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830
458,574	446,013	433,427	420,817	408,182	395,521	382,832	370,116
1,439,316	1,400,126	1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846
603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410
603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410
3,962,039	3,820,636	3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216
$ 12,989,287	$ 12,565,939	$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401

2018	2019	2020	2021	2022	2023	2024	2025
37,868,076	37,678,736	37,490,342	37,302,890	37,116,376	36,930,794	36,746,140	36,562,409
15,454,997	15,377,722	15,300,834	15,224,330	15,148,208	15,072,467	14,997,105	14,922,119
10,625,579	10,572,451	10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216
2,464,532	2,452,210	2,439,949	2,427,749	2,415,610	2,403,532	2,391,514	2,379,557
10,572,451	10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216	10,207,920
3,366,268	3,349,437	3,332,690	3,316,026	3,299,446	3,282,949	3,266,534	3,250,202
3,787,052	3,768,117	3,749,276	3,730,530	3,711,877	3,693,318	3,674,851	3,656,477
21,465,274	21,357,948	21,251,158	21,144,902	21,039,178	20,933,982	20,829,312	20,725,165
105,604,230	105,076,209	104,550,828	104,028,074	103,507,933	102,990,394	102,475,441	101,963,065

2018	2019	2020	2021	2022	2023	2024	2025
0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.10

Weighted Average $/kWh for Total System



Hypothetical 10 MW SAT PV
10 MW
Levelized Cost of Energy ($/kWh)

Assumptions		
Original Cost	$	17,000,000
Asset Life		30
O&M First Year (5)	$	10,000
Escalation Factor		2.00%
Income Tax Rate (Federal & State)(2)		38.24%
Debt Return (wtd cost)(1)		4.00%
Equity Return (wtd cost)(1)		2.00%
Tax Depreciation (Yrs)(3)		6
ITC Claimed		5,100,000
Property Tax Rate(2)		7.000%

	0	Yr. 1 1	Yr. 2 2	Yr. 3 3	Yr. 4 4	Yr. 5 5	Yr.6 6	Yr.7 7	Yr.8 8	Yr.9 9	Yr. 10 10	Yr. 11 11
Tax Depreciation(3)	$	8,670,000	$ 2,312,000	$ 1,387,200	$ 832,320	$ 832,320	$ 416,160	$ -	$ -	$ -	$ -	$ -
Book Depreciation		566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
Less: Book Depr on ITC Adj(3)		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
Timing Difference		8,188,333	1,830,333	905,533	350,653	350,653	(65,507)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)
Def. Tax @ 38.24%		3,131,219	699,919	346,276	134,090	134,090	(25,050)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)
A.D.I.T.		3,131,219	3,831,138	4,177,414	4,311,504	4,445,594	4,420,544	4,236,355	4,052,165	3,867,976	3,683,787	3,499,597
Plant in Service		17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000
Accum. Depreciation		(566,667)	(1,133,333)	(1,700,000)	(2,266,667)	(2,833,333)	(3,400,000)	(3,966,667)	(4,533,333)	(5,100,000)	(5,666,667)	(6,233,333)
Net Plant in Service		16,433,333	15,866,667	15,300,000	14,733,333	14,166,667	13,600,000	13,033,333	12,466,667	11,900,000	11,333,333	10,766,667
Unamortized ITC(3)		(4,590,000)	(3,570,000)	(2,550,000)	(1,530,000)	(510,000)	-	-	-	-	-	-
A.D.I.T.		(3,131,219)	(3,831,138)	(4,177,414)	(4,311,504)	(4,445,594)	(4,420,544)	(4,236,355)	(4,052,165)	(3,867,976)	(3,683,787)	(3,499,597)
Net Rate Base		8,712,115	8,465,529	8,572,586	8,891,829	9,211,073	9,179,456	8,796,979	8,414,501	8,032,024	7,649,547	7,267,069
Return on Rate Base:												
Equity Return		174,242	169,311	171,452	177,837	184,221	183,589	175,940	168,290	160,640	152,991	145,341
Debt Return		348,485	338,621	342,903	355,673	368,443	367,178	351,879	336,580	321,281	305,982	290,683
Total		522,727	507,932	514,355	533,510	552,664	550,767	527,819	504,870	481,921	458,973	436,024
Operating Expenses & Taxes:												
Operations and Maintenance		10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	12,190
Depreciation		566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
Property Taxes(4)		28,789	27,589	26,389	25,190	23,990	22,791	21,591	20,392	19,192	17,993	16,793
Total		605,455	604,456	603,460	602,469	601,481	600,498	599,520	598,545	597,576	596,610	595,650
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		107,886	104,832	106,158	110,111	114,065	113,673	108,937	104,200	99,464	94,728	89,991
Revenue Requirement	$	1,236,068	$ 1,217,220	$ 1,223,973	$ 1,246,090	$ 1,268,210	$ 1,264,939	$ 1,236,275	$ 1,207,616	$ 1,178,961	$ 1,150,311	$ 1,121,665
NPV Cost	$	14,813,840										
Estimated Output (kWh)		24,002,400	23,882,388	23,404,740	23,346,228	23,287,863	23,229,643	23,171,569	23,113,640	23,055,856	22,998,216	22,940,721
NPV Output		316,394,397										
Annual equivalent price per kWh		0.051	0.051	0.052	0.053	0.054	0.054	0.053	0.052	0.051	0.050	0.049
LCOE ($/kWh)	$	0.0468										

(1) Assumptions for the debt and equity returns are based on a 80/20 debt/equity capital structure with a required debt return of 5.0% and a required equity return of 10.0%
(2) Assumption in 2015 Rate Filing
(3) Assumes tax benefits can be utilized in the year generated
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
12	13	14	15	16	17	18	19	20
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)
(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)
3,315,408	3,131,219	2,947,029	2,762,840	2,578,651	2,394,461	2,210,272	2,026,083	1,841,893
17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000
(6,800,000)	(7,366,667)	(7,933,333)	(8,500,000)	(9,066,667)	(9,633,333)	(10,200,000)	(10,766,667)	(11,333,333)
10,200,000	9,633,333	9,066,667	8,500,000	7,933,333	7,366,667	6,800,000	6,233,333	5,666,667
-	-	-	-	-	-	-	-	-
(3,315,408)	(3,131,219)	(2,947,029)	(2,762,840)	(2,578,651)	(2,394,461)	(2,210,272)	(2,026,083)	(1,841,893)
6,884,592	6,502,115	6,119,637	5,737,160	5,354,683	4,972,205	4,589,728	4,207,251	3,824,773
137,692	130,042	122,393	114,743	107,094	99,444	91,795	84,145	76,495
275,384	260,085	244,785	229,486	214,187	198,888	183,589	168,290	152,991
413,076	390,127	367,178	344,230	321,281	298,332	275,384	252,435	229,486
12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
15,594	14,394	13,195	11,995	10,796	9,596	8,397	7,197	5,998
594,694	593,743	592,797	591,857	590,921	589,991	589,066	588,146	587,232
85,255	80,518	75,782	71,046	66,309	61,573	56,837	52,100	47,364
$ 1,093,025	$ 1,064,389	$ 1,035,758	$ 1,007,132	$ 978,511	$ 949,896	$ 921,286	$ 892,681	$ 864,083
22,883,369	22,826,161	22,769,095	22,712,172	22,655,392	22,598,754	22,542,257	22,485,901	22,429,686
0.048	0.047	0.045	0.044	0.043	0.042	0.041	0.040	0.039

Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
Fort Huahuca	TEP	Fixed PV	$ 0.07	2014
Rio Rico	UNSE	Fixed PV	$ 0.09	2014
Prairie Fire	TEP	Fixed PV	$ 0.13	2012
La Senita	UNSE	Single Axix PV	$ 0.17	2011
UASTP II	TEP	Fixed PV	$ 0.14	2011
UASTP I	TEP	Single Axix PV	$ 0.12	2010
Springerville 1.8	TEP	Fixed PV	$ 0.15	2010
Springerville 4.6	TEP	Fixed PV	$ 0.30	2004

Non-Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
White Mtn	TEP	Low Concentrating PV	$ 0.17	2014
Areva	TEP	Solar Thermal Steam Augmentation	$ 0.06	2014

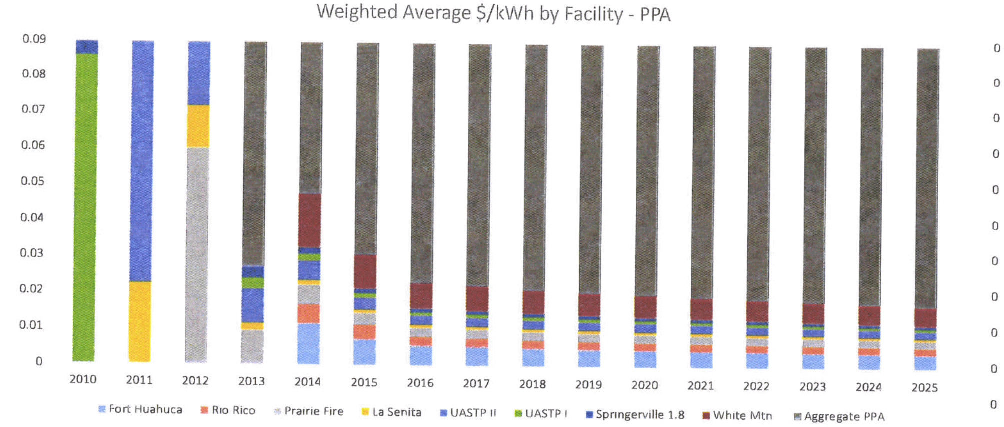
HIGHLY CONFIDENTIAL

Cost	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					$ 4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558
Rio Rico					2,044,267	1,990,607	1,569,739	1,505,232
Prairie Fire			2,168,426	2,112,189	2,055,913	1,608,682	1,552,322	1,495,919
La Senita		571,091	426,107	444,353	462,579	480,785	483,630	471,113
UASTP II		2,211,064	2,153,718	2,096,331	2,038,902	1,556,596	1,517,550	1,478,457
UASTP I	640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798
Springerville 1.8	640,917	657,303	673,673	690,027	706,363	653,181	636,499	619,798
White Mtn					5,639,668	4,554,957	4,404,485	4,253,913
Aggregate PPA	-	617,011	617,011	25,574,585	34,524,821	42,190,642	44,876,458	44,876,458
	$ 1,281,833	$ 4,096,761	$ 6,095,598	$ 6,032,926	$ 17,958,572	$ 14,975,097	$ 14,163,096	$ 13,691,789

Output	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					38,635,000	38,441,825	38,249,616	38,058,368
Rio Rico					15,768,000	15,689,160	15,610,714	15,532,661
Prairie Fire			10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974
La Senita		2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917
UASTP II		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579
UASTP I	3,504,000	3,486,480	3,469,048	3,451,702	3,434,444	3,417,272	3,400,185	3,383,184
Springerville 1.8	3,942,000	3,922,290	3,902,679	3,883,165	3,863,749	3,844,431	3,825,208	3,806,082
White Mtn					21,900,000	21,790,500	21,681,548	21,573,140
Aggregate PPA	-	4,380,000	4,380,000	190,989,900	270,662,100	382,899,600	511,014,600	511,014,600
	7,446,000	25,410,570	36,136,756	222,587,872	378,405,082	490,103,867	617,682,846	617,149,505

	2010	2011	2012	2013	2014	2015	2016	2017
Fort Huahuca					0.01	0.01	0.01	0.01
Rio Rico					0.01	0.00	0.00	0.00
Prairie Fire			0.06	0.01	0.01	0.00	0.00	0.00
La Senita		0.02	0.01	0.00	0.00	0.00	0.00	0.00
UASTP II		0.09	0.06	0.01	0.01	0.00	0.00	0.00
UASTP I	0.09	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Springerville 1.8	0.09	0.03	0.02	0.00	0.00	0.00	0.00	0.00
White Mtn					0.01	0.01	0.01	0.01
Aggregate PPA	-	0.02	0.02	0.11	0.09	0.09	0.07	0.07
$/kWh	0.17	0.19	0.19	0.14	0.14	0.12	0.10	0.09

Weighted Average $/kWh by Facility - PPA

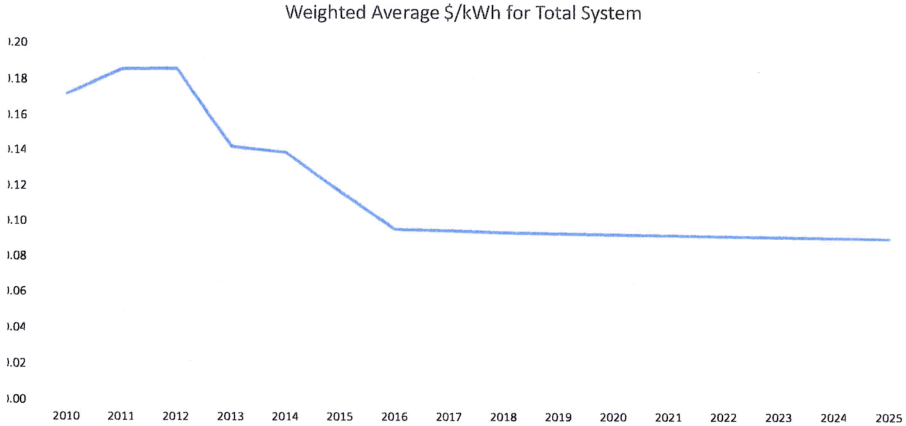


2018	2019	2020	2021	2022	2023	2024	2025
$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242
1,440,663	1,390,151	1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330
1,457,584	1,419,202	1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830
458,574	446,013	433,427	420,817	408,182	395,521	382,832	370,116
1,439,316	1,400,126	1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846
603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410
603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410
3,962,039	3,820,636	3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216
44,876,458	44,876,458	44,876,458	44,876,458	44,876,458	44,876,458	44,876,458	44,876,458
$ 12,989,287	$ 12,565,939	$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401

2018	2019	2020	2021	2022	2023	2024	2025
37,868,076	37,678,736	37,490,342	37,302,890	37,116,376	36,930,794	36,746,140	36,562,409
15,454,997	15,377,722	15,300,834	15,224,330	15,148,208	15,072,467	14,997,105	14,922,119
10,625,579	10,572,451	10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216
2,464,532	2,452,210	2,439,949	2,427,749	2,415,610	2,403,532	2,391,514	2,379,557
10,572,451	10,519,589	10,466,991	10,414,656	10,362,583	10,310,770	10,259,216	10,207,920
3,366,268	3,349,437	3,332,690	3,316,026	3,299,446	3,282,949	3,266,534	3,250,202
3,787,052	3,768,117	3,749,276	3,730,530	3,711,877	3,693,318	3,674,851	3,656,477
21,465,274	21,357,948	21,251,158	21,144,902	21,039,178	20,933,982	20,829,312	20,725,165
511,014,600	511,014,600	511,014,600	511,014,600	511,014,600	511,014,600	511,014,600	511,014,600
616,618,830	616,090,809	615,565,428	615,042,674	614,522,533	614,004,994	613,490,041	612,977,665

2018	2019	2020	2021	2022	2023	2024	2025
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09

Weighted Average $/kWh for Total System



La Senita Single-Axis System - UNSE

1 MW HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2011
Original Cost	$ 5,308,701	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.95%	
Debt Return (wtd cost)	2.83%	
Equity Return (wtd cost)	5.00%	
Tax Depreciation (Yrs)	6	
ITC Claimed	1,592,610	796305.15

Original Cost	$ 5,308,701	
ITC @ 30%	$ 1,592,610.30	
Depeciable Tax Basis	$ 4,512,395.85	$ -
Tax Basis After 50% Bonus	$ 2,256,197.93	

	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate	11.237%	11.462%	11.691%	11.925%	12.163%	12.407%	12.655%	12.908%	13.166%	13.429%
	1	2	3	4	5	6	7	8	9	10
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tax Depreciation	$ 4,512,396									
Tax Depreciation included in Rate Base	$ 161,157	$ 4,351,239	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Book Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Less: Book Depr on ITC Adj	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
Timing Difference	(0)	4,190,082	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
Def. Tax @ 38.95%	(0)	1,632,037	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
A.D.I.T.	(0)	1,632,037	1,569,266	1,506,496	1,443,725	1,380,954	1,318,184	1,255,413	1,192,642	1,129,872
Plant in Service	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
Accum. Depreciation	(189,596)	(379,193)	(568,789)	(758,386)	(947,982)	(1,137,579)	(1,327,175)	(1,516,772)	(1,706,368)	(1,895,965)
Net Plant in Service	5,119,105	4,929,508	4,739,912	4,550,315	4,360,719	4,171,122	3,981,526	3,791,929	3,602,333	3,412,736
Unamortized ITC	(1,433,349)	(1,114,827)	(796,305)	(477,783)	(159,261)					
Unamortized ITC included in Rate Base	$ (1,433,349)	$ (1,114,827)	$ (796,305)	$ (477,783)	$ (159,261)					
A.D.I.T.	0	(1,632,037)	(1,569,266)	(1,506,496)	(1,443,725)	(1,380,954)	(1,318,184)	(1,255,413)	(1,192,642)	(1,129,872)
Net Rate Base	3,685,755	2,182,644	2,374,340	2,566,036	2,757,733	2,790,168	2,663,342	2,536,516	2,409,690	2,282,865
Return on Rate Base:										
Debt Return	184,177	109,067	118,646	128,225	137,804	139,425	133,087	126,750	120,412	114,075
Equity Return	104,299	61,764	67,189	72,613	78,038	78,956	75,367	71,778	68,189	64,600
Total	288,476	170,831	185,834	200,838	215,842	218,380	208,454	198,528	188,601	178,675
Operating Expenses & Taxes:										
Operations and Maintenance	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Property Taxes(1)	21,475	21,175	20,853	20,511	20,146	19,759	19,348	18,912	18,452	17,966
Total	216,072	215,871	215,652	215,413	215,155	214,876	214,575	214,252	213,907	213,537
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate	66,543	39,406	42,866	46,327	49,788	50,374	48,084	45,794	43,505	41,215
Revenue Requirement	$ 571,091	$ 426,107	$ 444,353	$ 462,579	$ 480,785	$ 483,630	$ 471,113	$ 458,574	$ 446,013	$ 433,427
NPV Cost	$ 4,696,059									
Estimated Output (KWh)	2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917	2,464,532	2,452,210	2,439,949
NPV Output	27,557,562									
LCOE ($/KWh)	$ 0.17									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x a 18% valuation factor - then increase the tax rate annually by the escalation factor

13.698%	13.972%	14.251%	14.536%	14.827%	15.124%	15.426%	15.735%	16.049%	16.370%	16.698%	17.032%	17.372%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
1,067,101	1,004,330	941,560	878,789	816,018	753,248	690,477	627,706	564,936	502,165	439,395	376,624	313,853
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(2,085,561)	(2,275,158)	(2,464,754)	(2,654,351)	(2,843,947)	(3,033,543)	(3,223,140)	(3,412,736)	(3,602,333)	(3,791,929)	(3,981,526)	(4,171,122)	(4,360,719)
3,223,140	3,033,543	2,843,947	2,654,351	2,464,754	2,275,158	2,085,561	1,895,965	1,706,368	1,516,772	1,327,175	1,137,579	947,982
(1,067,101)	(1,004,330)	(941,560)	(878,789)	(816,018)	(753,248)	(690,477)	(627,706)	(564,936)	(502,165)	(439,395)	(376,624)	(313,853)
2,156,039	2,029,213	1,902,387	1,775,561	1,648,736	1,521,910	1,395,084	1,268,258	1,141,432	1,014,607	887,781	760,955	634,129
107,737	101,400	95,062	88,725	82,387	76,050	69,712	63,375	57,037	50,700	44,362	38,025	31,687
61,011	57,422	53,833	50,244	46,656	43,067	39,478	35,889	32,300	28,711	25,122	21,533	17,944
168,748	158,822	148,896	138,969	129,043	119,117	109,190	99,264	89,337	79,411	69,485	59,558	49,632
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
17,452	16,911	16,342	15,742	15,113	14,452	13,758	13,031	12,269	11,471	10,637	9,765	8,853
213,144	212,725	212,279	211,807	211,307	210,777	210,218	209,628	209,007	208,352	207,663	206,940	206,180
38,925	36,635	34,346	32,056	29,766	27,477	25,187	22,897	20,607	18,318	16,028	13,738	11,449
$ 420,817	$ 408,182	$ 395,521	$ 382,832	$ 370,116	$ 357,370	$ 344,595	$ 331,789	$ 318,951	$ 306,081	$ 293,176	$ 280,236	$ 267,260
2,427,749	2,415,610	2,403,532	2,391,514	2,379,557	2,367,659	2,355,821	2,344,042	2,332,321	2,320,660	2,309,057	2,297,511	2,286,024

17.720%	18.074%	18.435%	18.804%	19.180%
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28
24	25	26	27	28
2034	2035	2036	2037	2038
$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
251,083	188,312	125,541	62,771	(0)
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(4,550,315)	(4,739,912)	(4,929,508)	(5,119,105)	(5,308,701)
758,386	568,789	379,193	189,596	0
(251,083)	(188,312)	(125,541)	(62,771)	0
507,303	380,477	253,652	126,826	0
25,350	19,012	12,675	6,337	0
14,356	10,767	7,178	3,589	0
39,706	29,779	19,853	9,926	0
7,884	8,042	8,203	8,367	8,534
189,596	189,596	189,596	189,596	189,596
7,902	6,908	5,872	4,792	3,666
205,383	204,547	203,672	202,755	201,797
9,159	6,869	4,579	2,290	0
$ 254,247	$ 241,195	$ 228,104	$ 214,971	$ 201,797
2,274,594	2,263,221	2,308,999	2,297,338	2,285,851

HIGHLY CONFIDENTIAL

La Senita Esimated KWh

COD:11/4/2011	Contract Year	Estimated Power Production (KWh)
2012	1	2,671,800
2013	2	2,539,780
2014	3	2,527,081
2015	4	2,514,445
2016	5	2,501,873
2017	6	2,489,364
2018	7	2,476,917
2019	8	2,464,532
2020	9	2,452,210
2021	10	2,439,949
2022	11	2,427,749
2023	12	2,415,610
2024	13	2,403,532
2025	14	2,391,514
2026	15	2,379,557
2027	16	2,367,659
2028	17	2,355,821
2029	18	2,344,042
2030	19	2,332,321
2031	20	2,320,660
2032	21	2,309,057
2033	22	2,297,511
2034	23	2,286,024
2035	24	2,274,594
2036	25	2,263,221
2037	26	2,308,999
2038	27	2,297,338
2039	28	2,285,851
		67,139,011

Fort Hauchuca Fixed PV System

13.6 MW

HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/kWh)

Assumptions		DPIS - 2014
Original Cost	$ 32,005,100	
Asset Life	28	
O&M First Year	$ 10,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)(2)	38.24%	
Debt Return (wtd cost)(1)	2.91%	
Equity Return (wtd cost)(1)	4.35%	
Tax Depreciation (Yrs)(3)	6	
ITC Claimed(3)	9,601,530	

Original Cost	$ 32,005,100	
ITC @ 30%	$ 9,601,530.00	
Depeciable Tax Basis	$ 27,204,335.00	$ -
Tax Basis After 50% Bonus	$ 13,602,167.50	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10	Yr. 11
Property Tax Rate(2)		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%	8.533%
		1	2	3	4	5	6	7	8	9	10	11
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tax Depreciation(3)		$ 16,322,601	$ 4,352,694	$ 2,611,616	$ 1,566,970	$ 1,566,970	$ 783,485	$ -	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base		971,583	19,703,711	971,583	971,583	3,802,389	783,485	-	-	-	-	-
Book Depreciation		1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
Less: Book Depr on ITC Adj(3)		171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456
Timing Difference		0	18,732,128	0	0	2,830,805	(188,099)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)
Def. Tax @ 38.24%		0	7,163,166	0	0	1,082,500	(71,929)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)
A.D.I.T.		0	7,163,166	7,163,166	7,163,166	8,245,666	8,173,737	7,802,203	7,430,670	7,059,136	6,687,603	6,316,069
Plant in Service		32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100
Accum. Depreciation		(1,143,039)	(2,286,079)	(3,429,118)	(4,572,157)	(5,715,196)	(6,858,236)	(8,001,275)	(9,144,314)	(10,287,354)	(11,430,393)	(12,573,432)
Net Plant in Service		30,862,061	29,719,021	28,575,982	27,432,943	26,289,904	25,146,864	24,003,825	22,860,786	21,717,746	20,574,707	19,431,668
Unamortized ITC(3)		(8,641,377)	(6,721,071)	(4,800,765)	(2,880,459)	(960,153)						
Unamortized ITC included in Rate Base		-	-	-	-	-		-	-	-	-	-
A.D.I.T.		(0)	(7,163,166)	(7,163,166)	(7,163,166)	(8,245,666)	(8,173,737)	(7,802,203)	(7,430,670)	(7,059,136)	(6,687,603)	(6,316,069)
Net Rate Base		30,862,061	22,555,856	21,412,816	20,269,777	18,044,238	16,973,128	16,201,622	15,430,116	14,658,610	13,887,104	13,115,599
Return on Rate Base:												
Equity Return		1,342,500	981,180	931,458	881,735	784,924	738,331	704,771	671,210	637,650	604,089	570,529
Debt Return		897,090	655,647	622,422	589,196	524,505	493,370	470,944	448,518	426,092	403,666	381,241
Total		2,239,589	1,636,827	1,553,879	1,470,932	1,309,429	1,231,701	1,175,715	1,119,728	1,063,742	1,007,755	951,769
Operating Expenses & Taxes:												
Operations and Maintenance		10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	12,190
Depreciation		1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
Property Taxes(4)		80,653	79,524	78,317	77,031	75,661	74,206	72,663	71,028	69,298	67,471	65,544
Total		1,233,692	1,232,763	1,231,760	1,230,682	1,229,525	1,228,286	1,226,963	1,225,554	1,224,054	1,222,462	1,220,773
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		831,237	607,518	576,731	545,945	486,002	457,153	436,373	415,594	394,814	374,034	353,255
Revenue Requirement	$	4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558	$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797
NPV Cost	$	32,093,921										
Estimated Output (kWh)		38,635,000	38,441,825	38,249,616	38,058,368	37,868,076	37,678,736	37,490,342	37,302,890	37,116,376	36,930,794	36,746,140
NPV Output		437,203,807										
LCOE ($/kWh)	$	0.07										

(1) Assumptions approved in 2013 Rate Order
(2) Assumption in 2015 Rate Filing
(3) Assumptions regarding tax depreciation and ITC include actual company circumstances
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%
Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
12	13	14	15	16	17	18	19	20
2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-	-
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456
(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)
(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)
5,944,536	5,573,002	5,201,469	4,829,935	4,458,402	4,086,868	3,715,335	3,343,801	2,972,268
32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100
(13,716,471)	(14,859,511)	(16,002,550)	(17,145,589)	(18,288,629)	(19,431,668)	(20,574,707)	(21,717,746)	(22,860,786)
18,288,629	17,145,589	16,002,550	14,859,511	13,716,471	12,573,432	11,430,393	10,287,354	9,144,314
-	-	-	-	-	-	-	-	-
(5,944,536)	(5,573,002)	(5,201,469)	(4,829,935)	(4,458,402)	(4,086,868)	(3,715,335)	(3,343,801)	(2,972,268)
12,344,093	11,572,587	10,801,081	10,029,575	9,258,070	8,486,564	7,715,058	6,943,552	6,172,046
536,968	503,408	469,847	436,287	402,726	369,166	335,605	302,045	268,484
358,815	336,389	313,963	291,537	269,111	246,685	224,259	201,833	179,407
895,783	839,796	783,810	727,823	671,837	615,851	559,864	503,878	447,891
12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
63,512	61,372	59,122	56,757	54,274	51,669	48,938	46,077	43,082
1,218,985	1,217,094	1,215,097	1,212,991	1,210,772	1,208,436	1,205,980	1,203,399	1,200,689
332,475	311,695	290,916	270,136	249,356	228,577	207,797	187,017	166,238
$ 2,447,242	$ 2,368,586	$ 2,289,823	$ 2,210,951	$ 2,131,965	$ 2,052,863	$ 1,973,641	$ 1,894,294	$ 1,814,818
36,562,409	36,379,597	36,197,699	36,016,711	35,836,627	35,657,444	35,479,157	35,301,761	35,125,252

White Mountain Fixed/LCPV System

8.25 MW

HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/kWh)

Assumptions		DPIS - 2014
Original Cost	$ 41,955,366	
Asset Life	28	
O&M First Year	$ 10,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)(2)	38.24%	
Debt Return (wtd cost)(1)	2.91%	
Equity Return (wtd cost)(1)	4.35%	
Tax Depreciation (Yrs)(3)	6	
ITC Claimed(3)	12,586,610	

Original Cost	$ 41,955,366	
ITC @ 30%	$ 12,586,609.80	
Depeciable Tax Basis	$ 35,662,061.10	$ -
Tax Basis After 50% Bonus	$ 17,831,030.55	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10	Yr. 11
Property Tax Rate(2)		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%	8.533%
Year		1	2	3	4	5	6	7	8	9	10	11
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tax Depreciation(3)		$ 21,397,237	$ 5,705,930	$ 3,423,558	$ 2,054,135	$ 2,054,135	$ 1,027,067	$ -	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base		1,273,645	25,829,521	1,273,645	1,273,645	4,984,537	1,027,067	-	-	-	-	-
Book Depreciation		1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
Less: Book Depr on ITC Adj(3)		224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761
Timing Difference		(0)	24,555,876	(0)	(0)	3,710,892	(246,578)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)
Def. Tax @ 38.24%		(0)	9,390,167	(0)	(0)	1,419,045	(94,291)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)
A.D.I.T.		(0)	9,390,167	9,390,167	9,390,167	10,809,212	10,714,921	10,227,879	9,740,837	9,253,795	8,766,754	8,279,712
Plant in Service		41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366
Accum. Depreciation		(1,498,406)	(2,996,812)	(4,495,218)	(5,993,624)	(7,492,030)	(8,990,436)	(10,488,842)	(11,987,247)	(13,485,653)	(14,984,059)	(16,482,465)
Net Plant in Service		40,456,960	38,958,554	37,460,148	35,961,742	34,463,336	32,964,930	31,466,525	29,968,119	28,469,713	26,971,307	25,472,901
Unamortized ITC(3)		(11,327,949)	(8,810,627)	(6,293,305)	(3,775,983)	(1,258,661)						
Unamortized ITC included in Rate Base		-	-	-	-	-	-	-	-	-	-	-
A.D.I.T.		0	(9,390,167)	(9,390,167)	(9,390,167)	(10,809,212)	(10,714,921)	(10,227,879)	(9,740,837)	(9,253,795)	(8,766,754)	(8,279,712)
Net Rate Base		40,456,960	29,568,387	28,069,981	26,571,575	23,654,124	22,250,009	21,238,645	20,227,281	19,215,917	18,204,553	17,193,189
Return on Rate Base:												
Equity Return		1,759,878	1,286,225	1,221,044	1,155,864	1,028,954	967,875	923,881	879,887	835,892	791,898	747,904
Debt Return		1,175,992	859,486	815,930	772,375	687,571	646,757	617,359	587,961	558,563	529,165	499,767
Total		2,935,869	2,145,710	2,036,975	1,928,239	1,716,526	1,614,632	1,541,240	1,467,848	1,394,455	1,321,063	1,247,671
Operating Expenses & Taxes:												
Operations and Maintenance		10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	12,190
Depreciation		1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
Property Taxes(4)		105,728	104,248	102,666	100,979	99,184	97,277	95,253	93,110	90,843	88,448	85,921
Total		1,614,134	1,612,853	1,611,476	1,609,997	1,608,414	1,606,723	1,604,921	1,603,003	1,600,966	1,598,805	1,596,517
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		1,089,665	796,393	756,035	715,677	637,099	599,280	572,040	544,800	517,560	490,320	463,080
Revenue Requirement		$ 5,639,668	$ 4,554,957	$ 4,404,485	$ 4,253,913	$ 3,962,039	$ 3,820,636	$ 3,718,201	$ 3,615,651	$ 3,512,981	$ 3,410,188	$ 3,307,268
NPV Cost	$	42,027,142										
Estimated Output (kWh)		21,900,000	21,790,500	21,681,548	21,573,140	21,465,274	21,357,948	21,251,158	21,144,902	21,039,178	20,933,982	20,829,312
NPV Output		247,826,152										
LCOE ($/kWh)	$	0.17										

(1) Assumptions approved in 2013 Rate Order
(2) Assumption in 2015 Rate Filing
(3) Assumptions regarding tax depreciation and ITC include actual company circumstances
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
8.704%	8.878%	9.055%	9.236%	9.421%	9.610%	9.802%	9.998%	10.198%
12	13	14	15	16	17	18	19	20
2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-	-
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761
(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)
(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)
7,792,670	7,305,628	6,818,586	6,331,544	5,844,502	5,357,460	4,870,419	4,383,377	3,896,335
41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366
(17,980,871)	(19,479,277)	(20,977,683)	(22,476,089)	(23,974,495)	(25,472,901)	(26,971,307)	(28,469,713)	(29,968,119)
23,974,495	22,476,089	20,977,683	19,479,277	17,980,871	16,482,465	14,984,059	13,485,653	11,987,247
-	-	-	-	-	-	-	-	-
(7,792,670)	(7,305,628)	(6,818,586)	(6,331,544)	(5,844,502)	(5,357,460)	(4,870,419)	(4,383,377)	(3,896,335)
16,181,825	15,170,461	14,159,097	13,147,733	12,136,369	11,125,005	10,113,641	9,102,277	8,090,913
703,909	659,915	615,921	571,926	527,932	483,938	439,943	395,949	351,955
470,369	440,971	411,573	382,175	352,777	323,379	293,980	264,582	235,184
1,174,278	1,100,886	1,027,493	954,101	880,709	807,316	733,924	660,531	587,139
12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
83,257	80,453	77,503	74,403	71,148	67,733	64,153	60,402	56,476
1,594,097	1,591,541	1,588,845	1,586,004	1,583,012	1,579,866	1,576,561	1,573,090	1,569,450
435,840	408,600	381,360	354,120	326,880	299,640	272,400	245,160	217,920
$ 3,204,216	$ 3,101,027	$ 2,997,699	$ 2,894,225	$ 2,790,601	$ 2,686,823	$ 2,582,885	$ 2,478,782	$ 2,374,509
20,725,165	20,621,539	20,518,432	20,415,840	20,313,760	20,212,192	20,111,131	20,010,575	19,910,522

HIGHLY CONFIDENTIAL

White Mountain Solar Esimated kWh

8.25 MWac COD: 12/14/2014	Year	Estimated Power Production (kWh)
2015	1	21,900,000
2016	2	21,790,500
2017	3	21,681,548
2018	4	21,573,140
2019	5	21,465,274
2020	6	21,357,948
2021	7	21,251,158
2022	8	21,144,902
2023	9	21,039,178
2024	10	20,933,982
2025	11	20,829,312
2026	12	20,725,165
2027	13	20,621,539
2028	14	20,518,432
2029	15	20,415,840
2030	16	20,313,760
2031	17	20,212,192
2032	18	20,111,131
2033	19	20,010,575
2034	20	19,910,522
2034	21	19,810,970
2034	22	19,711,915
2034	23	19,613,355
2034	24	19,515,288
2034	25	19,417,712
2034	26	19,320,623
2034	27	19,224,020
2034	28	19,127,900
		573,547,880

Rio Rico PV System - UNSE

5.76 MW HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2014
Original Cost	$ 15,374,286	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.95%	
Debt Return (wtd cost)	2.83%	
Equity Return (wtd cost)	5.00%	
Tax Depreciation (Yrs)	6	
ITC Claimed	4,612,286	

Original Cost	$ 15,374,286	
ITC @ 30%	$ 4,612,285.80	
Depeciable Tax Basis	$ 13,068,143.10	$ -
Tax Basis After 50% Bonus	$ 6,534,071.55	

		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		11.237%	11.462%	11.691%	11.925%	12.163%	12.407%	12.655%	12.908%	13.166%	13.429%
	0	1	2	3	4	5	6	7	8	9	10
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tax Depreciation		$ 7,840,886	$ 2,090,903	$ 1,254,542	$ 752,725	$ 752,725	$ 376,363	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base		$ 466,719	$ 466,719	$ 10,252,892	$ 752,725	$ 752,725	$ 376,363	$ -	$ -	$ -	$ -
Book Depreciation		549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
Less: Book Depr on ITC Adj		82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362
Timing Difference		0	0	9,786,172	286,006	286,006	(90,357)	(466,719)	(466,719)	(466,719)	(466,719)
Def. Tax @ 38.95%		0	0	3,811,714	111,399	111,399	(35,194)	(181,787)	(181,787)	(181,787)	(181,787)
A.D.I.T.		0	0	3,811,714	3,923,113	4,034,513	3,999,319	3,817,531	3,635,744	3,453,957	3,272,170
Plant in Service		15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286
Accum. Depreciation		(549,082)	(1,098,163)	(1,647,245)	(2,196,327)	(2,745,408)	(3,294,490)	(3,843,572)	(4,392,653)	(4,941,735)	(5,490,816)
Net Plant in Service		14,825,204	14,276,123	13,727,041	13,177,959	12,628,878	12,079,796	11,530,715	10,981,633	10,432,551	9,883,470
Unamortized ITC		(4,151,057)	(3,228,600)	(2,306,143)	(1,383,686)	(461,229)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		(0)	(0)	(3,811,714)	(3,923,113)	(4,034,513)	(3,999,319)	(3,817,531)	(3,635,744)	(3,453,957)	(3,272,170)
Net Rate Base		14,825,204	14,276,123	9,915,327	9,254,846	8,594,365	8,080,478	7,713,183	7,345,889	6,978,594	6,611,300
Return on Rate Base:											
Debt Return		740,815	713,378	495,469	462,465	429,460	403,781	385,428	367,074	348,720	330,367
Equity Return		419,521	403,983	280,582	261,892	243,202	228,660	218,266	207,872	197,479	187,085
Total		1,160,336	1,117,361	776,051	724,356	672,662	632,441	603,694	574,947	546,199	517,452
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
Property Taxes(1)		62,194	61,323	60,393	59,401	58,345	57,223	56,032	54,772	53,438	52,029
Total		616,276	615,505	614,676	613,788	612,838	611,825	610,745	609,597	608,378	607,086
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		267,655	257,742	179,012	167,087	155,163	145,885	139,254	132,623	125,992	119,361
Revenue Requirement		$ 2,044,267	$ 1,990,607	$ 1,569,739	$ 1,505,232	$ 1,440,663	$ 1,390,151	$ 1,353,693	$ 1,317,166	$ 1,280,569	$ 1,243,899
NPV Cost		$ 14,905,145									
Estimated Output (KWh)		15,768,000	15,689,160	15,610,714	15,532,661	15,454,997	15,377,722	15,300,834	15,224,330	15,148,208	15,072,467
NPV Output		169,412,295									
LCOE ($/KWh)		$ 0.088									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

13.698%	13.972%	14.251%	14.536%	14.827%	15.124%	15.426%	15.735%	16.049%	16.370%	16.698%	17.032%	17.372%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362
(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)
(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)
3,090,382	2,908,595	2,726,808	2,545,021	2,363,234	2,181,446	1,999,659	1,817,872	1,636,085	1,454,298	1,272,510	1,090,723	908,936
15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286
(6,039,898)	(6,588,980)	(7,138,061)	(7,687,143)	(8,236,225)	(8,785,306)	(9,334,388)	(9,883,470)	(10,432,551)	(10,981,633)	(11,530,715)	(12,079,796)	(12,628,878)
9,334,388	8,785,306	8,236,225	7,687,143	7,138,061	6,588,980	6,039,898	5,490,816	4,941,735	4,392,653	3,843,572	3,294,490	2,745,408
(3,090,382)	(2,908,595)	(2,726,808)	(2,545,021)	(2,363,234)	(2,181,446)	(1,999,659)	(1,817,872)	(1,636,085)	(1,454,298)	(1,272,510)	(1,090,723)	(908,936)
6,244,005	5,876,711	5,509,417	5,142,122	4,774,828	4,407,533	4,040,239	3,672,944	3,305,650	2,938,356	2,571,061	2,203,767	1,836,472
312,013	293,659	275,306	256,952	238,598	220,244	201,891	183,537	165,183	146,830	128,476	110,122	91,769
176,692	166,298	155,904	145,511	135,117	124,723	114,330	103,936	93,543	83,149	72,755	62,362	51,968
488,705	459,957	431,210	402,463	373,715	344,968	316,221	287,473	258,726	229,979	201,231	172,484	143,737
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
50,543	48,976	47,326	45,591	43,767	41,852	39,843	37,737	35,531	33,222	30,806	28,280	25,640
605,719	604,274	602,749	601,141	599,446	597,663	595,789	593,820	591,754	589,587	587,317	584,940	582,452
112,730	106,098	99,467	92,836	86,205	79,574	72,943	66,311	59,680	53,049	46,418	39,787	33,156
$ 1,207,153	$ 1,170,330	$ 1,133,426	$ 1,096,439	$ 1,059,366	$ 1,022,205	$ 984,952	$ 947,605	$ 910,160	$ 872,615	$ 834,966	$ 797,210	$ 759,344
14,997,105	14,922,119	14,847,508	14,773,271	14,699,405	14,625,908	14,552,778	14,480,014	14,407,614	14,335,576	14,263,898	14,192,579	14,121,616

Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
17.720%	18.074%	18.435%	18.804%	19.180%		
24	25	26	27	28	29	30
2037	2038	2039	2040	2041		
$ -	$ -	$ -	$ -	$ -		
$ -	$ -	$ -	$ -	$ -		
549,082	549,082	549,082	549,082	549,082		
82,362	82,362	82,362	82,362	82,362	82,362	82,362
(466,719)	(466,719)	(466,719)	(466,719)	(466,719)		
(181,787)	(181,787)	(181,787)	(181,787)	(181,787)		
727,149	545,362	363,574	181,787	0		
15,374,286	15,374,286	15,374,286	15,374,286	15,374,286		
(13,177,959)	(13,727,041)	(14,276,123)	(14,825,204)	(15,374,286)		
2,196,327	1,647,245	1,098,163	549,082	(0)		
(727,149)	(545,362)	(363,574)	(181,787)	(0)		
1,469,178	1,101,883	734,589	367,294	(0)		
73,415	55,061	36,707	18,354	(0)		
41,574	31,181	20,787	10,394	(0)		
114,989	86,242	57,495	28,747	(0)		
7,884	8,042	8,203	8,367	8,534		
549,082	549,082	549,082	549,082	549,082		
22,884	20,007	17,006	13,877	10,616		
579,850	577,131	574,291	571,326	568,232		
26,525	19,893	13,262	6,631	(0)		
$ 721,364	$ 683,266	$ 645,048	$ 606,704	$ 568,232		
14,051,008	13,980,753	13,910,849	13,841,295	13,772,088		

HIGHLY CONFIDENTIAL

Rio Rico Esimated KWh

COD: 3/1/2014	Contract Year	Estimated Power Production (KWh)
2015	1	15,768,000
2016	2	15,689,160
2017	3	15,610,714
2018	4	15,532,661
2019	5	15,454,997
2020	6	15,377,722
2021	7	15,300,834
2022	8	15,224,330
2023	9	15,148,208
2024	10	15,072,467
2025	11	14,997,105
2026	12	14,922,119
2027	13	14,847,508
2028	14	14,773,271
2029	15	14,699,405
2030	16	14,625,908
2031	17	14,552,778
2032	18	14,480,014
2033	19	14,407,614
2034	20	14,335,576
2035	21	14,263,898
2036	22	14,192,579
2037	23	14,121,616
2038	24	14,051,008
2039	25	13,980,753
2040	26	13,910,849
2041	27	13,841,295
2042	28	13,772,088
2043	29	13,703,228
2044	30	13,634,711
		440,292,412

Areva - Thermal

5 MW

HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2014
Original Cost	$ 9,790,236	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.24%	
Debt Return (wtd cost)	2.91%	
Equity Return (wtd cost)	4.35%	
Tax Depreciation (Yrs)	6	
ITC Claimed	2,937,071	
Property Tax Rate	7.000%	

Original Cost	$	9,790,236	
ITC @ 30%	$	2,937,070.90	
Depeciable Tax Basis	$	8,321,700.88	$ -
Tax Basis After 50% Bonus	$	4,160,850.44	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tax Depreciation	$	4,993,021	$ 1,331,472	$ 798,883	$ 479,330	$ 479,330	$ 239,665				
Tax Depreciation included in Rate Base		297,204	6,027,289	297,204	297,204	1,163,136	239,665	-	-	-	-
Book Depreciation		349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
Less: Book Depr on ITC Adj		52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448
Timing Difference		(0)	5,730,085	(0)	(0)	865,932	(57,539)	(297,204)	(297,204)	(297,204)	(297,204)
Def. Tax @ 38.24%		(0)	2,191,185	(0)	(0)	331,133	(22,003)	(113,651)	(113,651)	(113,651)	(113,651)
A.D.I.T.		(0)	2,191,185	2,191,185	2,191,185	2,522,317	2,500,314	2,386,664	2,273,013	2,159,362	2,045,712
Plant in Service		9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236
Accum. Depreciation		(349,651)	(699,303)	(1,048,954)	(1,398,605)	(1,748,256)	(2,097,908)	(2,447,559)	(2,797,210)	(3,146,862)	(3,496,513)
Net Plant in Service		9,440,585	9,090,934	8,741,282	8,391,631	8,041,980	7,692,329	7,342,677	6,993,026	6,643,375	6,293,723
Unamortized ITC		(2,643,364)	(2,055,950)	(1,468,535)	(881,121)	(293,707)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		0	(2,191,185)	(2,191,185)	(2,191,185)	(2,522,317)	(2,500,314)	(2,386,664)	(2,273,013)	(2,159,362)	(2,045,712)
Net Rate Base		9,440,585	6,899,749	6,550,098	6,200,446	5,519,663	5,192,014	4,956,013	4,720,013	4,484,012	4,248,012
Return on Rate Base:											
Debt Return		410,665	300,139	284,929	269,719	240,105	225,853	215,587	205,321	195,055	184,789
Equity Return		274,416	200,560	190,396	180,233	160,444	150,920	144,060	137,200	130,340	123,480
Total		685,082	500,699	475,326	449,952	400,549	376,773	359,647	342,521	325,395	308,269
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
Property Taxes(1)		24,671	24,326	23,957	23,563	23,144	22,699	22,227	21,727	21,198	20,639
Total		379,323	379,077	378,810	378,521	378,208	377,871	377,509	377,122	376,708	376,266
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		169,911	124,181	117,888	111,595	99,342	93,445	89,198	84,950	80,703	76,455
Revenue Requirement	$	1,234,315	$ 1,003,957	$ 972,024	$ 940,068	$ 878,099	$ 848,089	$ 826,354	$ 804,593	$ 782,805	$ 760,990
NPV Cost	$	9,360,291									
Estimated Output (KWh)		14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000
NPV Output		169,461,664									
LCOE ($/KWh)	$	0.06									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
-	-	-	-	-	-	-	-	-	-	-	-	-
349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448
(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)
(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)
1,932,061	1,818,411	1,704,760	1,591,109	1,477,459	1,363,808	1,250,157	1,136,507	1,022,856	909,205	795,555	681,904	568,253
9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236
(3,846,164)	(4,195,816)	(4,545,467)	(4,895,118)	(5,244,769)	(5,594,421)	(5,944,072)	(6,293,723)	(6,643,375)	(6,993,026)	(7,342,677)	(7,692,329)	(8,041,980)
5,944,072	5,594,421	5,244,769	4,895,118	4,545,467	4,195,816	3,846,164	3,496,513	3,146,862	2,797,210	2,447,559	2,097,908	1,748,256
(1,932,061)	(1,818,411)	(1,704,760)	(1,591,109)	(1,477,459)	(1,363,808)	(1,250,157)	(1,136,507)	(1,022,856)	(909,205)	(795,555)	(681,904)	(568,253)
4,012,011	3,776,010	3,540,010	3,304,009	3,068,008	2,832,008	2,596,007	2,360,006	2,124,006	1,888,005	1,652,004	1,416,004	1,180,003
174,522	164,256	153,990	143,724	133,458	123,192	112,926	102,660	92,394	82,128	71,862	61,596	51,330
116,620	109,760	102,900	96,040	89,180	82,320	75,460	68,600	61,740	54,880	48,020	41,160	34,300
291,142	274,016	256,890	239,764	222,638	205,512	188,386	171,260	154,134	137,008	119,882	102,756	85,630
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
20,050	19,428	18,774	18,085	17,362	16,602	15,805	14,970	14,095	13,179	12,220	11,218	10,171
375,796	375,296	374,766	374,205	373,610	372,983	372,321	371,622	370,887	370,114	369,301	368,448	367,552
72,208	67,960	63,713	59,465	55,218	50,970	46,723	42,475	38,228	33,980	29,733	25,485	21,238
$ 739,146	$ 717,273	$ 695,369	$ 673,434	$ 651,467	$ 629,465	$ 607,430	$ 585,358	$ 563,249	$ 541,102	$ 518,916	$ 496,689	$ 474,420
14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2037	2038	2039	2040	2041		
-	-	-	-	-		
349,651	349,651	349,651	349,651	349,651		
52,448	52,448	52,448	52,448	52,448	52,448	52,448
(297,204)	(297,204)	(297,204)	(297,204)	(297,204)		
(113,651)	(113,651)	(113,651)	(113,651)	(113,651)		
454,603	340,952	227,301	113,651	0		
9,790,236	9,790,236	9,790,236	9,790,236	9,790,236		
(8,391,631)	(8,741,282)	(9,090,934)	(9,440,585)	(9,790,236)		
1,398,605	1,048,954	699,303	349,651	-		
(454,603)	(340,952)	(227,301)	(113,651)	(0)		
944,003	708,002	472,001	236,001	(0)		
41,064	30,798	20,532	10,266	(0)		
27,440	20,580	13,720	6,860	(0)		
68,504	51,378	34,252	17,126	(0)		
7,884	8,042	8,203	8,367	8,534		
349,651	349,651	349,651	349,651	349,651		
9,078	7,936	6,746	5,505	4,211		
366,613	365,630	364,600	363,523	362,397		
16,990	12,743	8,495	4,248	(0)		
$ 452,108	$ 429,751	$ 407,347	$ 384,897	$ 362,397		
14,310,000	14,310,000	14,310,000	14,310,000	14,310,000		

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Areva Esimated KWh

COD: 12/30/2014	Contract Year	Estimated Power Production (KWh)
2014	1	14,310,000.00
2015	2	14,310,000.00
2016	3	14,310,000.00
2017	4	14,310,000.00
2018	5	14,310,000.00
2019	6	14,310,000.00
2020	7	14,310,000.00
2021	8	14,310,000.00
2022	9	14,310,000.00
2023	10	14,310,000.00
2024	11	14,310,000.00
2025	12	14,310,000.00
2026	13	14,310,000.00
2027	14	14,310,000.00
2028	15	14,310,000.00
2029	16	14,310,000.00
2030	17	14,310,000.00
2031	18	14,310,000.00
2032	19	14,310,000.00
2033	20	14,310,000.00
2034	21	14,310,000.00
2035	22	14,310,000.00
2036	23	14,310,000.00
2037	24	14,310,000.00
2038	25	14,310,000.00
2039	26	14,310,000.00
2040	27	14,310,000.00
2041	28	14,310,000.00
2042	29	14,310,000.00
2043	30	14,310,000.00
		429,300,000.00

Prairie Fire Fixed PV

4 MW

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Levelized Cost of Energy ($/KWh)

Assumptions			DPIS - 2012
Original Cost	$	17,229,473	
Asset Life		28	
O&M First Year	$	5,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)		38.24%	
Debt Return (wtd cost)		2.91%	
Equity Return (wtd cost)		4.35%	
Tax Depreciation (Yrs)		6	
ITC Claimed		5,168,842	
Property Tax Rate		7.000%	

Original Cost	$	17,229,473		
ITC @ 30%	$	5,168,841.90		
Depeciable Tax Basis	$	14,645,052.05	$	-
Tax Basis After 50% Bonus	$	7,322,526.03		

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Tax Depreciation	$	8,787,031	$ 2,343,208	$ 1,405,925	$ 843,555	$ 843,555	$ 421,777				
Tax Depreciation included in Rate Base		523,038	523,038	523,038	11,810,607	523,038	523,038	219,257	-	-	
Book Depreciation		615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
Less: Book Depr on ITC Adj		92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301
Timing Difference		-	-	-	11,287,569	-	-	(523,038)	(523,038)	(523,038)	(523,038)
Def. Tax @ 38.24%		-	-	-	4,316,366	-	-	(200,010)	(200,010)	(200,010)	(200,010)
A.D.I.T.		-	-	-	4,316,366	4,316,366	4,316,366	4,116,357	3,916,347	3,716,338	3,516,328
Plant in Service		17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473
Accum. Depreciation		(615,338)	(1,230,677)	(1,846,015)	(2,461,353)	(3,076,692)	(3,692,030)	(4,307,368)	(4,922,707)	(5,538,045)	(6,153,383)
Net Plant in Service		16,614,135	15,998,796	15,383,458	14,768,120	14,152,781	13,537,443	12,922,105	12,306,766	11,691,428	11,076,090
Unamortized ITC		(4,651,958)	(3,618,189)	(2,584,421)	(1,550,653)	(516,884)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		-	-	-	(4,316,366)	(4,316,366)	(4,316,366)	(4,116,357)	(3,916,347)	(3,716,338)	(3,516,328)
Net Rate Base		16,614,135	15,998,796	15,383,458	10,451,753	9,836,415	9,221,077	8,805,748	8,390,419	7,975,090	7,559,762
Return on Rate Base:											
Debt Return		722,715	695,948	669,180	454,651	427,884	401,117	383,050	364,983	346,916	328,850
Equity Return		482,935	465,049	447,162	303,809	285,922	268,036	255,963	243,890	231,818	219,745
Total		1,205,650	1,160,996	1,116,342	758,460	713,806	669,153	639,013	608,874	578,734	548,595
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
Property Taxes(1)		43,418	42,810	42,161	41,468	40,731	39,948	39,117	38,237	37,306	36,322
Total		663,757	663,249	662,701	662,113	661,482	660,806	660,086	659,318	658,502	657,636
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		299,019	287,945	276,870	188,109	177,035	165,960	158,485	151,010	143,535	136,060
Revenue Requirement	$	2,168,426	$ 2,112,189	$ 2,055,913	$ 1,608,682	$ 1,552,322	$ 1,495,919	$ 1,457,584	$ 1,419,202	$ 1,380,771	$ 1,342,290
NPV Cost	$	17,040,198									
Estimated Output (KWh)		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451	10,519,589	10,466,991
NPV Output		130,161,899									
LCOE ($/KWh)	$	0.13									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301
(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)
(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)
3,316,319	3,116,309	2,916,300	2,716,290	2,516,280	2,316,271	2,116,261	1,916,252	1,716,242	1,516,233	1,316,223	1,116,213	916,204
17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473
(6,768,722)	(7,384,060)	(7,999,398)	(8,614,737)	(9,230,075)	(9,845,413)	(10,460,751)	(11,076,090)	(11,691,428)	(12,306,766)	(12,922,105)	(13,537,443)	(14,152,781)
10,460,751	9,845,413	9,230,075	8,614,737	7,999,398	7,384,060	6,768,722	6,153,383	5,538,045	4,922,707	4,307,368	3,692,030	3,076,692
(3,316,319)	(3,116,309)	(2,916,300)	(2,716,290)	(2,516,280)	(2,316,271)	(2,116,261)	(1,916,252)	(1,716,242)	(1,516,233)	(1,316,223)	(1,116,213)	(916,204)
7,144,433	6,729,104	6,313,775	5,898,447	5,483,118	5,067,789	4,652,460	4,237,132	3,821,803	3,406,474	2,991,145	2,575,817	2,160,488
310,783	292,716	274,649	256,582	238,516	220,449	202,382	184,315	166,248	148,182	130,115	112,048	93,981
207,672	195,600	183,527	171,454	159,382	147,309	135,236	123,164	111,091	99,018	86,946	74,873	62,800
518,455	488,316	458,176	428,037	397,897	367,758	337,618	307,479	277,340	247,200	217,061	186,921	156,782
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
35,284	34,191	33,039	31,827	30,554	29,218	27,815	26,345	24,805	23,192	21,506	19,742	17,900
656,718	655,746	654,718	653,634	652,490	651,285	650,017	648,684	647,284	645,815	644,274	642,659	640,968
128,585	121,110	113,635	106,160	98,685	91,210	83,734	76,259	68,784	61,309	53,834	46,359	38,884
$ 1,303,758	$ 1,265,171	$ 1,226,529	$ 1,187,830	$ 1,149,072	$ 1,110,253	$ 1,071,370	$ 1,032,423	$ 993,408	$ 954,324	$ 915,169	$ 875,939	$ 836,634
10,414,656	10,362,583	10,310,770	10,259,216	10,207,920	10,156,880	10,106,096	10,055,565	10,005,288	9,955,261	14,263,898	14,192,579	14,121,616

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2035	2036	2037	2038	2039	2040	2041
615,338	615,338	615,338	615,338	615,338		
92,301	92,301	92,301	92,301	92,301	92,301	92,301
(523,038)	(523,038)	(523,038)	(523,038)	(523,038)		
(200,010)	(200,010)	(200,010)	(200,010)	(200,010)		
716,194	516,185	316,175	116,166	(83,844)		
17,229,473	17,229,473	17,229,473	17,229,473	17,229,473		
(14,768,120)	(15,383,458)	(15,998,796)	(16,614,135)	(17,229,473)		
2,461,353	1,846,015	1,230,677	615,338	0		
(716,194)	(516,185)	(316,175)	(116,166)	83,844		
1,745,159	1,329,830	914,502	499,173	83,844		
75,914	57,848	39,781	21,714	3,647		
50,728	38,655	26,582	14,510	2,437		
126,642	96,503	66,363	36,224	6,084		
7,884	8,042	8,203	8,367	8,534		
615,338	615,338	615,338	615,338	615,338		
15,975	13,967	11,872	9,688	7,411		
639,198	637,348	635,413	633,393	631,284		
31,409	23,934	16,459	8,984	1,509		
$ 797,250	$ 757,785	$ 718,236	$ 678,601	$ 638,877		
14,051,008	13,980,753	13,910,849	13,841,295	13,772,088		

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Prairie Fire Esimated KWh

COD: 12/28/2012	Contract Year	Estimated Power Production (KWh)
2012	1	10,950,000
2013	2	10,895,250
2014	3	10,840,774
2015	4	10,786,570
2016	5	10,732,637
2017	6	10,678,974
2018	7	10,625,579
2019	8	10,572,451
2020	9	10,519,589
2021	10	10,466,991
2022	11	10,414,656
2023	12	10,362,583
2024	13	10,310,770
2025	14	10,259,216
2026	15	10,207,920
2027	16	10,156,880
2028	17	10,106,096
2029	18	10,055,565
2030	19	10,005,288
2031	20	9,955,261
2032	21	9,905,485
2033	22	9,855,957
2034	23	9,806,678
2035	24	9,757,644
2036	25	9,708,856
2037	26	9,660,312
2038	27	9,612,010
2039	28	9,563,950
2040	29	9,516,130
2041	30	9,468,550
		305,758,620

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Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
Fort Huahuca	TEP	Fixed PV	$ 0.07	2014
Rio Rico	UNSE	Fixed PV	$ 0.09	2014
Prairie Fire	TEP	Fixed PV	$ 0.13	2012
La Senita	UNSE	Single Axix PV	$ 0.17	2011
UASTP II	TEP	Fixed PV	$ 0.14	2011
UASTP I	TEP	Single Axix PV	$ 0.12	2010
Springerville 1.8	TEP	Fixed PV	$ 0.15	2010
Springerville 4.6	TEP	Fixed PV	$ 0.30	2004

Non-Equivalent Technologies

Project Name	Company	Technology	LCOE	COD
White Mtn	TEP	Low Concentrating PV	$ 0.17	2014
Areva	TEP	Solar Thermal Steam Augmentation	$ 0.06	2014

UASTP I Single Axis PV
1.28 MW
Levelized Cost of Energy ($/KWh)

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Assumptions			DPIS - 2010
Original Cost	$	7,525,500	
Asset Life		28	
O&M First Year	$	5,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)		38.24%	
Debt Return (wtd cost)		2.91%	
Equity Return (wtd cost)		4.35%	
Tax Depreciation (Yrs)		6	
ITC Claimed		2,257,650	
Property Tax Rate		7.000%	

Original Cost	$	7,525,500		
ITC @ 30%	$	2,257,650.00		
Depeciable Tax Basis	$	6,396,675.00	$	-
Tax Basis After 50% Bonus	$	3,198,337.50		

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Tax Depreciation	$	3,838,005 $	1,023,468 $	614,081 $	368,448 $	368,448 $	184,224				
Tax Depreciation included in Rate Base		3,838,005	228,453	228,453	228,453	228,453	1,644,859	-	-	-	-
Book Depreciation		268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
Less: Book Depr on ITC Adj		40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315
Timing Difference		3,609,552	(0)	(0)	(0)	(0)	1,416,407	(228,453)	(228,453)	(228,453)	(228,453)
Def. Tax @ 38.24%		1,380,293	(0)	(0)	(0)	(0)	541,634	(87,360)	(87,360)	(87,360)	(87,360)
A.D.I.T.		1,380,293	1,380,293	1,380,293	1,380,293	1,380,293	1,921,927	1,834,566	1,747,206	1,659,846	1,572,485
Plant in Service		7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500
Accum. Depreciation		(268,768)	(537,536)	(806,304)	(1,075,071)	(1,343,839)	(1,612,607)	(1,881,375)	(2,150,143)	(2,418,911)	(2,687,679)
Net Plant in Service		7,256,732	6,987,964	6,719,196	6,450,429	6,181,661	5,912,893	5,644,125	5,375,357	5,106,589	4,837,821
Unamortized ITC		(2,031,885)	(1,580,355)	(1,128,825)	(677,295)	(225,765)					
Unamortized ITC included in Rate Base		(2,031,885)	(1,580,355)	(1,128,825)	(677,295)	(225,765)					
A.D.I.T.		(1,380,293)	(1,380,293)	(1,380,293)	(1,380,293)	(1,380,293)	(1,921,927)	(1,834,566)	(1,747,206)	(1,659,846)	(1,572,485)
Net Rate Base		3,844,554	4,027,316	4,210,079	4,392,841	4,575,603	3,990,966	3,809,559	3,628,151	3,446,744	3,265,336
Return on Rate Base:											
Debt Return		167,238	175,188	183,138	191,089	199,039	173,607	165,716	157,825	149,933	142,042
Equity Return		111,752	117,065	122,377	127,690	133,002	116,008	110,735	105,462	100,189	94,916
Total		278,991	292,253	305,516	318,778	332,041	289,615	276,451	263,287	250,122	236,958
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
Property Taxes(1)		18,964	18,699	18,415	18,113	17,791	17,448	17,085	16,701	16,294	15,865
Total		292,732	292,567	292,385	292,186	291,971	291,737	291,484	291,212	290,921	290,608
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		69,194	72,483	75,773	79,062	82,351	71,829	68,564	65,299	62,034	58,769
Revenue Requirement	$	640,917 $	657,303 $	673,673 $	690,027 $	706,363 $	653,181 $	636,499 $	619,798 $	603,077 $	586,335
NPV Cost	$	6,758,177									
Estimated Output (KWh)		3,504,000	3,486,480	3,469,048	3,451,702	3,434,444	3,417,272	3,400,185	3,383,184	3,366,268	3,349,437
NPV Output		55,558,280									
LCOE ($/KWh)	$	0.12									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
-	-	-	-	-	-	-	-	-	-	-	-	-
268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315
(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)
(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)
1,485,125	1,397,765	1,310,405	1,223,044	1,135,684	1,048,324	960,963	873,603	786,243	698,882	611,522	524,162	436,802
7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500
(2,956,446)	(3,225,214)	(3,493,982)	(3,762,750)	(4,031,518)	(4,300,286)	(4,569,054)	(4,837,821)	(5,106,589)	(5,375,357)	(5,644,125)	(5,912,893)	(6,181,661)
4,569,054	4,300,286	4,031,518	3,762,750	3,493,982	3,225,214	2,956,446	2,687,679	2,418,911	2,150,143	1,881,375	1,612,607	1,343,839
(1,485,125)	(1,397,765)	(1,310,405)	(1,223,044)	(1,135,684)	(1,048,324)	(960,963)	(873,603)	(786,243)	(698,882)	(611,522)	(524,162)	(436,802)
3,083,928	2,902,521	2,721,113	2,539,706	2,358,298	2,176,891	1,995,483	1,814,076	1,632,668	1,451,260	1,269,853	1,088,445	907,038
134,151	126,260	118,368	110,477	102,586	94,695	86,804	78,912	71,021	63,130	55,239	47,347	39,456
89,643	84,370	79,097	73,823	68,550	63,277	58,004	52,731	47,458	42,185	36,912	31,639	26,366
223,794	210,629	197,465	184,301	171,136	157,972	144,808	131,643	118,479	105,315	92,150	78,986	65,822
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
15,412	14,934	14,431	13,902	13,346	12,762	12,149	11,507	10,834	10,130	9,393	8,623	7,818
290,274	289,919	289,540	289,138	288,711	288,259	287,781	287,276	286,743	286,182	285,591	284,969	284,316
55,504	52,239	48,974	45,709	42,444	39,179	35,914	32,650	29,385	26,120	22,855	19,590	16,325
$ 569,572	$ 552,787	$ 535,979	$ 519,148	$ 502,292	$ 485,410	$ 468,503	$ 451,569	$ 434,607	$ 417,616	$ 400,596	$ 383,545	$ 366,462
3,332,690	3,316,026	3,299,446	3,282,949	3,266,534	3,250,202	3,233,951	3,217,781	3,201,692	3,185,684	14,263,898	14,192,579	14,121,616

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2033	2034	2035	2036	2037	2038	2039
-	-	-	-	-		
268,768	268,768	268,768	268,768	268,768		
40,315	40,315	40,315	40,315	40,315	40,315	40,315
(228,453)	(228,453)	(228,453)	(228,453)	(228,453)		
(87,360)	(87,360)	(87,360)	(87,360)	(87,360)		
349,441	262,081	174,721	87,360	(0)		
7,525,500	7,525,500	7,525,500	7,525,500	7,525,500		
(6,450,429)	(6,719,196)	(6,987,964)	(7,256,732)	(7,525,500)		
1,075,071	806,304	537,536	268,768	(0)		
(349,441)	(262,081)	(174,721)	(87,360)	0		
725,630	544,223	362,815	181,408	(0)		
31,565	23,674	15,782	7,891	(0)		
21,092	15,819	10,546	5,273	(0)		
52,657	39,493	26,329	13,164	(0)		
7,884	8,042	8,203	8,367	8,534		
268,768	268,768	268,768	268,768	268,768		
6,978	6,101	5,185	4,231	3,237		
283,630	282,911	282,156	281,366	280,539		
13,060	9,795	6,530	3,265	(0)		
$ 349,347	$ 332,198	$ 315,015	$ 297,796	$ 280,539		
14,051,008	13,980,753	13,910,849	13,841,295	13,772,088		

HIGHLY CONFIDENTIAL

UASTP Esimated KWh

COD: 12/31/2010	Contract Year	Estimated Power Production (KWh)
2010	1	3,504,000
2011	2	3,486,480
2012	3	3,469,048
2013	4	3,451,702
2014	5	3,434,444
2015	6	3,417,272
2016	7	3,400,185
2017	8	3,383,184
2018	9	3,366,268
2019	10	3,349,437
2020	11	3,332,690
2021	12	3,316,026
2022	13	3,299,446
2023	14	3,282,949
2024	15	3,266,534
2025	16	3,250,202
2026	17	3,233,951
2027	18	3,217,781
2028	19	3,201,692
2029	20	3,185,684
2030	21	3,169,755
2031	22	3,153,906
2032	23	3,138,137
2033	24	3,122,446
2034	25	3,106,834
2035	26	3,091,300
2036	27	3,075,843
2037	28	3,060,464
2038	29	3,045,162
2039	30	3,029,936
		97,842,758

UASTP II Fixed PV
4 MW

HIGHLY CONFIDENTIAL

Levelized Cost of Energy ($/KWh)

Assumptions			DPIS - 2011
Original Cost	$	17,569,046	
Asset Life		28	
O&M First Year	$	5,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)		38.24%	
Debt Return (wtd cost)		2.91%	
Equity Return (wtd cost)		4.35%	
Tax Depreciation (Yrs)		6	
ITC Claimed		5,270,714	
Property Tax Rate		7.000%	

Original Cost	$	17,569,046		
ITC @ 30%	$	5,270,713.80		
Depeciable Tax Basis	$	14,933,689.10	$	-
Tax Basis After 50% Bonus	$	7,466,844.55		

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tax Depreciation	$	14,933,689									
Tax Depreciation included in Rate Base		533,346	533,346	533,346	533,346	12,800,305	-	-	-	-	-
Book Depreciation		627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466
Less: Book Depr on ITC Adj		94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120
Timing Difference		0	0	0	0	12,266,959	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)
Def. Tax @ 38.24%		0	0	0	0	4,690,885	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)
A.D.I.T.		0	0	0	0	4,690,885	4,486,934	4,282,982	4,079,031	3,875,079	3,671,127
Plant in Service		17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046
Accum. Depreciation		(627,466)	(1,254,932)	(1,882,398)	(2,509,864)	(3,137,330)	(3,764,796)	(4,392,262)	(5,019,727)	(5,647,193)	(6,274,659)
Net Plant in Service		16,941,580	16,314,114	15,686,648	15,059,182	14,431,716	13,804,250	13,176,785	12,549,319	11,921,853	11,294,387
Unamortized ITC		(4,743,642)	(3,689,500)	(2,635,357)	(1,581,214)	(527,071)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		(0)	(0)	(0)	(0)	(4,690,885)	(4,486,934)	(4,282,982)	(4,079,031)	(3,875,079)	(3,671,127)
Net Rate Base		16,941,580	16,314,114	15,686,648	15,059,182	9,740,831	9,317,317	8,893,802	8,470,288	8,046,774	7,623,259
Return on Rate Base:											
Debt Return		736,959	709,664	682,369	655,074	423,726	405,303	386,880	368,458	350,035	331,612
Equity Return		492,453	474,214	455,975	437,736	283,144	270,833	258,523	246,212	233,901	221,591
Total		1,229,412	1,183,878	1,138,344	1,092,811	706,870	676,136	645,403	614,669	583,936	553,203
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466
Property Taxes(1)		44,274	43,654	42,992	42,286	41,534	40,735	39,888	38,990	38,041	37,038
Total		676,740	676,220	675,660	675,057	674,412	673,721	672,985	672,200	671,365	670,479
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		304,913	293,620	282,327	271,033	175,314	167,692	160,070	152,447	144,825	137,203
Revenue Requirement	$	2,211,064	$ 2,153,718	$ 2,096,331	$ 2,038,902	$ 1,556,596	$ 1,517,550	$ 1,478,457	$ 1,439,316	$ 1,400,126	$ 1,360,885
NPV Cost	$	17,597,197									
Estimated Output (KWh)		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451	10,519,589	10,466,991
NPV Output		123,913,076									
LCOE ($/KWh)	$	0.14									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
-	-	-	-	-	-	-	-	-	-	-	-	-
627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466
94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120	94,120
(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)	(533,346)
(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)	(203,952)
3,467,176	3,263,224	3,059,273	2,855,321	2,651,370	2,447,418	2,243,467	2,039,515	1,835,564	1,631,612	1,427,661	1,223,709	1,019,758
17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046	17,569,046
(6,902,125)	(7,529,591)	(8,157,057)	(8,784,523)	(9,411,989)	(10,039,455)	(10,666,921)	(11,294,387)	(11,921,853)	(12,549,319)	(13,176,785)	(13,804,250)	(14,431,716)
10,666,921	10,039,455	9,411,989	8,784,523	8,157,057	7,529,591	6,902,125	6,274,659	5,647,193	5,019,727	4,392,262	3,764,796	3,137,330
(3,467,176)	(3,263,224)	(3,059,273)	(2,855,321)	(2,651,370)	(2,447,418)	(2,243,467)	(2,039,515)	(1,835,564)	(1,631,612)	(1,427,661)	(1,223,709)	(1,019,758)
7,199,745	6,776,230	6,352,716	5,929,202	5,505,687	5,082,173	4,658,658	4,235,144	3,811,630	3,388,115	2,964,601	2,541,086	2,117,572
313,189	294,766	276,343	257,920	239,497	221,075	202,652	184,229	165,806	147,383	128,960	110,537	92,114
209,280	196,970	184,659	172,348	160,038	147,727	135,417	123,106	110,795	98,485	86,174	73,864	61,553
522,469	491,736	461,002	430,269	399,535	368,802	338,068	307,335	276,601	245,868	215,134	184,401	153,667
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466	627,466
35,980	34,864	33,690	32,455	31,157	29,793	28,363	26,864	25,294	23,650	21,930	20,131	18,252
669,541	668,547	667,497	666,389	665,220	663,989	662,693	661,331	659,901	658,400	656,825	655,176	653,448
129,580	121,958	114,335	106,713	99,091	91,468	83,846	76,224	68,601	60,979	53,357	45,734	38,112
$ 1,321,590	$ 1,282,241	$ 1,242,835	$ 1,203,370	$ 1,163,846	$ 1,124,259	$ 1,084,607	$ 1,044,890	$ 1,005,103	$ 965,246	$ 925,316	$ 885,311	$ 845,227
10,414,656	10,362,583	10,310,770	10,259,216	10,207,920	10,156,880	10,106,096	10,055,565	10,005,288	9,955,261	9,905,485	9,855,957	9,806,678

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2034	2035	2036	2037	2038	2039	2040
-	-	-	-	-		
627,466	627,466	627,466	627,466	627,466		
94,120	94,120	94,120	94,120	94,120	94,120	94,120
(533,346)	(533,346)	(533,346)	(533,346)	(533,346)		
(203,952)	(203,952)	(203,952)	(203,952)	(203,952)		
815,806	611,855	407,903	203,952	-		
17,569,046	17,569,046	17,569,046	17,569,046	17,569,046		
(15,059,182)	(15,686,648)	(16,314,114)	(16,941,580)	(17,569,046)		
2,509,864	1,882,398	1,254,932	627,466	(0)		
(815,806)	(611,855)	(407,903)	(203,952)	-		
1,694,058	1,270,543	847,029	423,514	(0)		
73,692	55,269	36,846	18,423	(0)		
49,242	36,932	24,621	12,311	(0)		
122,934	92,200	61,467	30,733	(0)		
7,884	8,042	8,203	8,367	8,534		
627,466	627,466	627,466	627,466	627,466		
16,290	14,242	12,106	9,879	7,557		
651,641	649,751	647,775	645,712	643,557		
30,489	22,867	15,245	7,622	(0)		
$ 805,064	$ 764,818	$ 724,487	$ 684,067	$ 643,557		
9,757,644	9,708,856	9,660,312	9,612,010	9,563,950		

HIGHLY CONFIDENTIAL

UASTP Esimated KWh

COD: 12/29/2011	Contract Year	Estimated Power Production (KWh)
2011	1	10,950,000
2012	2	10,895,250
2013	3	10,840,774
2014	4	10,786,570
2015	5	10,732,637
2016	6	10,678,974
2017	7	10,625,579
2018	8	10,572,451
2019	9	10,519,589
2020	10	10,466,991
2021	11	10,414,656
2022	12	10,362,583
2023	13	10,310,770
2024	14	10,259,216
2025	15	10,207,920
2026	16	10,156,880
2027	17	10,106,096
2028	18	10,055,565
2029	19	10,005,288
2030	20	9,955,261
2031	21	9,905,485
2032	22	9,855,957
2033	23	9,806,678
2034	24	9,757,644
2035	25	9,708,856
2036	26	9,660,312
2037	27	9,612,010
2038	28	9,563,950
2039	29	9,516,130
2040	30	9,468,550
		305,758,619.71

Springerville 4.6 Fixed PV HIGHLY CONFIDENTIAL
3.68 MW
Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2004
Original Cost	$ 36,640,478	NOT Sure this is correct
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.24%	
Debt Return (wtd cost)	2.91%	
Equity Return (wtd cost)	4.35%	
Tax Depreciation (Yrs)	6	
ITC Claimed	-	
Property Tax Rate	7.000%	

Original Cost	$ 36,640,478	
ITC @ 30%	$ 10,992,143.40	
Depeciable Tax Basis	$ 31,144,406.30	$ (5,496,071.70)
Tax Basis After 50% Bonus	$ 15,572,203.15	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Tax Depreciation		$ 7,328,096	$ 11,724,953	$ 7,034,972	$ 4,220,983	$ 4,220,983	$ 2,110,492				
Tax Depreciation included in Rate Base		$ 7,328,096	$ 11,724,953	$ 7,034,972	$ 4,220,983	$ 4,220,983	$ 2,110,492				
Book Depreciation		1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589
Less: Book Depr on ITC Adj		-	-	-	-	-	-	-	-	-	-
Timing Difference		6,019,507	10,416,364	5,726,383	2,912,395	2,912,395	801,903	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)
Def. Tax @ 38.24%		2,301,860	3,983,218	2,189,769	1,113,700	1,113,700	306,648	(500,404)	(500,404)	(500,404)	(500,404)
A.D.I.T.		2,301,860	6,285,077	8,474,846	9,588,546	10,702,246	11,008,893	10,508,489	10,008,085	9,507,681	9,007,276
Plant in Service		36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478
Accum. Depreciation		(1,308,589)	(2,617,177)	(3,925,766)	(5,234,354)	(6,542,943)	(7,851,531)	(9,160,120)	(10,468,708)	(11,777,297)	(13,085,885)
Net Plant in Service		35,331,890	34,023,301	32,714,713	31,406,124	30,097,536	28,788,947	27,480,359	26,171,770	24,863,182	23,554,593
Unamortized ITC		-	-	-	-	-					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		(2,301,860)	(6,285,077)	(8,474,846)	(9,588,546)	(10,702,246)	(11,008,893)	(10,508,489)	(10,008,085)	(9,507,681)	(9,007,276)
Net Rate Base		33,030,030	27,738,224	24,239,866	21,817,578	19,395,290	17,780,054	16,971,869	16,163,685	15,355,501	14,547,317
Return on Rate Base:											
Debt Return		1,436,806	1,206,613	1,054,434	949,065	843,695	773,432	738,276	703,120	667,964	632,808
Equity Return		960,108	806,287	704,598	634,187	563,777	516,826	493,334	469,841	446,349	422,857
Total		2,396,914	2,012,900	1,759,032	1,583,252	1,407,472	1,290,258	1,231,610	1,172,962	1,114,314	1,055,666
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589
Property Taxes(1)		92,334	91,041	89,660	88,187	86,619	84,954	83,186	81,315	79,335	77,243
Total		1,405,923	1,404,730	1,403,451	1,402,082	1,400,620	1,399,062	1,397,406	1,395,647	1,393,782	1,391,807
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		594,471	499,229	436,266	392,670	349,074	320,003	305,458	290,912	276,367	261,821
Revenue Requirement		$ 4,397,307	$ 3,916,859	$ 3,598,749	$ 3,378,004	$ 3,157,166	$ 3,009,324	$ 2,934,473	$ 2,859,521	$ 2,784,462	$ 2,709,294
NPV Cost		$ 33,858,004									
Estimated Output (KWh)		10,074,000	10,023,630	9,973,512	9,923,644	9,874,026	9,824,656	9,775,533	9,726,655	9,678,022	9,629,632
NPV Output		114,000,030									
LCOE ($/KWh)		$ 0.30									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589
-	-	-	-	-	-	-	-	-	-	-	-	-
(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)
(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)	(500,404)
8,506,872	8,006,468	7,506,064	7,005,659	6,505,255	6,004,851	5,504,447	5,004,042	4,503,638	4,003,234	3,502,830	3,002,425	2,502,021
36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478	36,640,478
(14,394,474)	(15,703,062)	(17,011,651)	(18,320,239)	(19,628,828)	(20,937,416)	(22,246,005)	(23,554,593)	(24,863,182)	(26,171,770)	(27,480,359)	(28,788,947)	(30,097,536)
22,246,005	20,937,416	19,628,828	18,320,239	17,011,651	15,703,062	14,394,474	13,085,885	11,777,297	10,468,708	9,160,120	7,851,531	6,542,943
(8,506,872)	(8,006,468)	(7,506,064)	(7,005,659)	(6,505,255)	(6,004,851)	(5,504,447)	(5,004,042)	(4,503,638)	(4,003,234)	(3,502,830)	(3,002,425)	(2,502,021)
13,739,132	12,930,948	12,122,764	11,314,580	10,506,395	9,698,211	8,890,027	8,081,843	7,273,658	6,465,474	5,657,290	4,849,106	4,040,921
597,652	562,496	527,340	492,184	457,028	421,872	386,716	351,560	316,404	281,248	246,092	210,936	175,780
399,365	375,873	352,381	328,889	305,397	281,905	258,413	234,921	211,429	187,937	164,445	140,952	117,460
997,018	938,369	879,721	821,073	762,425	703,777	645,129	586,481	527,833	469,185	410,537	351,889	293,240
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589	1,308,589
75,036	72,710	70,261	67,685	64,977	62,135	59,152	56,026	52,750	49,322	45,734	41,984	38,066
1,389,720	1,387,516	1,385,191	1,382,741	1,380,163	1,377,453	1,374,605	1,371,615	1,368,480	1,365,194	1,361,753	1,358,151	1,354,384
247,275	232,730	218,184	203,639	189,093	174,547	160,002	145,456	130,910	116,365	101,819	87,274	72,728
$ 2,634,013	$ 2,558,615	$ 2,483,096	$ 2,407,453	$ 2,331,681	$ 2,255,777	$ 2,179,735	$ 2,103,552	$ 2,027,223	$ 1,950,744	$ 1,874,109	$ 1,797,313	$ 1,720,353
9,581,483	9,533,576	9,485,908	9,438,479	9,391,286	9,344,330	9,297,608	9,251,120	9,204,865	9,158,840	9,113,046	9,067,481	9,022,143

Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
11.038%	11.259%	11.484%	11.714%	11.948%		
24	25	26	27	28	29	30
2027	2028	2029	2030	2031	2032	2033
1,308,589	1,308,589	1,308,589	1,308,589	1,308,589		
-	-	-	-	-	-	-
(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)	(1,308,589)		
(500,404)	(500,404)	(500,404)	(500,404)	(500,404)		
2,001,617	1,501,213	1,000,808	500,404	0		
36,640,478	36,640,478	36,640,478	36,640,478	36,640,478		
(31,406,124)	(32,714,713)	(34,023,301)	(35,331,890)	(36,640,478)		
5,234,354	3,925,766	2,617,177	1,308,589	-		
(2,001,617)	(1,501,213)	(1,000,808)	(500,404)	(0)		
3,232,737	2,424,553	1,616,369	808,184	(0)		
140,624	105,468	70,312	35,156	(0)		
93,968	70,476	46,984	23,492	(0)		
234,592	175,944	117,296	58,648	(0)		
7,884	8,042	8,203	8,367	8,534		
1,308,589	1,308,589	1,308,589	1,308,589	1,308,589		
33,974	29,703	25,247	20,602	15,760		
1,350,447	1,346,333	1,342,039	1,337,557	1,332,883		
58,182	43,637	29,091	14,546	(0)		
$ 1,643,221	$ 1,565,914	$ 1,488,426	$ 1,410,751	$ 1,332,883		
8,977,033	8,932,147	8,887,487	8,843,049	8,798,834		

HIGHLY CONFIDENTIAL

COD: 12/29/2011	Contract Year	Estimated Power Production (KWh)
	Springerville 4.6 Esimated KWh	
2011	1	10,074,000
2012	2	10,023,630
2013	3	9,973,512
2014	4	9,923,644
2015	5	9,874,026
2016	6	9,824,656
2017	7	9,775,533
2018	8	9,726,655
2019	9	9,678,022
2020	10	9,629,632
2021	11	9,581,483
2022	12	9,533,576
2023	13	9,485,908
2024	14	9,438,479
2025	15	9,391,286
2026	16	9,344,330
2027	17	9,297,608
2028	18	9,251,120
2029	19	9,204,865
2030	20	9,158,840
2031	21	9,113,046
2032	22	9,067,481
2033	23	9,022,143
2034	24	8,977,033
2035	25	8,932,147
2036	26	8,887,487
2037	27	8,843,049
2038	28	8,798,834
2039	29	8,754,840
2040	30	8,711,066
		281,297,930.13

Springerville 1.0 Fixed PV HIGHLY CONFIDENTIAL
1.28 MW
Levelized Cost of Energy ($/KWh)

Assumptions			DPIS - 2010
Original Cost	$	7,525,500	
Asset Life		28	
O&M First Year	$	5,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)		38.24%	
Debt Return (wtd cost)		2.91%	
Equity Return (wtd cost)		4.35%	
Tax Depreciation (Yrs)		6	
ITC Claimed		2,257,650	
Property Tax Rate		7.000%	

Original Cost	$	7,525,500	
ITC @ 30%	$	2,257,650.00	
Depeciable Tax Basis	$	6,396,675.00	$ -
Tax Basis After 50% Bonus	$	3,198,337.50	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property tax rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Tax Depreciation	$	3,838,005	$ 1,023,468	$ 614,081	$ 368,448	$ 368,448	$ 184,224				
Tax Depreciation included in Rate Base		3,838,005	228,453	228,453	228,453	228,453	1,644,859	-	-	-	-
Book Depreciation		268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
Less: Book Depr on ITC Adj		40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315
Timing Difference		3,609,552	(0)	(0)	(0)	(0)	1,416,407	(228,453)	(228,453)	(228,453)	(228,453)
Def. Tax @ 38.24%		1,380,293	(0)	(0)	(0)	(0)	541,634	(87,360)	(87,360)	(87,360)	(87,360)
A.D.I.T.		1,380,293	1,380,293	1,380,293	1,380,293	1,380,293	1,921,927	1,834,566	1,747,206	1,659,846	1,572,485
Plant in Service		7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500
Accum. Depreciation		(268,768)	(537,536)	(806,304)	(1,075,071)	(1,343,839)	(1,612,607)	(1,881,375)	(2,150,143)	(2,418,911)	(2,687,679)
Net Plant in Service		7,256,732	6,987,964	6,719,196	6,450,429	6,181,661	5,912,893	5,644,125	5,375,357	5,106,589	4,837,821
Unamortized ITC		(2,031,885)	(1,580,355)	(1,128,825)	(677,295)	(225,765)					
Unamortized ITC included in Rate Base		(2,031,885)	(1,580,355)	(1,128,825)	(677,295)	(225,765)					
A.D.I.T.		(1,380,293)	(1,380,293)	(1,380,293)	(1,380,293)	(1,380,293)	(1,921,927)	(1,834,566)	(1,747,206)	(1,659,846)	(1,572,485)
Net Rate Base		3,844,554	4,027,316	4,210,079	4,392,841	4,575,603	3,990,966	3,809,559	3,628,151	3,446,744	3,265,336
Return on Rate Base:											
Debt Return		167,238	175,188	183,138	191,089	199,039	173,607	165,716	157,825	149,933	142,042
Equity Return		111,752	117,065	122,377	127,690	133,002	116,008	110,735	105,462	100,189	94,916
Total		278,991	292,253	305,516	318,778	332,041	289,615	276,451	263,287	250,122	236,958
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
Property Taxes(1)		18,964	18,699	18,415	18,113	17,791	17,448	17,085	16,701	16,294	15,865
Total		292,732	292,567	292,385	292,186	291,971	291,737	291,484	291,212	290,921	290,608
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		69,194	72,483	75,773	79,062	82,351	71,829	68,564	65,299	62,034	58,769
Revenue Requirement	$	640,917	$ 657,303	$ 673,673	$ 690,027	$ 706,363	$ 653,181	$ 636,499	$ 619,798	$ 603,077	$ 586,335
NPV Cost	$	6,758,177									
Estimated Output (KWh)		3,942,000	3,922,290	3,902,679	3,883,165	3,863,749	3,844,431	3,825,208	3,806,082	3,787,052	3,768,117
NPV Output		44,608,707									
LCOE ($/KWh)	$	0.15									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
-	-	-	-	-	-	-	-	-	-	-	-	-
268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315	40,315
(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)	(228,453)
(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)	(87,360)
1,485,125	1,397,765	1,310,405	1,223,044	1,135,684	1,048,324	960,963	873,603	786,243	698,882	611,522	524,162	436,802
7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500	7,525,500
(2,956,446)	(3,225,214)	(3,493,982)	(3,762,750)	(4,031,518)	(4,300,286)	(4,569,054)	(4,837,821)	(5,106,589)	(5,375,357)	(5,644,125)	(5,912,893)	(6,181,661)
4,569,054	4,300,286	4,031,518	3,762,750	3,493,982	3,225,214	2,956,446	2,687,679	2,418,911	2,150,143	1,881,375	1,612,607	1,343,839
(1,485,125)	(1,397,765)	(1,310,405)	(1,223,044)	(1,135,684)	(1,048,324)	(960,963)	(873,603)	(786,243)	(698,882)	(611,522)	(524,162)	(436,802)
3,083,928	2,902,521	2,721,113	2,539,706	2,358,298	2,176,891	1,995,483	1,814,076	1,632,668	1,451,260	1,269,853	1,088,445	907,038
134,151	126,260	118,368	110,477	102,586	94,695	86,804	78,912	71,021	63,130	55,239	47,347	39,456
89,643	84,370	79,097	73,823	68,550	63,277	58,004	52,731	47,458	42,185	36,912	31,639	26,366
223,794	210,629	197,465	184,301	171,136	157,972	144,808	131,643	118,479	105,315	92,150	78,986	65,822
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768	268,768
15,412	14,934	14,431	13,902	13,346	12,762	12,149	11,507	10,834	10,130	9,393	8,623	7,818
290,274	289,919	289,540	289,138	288,711	288,259	287,781	287,276	286,743	286,182	285,591	284,969	284,316
55,504	52,239	48,974	45,709	42,444	39,179	35,914	32,650	29,385	26,120	22,855	19,590	16,325
$ 569,572	$ 552,787	$ 535,979	$ 519,148	$ 502,292	$ 485,410	$ 468,503	$ 451,569	$ 434,607	$ 417,616	$ 400,596	$ 383,545	$ 366,462
3,749,276	3,730,530	3,711,877	3,693,318	3,674,851	3,656,477	3,638,194	3,620,004	3,601,904	3,583,894	3,565,975	3,548,145	3,530,404

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2033	2034	2035	2036	2037	2038	2039
-	-	-	-	-		
268,768	268,768	268,768	268,768	268,768		
40,315	40,315	40,315	40,315	40,315	40,315	40,315
(228,453)	(228,453)	(228,453)	(228,453)	(228,453)		
(87,360)	(87,360)	(87,360)	(87,360)	(87,360)		
349,441	262,081	174,721	87,360	(0)		
7,525,500	7,525,500	7,525,500	7,525,500	7,525,500		
(6,450,429)	(6,719,196)	(6,987,964)	(7,256,732)	(7,525,500)		
1,075,071	806,304	537,536	268,768	(0)		
(349,441)	(262,081)	(174,721)	(87,360)	0		
725,630	544,223	362,815	181,408	(0)		
31,565	23,674	15,782	7,891	(0)		
21,092	15,819	10,546	5,273	(0)		
52,657	39,493	26,329	13,164	(0)		
7,884	8,042	8,203	8,367	8,534		
268,768	268,768	268,768	268,768	268,768		
6,978	6,101	5,185	4,231	3,237		
283,630	282,911	282,156	281,366	280,539		
13,060	9,795	6,530	3,265	(0)		
$ 349,347	$ 332,198	$ 315,015	$ 297,796	$ 280,539		
3,512,752	3,495,188	3,477,712	3,460,324	3,443,022		

HIGHLY CONFIDENTIAL

	Springerville 1.0 Esimated KWh	
COD: 12/29/2010	Contract Year	Estimated Power Production (KWh)
2010	1	3,942,000
2011	2	3,922,290
2012	3	3,902,679
2013	4	3,883,165
2014	5	3,863,749
2015	6	3,844,431
2016	7	3,825,208
2017	8	3,806,082
2018	9	3,787,052
2019	10	3,768,117
2020	11	3,749,276
2021	12	3,730,530
2022	13	3,711,877
2023	14	3,693,318
2024	15	3,674,851
2025	16	3,656,477
2026	17	3,638,194
2027	18	3,620,004
2028	19	3,601,904
2029	20	3,583,894
2030	21	3,565,975
2031	22	3,548,145
2032	23	3,530,404
2033	24	3,512,752
2034	25	3,495,188
2035	26	3,477,712
2036	27	3,460,324
2037	28	3,443,022
2038	29	3,425,807
2039	30	3,408,678
		110,073,103.09

HIGHLY CONFIDENTIAL

Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6
0.2	0.32	0.192	0.1152	0.1152	0.0576

HIGHLY CONFIDENTIAL

Notes:

TEP generated NOLs 2011-2014, utilized part of their NOL CF in 2015, is forecast to generate more NOL in 2016 and 2017 and start generating taxable income before NOLs after that.
For this analysis we assume the NOLs utilized in 2015 relate to solar projects.
For ITC we assume it will not be realized until 2019 and thereafter.

UNSE utilized NOL in 2012, generated NOLs in 2013, 2014 and 2015, is forecast to utilize NOLs in 2016 and years after until NOL Carryforward has been used.
For ITC we assume it will not be realized until 2020 and thereafter.

Prairie Fire Fixed PV HIGHLY CONFIDENTIAL
4 MW
Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2012
Original Cost	$ 17,229,473	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.24%	
Debt Return (wtd cost)	2.91%	
Equity Return (wtd cost)	4.35%	
Tax Depreciation (Yrs)	6	
ITC Claimed	5,168,842	
Property Tax Rate	7.000%	

Original Cost	$ 17,229,473	
ITC @ 30%	$ 5,168,841.90	
Depeciable Tax Basis	$ 14,645,052.05	$ -
Tax Basis After 50% Bonus	$ 7,322,526.03	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Tax Depreciation		$ 8,787,031	$ 2,343,208	$ 1,405,925	$ 843,555	$ 843,555	$ 421,777				
Tax Depreciation included in Rate Base		523,038	523,038	523,038	11,810,607	523,038	523,038	219,257	-	-	
Book Depreciation		615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
Less: Book Depr on ITC Adj		92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301
Timing Difference		-	-	-	11,287,569	-	-	(523,038)	(523,038)	(523,038)	(523,038)
Def. Tax @ 38.24%		-	-	-	4,316,366	-	-	(200,010)	(200,010)	(200,010)	(200,010)
A.D.I.T.		-	-	-	4,316,366	4,316,366	4,316,366	4,116,357	3,916,347	3,716,338	3,516,328
Plant in Service		17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473
Accum. Depreciation		(615,338)	(1,230,677)	(1,846,015)	(2,461,353)	(3,076,692)	(3,692,030)	(4,307,368)	(4,922,707)	(5,538,045)	(6,153,383)
Net Plant in Service		16,614,135	15,998,796	15,383,458	14,768,120	14,152,781	13,537,443	12,922,105	12,306,766	11,691,428	11,076,090
Unamortized ITC		(4,651,958)	(3,618,189)	(2,584,421)	(1,550,653)	(516,884)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		-	-	-	(4,316,366)	(4,316,366)	(4,316,366)	(4,116,357)	(3,916,347)	(3,716,338)	(3,516,328)
Net Rate Base		16,614,135	15,998,796	15,383,458	10,451,753	9,836,415	9,221,077	8,805,748	8,390,419	7,975,090	7,559,762
Return on Rate Base:											
Debt Return		722,715	695,948	669,180	454,651	427,884	401,117	383,050	364,983	346,916	328,850
Equity Return		482,935	465,049	447,162	303,809	285,922	268,036	255,963	243,890	231,818	219,745
Total		1,205,650	1,160,996	1,116,342	758,460	713,806	669,153	639,013	608,874	578,734	548,595
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
Property Taxes(1)		43,418	42,810	42,161	41,468	40,731	39,948	39,117	38,237	37,306	36,322
Total		663,757	663,249	662,701	662,113	661,482	660,806	660,086	659,318	658,502	657,636
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		299,019	287,945	276,870	188,109	177,035	165,960	158,485	151,010	143,535	136,060
Revenue Requirement		$ 2,168,426	$ 2,112,189	$ 2,055,913	$ 1,608,682	$ 1,552,322	$ 1,495,919	$ 1,457,584	$ 1,419,202	$ 1,380,771	$ 1,342,290
NPV Cost		$ 17,040,198									
Estimated Output (KWh)		10,950,000	10,895,250	10,840,774	10,786,570	10,732,637	10,678,974	10,625,579	10,572,451	10,519,589	10,466,991
NPV Output		130,161,899									
LCOE ($/KWh)		$ 0.13									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301	92,301
(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)	(523,038)
(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)	(200,010)
3,316,319	3,116,309	2,916,300	2,716,290	2,516,280	2,316,271	2,116,261	1,916,252	1,716,242	1,516,233	1,316,223	1,116,213	916,204
17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473	17,229,473
(6,768,722)	(7,384,060)	(7,999,398)	(8,614,737)	(9,230,075)	(9,845,413)	(10,460,751)	(11,076,090)	(11,691,428)	(12,306,766)	(12,922,105)	(13,537,443)	(14,152,781)
10,460,751	9,845,413	9,230,075	8,614,737	7,999,398	7,384,060	6,768,722	6,153,383	5,538,045	4,922,707	4,307,368	3,692,030	3,076,692
(3,316,319)	(3,116,309)	(2,916,300)	(2,716,290)	(2,516,280)	(2,316,271)	(2,116,261)	(1,916,252)	(1,716,242)	(1,516,233)	(1,316,223)	(1,116,213)	(916,204)
7,144,433	6,729,104	6,313,775	5,898,447	5,483,118	5,067,789	4,652,460	4,237,132	3,821,803	3,406,474	2,991,145	2,575,817	2,160,488
310,783	292,716	274,649	256,582	238,516	220,449	202,382	184,315	166,248	148,182	130,115	112,048	93,981
207,672	195,600	183,527	171,454	159,382	147,309	135,236	123,164	111,091	99,018	86,946	74,873	62,800
518,455	488,316	458,176	428,037	397,897	367,758	337,618	307,479	277,340	247,200	217,061	186,921	156,782
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338	615,338
35,284	34,191	33,039	31,827	30,554	29,218	27,815	26,345	24,805	23,192	21,506	19,742	17,900
656,718	655,746	654,718	653,634	652,490	651,285	650,017	648,684	647,284	645,815	644,274	642,659	640,968
128,585	121,110	113,635	106,160	98,685	91,210	83,734	76,259	68,784	61,309	53,834	46,359	38,884
$ 1,303,758	$ 1,265,171	$ 1,226,529	$ 1,187,830	$ 1,149,072	$ 1,110,253	$ 1,071,370	$ 1,032,423	$ 993,408	$ 954,324	$ 915,169	$ 875,939	$ 836,634
10,414,656	10,362,583	10,310,770	10,259,216	10,207,920	10,156,880	10,106,096	10,055,565	10,005,288	9,955,261	14,263,898	14,192,579	14,121,616

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2035	2036	2037	2038	2039	2040	2041
615,338	615,338	615,338	615,338	615,338		
92,301	92,301	92,301	92,301	92,301	92,301	92,301
(523,038)	(523,038)	(523,038)	(523,038)	(523,038)		
(200,010)	(200,010)	(200,010)	(200,010)	(200,010)		
716,194	516,185	316,175	116,166	(83,844)		
17,229,473	17,229,473	17,229,473	17,229,473	17,229,473		
(14,768,120)	(15,383,458)	(15,998,796)	(16,614,135)	(17,229,473)		
2,461,353	1,846,015	1,230,677	615,338	0		
(716,194)	(516,185)	(316,175)	(116,166)	83,844		
1,745,159	1,329,830	914,502	499,173	83,844		
75,914	57,848	39,781	21,714	3,647		
50,728	38,655	26,582	14,510	2,437		
126,642	96,503	66,363	36,224	6,084		
7,884	8,042	8,203	8,367	8,534		
615,338	615,338	615,338	615,338	615,338		
15,975	13,967	11,872	9,688	7,411		
639,198	637,348	635,413	633,393	631,284		
31,409	23,934	16,459	8,984	1,509		
$ 797,250	$ 757,785	$ 718,236	$ 678,601	$ 638,877		
14,051,008	13,980,753	13,910,849	13,841,295	13,772,088		

HIGHLY CONFIDENTIAL

Prairie Fire Esimated KWh

COD: 12/28/2012	Contract Year	Estimated Power Production (KWh)
2012	1	10,950,000
2013	2	10,895,250
2014	3	10,840,774
2015	4	10,786,570
2016	5	10,732,637
2017	6	10,678,974
2018	7	10,625,579
2019	8	10,572,451
2020	9	10,519,589
2021	10	10,466,991
2022	11	10,414,656
2023	12	10,362,583
2024	13	10,310,770
2025	14	10,259,216
2026	15	10,207,920
2027	16	10,156,880
2028	17	10,106,096
2029	18	10,055,565
2030	19	10,005,288
2031	20	9,955,261
2032	21	9,905,485
2033	22	9,855,957
2034	23	9,806,678
2035	24	9,757,644
2036	25	9,708,856
2037	26	9,660,312
2038	27	9,612,010
2039	28	9,563,950
2040	29	9,516,130
2041	30	9,468,550
		305,758,620

La Senita Single-Axis System - UNSE HIGHLY CONFIDENTIAL

1 MW

Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2011
Original Cost	$ 5,308,701	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.95%	
Debt Return (wtd cost)	2.83%	
Equity Return (wtd cost)	5.00%	
Tax Depreciation (Yrs)	6	
ITC Claimed	1,592,610	796305.15

Original Cost	$ 5,308,701	
ITC @ 30%	$ 1,592,610.30	
Depeciable Tax Basis	$ 4,512,395.85	$ -
Tax Basis After 50% Bonus	$ 2,256,197.93	

	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate	11.237%	11.462%	11.691%	11.925%	12.163%	12.407%	12.655%	12.908%	13.166%	13.429%
	1	2	3	4	5	6	7	8	9	10
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tax Depreciation	$ 4,512,396									
Tax Depreciation included in Rate Base	$ 161,157	$ 4,351,239	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Book Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Less: Book Depr on ITC Adj	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
Timing Difference	(0)	4,190,082	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
Def. Tax @ 38.95%	(0)	1,632,037	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
A.D.I.T.	(0)	1,632,037	1,569,266	1,506,496	1,443,725	1,380,954	1,318,184	1,255,413	1,192,642	1,129,872
Plant in Service	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
Accum. Depreciation	(189,596)	(379,193)	(568,789)	(758,386)	(947,982)	(1,137,579)	(1,327,175)	(1,516,772)	(1,706,368)	(1,895,965)
Net Plant in Service	5,119,105	4,929,508	4,739,912	4,550,315	4,360,719	4,171,122	3,981,526	3,791,929	3,602,333	3,412,736
Unamortized ITC	(1,433,349)	(1,114,827)	(796,305)	(477,783)	(159,261)					
Unamortized ITC included in Rate Base	$ (1,433,349)	$ (1,114,827)	$ (796,305)	$ (477,783)	$ (159,261)					
A.D.I.T.	0	(1,632,037)	(1,569,266)	(1,506,496)	(1,443,725)	(1,380,954)	(1,318,184)	(1,255,413)	(1,192,642)	(1,129,872)
Net Rate Base	3,685,755	2,182,644	2,374,340	2,566,036	2,757,733	2,790,168	2,663,342	2,536,516	2,409,690	2,282,865
Return on Rate Base:										
Debt Return	184,177	109,067	118,646	128,225	137,804	139,425	133,087	126,750	120,412	114,075
Equity Return	104,299	61,764	67,189	72,613	78,038	78,956	75,367	71,778	68,189	64,600
Total	288,476	170,831	185,834	200,838	215,842	218,380	208,454	198,528	188,601	178,675
Operating Expenses & Taxes:										
Operations and Maintenance	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
Property Taxes(1)	21,475	21,175	20,853	20,511	20,146	19,759	19,348	18,912	18,452	17,966
Total	216,072	215,871	215,652	215,413	215,155	214,876	214,575	214,252	213,907	213,537
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate	66,543	39,406	42,866	46,327	49,788	50,374	48,084	45,794	43,505	41,215
Revenue Requirement	$ 571,091	$ 426,107	$ 444,353	$ 462,579	$ 480,785	$ 483,630	$ 471,113	$ 458,574	$ 446,013	$ 433,427
NPV Cost	$ 4,696,059									
Estimated Output (KWh)	2,671,800	2,539,780	2,527,081	2,514,445	2,501,873	2,489,364	2,476,917	2,464,532	2,452,210	2,439,949
NPV Output	27,557,562									
LCOE ($/KWh)	$ 0.17									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x a 18% valuation factor - then increase the tax rate annually by the escalation factor

13.698%	13.972%	14.251%	14.536%	14.827%	15.124%	15.426%	15.735%	16.049%	16.370%	16.698%	17.032%	17.372%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
1,067,101	1,004,330	941,560	878,789	816,018	753,248	690,477	627,706	564,936	502,165	439,395	376,624	313,853
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(2,085,561)	(2,275,158)	(2,464,754)	(2,654,351)	(2,843,947)	(3,033,543)	(3,223,140)	(3,412,736)	(3,602,333)	(3,791,929)	(3,981,526)	(4,171,122)	(4,360,719)
3,223,140	3,033,543	2,843,947	2,654,351	2,464,754	2,275,158	2,085,561	1,895,965	1,706,368	1,516,772	1,327,175	1,137,579	947,982
(1,067,101)	(1,004,330)	(941,560)	(878,789)	(816,018)	(753,248)	(690,477)	(627,706)	(564,936)	(502,165)	(439,395)	(376,624)	(313,853)
2,156,039	2,029,213	1,902,387	1,775,561	1,648,736	1,521,910	1,395,084	1,268,258	1,141,432	1,014,607	887,781	760,955	634,129
107,737	101,400	95,062	88,725	82,387	76,050	69,712	63,375	57,037	50,700	44,362	38,025	31,687
61,011	57,422	53,833	50,244	46,656	43,067	39,478	35,889	32,300	28,711	25,122	21,533	17,944
168,748	158,822	148,896	138,969	129,043	119,117	109,190	99,264	89,337	79,411	69,485	59,558	49,632
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596	189,596
17,452	16,911	16,342	15,742	15,113	14,452	13,758	13,031	12,269	11,471	10,637	9,765	8,853
213,144	212,725	212,279	211,807	211,307	210,777	210,218	209,628	209,007	208,352	207,663	206,940	206,180
38,925	36,635	34,346	32,056	29,766	27,477	25,187	22,897	20,607	18,318	16,028	13,738	11,449
$ 420,817	$ 408,182	$ 395,521	$ 382,832	$ 370,116	$ 357,370	$ 344,595	$ 331,789	$ 318,951	$ 306,081	$ 293,176	$ 280,236	$ 267,260
2,427,749	2,415,610	2,403,532	2,391,514	2,379,557	2,367,659	2,355,821	2,344,042	2,332,321	2,320,660	2,309,057	2,297,511	2,286,024

17.720%	18.074%	18.435%	18.804%	19.180%
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28
24	25	26	27	28
2034	2035	2036	2037	2038
$ -	$ -	$ -	$ -	$ -
189,596	189,596	189,596	189,596	189,596
28,439	28,439	28,439	28,439	28,439
(161,157)	(161,157)	(161,157)	(161,157)	(161,157)
(62,771)	(62,771)	(62,771)	(62,771)	(62,771)
251,083	188,312	125,541	62,771	(0)
5,308,701	5,308,701	5,308,701	5,308,701	5,308,701
(4,550,315)	(4,739,912)	(4,929,508)	(5,119,105)	(5,308,701)
758,386	568,789	379,193	189,596	0
(251,083)	(188,312)	(125,541)	(62,771)	0
507,303	380,477	253,652	126,826	0
25,350	19,012	12,675	6,337	0
14,356	10,767	7,178	3,589	0
39,706	29,779	19,853	9,926	0
7,884	8,042	8,203	8,367	8,534
189,596	189,596	189,596	189,596	189,596
7,902	6,908	5,872	4,792	3,666
205,383	204,547	203,672	202,755	201,797
9,159	6,869	4,579	2,290	0
$ 254,247	$ 241,195	$ 228,104	$ 214,971	$ 201,797
2,274,594	2,263,221	2,308,999	2,297,338	2,285,851

HIGHLY CONFIDENTIAL

	La Senita Esimated KWh	
COD:11/4/2011	Contract Year	Estimated Power Production (KWh)
2012	1	2,671,800
2013	2	2,539,780
2014	3	2,527,081
2015	4	2,514,445
2016	5	2,501,873
2017	6	2,489,364
2018	7	2,476,917
2019	8	2,464,532
2020	9	2,452,210
2021	10	2,439,949
2022	11	2,427,749
2023	12	2,415,610
2024	13	2,403,532
2025	14	2,391,514
2026	15	2,379,557
2027	16	2,367,659
2028	17	2,355,821
2029	18	2,344,042
2030	19	2,332,321
2031	20	2,320,660
2032	21	2,309,057
2033	22	2,297,511
2034	23	2,286,024
2035	24	2,274,594
2036	25	2,263,221
2037	26	2,308,999
2038	27	2,297,338
2039	28	2,285,851
		67,139,011

Fort Hauchuca Fixed PV System HIGHLY CONFIDENTIAL
13.6 MW
Levelized Cost of Energy ($/kWh)

Assumptions			DPIS - 2014
Original Cost	$	32,005,100	
Asset Life		28	
O&M First Year	$	10,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)(2)		38.24%	
Debt Return (wtd cost)(1)		2.91%	
Equity Return (wtd cost)(1)		4.35%	
Tax Depreciation (Yrs)(3)		6	
ITC Claimed(3)		9,601,530	

Original Cost	$ 32,005,100		
ITC @ 30%	$ 9,601,530.00		
Depeciable Tax Basis	$ 27,204,335.00	$	-
Tax Basis After 50% Bonus	$ 13,602,167.50		

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10	Yr. 11
Property Tax Rate(2)		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%	8.533%
		1	2	3	4	5	6	7	8	9	10	11
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tax Depreciation(3)		$ 16,322,601	$ 4,352,694	$ 2,611,616	$ 1,566,970	$ 1,566,970	$ 783,485	$ -	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base		971,583	19,703,711	971,583	971,583	3,802,389	783,485	-	-	-	-	-
Book Depreciation		1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
Less: Book Depr on ITC Adj(3)		171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456
Timing Difference		0	18,732,128	0	0	2,830,805	(188,099)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)
Def. Tax @ 38.24%		0	7,163,166	0	0	1,082,500	(71,929)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)
A.D.I.T.		0	7,163,166	7,163,166	7,163,166	8,245,666	8,173,737	7,802,203	7,430,670	7,059,136	6,687,603	6,316,069
Plant in Service		32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100
Accum. Depreciation		(1,143,039)	(2,286,079)	(3,429,118)	(4,572,157)	(5,715,196)	(6,858,236)	(8,001,275)	(9,144,314)	(10,287,354)	(11,430,393)	(12,573,432)
Net Plant in Service		30,862,061	29,719,021	28,575,982	27,432,943	26,289,904	25,146,864	24,003,825	22,860,786	21,717,746	20,574,707	19,431,668
Unamortized ITC(3)		(8,641,377)	(6,721,071)	(4,800,765)	(2,880,459)	(960,153)		-	-	-	-	-
Unamortized ITC included in Rate Base		-	-	-	-	-						
A.D.I.T.		(0)	(7,163,166)	(7,163,166)	(7,163,166)	(8,245,666)	(8,173,737)	(7,802,203)	(7,430,670)	(7,059,136)	(6,687,603)	(6,316,069)
Net Rate Base		30,862,061	22,555,856	21,412,816	20,269,777	18,044,238	16,973,128	16,201,622	15,430,116	14,658,610	13,887,104	13,115,599
Return on Rate Base:												
Equity Return		1,342,500	981,180	931,458	881,735	784,924	738,331	704,771	671,210	637,650	604,089	570,529
Debt Return		897,090	655,647	622,422	589,196	524,505	493,370	470,944	448,518	426,092	403,666	381,241
Total		2,239,589	1,636,827	1,553,879	1,470,932	1,309,429	1,231,701	1,175,715	1,119,728	1,063,742	1,007,755	951,769
Operating Expenses & Taxes:												
Operations and Maintenance		10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	12,190
Depreciation		1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
Property Taxes(4)		80,653	79,524	78,317	77,031	75,661	74,206	72,663	71,028	69,298	67,471	65,544
Total		1,233,692	1,232,763	1,231,760	1,230,682	1,229,525	1,228,286	1,226,963	1,225,554	1,224,054	1,222,462	1,220,773
Income Tax on Equity Return:												
(Return/(1-Tax Rate) X Tax Rate		831,237	607,518	576,731	545,945	486,002	457,153	436,373	415,594	394,814	374,034	353,255
Revenue Requirement		$ 4,304,518	$ 3,477,108	$ 3,362,371	$ 3,247,558	$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797
NPV Cost		$ 32,093,921										
Estimated Output (kWh)		38,635,000	38,441,825	38,249,616	38,058,368	37,868,076	37,678,736	37,490,342	37,302,890	37,116,376	36,930,794	36,746,140
NPV Output		437,203,807										
LCOE ($/kWh)		$ 0.07										

(1) Assumptions approved in 2013 Rate Order
(2) Assumption in 2015 Rate Filing
(3) Assumptions regarding tax depreciation and ITC include actual company circumstances
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%
Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
12	13	14	15	16	17	18	19	20
2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-	-
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456
(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)
(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)
5,944,536	5,573,002	5,201,469	4,829,935	4,458,402	4,086,868	3,715,335	3,343,801	2,972,268
32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100
(13,716,471)	(14,859,511)	(16,002,550)	(17,145,589)	(18,288,629)	(19,431,668)	(20,574,707)	(21,717,746)	(22,860,786)
18,288,629	17,145,589	16,002,550	14,859,511	13,716,471	12,573,432	11,430,393	10,287,354	9,144,314
-	-	-	-	-	-	-	-	-
(5,944,536)	(5,573,002)	(5,201,469)	(4,829,935)	(4,458,402)	(4,086,868)	(3,715,335)	(3,343,801)	(2,972,268)
12,344,093	11,572,587	10,801,081	10,029,575	9,258,070	8,486,564	7,715,058	6,943,552	6,172,046
536,968	503,408	469,847	436,287	402,726	369,166	335,605	302,045	268,484
358,815	336,389	313,963	291,537	269,111	246,685	224,259	201,833	179,407
895,783	839,796	783,810	727,823	671,837	615,851	559,864	503,878	447,891
12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
63,512	61,372	59,122	56,757	54,274	51,669	48,938	46,077	43,082
1,218,985	1,217,094	1,215,097	1,212,991	1,210,772	1,208,436	1,205,980	1,203,399	1,200,689
332,475	311,695	290,916	270,136	249,356	228,577	207,797	187,017	166,238
$ 2,447,242	$ 2,368,586	$ 2,289,823	$ 2,210,951	$ 2,131,965	$ 2,052,863	$ 1,973,641	$ 1,894,294	$ 1,814,818
36,562,409	36,379,597	36,197,699	36,016,711	35,836,627	35,657,444	35,479,157	35,301,761	35,125,252

10.402%	10.610%	10.822%	11.038%	11.259%	11.484%	11.714%	11.948%
Yr. 21	Yr. 22	Yr. 23	Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28
21	22	23	24	25	26	27	28
2034	2035	2036	2037	2038	2039	2040	2041
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
171,456	171,456	171,456	171,456	171,456	171,456	171,456	171,456
(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)	(971,583)
(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)	(371,533)
2,600,734	2,229,201	1,857,667	1,486,134	1,114,600	743,067	371,533	0
32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100	32,005,100
(24,003,825)	(25,146,864)	(26,289,904)	(27,432,943)	(28,575,982)	(29,719,021)	(30,862,061)	(32,005,100)
8,001,275	6,858,236	5,715,196	4,572,157	3,429,118	2,286,079	1,143,039	(0)
-	-	-	-	-	-	-	-
(2,600,734)	(2,229,201)	(1,857,667)	(1,486,134)	(1,114,600)	(743,067)	(371,533)	(0)
5,400,541	4,629,035	3,857,529	3,086,023	2,314,517	1,543,012	771,506	(0)
234,924	201,363	167,803	134,242	100,682	67,121	33,561	(0)
156,981	134,555	112,130	89,704	67,278	44,852	22,426	(0)
391,905	335,918	279,932	223,946	167,959	111,973	55,986	(0)
14,859	15,157	15,460	15,769	16,084	16,406	16,734	17,069
1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039	1,143,039
39,949	36,673	33,250	29,676	25,945	22,053	17,995	13,767
1,197,847	1,194,869	1,191,749	1,188,484	1,185,069	1,181,499	1,177,769	1,173,875
145,458	124,678	103,898	83,119	62,339	41,559	20,780	(0)
$ 1,735,210	$ 1,655,465	$ 1,575,580	$ 1,495,548	$ 1,415,367	$ 1,335,031	$ 1,254,535	$ 1,173,875
34,949,626	34,774,878	34,601,003	34,427,998	34,255,858	34,084,579	33,914,156	33,744,585

HIGHLY CONFIDENTIAL

Fort Huachuca PHI Esimated kWh

13.6 MWac COD:12/9/2014	Contract Year	Estimated Power Production (kWh)
2015	1	38,635,000
2016	2	38,441,825
2017	3	38,249,616
2018	4	38,058,368
2019	5	37,868,076
2020	6	37,678,736
2021	7	37,490,342
2022	8	37,302,890
2023	9	37,116,376
2024	10	36,930,794
2025	11	36,746,140
2026	12	36,562,409
2027	13	36,379,597
2028	14	36,197,699
2029	15	36,016,711
2030	16	35,836,627
2031	17	35,657,444
2032	18	35,479,157
2033	19	35,301,761
2034	20	35,125,252
2035	21	34,949,626
2036	22	34,774,878
2037	23	34,601,003
2038	24	34,427,998
2039	25	34,255,858
2040	26	34,084,579
2041	27	33,914,156
2042	28	33,744,585
		1,011,827,503

White Mountain Fixed/LCPV System HIGHLY CONFIDENTIAL
8.25 MW
Levelized Cost of Energy ($/kWh)

Assumptions		DPIS - 2014
Original Cost	$ 41,955,366	
Asset Life	28	
O&M First Year	$ 10,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)(2)	38.24%	
Debt Return (wtd cost)(1)	2.91%	
Equity Return (wtd cost)(1)	4.35%	
Tax Depreciation (Yrs)(3)	6	
ITC Claimed(3)	12,586,610	

Original Cost	$ 41,955,366	
ITC @ 30%	$ 12,586,609.80	
Depeciable Tax Basis	$ 35,662,061.10	$ -
Tax Basis After 50% Bonus	$ 17,831,030.55	

	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate(2)	7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
0	1	2	3	4	5	6	7	8	9	10
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tax Depreciation(3)	$ 21,397,237	$ 5,705,930	$ 3,423,558	$ 2,054,135	$ 2,054,135	$ 1,027,067	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base	1,273,645	25,829,521	1,273,645	1,273,645	4,984,537	1,027,067	-	-	-	-
Book Depreciation	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
Less: Book Depr on ITC Adj(3)	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761
Timing Difference	(0)	24,555,876	(0)	(0)	3,710,892	(246,578)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)
Def. Tax @ 38.24%	(0)	9,390,167	(0)	(0)	1,419,045	(94,291)	(487,042)	(487,042)	(487,042)	(487,042)
A.D.I.T.	(0)	9,390,167	9,390,167	9,390,167	10,809,212	10,714,921	10,227,879	9,740,837	9,253,795	8,766,754
Plant in Service	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366
Accum. Depreciation	(1,498,406)	(2,996,812)	(4,495,218)	(5,993,624)	(7,492,030)	(8,990,436)	(10,488,842)	(11,987,247)	(13,485,653)	(14,984,059)
Net Plant in Service	40,456,960	38,958,554	37,460,148	35,961,742	34,463,336	32,964,930	31,466,525	29,968,119	28,469,713	26,971,307
Unamortized ITC(3)	(11,327,949)	(8,810,627)	(6,293,305)	(3,775,983)	(1,258,661)	-	-	-	-	-
Unamortized ITC included in Rate Base	-	-	-	-	-					
A.D.I.T.	0	(9,390,167)	(9,390,167)	(9,390,167)	(10,809,212)	(10,714,921)	(10,227,879)	(9,740,837)	(9,253,795)	(8,766,754)
Net Rate Base	40,456,960	29,568,387	28,069,981	26,571,575	23,654,124	22,250,009	21,238,645	20,227,281	19,215,917	18,204,553
Return on Rate Base:										
Equity Return	1,759,878	1,286,225	1,221,044	1,155,864	1,028,954	967,875	923,881	879,887	835,892	791,898
Debt Return	1,175,992	859,486	815,930	772,375	687,571	646,757	617,359	587,961	558,563	529,165
Total	2,935,869	2,145,710	2,036,975	1,928,239	1,716,526	1,614,632	1,541,240	1,467,848	1,394,455	1,321,063
Operating Expenses & Taxes:										
Operations and Maintenance	10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951
Depreciation	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
Property Taxes(4)	105,728	104,248	102,666	100,979	99,184	97,277	95,253	93,110	90,843	88,448
Total	1,614,134	1,612,853	1,611,476	1,609,997	1,608,414	1,606,723	1,604,921	1,603,003	1,600,966	1,598,805
Income Tax on Equity Return:										
(Return/(1-Tax Rate) X Tax Rate	1,089,665	796,393	756,035	715,677	637,099	599,280	572,040	544,800	517,560	490,320
Revenue Requirement	$ 5,639,668	$ 4,554,957	$ 4,404,485	$ 4,253,913	$ 3,962,039	$ 3,820,636	$ 3,718,201	$ 3,615,651	$ 3,512,981	$ 3,410,188
NPV Cost	$ 42,027,142									
Estimated Output (kWh)	21,900,000	21,790,500	21,681,548	21,573,140	21,465,274	21,357,948	21,251,158	21,144,902	21,039,178	20,933,982
NPV Output	247,826,152									
LCOE ($/kWh)	$ 0.17									

(1) Assumptions approved in 2013 Rate Order
(2) Assumption in 2015 Rate Filing
(3) Assumptions regarding tax depreciation and ITC include actual company circumstances
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.610%	9.802%	9.998%	10.198%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
11	12	13	14	15	16	17	18	19	20
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-	-	-
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761
(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)
(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)
8,279,712	7,792,670	7,305,628	6,818,586	6,331,544	5,844,502	5,357,460	4,870,419	4,383,377	3,896,335
41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366
(16,482,465)	(17,980,871)	(19,479,277)	(20,977,683)	(22,476,089)	(23,974,495)	(25,472,901)	(26,971,307)	(28,469,713)	(29,968,119)
25,472,901	23,974,495	22,476,089	20,977,683	19,479,277	17,980,871	16,482,465	14,984,059	13,485,653	11,987,247
-	-	-	-	-	-	-	-	-	-
(8,279,712)	(7,792,670)	(7,305,628)	(6,818,586)	(6,331,544)	(5,844,502)	(5,357,460)	(4,870,419)	(4,383,377)	(3,896,335)
17,193,189	16,181,825	15,170,461	14,159,097	13,147,733	12,136,369	11,125,005	10,113,641	9,102,277	8,090,913
747,904	703,909	659,915	615,921	571,926	527,932	483,938	439,943	395,949	351,955
499,767	470,369	440,971	411,573	382,175	352,777	323,379	293,980	264,582	235,184
1,247,671	1,174,278	1,100,886	1,027,493	954,101	880,709	807,316	733,924	660,531	587,139
12,190	12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
85,921	83,257	80,453	77,503	74,403	71,148	67,733	64,153	60,402	56,476
1,596,517	1,594,097	1,591,541	1,588,845	1,586,004	1,583,012	1,579,866	1,576,561	1,573,090	1,569,450
463,080	435,840	408,600	381,360	354,120	326,880	299,640	272,400	245,160	217,920
$ 3,307,268	$ 3,204,216	$ 3,101,027	$ 2,997,699	$ 2,894,225	$ 2,790,601	$ 2,686,823	$ 2,582,885	$ 2,478,782	$ 2,374,509
20,829,312	20,725,165	20,621,539	20,518,432	20,415,840	20,313,760	20,212,192	20,111,131	20,010,575	19,910,522

10.402%	10.610%	10.822%	11.038%	11.259%	11.484%	11.714%	11.948%
Yr. 21	Yr. 22	Yr. 23	Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28
21	22	23	24	25	26	27	28
2034	2035	2036	2037	2038	2039	2040	2041
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	-	-	-	-
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
224,761	224,761	224,761	224,761	224,761	224,761	224,761	224,761
(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)	(1,273,645)
(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)	(487,042)
3,409,293	2,922,251	2,435,209	1,948,167	1,461,126	974,084	487,042	(0)
41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366	41,955,366
(31,466,525)	(32,964,930)	(34,463,336)	(35,961,742)	(37,460,148)	(38,958,554)	(40,456,960)	(41,955,366)
10,488,842	8,990,436	7,492,030	5,993,624	4,495,218	2,996,812	1,498,406	0
-	-	-	-	-	-	-	-
(3,409,293)	(2,922,251)	(2,435,209)	(1,948,167)	(1,461,126)	(974,084)	(487,042)	0
7,079,548	6,068,184	5,056,820	4,045,456	3,034,092	2,022,728	1,011,364	0
307,960	263,966	219,972	175,977	131,983	87,989	43,994	0
205,786	176,388	146,990	117,592	88,194	58,796	29,398	0
513,747	440,354	366,962	293,570	220,177	146,785	73,392	0
14,859	15,157	15,460	15,769	16,084	16,406	16,734	17,069
1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406	1,498,406
52,369	48,074	43,587	38,902	34,011	28,910	23,590	18,047
1,565,634	1,561,637	1,557,453	1,553,077	1,548,502	1,543,722	1,538,730	1,533,521
190,680	163,440	136,200	108,960	81,720	54,480	27,240	0
$ 2,270,061	$ 2,165,431	$ 2,060,615	$ 1,955,606	$ 1,850,399	$ 1,744,986	$ 1,639,363	$ 1,533,521
19,810,970	19,711,915	19,613,355	19,515,288	19,417,712	19,320,623	19,224,020	19,127,900

HIGHLY CONFIDENTIAL

	Year	Estimated Power Production (kWh)
	White Mountain Solar Esimated kWh	
8.25 MWac COD: 12/14/2014	**Year**	**Estimated Power Production (kWh)**
2015	1	21,900,000
2016	2	21,790,500
2017	3	21,681,548
2018	4	21,573,140
2019	5	21,465,274
2020	6	21,357,948
2021	7	21,251,158
2022	8	21,144,902
2023	9	21,039,178
2024	10	20,933,982
2025	11	20,829,312
2026	12	20,725,165
2027	13	20,621,539
2028	14	20,518,432
2029	15	20,415,840
2030	16	20,313,760
2031	17	20,212,192
2032	18	20,111,131
2033	19	20,010,575
2034	20	19,910,522
2034	21	19,810,970
2034	22	19,711,915
2034	23	19,613,355
2034	24	19,515,288
2034	25	19,417,712
2034	26	19,320,623
2034	27	19,224,020
2034	28	19,127,900
		573,547,880

Rio Rico PV System - UNSE HIGHLY CONFIDENTIAL

5.76 MW

Levelized Cost of Energy ($/KWh)

Assumptions			DPIS - 2014
Original Cost	$	15,374,286	
Asset Life		28	
O&M First Year	$	5,000	
Escalation Factor		2.00%	
Income Tax Rate (Federal & State)		38.95%	
Debt Return (wtd cost)		2.83%	
Equity Return (wtd cost)		5.00%	
Tax Depreciation (Yrs)		6	
ITC Claimed		4,612,286	
Property Tax Rate		11.237%	

Original Cost	$	15,374,286	
ITC @ 30%	$	4,612,285.80	
Depeciable Tax Basis	$	13,068,143.10	$ -
Tax Basis After 50% Bonus	$	6,534,071.55	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		11.237%	11.462%	11.691%	11.925%	12.163%	12.407%	12.655%	12.908%	13.166%	13.429%
		1	2	3	4	5	6	7	8	9	10
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tax Depreciation		$ 7,840,886	$ 2,090,903	$ 1,254,542	$ 752,725	$ 752,725	$ 376,363	$ -	$ -	$ -	$ -
Tax Depreciation included in Rate Base		$ 466,719	$ 466,719	$ 10,252,892	$ 752,725	$ 752,725	$ 376,363	$ -	$ -	$ -	$ -
Book Depreciation		549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
Less: Book Depr on ITC Adj		82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362
Timing Difference		0	0	9,786,172	286,006	286,006	(90,357)	(466,719)	(466,719)	(466,719)	(466,719)
Def. Tax @ 38.95%		0	0	3,811,714	111,399	111,399	(35,194)	(181,787)	(181,787)	(181,787)	(181,787)
A.D.I.T.		0	0	3,811,714	3,923,113	4,034,513	3,999,319	3,817,531	3,635,744	3,453,957	3,272,170
Plant in Service		15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286
Accum. Depreciation		(549,082)	(1,098,163)	(1,647,245)	(2,196,327)	(2,745,408)	(3,294,490)	(3,843,572)	(4,392,653)	(4,941,735)	(5,490,816)
Net Plant in Service		14,825,204	14,276,123	13,727,041	13,177,959	12,628,878	12,079,796	11,530,715	10,981,633	10,432,551	9,883,470
Unamortized ITC		(4,151,057)	(3,228,600)	(2,306,143)	(1,383,686)	(461,229)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		(0)	(0)	(3,811,714)	(3,923,113)	(4,034,513)	(3,999,319)	(3,817,531)	(3,635,744)	(3,453,957)	(3,272,170)
Net Rate Base		14,825,204	14,276,123	9,915,327	9,254,846	8,594,365	8,080,478	7,713,183	7,345,889	6,978,594	6,611,300
Return on Rate Base:											
Debt Return		740,815	713,378	495,469	462,465	429,460	403,781	385,428	367,074	348,720	330,367
Equity Return		419,521	403,983	280,582	261,892	243,202	228,660	218,266	207,872	197,479	187,085
Total		1,160,336	1,117,361	776,051	724,356	672,662	632,441	603,694	574,947	546,199	517,452
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
Property Taxes(1)		62,194	61,323	60,393	59,401	58,345	57,223	56,032	54,772	53,438	52,029
Total		616,276	615,505	614,676	613,788	612,838	611,825	610,745	609,597	608,378	607,086
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		267,655	257,742	179,012	167,087	155,163	145,885	139,254	132,623	125,992	119,361
Revenue Requirement		$ 2,044,267	$ 1,990,607	$ 1,569,739	$ 1,505,232	$ 1,440,663	$ 1,390,151	$ 1,353,693	$ 1,317,166	$ 1,280,569	$ 1,243,899
NPV Cost		$ 14,905,145									
Estimated Output (KWh)		15,768,000	15,689,160	15,610,714	15,532,661	15,454,997	15,377,722	15,300,834	15,224,330	15,148,208	15,072,467
NPV Output		169,412,295									
LCOE ($/KWh)		$ 0.088									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

13.698%	13.972%	14.251%	14.536%	14.827%	15.124%	15.426%	15.735%	16.049%	16.370%	16.698%	17.032%	17.372%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362	82,362
(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)	(466,719)
(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)	(181,787)
3,090,382	2,908,595	2,726,808	2,545,021	2,363,234	2,181,446	1,999,659	1,817,872	1,636,085	1,454,298	1,272,510	1,090,723	908,936
15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286	15,374,286
(6,039,898)	(6,588,980)	(7,138,061)	(7,687,143)	(8,236,225)	(8,785,306)	(9,334,388)	(9,883,470)	(10,432,551)	(10,981,633)	(11,530,715)	(12,079,796)	(12,628,878)
9,334,388	8,785,306	8,236,225	7,687,143	7,138,061	6,588,980	6,039,898	5,490,816	4,941,735	4,392,653	3,843,572	3,294,490	2,745,408
(3,090,382)	(2,908,595)	(2,726,808)	(2,545,021)	(2,363,234)	(2,181,446)	(1,999,659)	(1,817,872)	(1,636,085)	(1,454,298)	(1,272,510)	(1,090,723)	(908,936)
6,244,005	5,876,711	5,509,417	5,142,122	4,774,828	4,407,533	4,040,239	3,672,944	3,305,650	2,938,356	2,571,061	2,203,767	1,836,472
312,013	293,659	275,306	256,952	238,598	220,244	201,891	183,537	165,183	146,830	128,476	110,122	91,769
176,692	166,298	155,904	145,511	135,117	124,723	114,330	103,936	93,543	83,149	72,755	62,362	51,968
488,705	459,957	431,210	402,463	373,715	344,968	316,221	287,473	258,726	229,979	201,231	172,484	143,737
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082	549,082
50,543	48,976	47,326	45,591	43,767	41,852	39,843	37,737	35,531	33,222	30,806	28,280	25,640
605,719	604,274	602,749	601,141	599,446	597,663	595,789	593,820	591,754	589,587	587,317	584,940	582,452
112,730	106,098	99,467	92,836	86,205	79,574	72,943	66,311	59,680	53,049	46,418	39,787	33,156
$ 1,207,153	$ 1,170,330	$ 1,133,426	$ 1,096,439	$ 1,059,366	$ 1,022,205	$ 984,952	$ 947,605	$ 910,160	$ 872,615	$ 834,966	$ 797,210	$ 759,344
14,997,105	14,922,119	14,847,508	14,773,271	14,699,405	14,625,908	14,552,778	14,480,014	14,407,614	14,335,576	14,263,898	14,192,579	14,121,616

Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
17.720%	18.074%	18.435%	18.804%	19.180%		
24	25	26	27	28	29	30
2037	2038	2039	2040	2041		
$ -	$ -	$ -	$ -	$ -		
$ -	$ -	$ -	$ -	$ -		
549,082	549,082	549,082	549,082	549,082		
82,362	82,362	82,362	82,362	82,362	82,362	82,362
(466,719)	(466,719)	(466,719)	(466,719)	(466,719)		
(181,787)	(181,787)	(181,787)	(181,787)	(181,787)		
727,149	545,362	363,574	181,787	0		
15,374,286	15,374,286	15,374,286	15,374,286	15,374,286		
(13,177,959)	(13,727,041)	(14,276,123)	(14,825,204)	(15,374,286)		
2,196,327	1,647,245	1,098,163	549,082	(0)		
(727,149)	(545,362)	(363,574)	(181,787)	(0)		
1,469,178	1,101,883	734,589	367,294	(0)		
73,415	55,061	36,707	18,354	(0)		
41,574	31,181	20,787	10,394	(0)		
114,989	86,242	57,495	28,747	(0)		
7,884	8,042	8,203	8,367	8,534		
549,082	549,082	549,082	549,082	549,082		
22,884	20,007	17,006	13,877	10,616		
579,850	577,131	574,291	571,326	568,232		
26,525	19,893	13,262	6,631	(0)		
$ 721,364	$ 683,266	$ 645,048	$ 606,704	$ 568,232		
14,051,008	13,980,753	13,910,849	13,841,295	13,772,088		

HIGHLY CONFIDENTIAL

	Rio Rico Esimated KWh	
COD: 3/1/2014	Contract Year	Estimated Power Production (KWh)
2015	1	15,768,000
2016	2	15,689,160
2017	3	15,610,714
2018	4	15,532,661
2019	5	15,454,997
2020	6	15,377,722
2021	7	15,300,834
2022	8	15,224,330
2023	9	15,148,208
2024	10	15,072,467
2025	11	14,997,105
2026	12	14,922,119
2027	13	14,847,508
2028	14	14,773,271
2029	15	14,699,405
2030	16	14,625,908
2031	17	14,552,778
2032	18	14,480,014
2033	19	14,407,614
2034	20	14,335,576
2035	21	14,263,898
2036	22	14,192,579
2037	23	14,121,616
2038	24	14,051,008
2039	25	13,980,753
2040	26	13,910,849
2041	27	13,841,295
2042	28	13,772,088
2043	29	13,703,228
2044	30	13,634,711
		440,292,412

Areva - Thermal HIGHLY CONFIDENTIAL
5 MW
Levelized Cost of Energy ($/KWh)

Assumptions		DPIS - 2014
Original Cost	$ 9,790,236	
Asset Life	28	
O&M First Year	$ 5,000	
Escalation Factor	2.00%	
Income Tax Rate (Federal & State)	38.24%	
Debt Return (wtd cost)	2.91%	
Equity Return (wtd cost)	4.35%	
Tax Depreciation (Yrs)	6	
ITC Claimed	2,937,071	
Property Tax Rate	7.000%	

Original Cost	$ 9,790,236	
ITC @ 30%	$ 2,937,070.90	
Depeciable Tax Basis	$ 8,321,700.88	$ -
Tax Basis After 50% Bonus	$ 4,160,850.44	

	0	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr.6	Yr.7	Yr.8	Yr.9	Yr. 10
Property Tax Rate		7.000%	7.140%	7.283%	7.428%	7.577%	7.729%	7.883%	8.041%	8.202%	8.366%
		1	2	3	4	5	6	7	8	9	10
Year		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Tax Depreciation		$ 4,993,021	$ 1,331,472	$ 798,883	$ 479,330	$ 479,330	$ 239,665				
Tax Depreciation included in Rate Base		297,204	6,027,289	297,204	297,204	1,163,136	239,665	-	-	-	-
Book Depreciation		349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
Less: Book Depr on ITC Adj		52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448
Timing Difference		(0)	5,730,085	(0)	(0)	865,932	(57,539)	(297,204)	(297,204)	(297,204)	(297,204)
Def. Tax @ 38.24%		(0)	2,191,185	(0)	(0)	331,133	(22,003)	(113,651)	(113,651)	(113,651)	(113,651)
A.D.I.T.		(0)	2,191,185	2,191,185	2,191,185	2,522,317	2,500,314	2,386,664	2,273,013	2,159,362	2,045,712
Plant in Service		9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236
Accum. Depreciation		(349,651)	(699,303)	(1,048,954)	(1,398,605)	(1,748,256)	(2,097,908)	(2,447,559)	(2,797,210)	(3,146,862)	(3,496,513)
Net Plant in Service		9,440,585	9,090,934	8,741,282	8,391,631	8,041,980	7,692,329	7,342,677	6,993,026	6,643,375	6,293,723
Unamortized ITC		(2,643,364)	(2,055,950)	(1,468,535)	(881,121)	(293,707)					
Unamortized ITC included in Rate Base		-	-	-	-	-					
A.D.I.T.		0	(2,191,185)	(2,191,185)	(2,191,185)	(2,522,317)	(2,500,314)	(2,386,664)	(2,273,013)	(2,159,362)	(2,045,712)
Net Rate Base		9,440,585	6,899,749	6,550,098	6,200,446	5,519,663	5,192,014	4,956,013	4,720,013	4,484,012	4,248,012
Return on Rate Base:											
Debt Return		410,665	300,139	284,929	269,719	240,105	225,853	215,587	205,321	195,055	184,789
Equity Return		274,416	200,560	190,396	180,233	160,444	150,920	144,060	137,200	130,340	123,480
Total		685,082	500,699	475,326	449,952	400,549	376,773	359,647	342,521	325,395	308,269
Operating Expenses & Taxes:											
Operations and Maintenance		5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Depreciation		349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
Property Taxes(1)		24,671	24,326	23,957	23,563	23,144	22,699	22,227	21,727	21,198	20,639
Total		379,323	379,077	378,810	378,521	378,208	377,871	377,509	377,122	376,708	376,266
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		169,911	124,181	117,888	111,595	99,342	93,445	89,198	84,950	80,703	76,455
Revenue Requirement		$ 1,234,315	$ 1,003,957	$ 972,024	$ 940,068	$ 878,099	$ 848,089	$ 826,354	$ 804,593	$ 782,805	$ 760,990
NPV Cost		$ 9,360,291									
Estimated Output (KWh)		14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000
NPV Output		169,461,664									
LCOE ($/KWh)		$ 0.06									

(1) Property taxes are the product of net book value x assesment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor

8.533%	8.704%	8.878%	9.055%	9.236%	9.421%	9.609%	9.802%	9.998%	10.198%	10.402%	10.610%	10.822%
Yr. 11	Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20	Yr. 21	Yr. 22	Yr. 23
11	12	13	14	15	16	17	18	19	20	21	22	23
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
-	-	-	-	-	-	-	-	-	-	-	-	-
349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448	52,448
(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)	(297,204)
(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)	(113,651)
1,932,061	1,818,411	1,704,760	1,591,109	1,477,459	1,363,808	1,250,157	1,136,507	1,022,856	909,205	795,555	681,904	568,253
9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236	9,790,236
(3,846,164)	(4,195,816)	(4,545,467)	(4,895,118)	(5,244,769)	(5,594,421)	(5,944,072)	(6,293,723)	(6,643,375)	(6,993,026)	(7,342,677)	(7,692,329)	(8,041,980)
5,944,072	5,594,421	5,244,769	4,895,118	4,545,467	4,195,816	3,846,164	3,496,513	3,146,862	2,797,210	2,447,559	2,097,908	1,748,256
(1,932,061)	(1,818,411)	(1,704,760)	(1,591,109)	(1,477,459)	(1,363,808)	(1,250,157)	(1,136,507)	(1,022,856)	(909,205)	(795,555)	(681,904)	(568,253)
4,012,011	3,776,010	3,540,010	3,304,009	3,068,008	2,832,008	2,596,007	2,360,006	2,124,006	1,888,005	1,652,004	1,416,004	1,180,003
174,522	164,256	153,990	143,724	133,458	123,192	112,926	102,660	92,394	82,128	71,862	61,596	51,330
116,620	109,760	102,900	96,040	89,180	82,320	75,460	68,600	61,740	54,880	48,020	41,160	34,300
291,142	274,016	256,890	239,764	222,638	205,512	188,386	171,260	154,134	137,008	119,882	102,756	85,630
6,095	6,217	6,341	6,468	6,597	6,729	6,864	7,001	7,141	7,284	7,430	7,578	7,730
349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651	349,651
20,050	19,428	18,774	18,085	17,362	16,602	15,805	14,970	14,095	13,179	12,220	11,218	10,171
375,796	375,296	374,766	374,205	373,610	372,983	372,321	371,622	370,887	370,114	369,301	368,448	367,552
72,208	67,960	63,713	59,465	55,218	50,970	46,723	42,475	38,228	33,980	29,733	25,485	21,238
$ 739,146	$ 717,273	$ 695,369	$ 673,434	$ 651,467	$ 629,465	$ 607,430	$ 585,358	$ 563,249	$ 541,102	$ 518,916	$ 496,689	$ 474,420
14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000	14,310,000

11.038%	11.259%	11.484%	11.714%	11.948%		
Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
24	25	26	27	28	29	30
2037	2038	2039	2040	2041		
-	-	-	-	-		
349,651	349,651	349,651	349,651	349,651		
52,448	52,448	52,448	52,448	52,448	52,448	52,448
(297,204)	(297,204)	(297,204)	(297,204)	(297,204)		
(113,651)	(113,651)	(113,651)	(113,651)	(113,651)		
454,603	340,952	227,301	113,651	0		
9,790,236	9,790,236	9,790,236	9,790,236	9,790,236		
(8,391,631)	(8,741,282)	(9,090,934)	(9,440,585)	(9,790,236)		
1,398,605	1,048,954	699,303	349,651	-		
(454,603)	(340,952)	(227,301)	(113,651)	(0)		
944,003	708,002	472,001	236,001	(0)		
41,064	30,798	20,532	10,266	(0)		
27,440	20,580	13,720	6,860	(0)		
68,504	51,378	34,252	17,126	(0)		
7,884	8,042	8,203	8,367	8,534		
349,651	349,651	349,651	349,651	349,651		
9,078	7,936	6,746	5,505	4,211		
366,613	365,630	364,600	363,523	362,397		
16,990	12,743	8,495	4,248	(0)		
$ 452,108	$ 429,751	$ 407,347	$ 384,897	$ 362,397		
14,310,000	14,310,000	14,310,000	14,310,000	14,310,000		

HIGHLY CONFIDENTIAL

Areva Esimated KWh

	Contract Year	Estimated Power Production (KWh)
COD: 12/30/2014		
2014	1	14,310,000.00
2015	2	14,310,000.00
2016	3	14,310,000.00
2017	4	14,310,000.00
2018	5	14,310,000.00
2019	6	14,310,000.00
2020	7	14,310,000.00
2021	8	14,310,000.00
2022	9	14,310,000.00
2023	10	14,310,000.00
2024	11	14,310,000.00
2025	12	14,310,000.00
2026	13	14,310,000.00
2027	14	14,310,000.00
2028	15	14,310,000.00
2029	16	14,310,000.00
2030	17	14,310,000.00
2031	18	14,310,000.00
2032	19	14,310,000.00
2033	20	14,310,000.00
2034	21	14,310,000.00
2035	22	14,310,000.00
2036	23	14,310,000.00
2037	24	14,310,000.00
2038	25	14,310,000.00
2039	26	14,310,000.00
2040	27	14,310,000.00
2041	28	14,310,000.00
2042	29	14,310,000.00
2043	30	14,310,000.00
		429,300,000.00

Hypothetical 10 MW SAT PV
10 MW
Levelized Cost of Energy ($/kWh)

Assumptions		
Original Cost	$	17,000,000
Asset Life		30
O&M First Year (5)	$	10,000
Escalation Factor		2.00%
Income Tax Rate (Federal & State)(2)		38.24%
Debt Return (wtd cost)(1)		4.00%
Equity Return (wtd cost)(1)		2.00%
Tax Depreciation (Yrs)(3)		6
ITC Claimed		5,100,000
Property Tax Rate(2)		7.000%

	0	Yr. 1 1	Yr. 2 2	Yr. 3 3	Yr. 4 4	Yr. 5 5	Yr.6 6	Yr.7 7	Yr.8 8	Yr.9 9	Yr. 10 10	Yr. 11 11
Tax Depreciation(3)	$	8,670,000	$ 2,312,000	$ 1,387,200	$ 832,320	$ 832,320	$ 416,160	$ -	$ -	$ -	$ -	$ -
Book Depreciation		566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
Less: Book Depr on ITC Adj(3)		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
Timing Difference		8,188,333	1,830,333	905,533	350,653	350,653	(65,507)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)
Def. Tax @ 38.24%		3,131,219	699,919	346,276	134,090	134,090	(25,050)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)
A.D.I.T.		3,131,219	3,831,138	4,177,414	4,311,504	4,445,594	4,420,544	4,236,355	4,052,165	3,867,976	3,683,787	3,499,597
Plant in Service		17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000
Accum. Depreciation		(566,667)	(1,133,333)	(1,700,000)	(2,266,667)	(2,833,333)	(3,400,000)	(3,966,667)	(4,533,333)	(5,100,000)	(5,666,667)	(6,233,333)
Net Plant in Service		16,433,333	15,866,667	15,300,000	14,733,333	14,166,667	13,600,000	13,033,333	12,466,667	11,900,000	11,333,333	10,766,667
Unamortized ITC(3)		(4,590,000)	(3,570,000)	(2,550,000)	(1,530,000)	(510,000)	-	-	-	-	-	-
A.D.I.T.		(3,131,219)	(3,831,138)	(4,177,414)	(4,311,504)	(4,445,594)	(4,420,544)	(4,236,355)	(4,052,165)	(3,867,976)	(3,683,787)	(3,499,597)
Net Rate Base		8,712,115	8,465,529	8,572,586	8,891,829	9,211,073	9,179,456	8,796,979	8,414,501	8,032,024	7,649,547	7,267,069
Return on Rate Base:												
Equity Return		174,242	169,311	171,452	177,837	184,221	183,589	175,940	168,290	160,640	152,991	145,341
Debt Return		348,485	338,621	342,903	355,673	368,443	367,178	351,879	336,580	321,281	305,982	290,683
Total		522,727	507,932	514,355	533,510	552,664	550,767	527,819	504,870	481,921	458,973	436,024
Operating Expenses & Taxes:												
Operations and Maintenance		10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	12,190
Depreciation		566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
Property Taxes(4)		28,789	27,589	26,389	25,190	23,990	22,791	21,591	20,392	19,192	17,993	16,793
Total		605,455	604,456	603,460	602,469	601,481	600,498	599,520	598,545	597,576	596,610	595,650
Income Tax on Equity Return: (Return/(1-Tax Rate) X Tax Rate		107,886	104,832	106,158	110,111	114,065	113,673	108,937	104,200	99,464	94,728	89,991
Revenue Requirement	$	1,236,068	$ 1,217,220	$ 1,223,973	$ 1,246,090	$ 1,268,210	$ 1,264,939	$ 1,236,275	$ 1,207,616	$ 1,178,961	$ 1,150,311	$ 1,121,665
NPV Cost	$	14,813,840										
Estimated Output (kWh)		24,002,400	23,882,388	23,404,740	23,346,228	23,287,863	23,229,643	23,171,569	23,113,640	23,055,856	22,998,216	22,940,721
NPV Output		316,394,397										
Annual equivalent price per kWh		0.051	0.051	0.052	0.053	0.054	0.054	0.053	0.052	0.051	0.050	0.049
LCOE ($/kWh)	$	0.0468										

(1) Assumptions for the debt and equity returns are based on a 80/20 debt/equity capital structure with a required debt return of 5.0% and a required equity return of 10.0%
(2) Assumption in 2015 Rate Filing
(3) Assumes tax benefits can be utilized in the year generated
(4) Property taxes are the product of (Cost minus ITC amortized over 25 years) x assessment rate x property tax rate x 20% valuation factor- then increase the property tax rate annually by the escalation factor
(5) O&M assumed at $0.01/kW

Yr. 12	Yr. 13	Yr. 14	Yr. 15	Yr. 16	Yr. 17	Yr. 18	Yr. 19	Yr. 20
12	13	14	15	16	17	18	19	20
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)
(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)
3,315,408	3,131,219	2,947,029	2,762,840	2,578,651	2,394,461	2,210,272	2,026,083	1,841,893
17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000
(6,800,000)	(7,366,667)	(7,933,333)	(8,500,000)	(9,066,667)	(9,633,333)	(10,200,000)	(10,766,667)	(11,333,333)
10,200,000	9,633,333	9,066,667	8,500,000	7,933,333	7,366,667	6,800,000	6,233,333	5,666,667
-	-	-	-	-	-	-	-	-
(3,315,408)	(3,131,219)	(2,947,029)	(2,762,840)	(2,578,651)	(2,394,461)	(2,210,272)	(2,026,083)	(1,841,893)
6,884,592	6,502,115	6,119,637	5,737,160	5,354,683	4,972,205	4,589,728	4,207,251	3,824,773
137,692	130,042	122,393	114,743	107,094	99,444	91,795	84,145	76,495
275,384	260,085	244,785	229,486	214,187	198,888	183,589	168,290	152,991
413,076	390,127	367,178	344,230	321,281	298,332	275,384	252,435	229,486
12,434	12,682	12,936	13,195	13,459	13,728	14,002	14,282	14,568
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
15,594	14,394	13,195	11,995	10,796	9,596	8,397	7,197	5,998
594,694	593,743	592,797	591,857	590,921	589,991	589,066	588,146	587,232
85,255	80,518	75,782	71,046	66,309	61,573	56,837	52,100	47,364
$ 1,093,025	$ 1,064,389	$ 1,035,758	$ 1,007,132	$ 978,511	$ 949,896	$ 921,286	$ 892,681	$ 864,083
22,883,369	22,826,161	22,769,095	22,712,172	22,655,392	22,598,754	22,542,257	22,485,901	22,429,686
0.048	0.047	0.045	0.044	0.043	0.042	0.041	0.040	0.039

Yr. 21	Yr. 22	Yr. 23	Yr. 24	Yr. 25	Yr. 26	Yr. 27	Yr. 28	Yr. 29	Yr. 30
21	22	23	24	25	26	27	28	29	30
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)	(481,667)
(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)	(184,189)
1,657,704	1,473,515	1,289,325	1,105,136	920,947	736,757	552,568	368,379	184,189	(0)
17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000	17,000,000
(11,900,000)	(12,466,667)	(13,033,333)	(13,600,000)	(14,166,667)	(14,733,333)	(15,300,000)	(15,866,667)	(16,433,333)	(17,000,000)
5,100,000	4,533,333	3,966,667	3,400,000	2,833,333	2,266,667	1,700,000	1,133,333	566,667	0
-	-	-	-	-	-	-	-	-	-
(1,657,704)	(1,473,515)	(1,289,325)	(1,105,136)	(920,947)	(736,757)	(552,568)	(368,379)	(184,189)	0
3,442,296	3,059,819	2,677,341	2,294,864	1,912,387	1,529,909	1,147,432	764,955	382,477	0
68,846	61,196	53,547	45,897	38,248	30,598	22,949	15,299	7,650	0
137,692	122,393	107,094	91,795	76,495	61,196	45,897	30,598	15,299	0
206,538	183,589	160,640	137,692	114,743	91,795	68,846	45,897	22,949	0
14,859	15,157	15,460	15,769	16,084	16,406	16,734	17,069	17,410	17,758
566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667	566,667
4,798	3,599	2,399	1,200	-	(1,200)	(2,399)	(3,599)	(4,798)	(5,998)
586,324	585,422	584,526	583,635	582,751	581,873	581,002	580,137	579,279	578,428
42,627	37,891	33,155	28,418	23,682	18,946	14,209	9,473	4,736	0
$ 835,489	$ 806,902	$ 778,321	$ 749,745	$ 721,176	$ 692,613	$ 664,057	$ 635,507	$ 606,964	$ 578,428
22,373,612	22,317,678	22,261,884	22,206,229	22,150,714	22,095,337	22,040,098	21,984,998	21,930,036	21,875,211
0.037	0.036	0.035	0.034	0.033	0.031	0.030	0.029	0.028	0.026

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
June 10, 2016

EXHIBIT
S-14
ADMITTED

STF 3.1

Please provide actual annual production numbers for all years prior to 2016 for each individual company-owned utility scale solar PV plant in your fleet. Provide similar actual annual production numbers for each utility-scale solar PV PPA resource.

RESPONSE: June 10, 2016

As the Company has previously stated, all data has been weather normalized for the sole purpose of a comparison evaluation between utility owned facilities and third party PPA's. Please see STF 3.1 TEP Utility-Scale Production 2010-2015.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Carmine Tilghman / Ted Burhans

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: June 10, 2016

Please see STF 3.1 TEP Utility-Scale Production 2010-2015-Revised.xlsx and STF 3.1 UNSE Utility-Scale Production 2011-2015.xlsx. The Excel files are <u>not</u> identified by Bates numbers.

RESPONDENT:

Ted Burhans

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION DOCKET NO. E-00000J-14-0023 June 10, 2016

STF 3.2

Please provide calculations for the actual annual total production load factor for each utility scale plant and PPA resource for all years prior to 2016.

RESPONSE: June 10, 2016

Please see STF 3.1 TEP Utility-Scale Production 2010-2015.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Ted Burhans

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: June 10, 2016

Please see STF 3.1 TEP Utility-Scale Production 2010-2015-Revised.xlsx and STF 3.1 UNSE Utility-Scale Production 2011-2015.xlsx. The Excel files are not identified by Bates numbers.

RESPONDENT:

Ted Burhans

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
June 10, 2016

STF 3.1

Please provide actual annual production numbers for all years prior to 2016 for each individual company-owned utility scale solar PV plant in your fleet. Provide similar actual annual production numbers for each utility-scale solar PV PPA resource.

RESPONSE:

As the Company has previously stated, all data has been weather normalized for the sole purpose of a comparison evaluation between utility owned facilities and third party PPA's. Please see STF 3.1 TEP Utility-Scale Production 2010-2015.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Carmine Tilghman / Ted Burhans

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION
DOCKET NO. E-00000J-14-0023
June 10, 2016

STF 3.2

Please provide calculations for the actual annual total production load factor for each utility scale plant and PPA resource for all years prior to 2016.

RESPONSE:

Please see STF 3.1 TEP Utility-Scale Production 2010-2015.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Ted Burhans

WITNESS:

Carmine Tilghman

Compliance Report - Energy **Tucson Electric Power Company**

Table 1a - Renewable Resources

Resource	Install Year	Technology	Ownership	MW(AC)	MW(DC)	Production (Actual) kWh	Production: Actual/(Annualized)[2] kWh	Multiplier Credits[3]	Total kWh or Equivalent		Capacity Factor
UTILITY OWNED:											
Generation:											
Springerville 1	2001-2004	Fixed Tilt	TEP	3.68	4.60	8,858,803	8,858,803	1.50	13,288,205		22.0%
Springerville 2	2010	Fixed Tilt	TEP	1.45	1.81	3,485,747	3,485,747	1.00	3,485,747		22.0%
White Mountain	2014	Fixed Tilt/LCPV	TEP	8.25	10.00	2,774,391	2,774,391	1.00	2,774,391		3.2%
Solon Tech Park 1	2010	Single Axis	TEP	1.28	1.60	2,606,835	2,606,835	1.00	2,606,835		18.6%
Solon Tech Park 2	2011	Fixed Tilt	TEP	4.00	5.00	7,657,297	7,657,297	1.00	7,657,297		17.5%
HQ	2012	Fixed Tilt	TEP	0.04	0.05	- [7]	-	1.00	-		0.0%
Warehouse OH	2012	Fixed Tilt	TEP	0.40	0.50	1,016,474	1,016,474	1.00	1,016,474		23.2%
Prairie Fire	2012	Fixed Tilt	TEP	4.00	5.00	8,644,608	8,644,608	1.00	8,644,608		19.7%
DeMoss-Petrie	2001	Fixed Tilt	TEP	0.18	0.22	127,989	127,989	1.00	127,989		6.8%
Sundt Augmentation	2014	Solar Steam Augmentation	TEP	5.00		12,264,431	12,264,431	1.00	12,264,431		
PPA:							-				
Fort Huachuca	2014				17.20	29,298,214	29,298,214	1.00	29,298,214		19.4%
Gross Total									538,599,410		
Adjustments 10% wholesale DG applied to Non-						-	-		-		
Total Production of AC &						**547,668,333**	**467,430,213**		**538,599,410**	(A)	
Subtotal Capacity AC				**89.40**							
Subtotal Capacity of DC				**159.64**	**204.42**						
Total AC Generation				**249.04**							

Compliance Report - Energy UNS Electric, Inc.

Table 1a - Renewable Resources

Resource		Technology	Ownership	MWac[1]	MWdc[1]			Production (Actual) kWh	> of	Production: Actual or Annualized[2] kWh	X	Multiplier Credits	=	Total kWh or Equivalent		Capacity Factor
PPAs																
La Senita		PV	UNSE		1.22			2,096,259		2,096,259		1.00		2,096,259	10,687,200	19.6%
Rio Rico		PV	UNSE		7.20			10,363,484		12,960,000		1.00		12,960,000	63,072,000	16.4%

~~HIGHLY CONFIDENTIAL~~

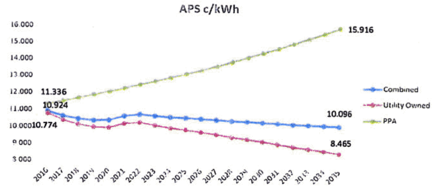
Year	Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2013	Hyder 2	5,721,187	5,495,175	5,336,511	5,245,204	5,154,208	5,063,531	4,973,184	4,883,176	4,793,517	4,704,218	4,615,290	4,526,743	4,438,590	4,350,842	4,263,511	4,176,609	4,090,150	4,004,147	3,918,613	3,833,563
2011	Cotton Center	5,995,310	5,960,153	5,911,553	5,916,193	6,006,823	6,251,936	6,359,588	6,238,177	6,117,215	5,996,717	5,876,697	5,757,168	5,638,146	5,519,645	5,401,682	5,284,273	5,167,433	5,051,181	4,935,534	4,820,509
2011	Paloma	4,842,745	4,826,996	4,799,065	4,819,550	4,918,207	5,157,279	5,271,482	5,177,577	5,084,122	4,991,131	4,898,617	4,806,595	4,715,080	4,624,086	4,533,630	4,443,727	4,354,395	4,265,649	4,177,509	4,089,991
2012	Hyder	4,207,841	4,251,249	4,284,334	4,418,660	4,716,723	5,309,242	5,638,979	5,531,078	5,423,597	5,316,549	5,209,946	5,103,801	4,998,129	4,892,944	4,788,259	4,684,091	4,580,455	4,477,366	4,374,841	4,272,897
2012	Chino Valley	6,161,232	6,061,948	6,043,491	6,107,505	6,304,819	6,741,760	6,965,110	6,832,659	6,700,696	6,569,237	6,438,295	6,307,887	6,178,029	6,048,737	5,920,028	5,791,920	5,664,430	5,537,578	5,411,381	5,285,861
2013	Foothills	10,668,465	10,316,011	10,100,530	10,135,432	10,334,391	10,828,140	11,059,449	10,860,761	10,655,568	10,451,181	10,247,624	10,044,923	9,850,751	9,649,838	9,449,859	9,250,843	9,052,819	8,863,848	8,667,897	8,473,030
2014	Gila Bend	10,795,709	10,404,232	10,013,404	9,738,872	9,580,655	9,423,148	9,266,371	9,110,347	8,955,098	8,800,648	8,647,020	8,494,239	8,342,331	8,191,322	8,041,238	7,892,108	7,743,960	7,596,823	7,450,729	7,305,707
2015	Luke AFB	3,493,755	3,474,256	3,344,043	3,214,033	3,121,736	3,067,158	3,012,802	2,958,676	2,904,782	2,851,132	2,797,732	2,744,588	2,691,710	2,639,103	2,586,778	2,534,742	2,483,004	2,431,573	2,380,458	2,329,669
2015	Desert Star	2,996,439	2,976,836	2,860,996	2,745,360	2,666,069	2,623,129	2,580,412	2,537,922	2,495,668	2,453,656	2,411,894	2,370,389	2,329,148	2,288,180	2,247,493	2,207,096	2,166,986	2,127,203	2,087,726	2,048,575
2017	Red Rock		12,146,614	11,266,695	10,313,965	9,457,111	8,897,541	8,338,481	8,002,538	7,889,726	7,777,470	7,665,784	7,554,685	7,444,191	7,334,318	7,225,085	7,116,511	7,008,613	6,901,412	6,794,927	6,689,180
	Aggregate	75,913,850	87,070,501	85,305,796	84,195,586	84,062,258	85,318,813	85,641,618	84,537,388	83,721,006	82,798,930	81,951,258	81,118,052	80,370,431	79,504,628	78,717,707	77,947,052	77,259,581	76,464,234	75,745,415	75,045,131

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Hyder 2	45,619	45,255	45,029	44,804	44,713	44,357	44,135	43,914	43,825	43,476	43,259	43,043	42,956	42,613	42,400	42,188	42,103	41,767	41,559	41,351
Cotton Center	45,442	45,213	45,122	45,032	45,080	44,852	44,762	44,673	44,720	44,494	44,405	44,316	44,364	44,139	44,051	43,963	44,010	43,787	43,700	43,612
Paloma	40,734	40,318	40,036	39,756	39,606	39,201	38,927	38,654	38,508	38,115	37,848	37,583	37,441	37,059	36,799	36,542	36,404	36,032	35,780	35,529
Chino Valley	47,504	47,267	47,030	46,795	46,561	46,328	46,097	45,866	45,637	45,409	45,182	44,956	44,731	44,507	44,285	44,063	43,843	43,624	43,406	43,189
Foothills	111,272	110,368	109,816	109,267	109,064	108,177	107,637	107,098	106,899	106,030	105,500	104,972	104,777	103,925	103,406	102,889	102,697	101,862	101,353	100,846
Gila Bend	108,225	107,344	106,808	106,274	106,076	105,214	104,688	104,164	103,971	103,125	102,609	102,096	101,907	101,078	100,573	100,070	99,884	99,072	98,576	98,083
Luke AFB	34,879	34,603	34,430	34,258	34,187	33,916	33,747	33,578	33,508	33,243	33,077	32,911	32,843	32,583	32,420	32,258	32,191	31,936	31,777	31,618
Desert Star	35,562	35,283	35,106	34,931	34,856	34,582	34,409	34,237	34,164	33,896	33,726	33,558	33,486	33,223	33,057	32,821	32,821	32,563	32,401	32,239
Red Rock		128,832	128,188	127,547	127,294	126,275	125,643	125,015	124,767	123,768	123,149	122,533	122,290	121,311	120,705	120,101	119,863	118,903	118,308	117,717
Aggregate	694,947	818,170	813,825	809,503	807,437	800,925	796,671	792,436	790,413	784,036	779,869	775,722	773,741	767,494	763,413	759,281	757,410	751,292	747,296	743,317

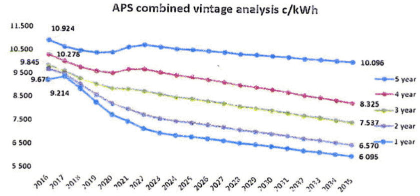
c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Hyder 2	12.541	12.143	11.851	11.707	11.527	11.415	11.268	11.120	10.938	10.820	10.669	10.517	10.333	10.210	10.055	9.900	9.715	9.587	9.429	9.271
Cotton Center	13.193	13.182	13.101	13.138	13.325	13.939	14.208	13.964	13.679	13.478	13.234	12.991	12.709	12.505	12.262	12.020	11.741	11.536	11.294	11.053
Paloma	11.889	11.972	11.987	12.123	12.418	13.156	13.542	13.395	13.203	13.095	12.943	12.789	12.593	12.478	12.320	12.161	11.961	11.839	11.676	11.512
Hyder	10.472	10.665	10.802	11.197	11.977	13.589	14.505	14.299	14.050	13.883	13.673	13.462	13.210	13.036	12.821	12.605	12.352	12.170	11.951	11.731
Chino Valley	12.970	12.825	12.850	13.052	13.541	14.552	15.110	14.897	14.683	14.467	14.250	14.031	13.812	13.591	13.368	13.145	12.920	12.694	12.467	12.239
Foothills	9.588	9.347	9.198	9.276	9.476	10.010	10.275	10.141	9.968	9.857	9.713	9.569	9.402	9.285	9.139	8.991	8.815	8.702	8.552	8.402
Gila Bend	9.975	9.692	9.375	9.164	9.032	8.956	8.851	8.746	8.613	8.534	8.427	8.320	8.186	8.104	7.995	7.887	7.753	7.668	7.558	7.448
Luke AFB	10.017	10.040	9.713	9.382	9.131	9.043	8.928	8.811	8.669	8.577	8.458	8.339	8.196	8.100	7.979	7.858	7.713	7.614	7.491	7.368
Desert Star	8.426	8.437	8.150	7.859	7.649	7.585	7.499	7.413	7.305	7.239	7.151	7.064	6.956	6.887	6.799	6.725	6.602	6.533	6.443	6.354
Red Rock		9.428	8.789	8.086	7.429	7.046	6.637	6.401	6.324	6.284	6.225	6.165	6.087	6.046	5.986	5.925	5.847	5.804	5.743	5.682
Aggregate	10.924	10.642	10.482	10.401	10.411	10.653	10.750	10.668	10.592	10.561	10.508	10.457	10.387	10.359	10.311	10.266	10.201	10.178	10.136	10.096

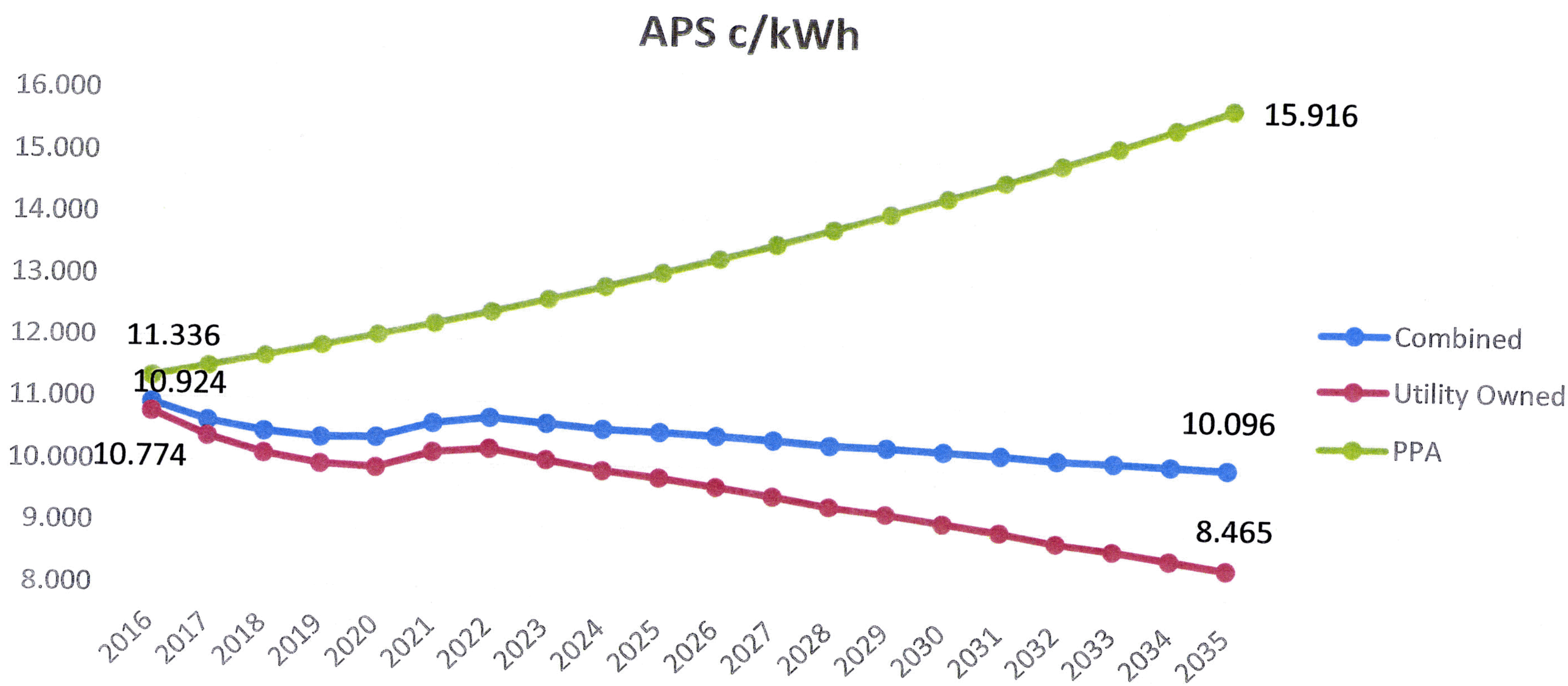
Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
14.00	Hyder 2	37.20%	36.90%	36.72%	36.53%	36.46%	36.17%	35.99%	35.81%	35.73%	35.45%	35.27%	35.10%	35.03%	34.75%	34.57%	34.40%	34.33%	34.06%	33.89%	33.72%
17.00	Cotton Center	30.51%	30.36%	30.30%	30.24%	30.27%	30.12%	30.06%	30.00%	30.03%	29.88%	29.82%	29.76%	29.79%	29.64%	29.58%	29.52%	29.55%	29.40%	29.34%	29.29%
17.00	Paloma	27.35%	27.07%	26.88%	26.70%	26.60%	26.32%	26.14%	25.96%	25.86%	25.59%	25.41%	25.24%	25.14%	24.89%	24.71%	24.54%	24.45%	24.20%	24.03%	23.86%
16.00	Hyder	28.67%	28.44%	28.30%	28.16%	28.10%	27.88%	27.74%	27.60%	27.54%	27.32%	27.19%	27.05%	26.99%	26.78%	26.65%	26.51%	26.46%	26.25%	26.12%	25.99%
19.00	Chino Valley	28.54%	28.40%	28.26%	28.12%	27.97%	27.83%	27.70%	27.56%	27.42%	27.28%	27.15%	27.01%	26.88%	26.74%	26.61%	26.47%	26.34%	26.21%	26.08%	25.95%
35.00	Foothills	36.29%	36.00%	35.82%	35.64%	35.57%	35.28%	35.11%	34.93%	34.87%	34.58%	34.41%	34.24%	34.17%	33.90%	33.73%	33.56%	33.50%	33.22%	33.06%	32.89%
32.00	Gila Bend	38.61%	38.29%	38.10%	37.91%	37.84%	37.53%	37.35%	37.16%	37.09%	36.79%	36.60%	36.42%	36.35%	36.06%	35.88%	35.70%	35.63%	35.34%	35.17%	34.99%
10.00	Luke AFB	39.82%	39.50%	39.30%	39.11%	39.03%	38.72%	38.52%	38.33%	38.25%	37.95%	37.76%	37.57%	37.49%	37.20%	37.01%	36.82%	36.75%	36.46%	36.28%	36.09%
10.00	Desert Star	40.60%	40.28%	40.08%	39.88%	39.79%	39.48%	39.28%	39.08%	39.00%	38.69%	38.50%	38.31%	38.23%	37.93%	37.74%	37.47%	37.47%	37.17%	36.99%	36.80%
40.00	Red Rock	0.00%	36.77%	36.58%	36.40%	36.33%	36.04%	35.86%	35.68%	35.61%	35.32%	35.15%	34.97%	34.90%	34.62%	34.45%	34.28%	34.21%	33.93%	33.76%	33.60%
284.50	**Aggregate**	27.88%	32.83%	32.65%	32.48%	32.40%	32.14%	31.97%	31.80%	31.72%	31.46%	31.29%	31.13%	31.05%	30.80%	30.63%	30.47%	30.39%	30.15%	29.99%	29.83%

APS c/kWh



APS combined vintage analysis c/kWh





APS c/kWh
16.000
15.000
14.000
13.000
12.000
11.000
10.000
9.000
8.000
11.336
10.924
10.774
15.916
10.096
8.465
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
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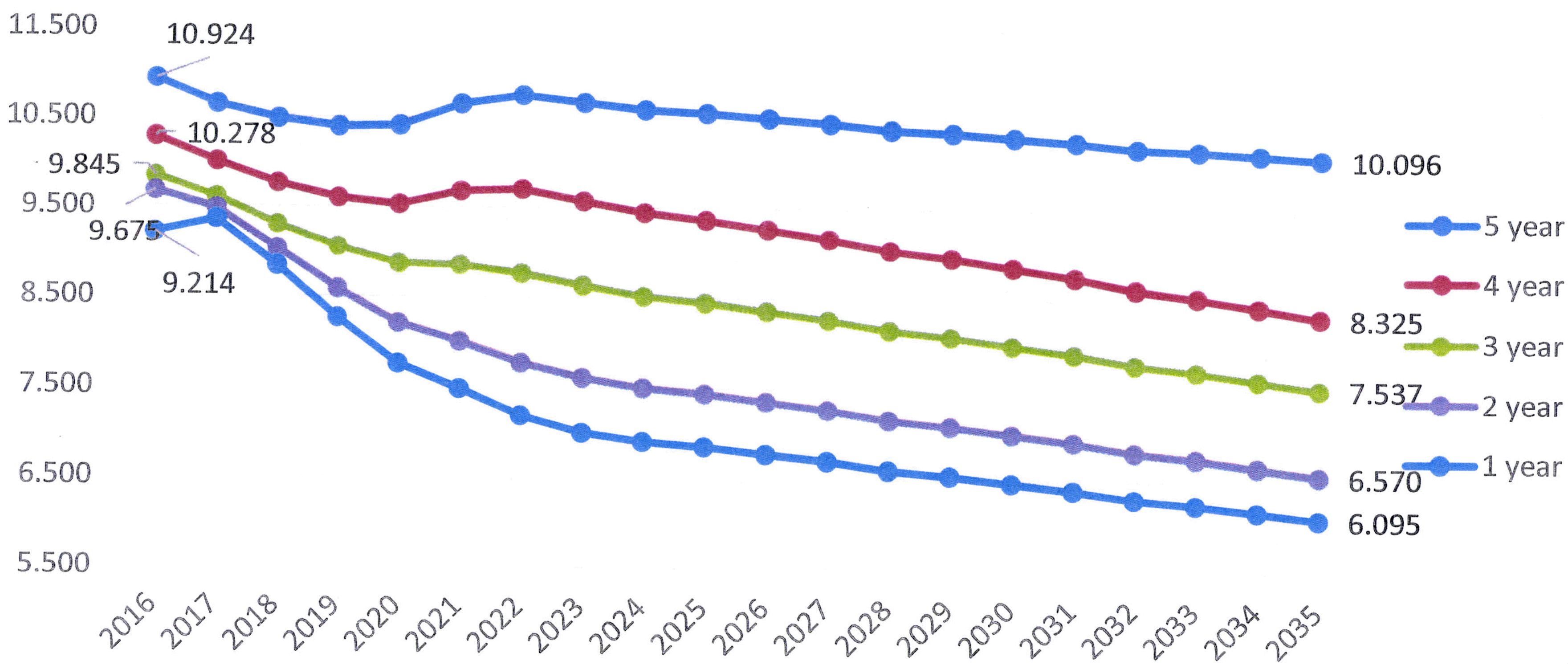
2030
2031
2032
2033
2034
2035
Combined
Utility Owned
PPA

APS combined vintage analysis c/kWh



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[redacted]

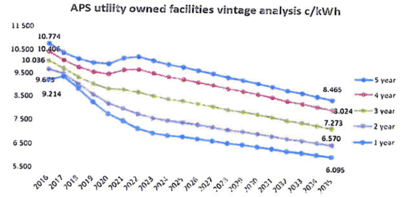
Year	Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2013	Hyder 2	5,721,187	5,495,175	5,336,511	5,245,204	5,154,208	5,063,531	4,973,184	4,883,176	4,793,517	4,704,218	4,615,290	4,526,743	4,438,590	4,350,842	4,263,511	4,176,609	4,090,150	4,004,147	3,918,613	3,833,563
2011	Cotton Center	5,995,310	5,960,153	5,911,553	5,916,193	6,006,823	6,251,936	6,359,588	6,238,177	6,117,215	5,996,717	5,876,697	5,757,168	5,638,146	5,519,645	5,401,682	5,284,273	5,167,433	5,051,181	4,935,534	4,820,509
2011	Paloma	4,842,745	4,826,996	4,799,065	4,819,550	4,918,207	5,157,279	5,271,482	5,177,577	5,084,122	4,991,131	4,898,617	4,806,595	4,715,080	4,624,086	4,533,630	4,443,727	4,354,395	4,265,649	4,177,509	4,089,991
2012	Hyder	4,207,841	4,251,249	4,284,334	4,418,660	4,716,723	5,309,242	5,638,979	5,531,078	5,423,597	5,316,549	5,209,946	5,103,801	4,998,129	4,892,944	4,788,259	4,684,091	4,580,455	4,477,366	4,374,841	4,272,897
2012	Chino Valley	6,161,232	6,061,948	6,043,491	6,107,505	6,304,819	6,741,760	6,965,110	6,832,659	6,700,696	6,569,237	6,438,295	6,307,887	6,178,029	6,048,737	5,920,028	5,791,920	5,664,430	5,537,578	5,411,381	5,285,861
2013	Foothills	10,668,465	10,316,011	10,100,530	10,135,432	10,334,391	10,828,140	11,059,449	10,860,761	10,655,568	10,451,181	10,247,624	10,044,923	9,850,751	9,649,838	9,449,859	9,250,843	9,052,819	8,863,848	8,667,897	8,473,030
2014	Gila Bend	10,795,709	10,404,232	10,013,404	9,738,872	9,580,655	9,423,148	9,266,371	9,110,347	8,955,098	8,800,648	8,647,020	8,494,239	8,342,331	8,191,322	8,041,238	7,892,108	7,743,960	7,596,823	7,450,729	7,305,707
2015	Luke AFB	3,493,755	3,474,256	3,344,043	3,214,033	3,121,736	3,067,158	3,012,802	2,958,675	2,904,782	2,851,132	2,797,732	2,744,588	2,691,710	2,639,103	2,586,778	2,534,742	2,483,004	2,431,573	2,380,458	2,329,669
2015	Desert Star	2,996,439	2,976,836	2,860,996	2,745,360	2,666,069	2,623,129	2,580,412	2,537,922	2,495,668	2,453,656	2,411,894	2,370,389	2,329,148	2,288,180	2,247,493	2,207,096	2,166,996	2,127,203	2,087,726	2,048,575
2017	Red Rock		12,146,614	11,266,695	10,313,965	9,457,111	8,897,541	8,338,481	8,002,538	7,889,726	7,777,470	7,665,784	7,554,685	7,444,191	7,334,318	7,225,085	7,116,511	7,008,613	6,901,412	6,794,927	6,689,180
	Aggregate	54,882,683	65,913,470	63,960,623	62,654,773	62,260,742	63,362,865	63,465,858	62,132,909	61,019,991	59,911,939	58,808,899	57,711,020	56,626,104	55,539,016	54,457,565	53,381,920	52,312,255	51,256,781	50,199,616	49,148,983

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Hyder 2	45,619	45,255	45,029	44,804	44,713	44,357	44,135	43,914	43,825	43,476	43,259	43,043	42,956	42,613	42,400	42,188	42,103	41,767	41,559	41,351
Cotton Center	45,442	45,213	45,122	45,032	45,080	44,852	44,762	44,673	44,720	44,494	44,405	44,316	44,364	44,139	44,051	43,963	44,010	43,787	43,700	43,612
Paloma	40,734	40,318	40,036	39,756	39,606	39,201	38,927	38,654	38,508	38,115	37,848	37,583	37,441	37,059	36,799	36,542	36,404	36,032	35,780	35,529
Hyder	40,181	39,862	39,663	39,464	39,383	39,071	38,875	38,681	38,602	38,295	38,104	37,913	37,835	37,535	37,347	37,160	37,084	36,790	36,606	36,423
Chino Valley	47,504	47,267	47,030	46,795	46,561	46,328	46,097	45,866	45,637	45,409	45,182	44,956	44,731	44,507	44,285	44,063	43,843	43,624	43,406	43,189
Foothills	111,272	110,368	109,816	109,267	109,064	108,177	107,637	107,098	106,899	106,030	105,500	104,972	104,777	103,925	103,406	102,889	102,697	101,862	101,353	100,846
Gila Bend	108,225	107,344	106,808	106,274	106,076	105,214	104,688	104,164	103,971	103,125	102,609	102,096	101,907	101,078	100,573	100,070	99,884	99,072	98,576	98,083
Luke AFB	34,879	34,603	34,430	34,258	34,187	33,916	33,747	33,578	33,508	33,243	33,077	32,911	32,843	32,583	32,420	32,258	32,191	31,936	31,777	31,618
Desert Star	35,562	35,283	35,106	34,931	34,856	34,582	34,409	34,237	34,164	33,896	33,726	33,558	33,486	33,223	33,057	32,821	32,821	32,563	32,401	32,239
Red Rock		128,832	128,188	127,547	127,294	126,275	125,643	125,015	124,767	123,768	123,149	122,533	122,290	121,311	120,705	120,101	119,863	118,903	118,308	117,717
Aggregate	509,418	634,345	631,228	628,128	626,820	621,973	618,920	615,880	614,601	609,851	606,859	603,881	602,630	597,973	595,043	592,055	590,900	586,336	583,466	580,607

c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Hyder 2	12.541	12.143	11.851	11.707	11.527	11.415	11.268	11.120	10.938	10.820	10.669	10.517	10.333	10.210	10.055	9.900	9.715	9.587	9.429	9.271
Cotton Center	13.193	13.182	13.101	13.138	13.325	13.939	14.208	13.964	13.679	13.478	13.234	12.991	12.709	12.505	12.262	12.020	11.741	11.536	11.294	11.053
Paloma	11.889	11.972	11.987	12.123	12.418	13.156	13.542	13.395	13.203	13.095	12.943	12.789	12.593	12.478	12.320	12.161	11.961	11.839	11.676	11.512
Hyder	10.472	10.665	10.802	11.197	11.977	13.589	14.505	14.299	14.050	13.883	13.673	13.462	13.210	13.036	12.821	12.605	12.352	12.170	11.951	11.731
Chino Valley	12.970	12.825	12.850	13.052	13.541	14.552	15.110	14.897	14.683	14.467	14.250	14.031	13.812	13.591	13.368	13.145	12.920	12.694	12.467	12.239
Foothills	9.588	9.347	9.198	9.276	9.476	10.010	10.275	10.141	9.968	9.857	9.713	9.569	9.402	9.285	9.139	8.991	8.815	8.702	8.552	8.402
Gila Bend	9.975	9.692	9.375	9.164	9.032	8.956	8.851	8.746	8.613	8.534	8.427	8.320	8.186	8.104	7.995	7.887	7.753	7.668	7.558	7.448
Luke AFB	10.017	10.040	9.713	9.382	9.131	9.043	8.928	8.811	8.669	8.577	8.458	8.339	8.196	8.100	7.979	7.858	7.713	7.614	7.491	7.368
Desert Star	8.426	8.437	8.150	7.859	7.649	7.585	7.499	7.413	7.305	7.239	7.151	7.064	6.956	6.887	6.799	6.725	6.602	6.533	6.443	6.354
Red Rock		9.428	8.789	8.086	7.429	7.046	6.637	6.401	6.324	6.284	6.225	6.165	6.087	6.046	5.986	5.925	5.847	5.804	5.743	5.682
Aggregate	10.774	10.391	10.133	9.975	9.933	10.187	10.254	10.088	9.928	9.824	9.691	9.557	9.396	9.288	9.152	9.016	8.853	8.742	8.604	8.465

Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
14.00	Hyder 2	37.20%	36.90%	36.72%	36.53%	36.46%	36.17%	35.99%	35.81%	35.73%	35.45%	35.27%	35.10%	35.03%	34.75%	34.57%	34.40%	34.33%	34.06%	33.89%	33.72%
17.00	Cotton Center	30.51%	30.36%	30.30%	30.24%	30.27%	30.12%	30.06%	30.00%	30.03%	29.88%	29.82%	29.76%	29.79%	29.64%	29.58%	29.52%	29.55%	29.40%	29.34%	29.29%
17.00	Paloma	27.35%	27.07%	26.88%	26.70%	26.60%	26.32%	26.14%	25.96%	25.86%	25.59%	25.41%	25.24%	25.14%	24.89%	24.71%	24.54%	24.45%	24.20%	24.03%	23.86%
16.00	Hyder	28.67%	28.44%	28.30%	28.16%	28.10%	27.88%	27.74%	27.60%	27.54%	27.32%	27.19%	27.05%	26.99%	26.78%	26.65%	26.51%	26.46%	26.25%	26.12%	25.99%
19.00	Chino Valley	28.54%	28.40%	28.26%	28.12%	27.97%	27.83%	27.70%	27.56%	27.42%	27.28%	27.15%	27.01%	26.88%	26.74%	26.61%	26.47%	26.34%	26.21%	26.08%	25.95%
35.00	Foothills	36.29%	36.00%	35.82%	35.64%	35.57%	35.28%	35.11%	34.93%	34.87%	34.58%	34.41%	34.24%	34.17%	33.90%	33.73%	33.56%	33.50%	33.22%	33.06%	32.89%
32.00	Gila Bend	38.61%	38.29%	38.10%	37.91%	37.84%	37.53%	37.35%	37.16%	37.09%	36.79%	36.60%	36.42%	36.35%	36.06%	35.88%	35.70%	35.63%	35.34%	35.17%	34.99%
10.00	Luke AFB	39.82%	39.50%	39.30%	39.11%	39.03%	38.72%	38.52%	38.33%	38.25%	37.95%	37.76%	37.57%	37.49%	37.20%	37.01%	36.82%	36.75%	36.46%	36.28%	36.09%
10.00	Desert Star	40.60%	40.28%	40.08%	39.88%	39.79%	39.48%	39.28%	39.08%	39.00%	38.69%	38.50%	38.31%	38.23%	37.93%	37.74%	37.47%	37.47%	37.17%	36.99%	36.80%
40.00	Red Rock	0.00%	36.77%	36.58%	36.40%	36.33%	36.04%	35.86%	35.68%	35.61%	35.32%	35.15%	34.97%	34.90%	34.62%	34.45%	34.28%	34.21%	33.93%	33.76%	33.60%
210.00	**Aggregate**	27.69%	34.48%	34.31%	34.14%	34.07%	33.81%	33.64%	33.48%	33.41%	33.15%	32.99%	32.83%	32.76%	32.51%	32.35%	32.18%	32.12%	31.87%	31.72%	31.56%

APS utility owned facilities vintage analysis c/kWh



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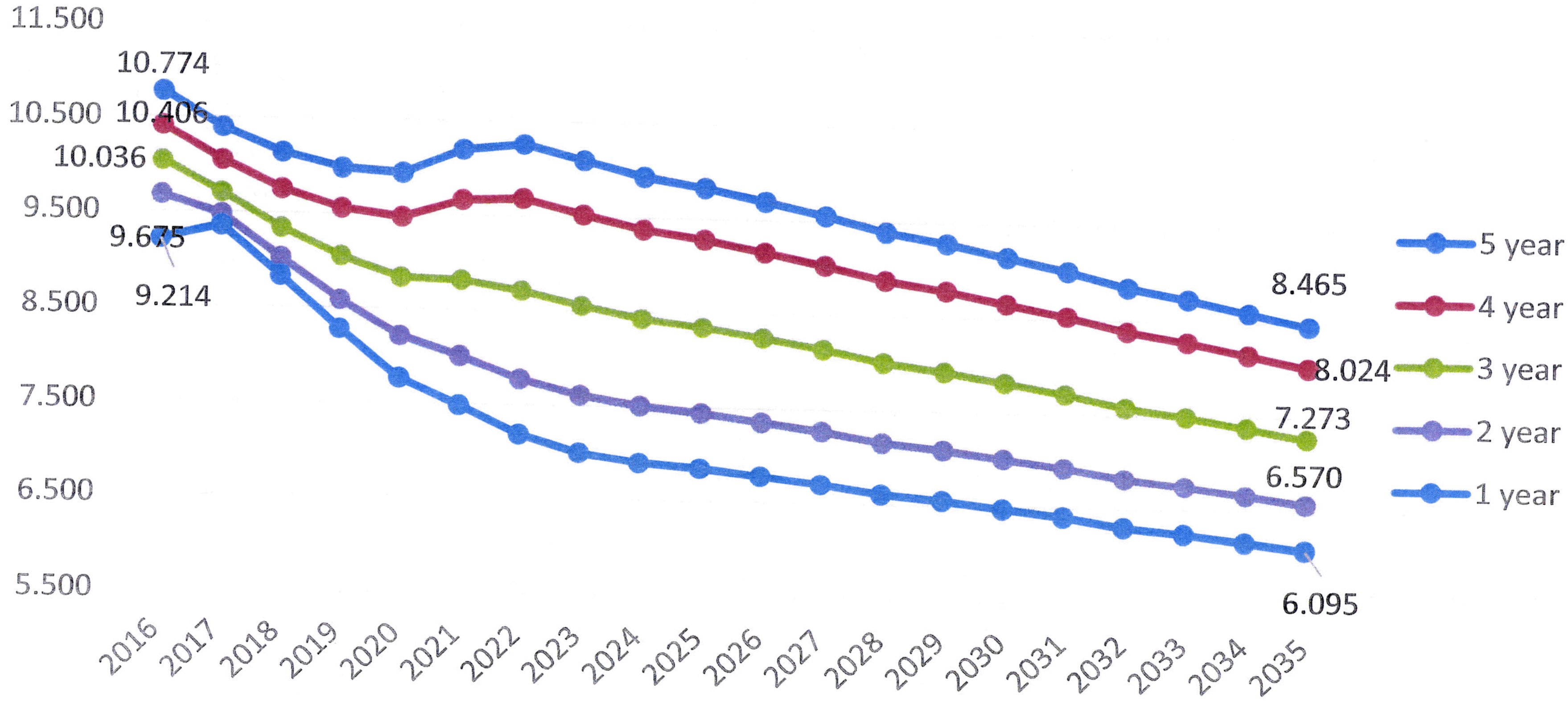
APS utility owned facilities vintage analysis c/kWh



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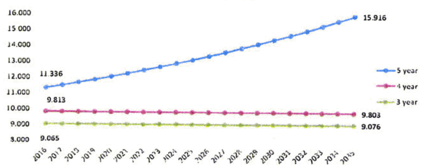
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Start Date	Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Aggregate	21,031,167	21,157,030	21,345,173	21,540,813	21,801,516	21,955,948	22,175,761	22,404,478	22,701,015	22,886,991
	Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Aggregate	185,529	183,825	182,597	181,375	180,617	178,953	177,751	176,556	175,812	174,186
Escalator	c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Aggregate	11.336	11.509	11.690	11.876	12.071	12.269	12.476	12.690	12.912	13.139
Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
74.50	Aggregate	28.43%	28.17%	27.98%	27.79%	27.68%	27.42%	27.24%	27.05%	26.94%	26.69%

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Start Date	Revenue Req ($)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	23,142,359	23,407,033	23,744,327	23,965,613	24,260,142	24,565,132	24,947,325	25,207,453	25,545,799	25,896,148
	Output (MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	173,010	171,841	171,111	169,521	168,371	167,226	166,510	164,956	163,830	162,710
Escalator	c/kWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	13.376	13.621	13.877	14.137	14.409	14.690	14.982	15.281	15.593	15.916
Capacity (MW)	Load Factor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
74.50	Aggregate	26.51%	26.33%	26.22%	25.98%	25.80%	25.62%	25.51%	25.28%	25.10%	24.93%

APS PPA vintage analysis c/kWh



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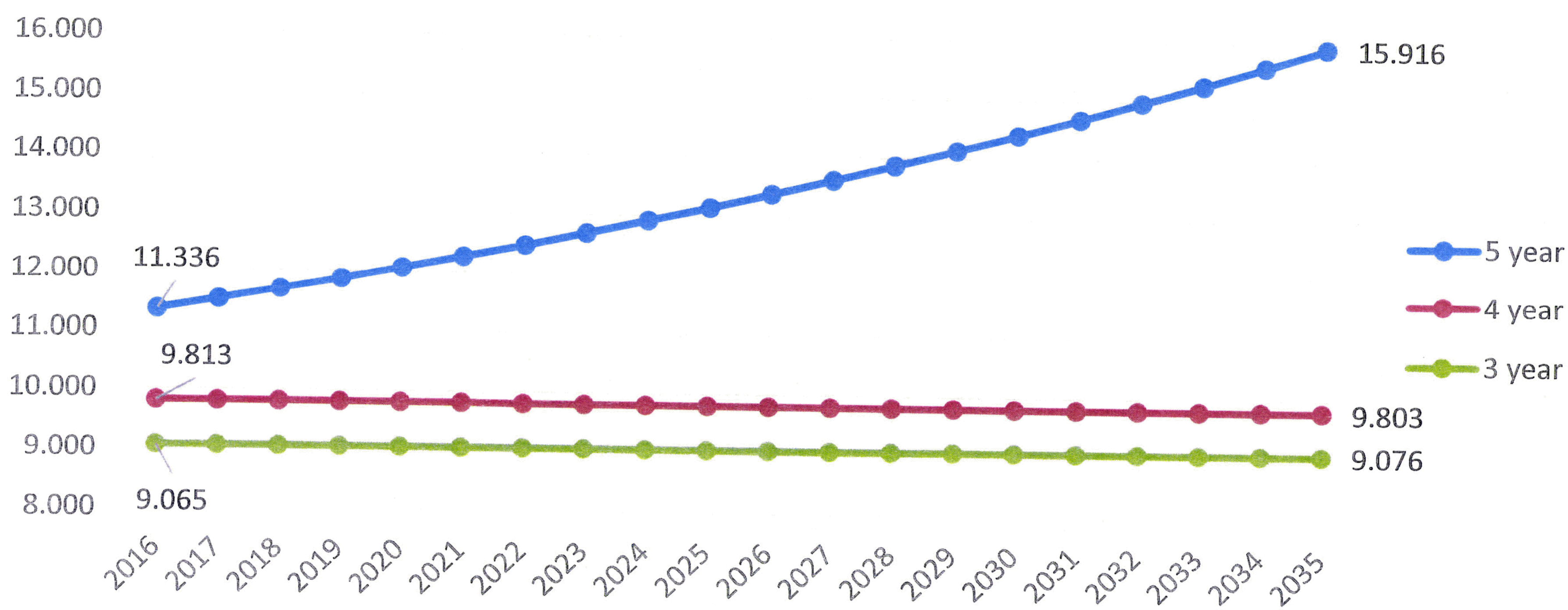
APS PPA vintage analysis c/kWh



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Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	14,163,096	13,691,789	12,989,287	12,565,939	12,225,173	11,883,965	11,542,299	11,200,160	10,857,533	10,514,401
Aggregate PPA	47,347,809	47,111,070	46,875,515	46,641,137	46,407,932	46,175,892	45,945,013	45,715,288	45,486,711	45,259,278
Combined	$ 61,510,905	$ 60,802,859	$ 59,864,802	$ 59,207,076	$ 58,633,105	$ 58,059,857	$ 57,487,312	$ 56,915,448	$ 56,344,244	$ 55,773,678

Revenue Req ($)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	10,170,747	9,826,554	9,481,805	9,136,482	8,790,565	8,444,037	8,096,877	7,749,064	7,400,579	7,051,400
Aggregate PPA	45,032,981	44,807,816	44,583,777	44,360,858	44,139,054	43,499,743	43,143,403	19,472,312	17,520,004	7,064,881
Combined	$ 55,203,728	$ 54,634,370	$ 54,065,582	$ 53,497,340	$ 52,929,619	$ 51,943,780	$ 51,240,280	$ 27,221,376	$ 24,920,583	$ 14,116,281

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	106,668	106,135	105,604	105,076	104,551	104,028	103,508	102,990	102,475	101,963
Aggregate PPA	445,933	443,703	441,485	439,277	437,081	434,895	432,721	430,557	428,405	426,263
Combined	552,601	549,838	547,089	544,353	541,632	538,923	536,229	533,548	530,880	528,226

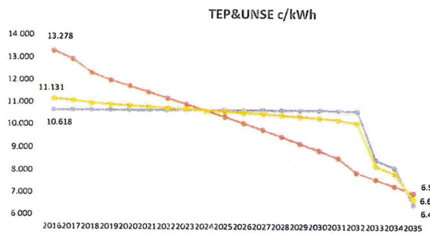
Output (MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	101,453	100,946	100,441	99,939	99,439	98,942	102,806	102,292	101,780	101,271
Aggregate PPA	424,131	422,011	419,900	417,801	415,712	410,662	407,623	230,297	216,136	109,500
Combined	525,584	522,957	520,342	517,740	515,151	509,604	510,429	332,589	317,916	210,771

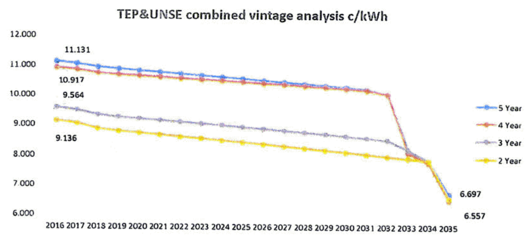
c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	13.278	12.900	12.300	11.959	11.693	11.424	11.151	10.875	10.595	10.312
Aggregate PPA	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618
Combined	11.131	11.058	10.942	10.877	10.825	10.773	10.721	10.667	10.613	10.559

c/kWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	10.025	9.734	9.440	9.142	8.840	8.534	7.876	7.575	7.271	6.963
Aggregate PPA	10.618	10.618	10.618	10.618	10.618	10.593	10.584	8.455	8.106	6.452
Combined	10.503	10.447	10.390	10.333	10.275	10.193	10.039	8.185	7.839	6.697

Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
39.17	Aggregate Utility Owned	31.09%	30.93%	30.78%	30.62%	30.47%	30.32%	30.17%	30.02%	29.86%	29.72%
162.48	Aggregate PPA	31.33%	31.17%	31.02%	30.86%	30.71%	30.55%	30.40%	30.25%	30.10%	29.95%
201.65	**Combined**	31.28%	31.13%	30.97%	30.82%	30.66%	30.51%	30.36%	30.20%	30.05%	29.90%

Load Factor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	29.57%	29.42%	29.27%	29.13%	28.98%	28.84%	29.96%	29.81%	29.66%	29.51%
Aggregate PPA	29.80%	29.65%	29.50%	29.35%	29.21%	28.85%	28.64%	16.18%	15.19%	7.69%
Combined	29.75%	29.60%	29.46%	29.31%	29.16%	28.85%	28.90%	18.83%	18.00%	11.93%





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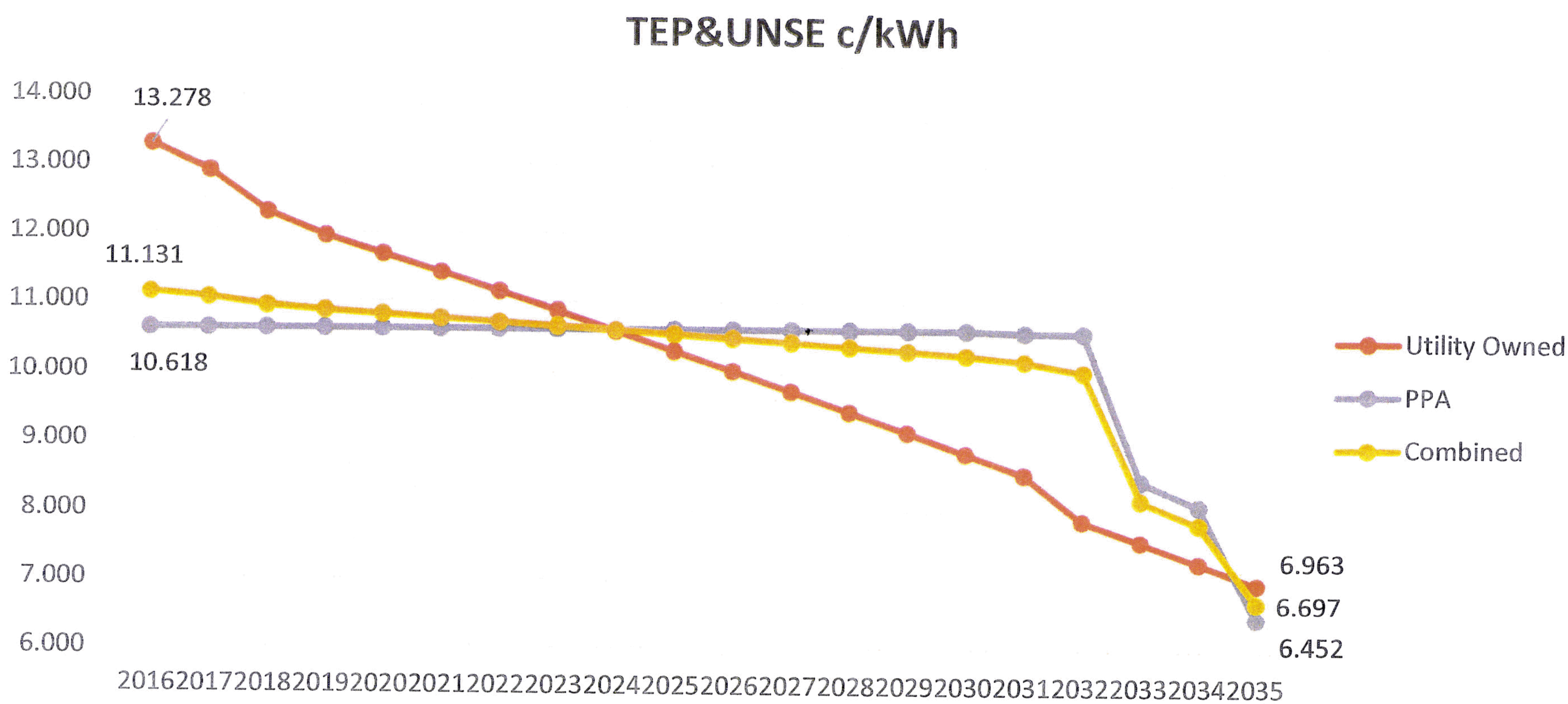

TEP&UNSE c/kWh
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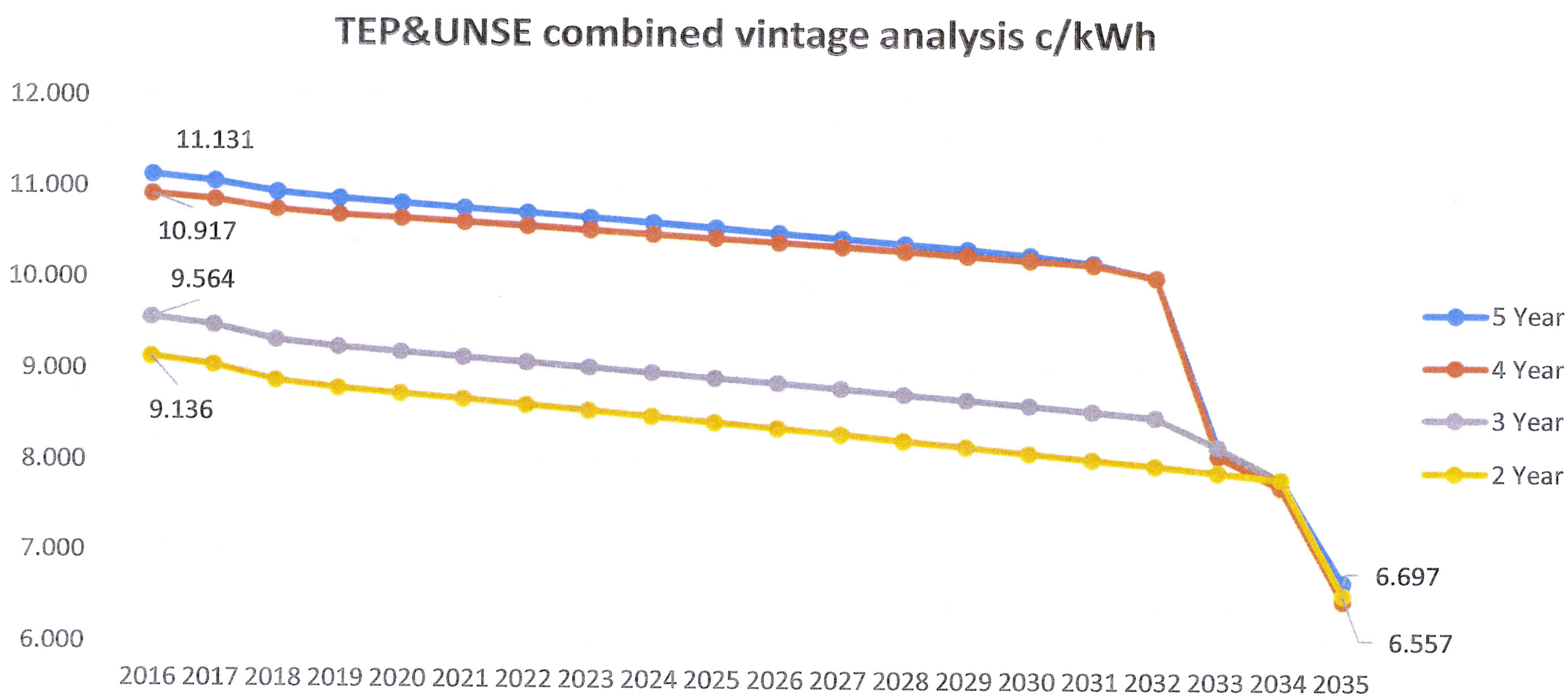
2016201720182019202020212022202320242025202620272028202920302031203220332034 2035
Utility Owned
PPA
Combined

9



TEP&UNSE combined vintage analysis c/kWh
12.000
11.000
10.000
9.000
8.000
7.000
6.000
11.131
10.917
9.564
9.136
6.697
6.557
2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
5 Year
4 Year
3 Year
2 Year

[redacted]

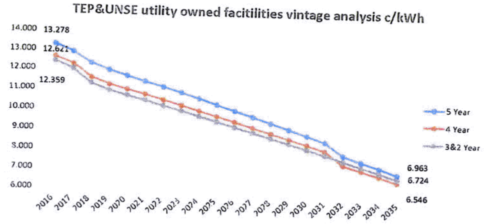
COD	Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
12/9/2014	Fort Huahuca	$ 3,362,371	$ 3,247,558	$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242	$ 2,368,586	$ 2,289,823	$ 2,210,951	$ 2,131,965	$ 2,052,863	$ 1,973,641	$ 1,894,294	$ 1,814,818	$ 1,735,210	$ 1,655,465
3/1/2014	Rio Rico	1,569,739	1,505,232	1,440,663	1,390,151	1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330	1,133,426	1,096,439	1,059,366	1,022,205	984,952	947,605	910,160	872,615	834,966	797,210
12/28/2012	Prairie Fire	1,552,322	1,495,919	1,457,584	1,419,202	1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830	1,149,072	1,110,253	1,071,370	1,032,423	993,408	954,324	915,169	875,939	836,634	797,250
11/4/2011	La Senita	483,630	471,113	458,574	446,013	433,427	420,817	408,182	395,521	382,832	370,116	357,370	344,595	331,789	318,951	306,081	293,176	280,236	267,260	254,247	241,195
12/29/2011	UASTP II	1,517,550	1,478,457	1,439,316	1,400,126	1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846	1,124,259	1,084,607	1,044,890	1,005,103	965,246	925,316	885,311	845,227	805,064	764,818
12/31/2010	UASTP I	636,499	619,798	603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410	468,503	451,569	434,607	417,616	400,596	383,545	366,462	349,347	332,198	315,015
12/30/2010	Springerville 1.8	636,499	619,798	603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410	468,503	451,569	434,607	417,616	400,596	383,545	366,462	349,347	332,198	315,015
12/12/2014	White Mtn	4,404,485	4,253,913	3,962,039	3,820,636	3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216	3,101,027	2,997,699	2,894,225	2,790,601	2,686,823	2,582,885	2,478,782	2,374,509	2,270,061	2,165,431
	Aggregate	$ 14,163,096	$ 13,691,789	$ 12,989,287	$ 12,565,939	$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401	$ 10,170,747	$ 9,826,554	$ 9,481,805	$ 9,136,482	$ 8,790,565	$ 8,444,037	$ 8,096,877	$ 7,749,064	$ 7,400,579	$ 7,051,400

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Fort Huahuca	38,250	38,058	37,868	37,679	37,490	37,303	37,116	36,931	36,746	36,562	36,380	36,198	36,017	35,837	35,657	35,479	35,302	35,125	34,950	34,775
Rio Rico	15,611	15,533	15,455	15,378	15,301	15,224	15,148	15,072	14,997	14,922	14,848	14,773	14,699	14,626	14,553	14,480	14,408	14,336	14,264	14,193
Prairie Fire	10,733	10,679	10,626	10,572	10,520	10,467	10,415	10,363	10,311	10,259	10,208	10,157	10,106	10,056	10,005	9,955	14,264	14,193	14,122	14,051
La Senita	2,489	2,477	2,465	2,452	2,440	2,428	2,416	2,404	2,392	2,380	2,368	2,356	2,344	2,332	2,321	2,309	2,298	2,286	2,275	2,263
UASTP II	10,679	10,626	10,572	10,520	10,467	10,415	10,363	10,311	10,259	10,208	10,157	10,106	10,056	10,005	9,955	9,905	9,856	9,807	9,758	9,709
UASTP I	3,400	3,383	3,366	3,349	3,333	3,316	3,299	3,283	3,267	3,250	3,234	3,218	3,202	3,186	3,170	3,154	3,138	3,122	3,107	3,091
Springerville 1.8	3,825	3,806	3,787	3,768	3,749	3,731	3,712	3,693	3,675	3,656	3,638	3,620	3,602	3,584	3,566	3,548	3,530	3,513	3,495	3,478
White Mtn	21,682	21,573	21,465	21,358	21,251	21,145	21,039	20,934	20,829	20,725	20,622	20,518	20,416	20,314	20,212	20,111	20,011	19,911	19,811	19,712
Aggregate	106,668	106,135	105,604	105,076	104,551	104,028	103,508	102,990	102,475	101,963	101,453	100,946	100,441	99,939	99,439	98,942	102,806	102,292	101,780	101,271

c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Fort Huahuca	8.791	8.533	7.988	7.742	7.573	7.401	7.228	7.052	6.874	6.693	6.511	6.326	6.139	5.949	5.757	5.563	5.366	5.167	4.965	4.761
Rio Rico	10.056	9.691	9.322	9.040	8.847	8.652	8.454	8.253	8.049	7.843	7.634	7.422	7.207	6.989	6.768	6.544	6.317	6.087	5.854	5.617
Prairie Fire	14.464	14.008	13.718	13.424	13.126	12.824	12.518	12.209	11.896	11.578	11.257	10.931	10.601	10.267	9.929	9.586	6.416	6.172	5.924	5.674
La Senita	19.428	19.020	18.607	18.188	17.764	17.334	16.898	16.456	16.008	15.554	15.094	14.627	14.155	13.675	13.189	12.697	12.197	11.691	11.178	10.657
UASTP II	14.211	13.914	13.614	13.310	13.002	12.690	12.374	12.054	11.730	11.401	11.069	10.732	10.391	10.046	9.696	9.341	8.982	8.619	8.251	7.878
UASTP I	18.720	18.320	17.915	17.505	17.090	16.670	16.245	15.813	15.377	14.935	14.487	14.034	13.574	13.109	12.638	12.161	11.678	11.188	10.693	10.190
Springerville 1.8	16.640	16.284	15.925	15.560	15.192	14.818	14.440	14.056	13.668	13.275	12.877	12.474	12.066	11.653	11.234	10.810	10.380	9.945	9.504	9.058
White Mtn	20.314	19.719	18.458	17.889	17.496	17.099	16.697	16.290	15.878	15.461	15.038	14.610	14.176	13.737	13.293	12.843	12.387	11.926	11.459	10.985
Aggregate	13.278	12.900	12.300	11.959	11.693	11.424	11.151	10.875	10.595	10.312	10.025	9.734	9.440	9.142	8.840	8.534	7.876	7.575	7.271	6.963

Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
13.60	Fort Huahuca	32.11%	31.95%	31.79%	31.63%	31.47%	31.31%	31.15%	31.00%	30.84%	30.69%	30.54%	30.38%	30.23%	30.08%	29.93%	29.78%	29.63%	29.48%	29.34%	29.19%
5.76	Rio Rico	30.94%	30.78%	30.63%	30.48%	30.32%	30.17%	30.02%	29.87%	29.72%	29.57%	29.43%	29.28%	29.13%	28.99%	28.84%	28.70%	28.55%	28.41%	28.27%	28.13%
4.00	Prairie Fire	30.63%	30.48%	30.32%	30.17%	30.02%	29.87%	29.72%	29.57%	29.43%	29.28%	29.13%	28.99%	28.84%	28.70%	28.55%	28.41%	40.71%	40.50%	40.30%	40.10%
1.00	La Senita	28.42%	28.28%	28.13%	27.99%	27.85%	27.71%	27.58%	27.44%	27.30%	27.16%	27.03%	26.89%	26.76%	26.62%	26.49%	26.36%	26.23%	26.10%	25.97%	25.84%
4.00	UASTP II	30.48%	30.32%	30.17%	30.02%	29.87%	29.72%	29.57%	29.43%	29.28%	29.13%	28.99%	28.84%	28.70%	28.55%	28.41%	28.27%	28.13%	27.99%	27.85%	27.71%
1.28	UASTP I	30.32%	30.17%	30.02%	29.87%	29.72%	29.57%	29.43%	29.28%	29.13%	28.99%	28.84%	28.70%	28.55%	28.41%	28.27%	28.13%	27.99%	27.85%	27.71%	27.57%
1.28	Springerville 1.8	34.11%	33.94%	33.77%	33.61%	33.44%	33.27%	33.10%	32.94%	32.77%	32.61%	32.45%	32.28%	32.12%	31.96%	31.80%	31.64%	31.49%	31.33%	31.17%	31.02%
8.25	White Mtn	30.00%	29.85%	29.70%	29.55%	29.41%	29.26%	29.11%	28.97%	28.82%	28.68%	28.53%	28.39%	28.25%	28.11%	27.97%	27.83%	27.69%	27.55%	27.41%	27.28%
39.17	**Aggregate**	31.09%	30.93%	30.78%	30.62%	30.47%	30.32%	30.17%	30.02%	29.86%	29.72%	29.57%	29.42%	29.27%	29.13%	28.98%	28.84%	29.96%	29.81%	29.66%	29.51%

TEP&UNSE utility owned facitilities vintage analysis c/kWh



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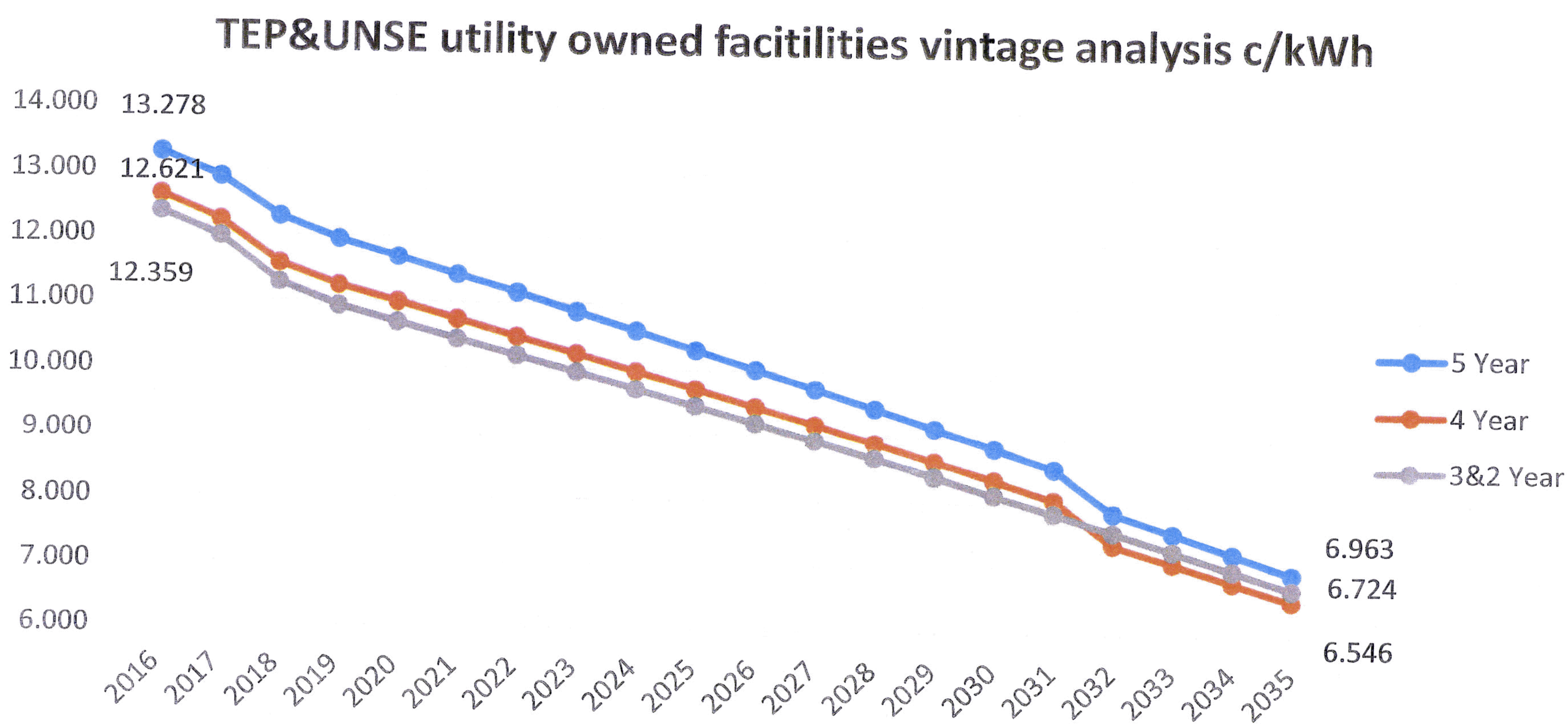


TEP&UNSE utility owned facitilities vintage analysis c/kWh
14.000
13.000
12.000
11.000
10.000
9.000
8.000
7.000
6.000
13.278
12.621
12.359
6.963
6.724
6.546
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
5 Year
4 Year
3&2 Year

[redacted]

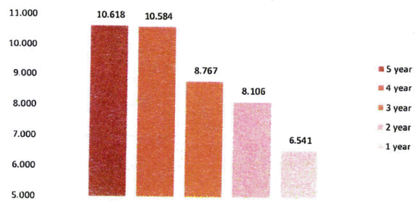
COD	Cost ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	47,347,809	47,111,070	46,875,515	46,641,137	46,407,932	46,175,892	45,945,013	45,715,288	45,486,711	45,259,278	45,032,981	44,807,816	44,583,777	44,360,858	44,139,054	43,499,743	43,143,403	19,472,312	17,520,004	7,064,881

	Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	445,933	443,703	441,485	439,277	437,081	434,895	432,721	430,557	428,405	426,263	424,131	422,011	419,900	417,801	415,712	410,662	407,623	230,297	216,136	109,500

	c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.593	10.584	8.455	8.106	6.452

AC Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
162.48	**Aggregate**	31.33%	31.17%	31.02%	30.86%	30.71%	30.55%	30.40%	30.25%	30.10%	29.95%	29.80%	29.65%	29.50%	29.35%	29.21%	28.85%	28.64%	16.18%	15.19%	7.69%

TEP&UNSE PPA vintage analysis c/kWh



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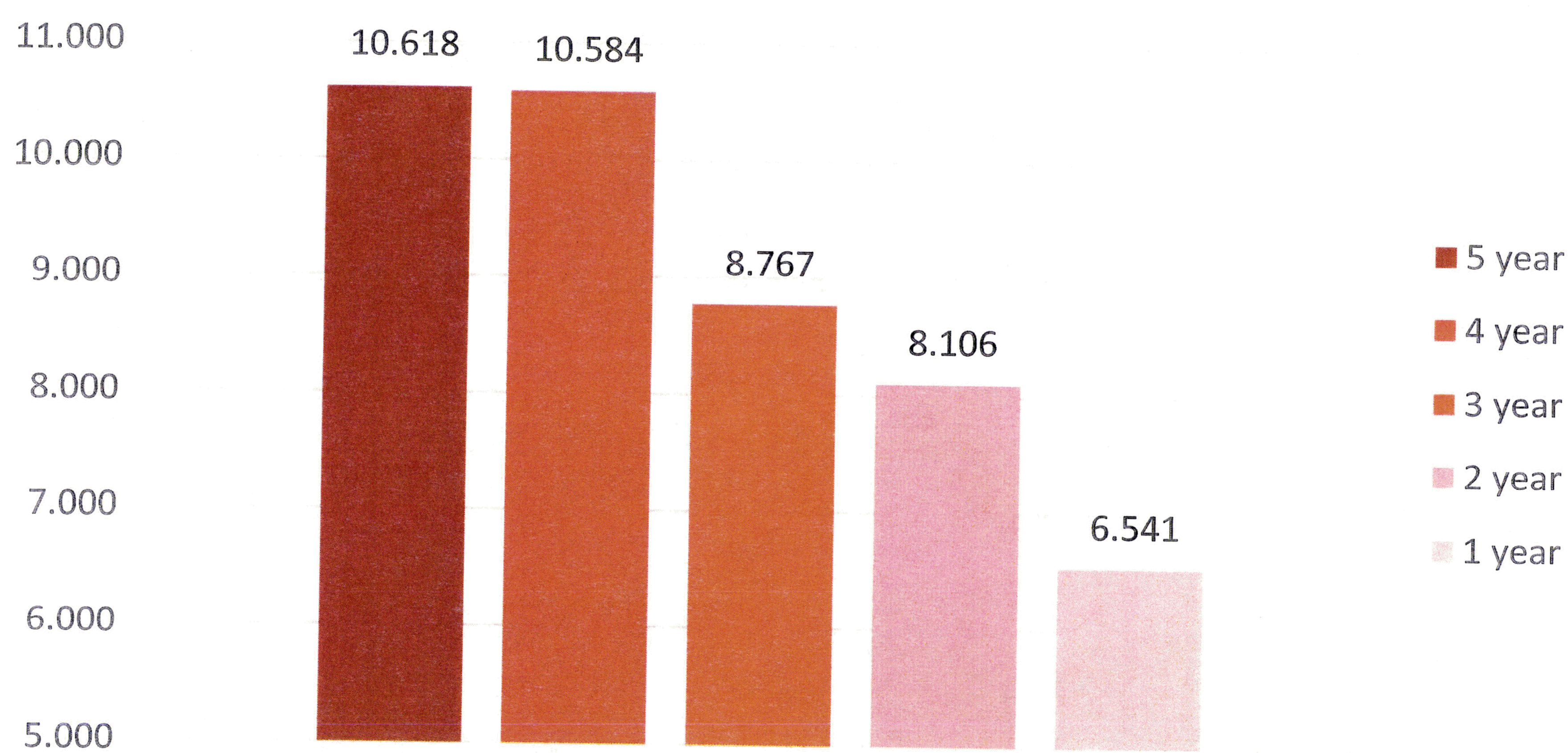
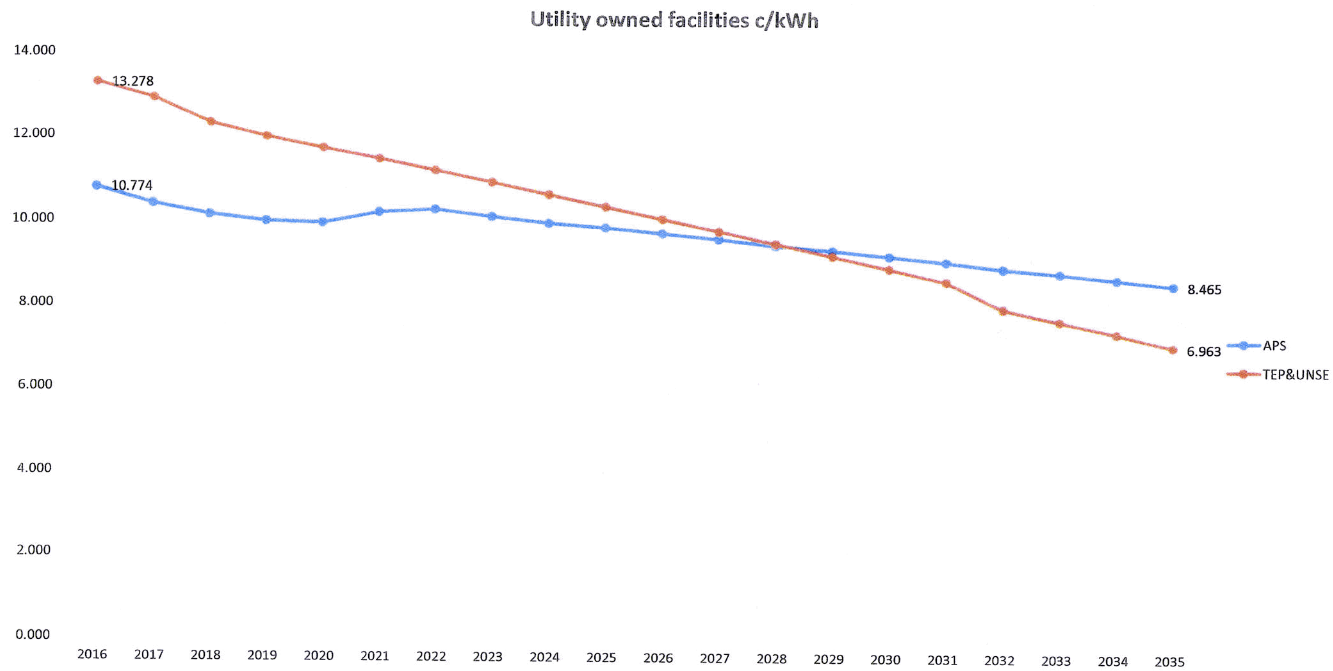
TEP&UNSE PPA vintage analysis c/kWh

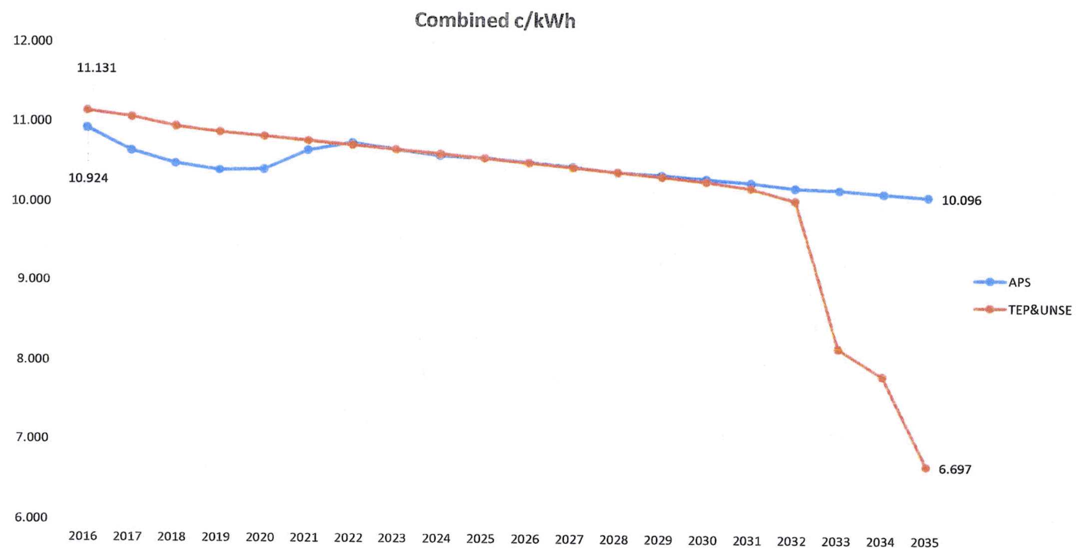


c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
APS	10.774	10.391	10.133	9.975	9.933	10.187	10.254	10.088	9.928	9.824	9.691	9.557	9.396	9.288	9.152	9.016	8.853	8.742	8.604	8.465
TEP&UNSE	13.278	12.900	12.300	11.959	11.693	11.424	11.151	10.875	10.595	10.312	10.025	9.734	9.440	9.142	8.840	8.534	7.876	7.575	7.271	6.963



c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
APS	10.924	10.642	10.482	10.401	10.411	10.653	10.750	10.668	10.592	10.561	10.508	10.457	10.387	10.359	10.311	10.266	[illegible]	[illegible]	[illegible]	10.096
TEP&UNSE	11.131	11.058	10.942	10.877	10.825	10.773	10.721	10.667	10.613	10.559	10.503	10.447	10.390	10.333	10.275	[illegible]	[illegible]	[illegible]	[illegible]	6.697

2035
7,051,400
7,064,881
14,116,281



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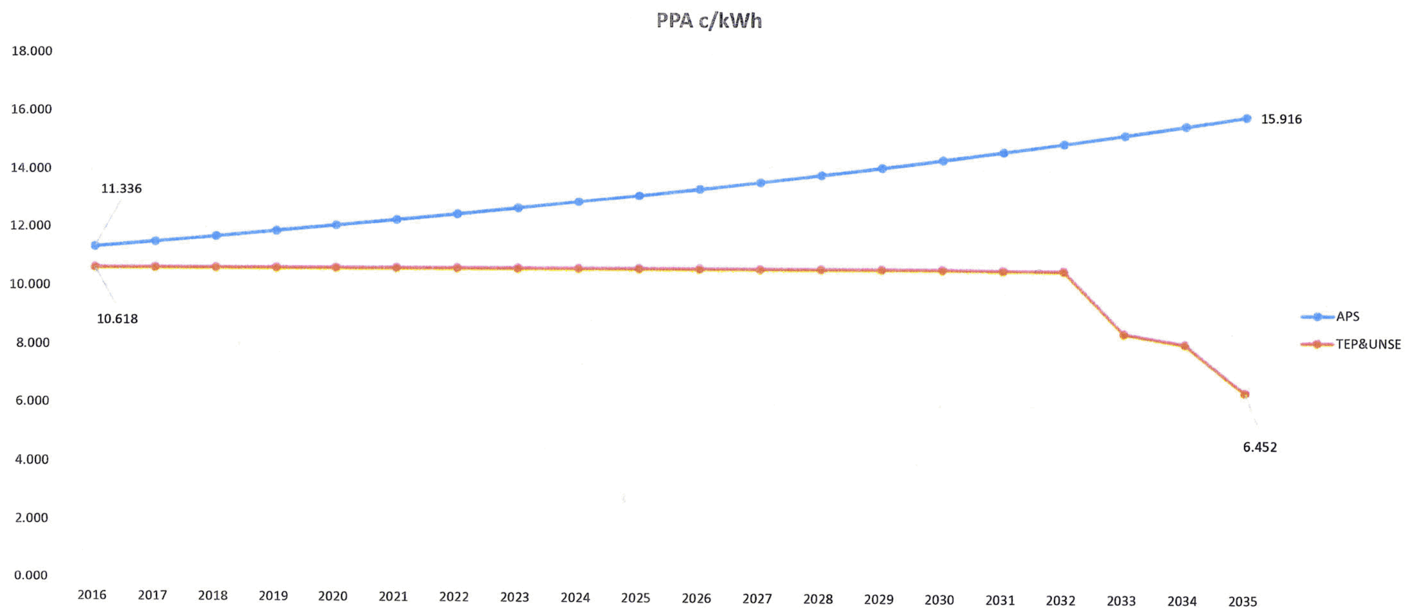
c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
APS	11.336	11.509	11.690	11.876	12.071	12.269	12.476	12.690	12.912	13.139	13.376	13.621	13.877	14.137	14.409	14.690	14.982	15.281	15.593	15.916
TEP&UNSE	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.618	10.593	10.584	8.455	8.106	6.452



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Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	14,163,096	13,691,789	12,989,287	12,565,939	12,225,173	11,883,965	11,542,299	11,200,160	10,857,533	10,514,401
Aggregate PPA	44,775,747	44,551,868	44,329,109	44,107,463	43,886,926	43,667,491	43,449,154	43,231,908	43,015,749	42,800,670
Combined	$ 58,938,843	$ 58,243,657	$ 57,318,396	$ 56,673,402	$ 56,112,099	$ 55,551,456	$ 54,991,453	$ 54,432,068	$ 53,873,281	$ 53,315,070

Revenue Req ($)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	10,170,747	9,826,554	9,481,805	9,136,482	8,790,565	8,444,037	8,096,877	7,749,064	7,400,579	7,051,400
Aggregate PPA	42,586,667	42,373,733	42,161,865	41,951,055	41,741,300	41,434,228	41,194,433	18,982,283	17,382,146	7,064,881
Combined	$ 52,757,413	$ 52,200,287	$ 51,643,670	$ 51,087,537	$ 50,531,865	$ 49,878,265	$ 49,291,309	$ 26,731,348	$ 24,782,725	$ 14,116,281

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	66,592	66,259	65,928	65,598	65,270	64,944	64,619	64,296	63,975	63,655
Aggregate PPA	426,210	424,079	421,959	419,849	417,750	415,661	413,583	411,515	409,457	407,410
Combined	492,803	490,339	487,887	485,448	483,020	480,605	478,202	475,811	473,432	471,065

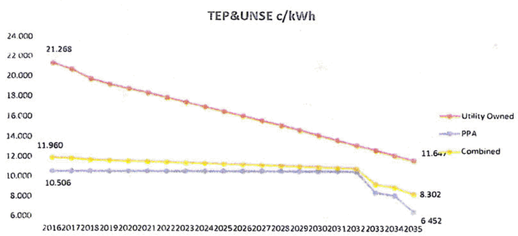
Output (MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	63,337	63,020	62,705	62,391	62,079	61,769	61,460	61,153	60,847	60,543
Aggregate PPA	405,373	403,346	401,329	399,323	397,326	394,641	392,437	226,502	214,812	109,500
Combined	468,710	466,366	464,034	461,714	459,405	456,410	453,897	287,655	275,659	170,042

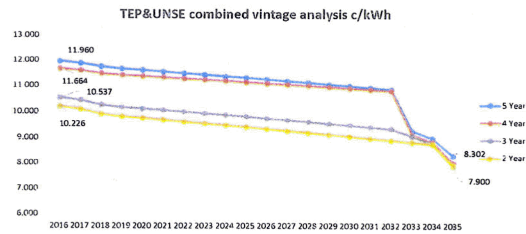
c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Aggregate Utility Owned	21.268	20.664	19.702	19.156	18.730	18.299	17.862	17.420	16.972	16.518
Aggregate PPA	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506
Combined	11.960	11.878	11.748	11.674	11.617	11.559	11.500	11.440	11.379	11.318

c/kWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Aggregate Utility Owned	16.058	15.593	15.121	14.644	14.160	13.670	13.174	12.672	12.163	11.647
Aggregate PPA	10.506	10.506	10.506	10.506	10.506	10.499	10.497	8.381	8.092	6.452
Combined	11.256	11.193	11.129	11.065	10.999	10.928	10.860	9.293	8.990	8.302

Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
39.17	Aggregate Utility Owned	19.41%	19.31%	19.21%	19.12%	19.02%	18.93%	18.83%	18.74%	18.64%	18.55%
162.48	Aggregate PPA	29.94%	29.79%	29.65%	29.50%	29.35%	29.20%	29.06%	28.91%	28.77%	28.62%
201.65	Combined	27.90%	27.76%	27.62%	27.48%	27.34%	27.21%	27.07%	26.94%	26.80%	26.67%

Capacity (MW)	Load Factor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
39.17	Aggregate Utility Owned	18.46%	18.37%	18.27%	18.18%	18.09%	18.00%	17.91%	17.82%	17.73%	17.64%
162.48	Aggregate PPA	28.48%	28.34%	28.20%	28.06%	27.92%	27.73%	27.57%	15.91%	15.09%	7.69%
201.65	Combined	26.53%	26.40%	26.27%	26.14%	26.01%	25.84%	25.70%	16.28%	15.61%	9.63%





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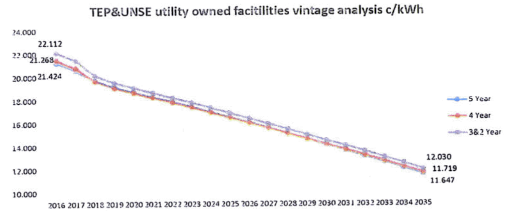
COD	Revenue Req ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
12/9/2014	Fort Huahuca	$ 3,362,371	$ 3,247,558	$ 3,024,956	$ 2,917,140	$ 2,839,052	$ 2,760,876	$ 2,682,610	$ 2,604,251	$ 2,525,797	$ 2,447,242	$ 2,368,586	$ 2,289,823	$ 2,210,951	$ 2,131,965	$ 2,052,863	$ 1,973,641	$ 1,894,294	$ 1,814,818	$ 1,735,210	$ 1,655,465
3/1/2014	Rio Rico	1,569,739	1,505,232	1,440,663	1,390,151	1,353,693	1,317,166	1,280,569	1,243,899	1,207,153	1,170,330	1,133,426	1,096,439	1,059,366	1,022,205	984,952	947,605	910,160	872,615	834,966	797,210
12/28/2012	Prairie Fire	1,552,322	1,495,919	1,457,584	1,419,202	1,380,771	1,342,290	1,303,758	1,265,171	1,226,529	1,187,830	1,149,072	1,110,253	1,071,370	1,032,423	993,408	954,324	915,169	875,939	836,634	797,250
11/4/2011	La Senita	483,630	471,113	458,574	446,013	433,427	420,817	408,182	395,521	382,832	370,116	357,370	344,595	331,789	318,951	306,081	293,176	280,236	267,260	254,247	241,195
12/29/2011	UASTP II	1,517,550	1,478,457	1,439,316	1,400,126	1,360,885	1,321,590	1,282,241	1,242,835	1,203,370	1,163,846	1,124,259	1,084,607	1,044,890	1,005,103	965,246	925,316	885,311	845,227	805,064	764,818
12/31/2010	UASTP I	636,499	619,798	603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410	468,503	451,569	434,607	417,616	400,596	383,545	366,462	349,347	332,198	315,015
12/30/2010	Springerville 1.8	636,499	619,798	603,077	586,335	569,572	552,787	535,979	519,148	502,292	485,410	468,503	451,569	434,607	417,616	400,596	383,545	366,462	349,347	332,198	315,015
12/12/2014	White Mtn	4,404,485	4,253,913	3,962,039	3,820,636	3,718,201	3,615,651	3,512,981	3,410,188	3,307,268	3,204,216	3,101,027	2,997,699	2,894,225	2,790,601	2,686,823	2,582,885	2,478,782	2,374,509	2,270,061	2,165,431
	Aggregate	$ 14,163,096	$ 13,691,789	$ 12,989,287	$ 12,565,939	$ 12,225,173	$ 11,883,965	$ 11,542,299	$ 11,200,160	$ 10,857,533	$ 10,514,401	$ 10,170,747	$ 9,826,554	$ 9,481,805	$ 9,136,482	$ 8,790,565	$ 8,444,037	$ 8,096,877	$ 7,749,064	$ 7,400,579	$ 7,051,400

Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Fort Huahuca	29,152	29,006	28,861	28,717	28,573	28,430	28,288	28,147	28,006	27,866	27,726	27,588	27,450	27,313	27,176	27,040	26,905	26,771	26,637	26,503
Rio Rico	10,312	10,260	10,209	10,158	10,107	10,056	10,006	9,956	9,906	9,857	9,808	9,758	9,710	9,661	9,613	9,565	9,517	9,469	9,422	9,375
Prairie Fire	8,601	8,558	8,516	8,473	8,431	8,388	8,347	8,305	8,263	8,222	8,181	8,140	8,099	8,059	8,018	7,978	7,938	7,899	7,859	7,820
La Senita	2,086	2,075	2,065	2,055	2,044	2,034	2,024	2,014	2,004	1,994	1,984	1,974	1,964	1,954	1,944	1,935	1,925	1,915	1,906	1,896
UASTP II	7,619	7,581	7,543	7,505	7,468	7,430	7,393	7,356	7,320	7,283	7,247	7,210	7,174	7,138	7,103	7,067	7,032	6,997	6,962	6,927
UASTP I	2,594	2,581	2,568	2,555	2,542	2,530	2,517	2,504	2,492	2,479	2,467	2,455	2,442	2,430	2,418	2,406	2,394	2,382	2,370	2,358
Springerville 1.8	3,468	3,451	3,434	3,417	3,399	3,382	3,366	3,349	3,332	3,315	3,299	3,282	3,266	3,250	3,233	3,217	3,201	3,185	3,169	3,153
White Mtn	2,761	2,747	2,733	2,719	2,706	2,692	2,679	2,665	2,652	2,639	2,626	2,612	2,599	2,586	2,573	2,561	2,548	2,535	2,522	2,510
Aggregate	66,592	66,259	65,928	65,598	65,270	64,944	64,619	64,296	63,975	63,655	63,337	63,020	62,705	62,391	62,079	61,769	61,460	61,153	60,847	60,543

c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Fort Huahuca	11.534	11.196	10.481	10.158	9.936	9.711	9.483	9.252	9.019	8.782	8.543	8.300	8.054	7.806	7.554	7.299	7.041	6.779	6.514	6.246
Rio Rico	15.223	14.671	14.112	13.686	13.394	13.098	12.798	12.494	12.186	11.873	11.557	11.236	10.910	10.581	10.246	9.907	9.564	9.215	8.862	8.504
Prairie Fire	18.047	17.479	17.117	16.750	16.378	16.002	15.620	15.234	14.843	14.447	14.046	13.640	13.228	12.811	12.389	11.961	11.528	11.090	10.645	10.195
La Senita	23.187	22.700	22.207	21.708	21.201	20.688	20.167	19.640	19.105	18.564	18.014	17.458	16.893	16.321	15.741	15.154	14.558	13.953	13.341	12.719
UASTP II	19.918	19.502	19.081	18.655	18.223	17.786	17.343	16.895	16.441	15.980	15.514	15.043	14.564	14.080	13.590	13.093	12.590	12.080	11.564	11.041
UASTP I	24.539	24.015	23.485	22.948	22.404	21.853	21.295	20.730	20.157	19.578	18.991	18.396	17.794	17.185	16.567	15.942	15.308	14.667	14.017	13.358
Springerville 1.8	18.352	17.960	17.563	17.162	16.755	16.343	15.925	15.503	15.075	14.641	14.202	13.758	13.308	12.852	12.390	11.922	11.448	10.968	10.482	9.990
White Mtn	159.553	154.873	144.971	140.500	137.420	134.301	131.143	127.946	124.708	121.429	118.109	114.748	111.343	107.896	104.406	100.871	97.292	93.668	89.998	86.281
Aggregate	21.268	20.664	19.702	19.156	18.730	18.299	17.862	17.420	16.972	16.518	16.058	15.593	15.121	14.644	14.160	13.670	13.174	12.672	12.163	11.647

Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
13.60	Fort Huahuca	24.47%	24.35%	24.23%	24.10%	23.98%	23.86%	23.74%	23.63%	23.51%	23.39%	23.27%	23.16%	23.04%	22.93%	22.81%	22.70%	22.58%	22.47%	22.36%	22.25%
5.76	Rio Rico	20.44%	20.33%	20.23%	20.13%	20.03%	19.93%	19.83%	19.73%	19.63%	19.53%	19.44%	19.34%	19.24%	19.15%	19.05%	18.96%	18.86%	18.77%	18.67%	18.58%
4.00	Prairie Fire	24.55%	24.42%	24.30%	24.18%	24.06%	23.94%	23.82%	23.70%	23.58%	23.46%	23.35%	23.23%	23.11%	23.00%	22.88%	22.77%	22.66%	22.54%	22.43%	22.32%
1.00	La Senita	23.81%	23.69%	23.57%	23.45%	23.34%	23.22%	23.10%	22.99%	22.87%	22.76%	22.65%	22.53%	22.42%	22.31%	22.20%	22.09%	21.98%	21.87%	21.76%	21.65%
4.00	UASTP II	21.74%	21.64%	21.53%	21.42%	21.31%	21.21%	21.10%	20.99%	20.89%	20.78%	20.68%	20.58%	20.47%	20.37%	20.27%	20.17%	20.07%	19.97%	19.87%	19.77%
1.28	UASTP I	23.13%	23.02%	22.90%	22.79%	22.67%	22.56%	22.45%	22.33%	22.22%	22.11%	22.00%	21.89%	21.78%	21.67%	21.56%	21.46%	21.35%	21.24%	21.14%	21.03%
1.28	Springerville 1.8	30.93%	30.78%	30.62%	30.47%	30.32%	30.17%	30.02%	29.87%	29.72%	29.57%	29.42%	29.27%	29.13%	28.98%	28.84%	28.69%	28.55%	28.41%	28.26%	28.12%
8.25	White Mtn	3.82%	3.80%	3.78%	3.76%	3.74%	3.73%	3.71%	3.69%	3.67%	3.65%	3.63%	3.61%	3.60%	3.58%	3.56%	3.54%	3.53%	3.51%	3.49%	3.47%
39.17	**Aggregate**	19.41%	19.31%	19.21%	19.12%	19.02%	18.93%	18.83%	18.74%	18.64%	18.55%	18.46%	18.37%	18.27%	18.18%	18.09%	18.00%	17.91%	17.82%	17.73%	17.64%

TEP&UNSE utility owned facitilities vintage analysis c/kWh



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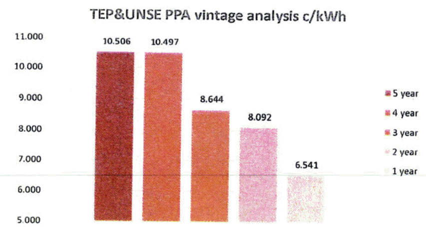
COD	Cost ($)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	44,775,747	44,551,868	44,329,109	44,107,463	43,886,926	43,667,491	43,449,154	43,231,908	43,015,749	42,800,670	42,586,667	42,373,733	42,161,865	41,951,055	41,741,300	41,434,228	41,194,433	18,982,283	17,382,146	7,064,881
	Output (MWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	426,210	424,079	421,959	419,849	417,750	415,661	413,583	411,515	409,457	407,410	405,373	403,346	401,329	399,323	397,326	394,641	392,437	226,502	214,812	109,500
	c/kWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Aggregate	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.506	10.499	10.497	8.381	8.092	6.452
AC Capacity (MW)	Load Factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
162.48	Aggregate	29.94%	29.79%	29.65%	29.50%	29.35%	29.20%	29.06%	28.91%	28.77%	28.62%	28.48%	28.34%	28.20%	28.06%	27.92%	27.73%	27.57%	15.91%	15.09%	7.69%



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