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BEFORE THE ARIZONA CORPORATIO[N COMMISSION]

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COMMISSIONERS

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

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

Arizona Corporation Commission
DOCKETED
DEC 21 2015
DOCKETED BY

NOTICE IS HEREBY GIVEN that the Direct Testimony of Daniel G. Hansen (the "Direct Testimony"), which was attached as Exhibit B to Arizona Investment Council's Notice of Filing, filed on December 9, 2015, inadvertently omitted its Exhibits. A true and correct copy of that Direct Testimony is attached hereto.

RESPECTFULLY SUBMITTED this 21st day of December, 2015.

OSBORN MALEDON, P.A.

By Meghan H. Grabel

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Original and 13 copies filed this
21st day of December, 2015, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing mailed
this 21st day of December, 2015, to:

All Parties of Record

Debra Huss

6438264

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
SUSAN BITTER SMITH – CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

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

Direct Testimony and Exhibits of

Daniel G. Hansen

on Behalf of

Arizona Investment Council

December 9, 2015

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

Q. Have you previously testified in utility regulation proceedings?

A. Yes. I have testified on issues related to utility fixed cost recovery in Arizona, Connecticut, Minnesota, New Mexico, Nevada, Oregon, and Utah. In these proceedings, I represented a broad range of clients, including a regulator, an environmental organization, a non-profit organization of utility investors, and investor-owned utilities. My education and work experience are described in AIC Exhibit DGH-1.

Q. On whose behalf are you testifying in this docket?

A. I am testifying on behalf of the Arizona Investment Council ("AIC").

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to support two proposals of UNS Electric, Inc. ("UNS Electric"): the introduction of a three-part rate (which has a demand charge in addition to the basic service charge and energy charge) that is optional for all residential and small commercial customers and mandatory for new net metering customers (where "new" is defined as beginning service on the Net Metering Rider R-10 after June 1, 2015); and the introduction of a new net metering rider (Rider R-10) that is applicable to new net metering customers (defined as those that completed an application for interconnection to UNS Electric's grid facilities after June 1, 2015) that changes the way net metered customers are compensated for excess generation relative to the current net metering rider (Rider R-4). Specifically, in the sections that follow, I will discuss:

- What demand charges are;
- Where demand charges have been used;
- Why a three-part rate is appropriate for UNS Electric;
- A description of UNS Electric's proposed net metering modifications; and
- Why the proposed net metering modifications are appropriate for UNS Electric.

II. DEMAND CHARGE DEFINITION, BENEFITS, AND APPLICATIONS

Q. Please describe UNS Electric's three-part rate proposals.

A. UNS Electric has proposed four new three-part rates, differentiated by their application to residential versus small commercial customers as well as whether the energy charges are differentiated by time-of-use ("TOU") pricing period. Specifically, the proposed tariffs are:

- Residential Service Demand (RES-01 Demand): optional for Residential Service customers, but mandatory for non-TOU Residential Service customers taking service under Net Metering Rider R-10 (UNS Electric's proposed net metering rider, which is also discussed in this testimony) beginning after June 1, 2015.

- Residential Service Demand Time-of-Use (RES-01 Demand TOU): an optional version of the RES-01 Demand rate that contains energy charges that are differentiated by time-of-day and season. The rate is mandatory for Residential Service TOU customers taking service under Net Metering Rider R-10 beginning after June 1, 2015.
- Small General Service Demand (SGS-10 Demand): optional for Small General Service customers, but mandatory for non-TOU Small General Service customers taking service under Net Metering Rider R-10 beginning after June 1, 2015. Small General Service rates apply to customers with maximum demand below 40 kW.
- Small General Service Demand Time-of-Use (SGS-10 Demand TOU): an optional version of the SGS-10 Demand rate that contains energy charges that are differentiated by time-of-day and season. The rate is mandatory for Small General Service TOU customers taking service under Net Metering Rider R-10 beginning after June 1, 2015.

Q. What is a demand charge?

A. A demand charge bills the customer based on its maximum usage defined over a short time interval. Demand charges are in units of dollar-per-kW. The measure of demand used to calculate the customer's bill (called billing demand) can vary across utilities and tariffs. For example, UNS Electric has proposed to base its residential and small commercial billing demand on the highest single hour of energy usage during the customer's billing month. Many demand-based rates (including UNS Electric's Large Power Service and Large General Service) measure billing demand over a 15-minute or 30-minute time interval. In addition, billing demand can be based on usage in previous billing months in addition to the current billing month (e.g., billing demand equals the greater of the maximum demand in the current month or 75 percent of the maximum demand in the previous eleven billing months). This is called a "ratcheted" demand charge. (UNS Electric has not proposed a ratcheted demand charge for its residential and small commercial customers.)

Q. What are the benefits of including a demand charge in retail rates?

A. Including a demand charge (in addition to a basic service charge and energy charges) in a retail rate provides customers with rates that better reflect the way utility costs are incurred. As I will describe below, this has several potential benefits, including:

- Giving customers appropriate incentives to manage their demand, thereby promoting a more efficient use of the system;
- Encouraging customers to adopt (and third parties to produce innovations in) capacity-saving technologies;

- Preventing the need for future rate modifications in response to emerging issues;
- Reducing intra-class cross subsidies; and
- Allowing UNS Electric to obtain more renewable energy for the same (or lower) total cost by purchasing (or building) at the utility scale.

Q. How does UNS Electric's three-part rate design better reflect the way utility costs are incurred?

A. UNS Electric's three-part rate has charges that better reflect the way utility costs are incurred, relative to the comparable non-demand rate. It is commonly accepted in utility cost-of-service studies that costs within functions (generation, transmission, distribution, and customer service) can be classified according to their primary driver, which can be one of the following:[1]

- **Customer-related costs**, which increase as the utility serves more customers, regardless of the amount of energy the customers use;
- **Energy-related costs**, which vary with the amount of energy used by customers; and
- **Demand-related costs**, which are associated with the maximum amount of energy used during a specified time interval (e.g., 15 to 60 minutes).

UNS Electric's demand rates contain charges that correspond to each of these cost drivers.

[1] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, pages 20-22.

Q. How can customers benefit from managing their demand on a three-part rate?

A. When customers who take service on a three-part rate reduce their billed demand, they can reduce their bill while at the same time contributing to lower utility costs in the short- and/or long-run. Customers can reduce billing demand by avoiding using electricity intensive appliances at the same time, ensuring that their demand stays low even if their total energy consumption changes little (e.g., by delaying washing clothes when the dishwasher is running).

Q. How do three-part rates encourage adoption of capacity-saving technologies?

A. Enabling technology can assist customers in managing their end uses to minimize billed demand. For example, the Residential Demand Control program at Otter Tail Power Company includes a demand controller and radio receiver to automate control of the end-uses during "control periods," which are called by the utility. In addition, the Rocky Mountain Institute (RMI) recently released a report on this topic called "The Economics of Demand Flexibility."[2] This study simulated the potential for customer bill savings on a variety of residential rates, with the largest simulated benefits coming from Salt River Project's residential demand rate. In addition, demand-based rates give customers with rooftop solar installations an incentive to invest in battery storage technologies, which can be used to help the customer manage its billing demand. This technology has the ability to effectively

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[2] "The Economics of Demand Flexibility", Rocky Mountain Institute, August 2015. The report is available for download at RMI's web site: http://www.rmi.org/electricity_demand_flexibility.

turn distributed solar power from an intermittent resource into a dispatchable resource. In the absence of the demand charge (or TOU pricing), a net-metered customer has little reason to invest in battery storage.[3]

Q. How do three-part rates reduce the need for future rate modifications in response to emerging issues?

A. Demand-based rates have the potential to reduce the need for future rate modifications in response to emerging issues because they better reflect the way utility costs are incurred. That is, a well-designed retail rate is more likely to function well in a variety of circumstances. For example, while the current two-part rate design (with inclining block energy charges) is beneficial for customers installing PV solar, it serves as a barrier to the proliferation of electric vehicles ("EVs"). By shifting cost recovery away from energy charges and toward demand charges, three-part rates have the potential to reduce the cost of charging EVs at home. That is, by charging an EV within the confines of the customer's existing demand, a customer could significantly reduce the cost of charging the EV relative to a two-part rate. It is not hard for me to imagine stakeholders calling for UNS Electric to implement a dedicated "EV Rate" (or an EV discount to its standard residential rate) after technological improvements reduce EV prices (thus increasing the quantity of EVs demanded). UNS Electric's proposed RES-01 Demand TOU rate removes the need for such a rate or rider. That is, that rate

[3] In this case, the customer's incentive to invest in battery storage would likely be limited to improved reliability (in case of service interruption).

would provide EV customers with the appropriate incentives to manage their demand and charge during off-peak hours.

Q. How do three-part rates reduce intra-class cross subsidies?

A. Three-part rates reduce intra-class cross subsidies by making the charges customers pay more closely reflect the way utility costs are incurred. UNS Electric has to have enough generating capacity (through ownership or purchase agreements) and network capability to serve peak demands. Under two-part rates, these demand-related costs are included in the energy charges. Therefore, customers who have relatively low levels of energy use contribute little to fixed-cost recovery regardless of the level of their maximum demand. A customer with low energy use relative to its demand level is referred to as a "low load factor" customer.[4] Under two-part rates, low load factor customers tend to be subsidized by high load factor customers (those whose average usage is closer to their maximum demand). A customer's low load factor may be caused by a high proportion of AC load, seasonal occupation of a residence (reducing the customer's annual load factor), or the installation of on-site DG. By reflecting the customer's load factor in their rates (as three-part rates do), high load factor customers will pay a lower average rate than low load factor customers (all else equal), which is consistent with utility cost-of-service methods. That is, demand-based rates give customers an incentive to use the utility's assets more efficiently

[4] Load factor is defined as the average usage over a period of time divided by the customer's maximum demand over that same period of time (where the period of time is typically one month or year).

(e.g., helping prevent the need for a generating unit designed to serve a low number of peak hours each year).

Q. Can the use of three-part rates for net metering customers allow for the acquisition of more renewable power?

A. Yes. A potential benefit of implementing three-part rates for net metered customers is that UNS Electric may be able to obtain more renewable energy for the same total cost. As described in Section III, the most recent renewable energy purchase power agreement by UNS Electric's sister company (Tucson Electric Power) was priced at 5.84 cents/kWh. As I describe later, there is some evidence that this is a high cost relative to more current purchase power agreements in the region. UNS Electric's volumetric retail rate is much higher than that. The lost fixed cost recovery that results from applying retail rates to net metered generation eventually increases rates to all customers in the rate class (through some combination of the LFCR and a subsequent rate case). Instead of incurring this rate increase to subsidize customer-sited DG, that amount of money could have been put toward more economic utility-scale renewable power purchases or facility construction. Given recent market costs, UNS Electric could have obtained more total renewable energy by purchasing it through wholesale transactions rather than from its customers through net metering. Put slightly differently, the existing net metering framework coupled with the two-part rate design (in which demand-related costs are recovered through energy charges) causes customers to overpay for renewable resources. Note that a three-part rate does not prevent an interested customer from installing PV solar, it simply reduces the amount of the subsidy that other customers are compelled to pay them if they do so. While the current subsidies embedded in UNS Electric's two-part rates may be the main factor behind some customer's decision to install PV solar, there are other customers would likely make the same decision in the absence of the subsidy. My preference for green power led me to enroll in a program in which I pay a 2.44 cent/kWh premium to offset 100 percent of my energy usage with green power.[5] This program, which is not subsidized by non-participants, provides an example in which customers purchased green power in the absence of a subsidy from other ratepayers.

Q. Are demand charges commonly used in electricity pricing?

A. Yes, demand charges are a common feature of electric tariffs. They are most commonly found in tariffs for medium and large commercial and industrial customers. For example, UNS Electric's Large General Service and Large Power Service rates include demand charges. Demand charges have also been applied to residential and small commercial customers for decades, and interest in applying demand charges to these customers appears to be growing. I am currently aware of 19 service territories in the United States in which the utility offers rates with demand charges to residential customers, including utilities in Alabama, Alaska,

[5] This is Madison Gas & Electric's Green Power Tomorrow program, which is described here: www.mge.com/environment/green-power/gpt/.

Arizona, Colorado, Georgia, Kansas, Minnesota, North Carolina, North Dakota, South Carolina, South Dakota, Vermont, Virginia, and Wyoming.[6] These rates are listed in AIC Exhibit DGH-2. Demand rates for these customer classes are also common in certain European countries and are being considered in Australia.

Q. Have residential rates with demand charges been approved in Arizona?

A. Yes, residential rates with demand charges have been approved for Arizona Public Service (APS) and Salt River Project (SRP). The Arizona Corporation Commission first approved a three-tiered residential demand rate for APS in 1980. Currently, APS's Rate Schedule ECT-2 (Residential Service Time-of-Use with Demand Charge Combined Advantage 7PM-Noon) has more than 110,000 enrolled residential customers.[7] In February 2015, SRP's board approved the Customer Generation Price Plan (E-27), which is a mandatory demand-based rate for customers that install on-site generation after December 8, 2014.[8] There is a corresponding voluntary pilot program for customers without on-site generation (E-27 P).

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[6] In addition to the rates contained in AIC Exhibit DGH-2, the Glasgow Electric Plant Board in Kentucky recently received approval to implement a mandatory residential demand rate in which the demand charge is based on the utility's monthly coincident peak. That is, the customer is billed based on their usage during the hour in which the entire utility's load is at its highest level. The rate will go into effect in January 2016.

[7] Snook and Grabel, "There and Back Again", Public Utilities Fortnightly, November 2015, pages 47-50.

[8] The press release for the board approval can be found at this link: http://www.srpnet.com/newsroom/releases/022615.aspx. The E-27 tariff can be found at this link: http://www.srpnet.com/prices/pdfx/April2015/E-27.pdf.

Q. What factors do you believe contribute to the increasing interest in the application of demand charges to residential and small commercial customers?

A. There are two likely causes for the increasing interest in offering demand charges to residential and small commercial customers. The first cause is the increasing ability of utilities to be able to bill a demand-based rate for smaller customers without incurring additional metering costs. Billing a rate that contains demand charges requires the ability to meter customer demand. In the past, energy-only meters have been in place for smaller customers. These meters are capable of measuring the total amount of energy consumed in a given billing period, but are not able to record the maximum amount of energy usage during any one short interval (e.g., a 15- to 60-minute period). In these cases, a separate demand meter is required to bill the demand-based rate, which entails additional meter costs. However, it has become more common for utilities to install advanced metering infrastructure (AMI) of some kind throughout their service territories, which is typically capable of recording customer usage on an hourly (or sub-hourly) basis.

Q. What is the second factor you believe contributes to the increasing interest in the application of demand charges to residential and small commercial customers?

A. The second factor contributing to increased interest in applying demand charges to smaller customers is the increase in distributed generation, particularly rooftop solar installations. Standard residential and small customer rate designs, which typically contain only a basic service charge and volumetric energy charges, tend to recover a significant share of fixed costs through the energy charge (i.e., the basic service charge is set well below the level required to recover all fixed costs). When a customer generates energy on-site and offsets the energy purchased from the utility, it correspondingly avoids paying the fixed costs included in the energy charge. This can lead to utility fixed cost under-recovery and/or a shift of fixed cost recovery to other customers. When a demand charge is added to the rate design, all or a portion of the fixed costs are removed from the energy charge (which is thereby lowered) and recovered through the demand component and basic service charge. The result is that all customers, those with and without on-site generation, pay for the infrastructure costs that they use.

Q. What are the proposed charges in UNS Electric's Residential Service Demand rate?

A. The Residential Service Demand rate contains three types of charges: a basic service charge of $20 per month; an energy charge of $0.059260 per kWh; and a tiered demand charge of $6.00 per kW for zero to 7 kW and $9.95 per kW for kW in excess of 7 kW. The inclusion of these three types of charges is why UNS Electric refers to its proposed demand rates as "three-part" rates. By comparison, its non-demand Residential Service and Small General Service rates could be considered "two-part" rates, because they include only a basic service charge and energy charges.

Q. Is UNS Electric's proposal to increase the basic service charge from $10 to $20 appropriate?

A. Yes. UNS Electric Witness Jones describes the proposed increase in the basic service charge as "consistent with the results of the COSS and equitable fixed cost recovery."[9] While the proposed $10 per month increase in the basic service charge improves the extent to which UNS Electric's rates reflect the cost to serve, the resulting $20 per month charge is still well below both the $54.46 per month basic service charge that would be required to recover all fixed costs.[10]

Q. How is the billing demand kW amount measured?

A. The kW amount that is used for customer billing purposes is based on the highest one-hour metered demand during the billing month. Intuitively, the billing demand represents the hour of the billing month in which the customer uses the most electricity. By basing billing demand on the maximum one-hour demand for the current billing month, UNS Electric has chosen a comparatively customer-friendly definition of billing demand. As AIC Exhibit DGH-2 shows, 26 out of 30 listed demand rates define billing demand using a 15- or 30-minute maximum demands (including SRP, which uses a 30-minute demand measure). Basing

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[9] Direct Testimony of Craig A. Jones, page 34, lines 12-13.
[10] Direct Testimony of Craig A. Jones, page 41, lines 1-4.

demand on a shorter time period increases the chance that a customer will have their billing demand increased by simultaneously using a set of electricity-intensive but short duration end uses. For example, a hair dryer or microwave oven can draw a relatively large amount of power, but they are not likely to be used for an extended period of time. Basing billing demand on longer periods of time helps smooth out the effect of some of these short-duration end uses.

Q. How do the proposed charges in the Residential Service Demand rate compare to the proposed charges in the Residential Service rate (RES-01)?

A. The demand and non-demand versions of the Residential Service rate contain the same basic service charge of $20 per month. The "standard" Residential Service rate excludes the demand charges, but contains higher (and tiered) energy charges. Specifically, the customers pay $0.08007 per kWh for the first 400 kWh consumed in a month and $0.10007 per kWh for kWh in excess of 400 kWh.

Q. Why is UNS Electric proposing to make its three-part rate design mandatory for customers who install distributed generation (DG)?

A. UNS Electric is proposing to make three-part rates mandatory for its new net metered customers (customers who install rooftop solar after June 1, 2015) due to the issues with respect to utility fixed cost recovery and customer cost shifting discussed above. Specifically, UNS Electric's two-part rates (e.g., RES-01) are designed to recover a significant amount of fixed costs through volumetric energy charges. According to the Direct Testimony of UNS Electric Witness Jones, the Residential basic service charge would need to be $54.46 per month in order to recover all of UNS Electric's fixed costs (which include customer-related and demand-related costs).[11] In contrast, UNS Electric is proposing a $20 per month basic service charge and currently has a $10 per month basic service charge. The remainder of the fixed costs (i.e., the difference between the revenue that would be recovered with a $54.46 basic service charge and the proposed $20 per month basic service charge) is recovered through the energy charge. As a result, the amount of fixed cost recovery UNS Electric obtains is affected by the amount of energy sold to its customers.

Q. What problems are caused by recovering fixed costs through energy charges for net metering customers?

A. When net metered rates recover fixed costs through volumetric charges (such as RES-01 plus Rider R-4), the reduction in billed sales to the net metered customers reduces utility fixed-cost recovery, which leads to a combination of cross-subsidies (i.e., an increase in rates to non-net metered customers) and reduced opportunity for the utility to earn its authorized rate of return. That is, some of the lost fixed cost recovery from net metering will be shifted to other customers through the Lost Fixed Cost Revenue Recovery (LFCR) Rider (R-8). Remaining unrecovered fixed costs that are not shifted to other customers through the LFCR

[11] Direct Testimony of Craig A. Jones, page 41, lines 1-4.

are borne by the utility until rates are re-set during UNS Electric's next rate case. In the rate case, the reduced level of test-year billed sales associated with DG leads to an increase in the energy charges that are paid by all customers in the rate class. That is, the fixed cost recovery will be spread across fewer billing units, so the resulting energy charge (which is the test-year revenue requirement divided by the test-year sales) is higher. While this rate reset theoretically makes the utility whole for net metering at test-year sales going forward, the class-wide increase in rates that results from net metered output from customer-sited DG perpetuates the shift of fixed-cost recovery from net metered customers to non-net metered customers.

III. PROPOSED NET METERING RIDER R-10

Q. Is UNS Electric proposing a new net metering rider?

A. Yes, UNS Electric has proposed Net Metering Rider R-10, which applies to customers taking service on one of the three-part rates proposed by UNS Electric. As such, this rider will only apply to customers who begin net metered service after June 1, 2015.

Q. How does Rider R-10 differ from the existing Net Metering Rider R-4?

A. The proposed R-10 differs from the existing net metering rider (R-4) in two ways: it replaces the "banking" of excess generation (the amount of generation during a billing month in excess of the customer's use) in favor of a bill credit calculated in the current month; and R-10 compensates customers for excess generation at the Renewable Credit Rate, whereas R-4 compensated customers at UNS Electric's avoided costs for any banked excess generation that remained when the October bill is calculated.[12]

Q. **How is the Renewable Credit Rate set?**

A. According to the direct testimony of UNS Electric Witness Tilghman, the Renewable Credit Rate is based on "the most recent comparable utility scale purchased power agreement for renewable energy that is connected to the Company's or TEP's distribution system."[13] The proposed value is 5.84 cents per kWh, which is based on a recent agreement with Tucson Electric Power (TEP).

Q. **Does the proposed Renewable Credit Rate appear to be reasonable?**

A. Yes, the proposed Renewable Credit Rate of 5.84 cents/kWh appears reasonable based on recent reports I have seen. For example, according to a recent article in Megawatt Daily,[14] the New Mexico Public Regulation Commission approved two 25-year, 70-MW solar contracts (on October 7, 2015) at levelized costs of 4.155 cents/kWh and 4.208 cents/kWh. The article goes on to say that the pricing of these contracts is "part of a national trend, with recent levelized PPA prices in the

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[12] The R-4 tariff describes the avoided cost calculation as "the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider R-3 for the applicable year."

[13] Tilghman Direct, p. 8, lines 7-9.

[14] "New Mexico PRC OKs $42/MWh solar contracts", Megawatt Daily, October 12, 2015, pages 13-14.

Southwest landing in the $40/MWh [4.0 cents/kWh] range, down from around $105/MWh [10.5 cents/kWh] on average in 2011, according to an annual report from the Lawrence Berkeley National Laboratory."

Q. Does the downward trend in PPA prices referenced in that article indicate a potential benefit for customers from the proposed Renewable Credit Rate methodology?

A. Yes, if recent trends continue, net metering customers can expect to benefit from UNS Electric's proposal to only update the Renewable Credit Rate when UNS Electric or TEP has entered into a new purchase power agreement or two years have passed, whichever comes first. That is, it is possible that UNS Electric customers will be paid a Renewable Energy Credit that is based on a purchased power agreement that is as much as two years old, in a market that has experienced significant recent cost/price reductions in recent years.

Q. Do you agree that UNS Electric should compensate net metered customers for excess generation using the proposed Renewable Credit Rate?

A. Yes. The proposed Renewable Credit Rate is consistent with UNS Electric's current practice of paying a premium for renewable energy in order to meet its renewable energy targets.

Q. Do you agree with UNS Electric's proposal to end the "banking" contained in the current net metering rider (R-4) and replace it with current-month credits at the Renewable Credit Rate?

A. Yes, I agree that the proposed current-month credits are preferred to the banking in the existing net meter rider (R-4). Compensating customers for excess generation in the current month at the Renewable Credit Rate is more reasonable than allowing customers to virtually store the excess generation in order to be compensated for it at their retail rate in a future month. This virtual storage does not correspond to any actual benefit provided by the customer-sited DG. I expect banking to be effective at increasing the cross subsidy that net metered customers receive, but that is not a policy goal I support.

IV. CONCLUSIONS

Q. Do you have any concluding observations?

A. Yes, I conclude that the Arizona Corporation Commission (ACC) should approve UNS Electric's proposed three-part rates and net metering riders. The three-part rates have several benefits: they provide customers with incentives to change their behavior in ways that reduce system costs; they provide a pricing template that is appropriate for a wide range of circumstances; they reduce intra-class customer cross-subsidies; they send price signals that create a market for demand control, energy storage, and other third-party technologies; and they may allow UNS Electric to obtain more renewable energy at the same total cost. I also recommend that the ACC approve UNS Electric's proposed net metering rider, which provides a more sensible means of compensating customers for excess generation than the current banking arrangement, while maintaining a subsidy (relative to UNS Electric's avoided costs) that encourages further adoption of renewable resources.

Q. Does this conclude your direct testimony?

A. Yes.

AIC EXHIBIT DGH-1

Daniel G. Hansen

RESUME

November 2015

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Academic Background:

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Developed long-term forecasting models for an electric utility.

Conducted a review of an electric utility's load forecasting methods.

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: *Ex-post* and *Ex-ante* Load Impacts," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2015.

"2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study," with EPRI (B. Neenan) and Marlies Patton, 2015.

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Public Service Company of New Mexico (PNM), New Mexico Case No. 15-00261-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 14-00332-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2014.

Xcel Energy, Inc, Minnesota E002/GR-13-868: Testimony supporting a revenue decoupling mechanism on behalf of Xcel Energy, 2013.

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding a the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

AIC EXHIBIT DGH-2

Number	Utility	State	Tariff	Name	Mandatory for Any Group	Billing Demand Definition
19	Otter Tail Power	SD	Schedule RDC	Residential Demand Control Service	No	60-minute during controlled hours of previous 12 months
20	Otter Tail Power	MN	Schedule RDC	Residential Demand Control Service	No	60-minute during controlled hours of previous 12 months
21	Otter Tail Power	ND	Schedule RDC	Residential Demand Control Service	No	60-minute during controlled hours of previous 12 months
22	Midwest Energy	KS	Schedule RD	Residential Demand Rate Service	Yes, 25 kW or more in any month	Higher of: 15-min during billing month or 80% of 15-min max from previous 3 billing periods
23	Swanton Village Electric	VT	Schedule A-D	Residential Demand Service	Yes, monthly kWh>=1,800 or 8kW for 2 consecutive months	Higher of: 15-min during billing month or 85% of 15-min max from previous 11 billing periods
24	Fort Morgan Light & Power	CO	Rate Schedule RD	Residential Demand Metered	Utility may require for customers who can use 25 kW	15-min during billing month
25	Dakota Electric Association	MN	Schedule 32	Residential and Farm Demand Control Rate	No	15-min during control periods of the billing month
26	Santee Cooper	SC	Rider RD-13	Residential Demand Service	Utility may require for customers with tankless electric water heaters or anyone with annual	30-min during billing month
27	Santee Cooper	SC	Schedule RB-14	Residential Net Billing Rate	"Available on a first-come, first-served basis"	30-min during billing month, by TOU period
28	City of Kinston	NC	E95	Residential Time-of-Use Service	No	15-min during on-peak hours of the billing month
29	Salt River Project	AZ	E-27 P	Pilot Price Plan for Residential Demand Rate Service	No	30-min during on-peak hours of the billing month
30	Salt River Project	AZ	E-27	Customer Generation Price Plan for Residential Service	Yes, for customers with on-site generation installed after	30-min during on-peak hours of the billing month

Source: "Top 10 Questions about Demand Charges", presented to the EUCI Residential Demand Charge Symposium by Ryan Hledik of The Brattle Group on August 31, 2015.

Number	Utility	State	Tariff	Name	Mandatory for Any Group	Billing Demand Definition
1	Alabama Power	AL	Rate RTA	Residential Time Advantage	No	15-min during billing month
2	Georgia Power	GA	Schedule TOU-RD-2	Time of Use - Residential Demand	No	30-min during billing month
3	Dominion Virginia Power	VA	Schedule 1S	Residential Service	No	30-min during peak hours of the billing month
4	Dominion North Carolina Power	NC	Schedule 1P	Residential Service	No	30-min during peak hours of the billing month
5	Duke Energy Carolinas	NC	Schedule RST (NC)	Residential Service, Time of Use Pilot	No	30-min during billing month
6	Duke Energy Carolinas	NC	Schedule RT (NC)	Residential Service, Time of Use	No	30-min during peak hours of the billing month
7	Duke Energy Carolinas	SC	Schedule RT (SC)	Residential Service, Time of Use	No	30-min during peak hours of the billing month
8	Black Hills Power	SD	Rate Code 14	Residential Demand Service	No	15-min during billing month
9	Black Hills Power	SD	Rate Code 14	Residential Demand Service, Maximum Value Option	No	15-min during peak hours of the billing month
10	Black Hills Power	WY	Rate ID WY914	Residential Demand Service	Yes, for on-site gen. customers (as of 10/1/2014)	15-min during billing month
11	Black Hills Power	WY	Rate ID WY916	Residential Demand Service, Maximum Value Option	Yes, for on-site gen. customers (as of 10/1/2014)	15-min during peak hours of the billing month
12	Xcel Energy	CO	Schedule RD	Residential Demand Service	No	15-min during billing month
13	APS	AZ	Rate Schedule ECT-2	Residential Service, Time-of-Use with Demand, Charge Combined Advantage 7PM-Noon	No	60-min during peak hours of the billing month
14	Alaska Electric Light & Power	AK	Rate 10-D	Residential with demand	Company may require if customers uses more than 5,000 kWh or 20kW for 3 consecutive	15-min during billing month
15	LADWP	CA	Schedule R-3	Residential Multifamily Service	No	15-min during billing month, except for facilities charge which has a 12-month ratchet
16	Fort Collins Utilities	CO	E110, A110, B110	Electric Demand Rate	No	15-min during billing month
17	City of Longmont	CO	RD	Residential Demand Rate	No	15-min during billing month
18	Westar Energy	KS	Schedule RS	Residential Peak Management Electric Service	Yes, for daily kWh>30. Closed to new enrollment.	30-min during billing month