STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the matter of:

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – ACQUISITION OF THE 375MW MANKATO ENERGY CENTER AND THE 345MW MANKATO ENERGY CENTER II

CASE NO. PU-18-403

Testimony of Paul J. Alvarez

May 28, 2019

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Q. PLEASE STATE YOUR NAME AND TITLE

A. My name is Paul J. Alvarez. I am the president of the Wired Group, a small consultancy dedicated to representing stakeholder interests in monopoly utility regulatory proceedings.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE

A. My career has largely been a function of my financial skills. My undergraduate and graduate degrees in business administration, from Indiana University and Northwestern University's Kellogg School, respectively, featured concentrations in corporate finance theory and practice. My early career consisted of roles with Fortune 500 companies utilizing financial skills, including financial analysis and product management. Some of these were general management roles, including responsibility for achieving challenging profit targets for defined product lines and geographies.

My career in the utility industry began in 2001 with Xcel Energy, parent company of Northern States Power (NSP). I was hired to develop energy efficiency and demand response programs as part of the Company's demand-side management portfolio, and worked there as an employee or as an external consultant through 2010. At Xcel Energy I learned about for-profit utility incentives under the cost-of-service regulatory model still in use today, and how it influences utility capital investment and operational decision-making. I was also exposed to resource planning, the objectives of demand-side management programs (primarily, to avoid or defer generation investment), and the impact of customer choices on the demand for electric energy and capacity.

In 2012 I formed the Wired Group to help satisfy an unmet need for utility expertise by stakeholders, including consumer, business, and environmental advocates. I have since testified as a subject matter expert on behalf of these groups in over a dozen cases before 10 state regulatory commissions. I have also served these and other groups in a consulting role in many utility-related engagements not involving testimony. I also led the development of the *Utility Evaluator*™, a commercial software program utilizing historical, utility-supplied financial and operating data from FERC Form 1 and EIA Form 861. The program simplifies the analysis of utility performance and operating characteristics, from revenues and reliability to capital and operating spending. My CV is included in this testimony as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. At the request of the North Dakota Public Service Commission's Advocacy Staff, I have examined NSP's application for an advance determination of prudence related to the purchase of the Mankato Energy Center I & II plants (MEC). I developed my testimony in satisfaction of the Advocacy Staff's role in ensuring that utility customers receive reliable and safe service at just and reasonable rates.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony focuses on two critical premises on which NSP's recommendation for an advance determination of prudence is based. The first premise is that the load NSP will need to serve in the future, when compared to a future projection of NSP's generation portfolio, indicates a need for MEC capacity once the purchased power agreements (PPAs) these plants currently satisfy expire. The second premise is that the cost of any capacity and energy which might be needed when the current PPAs expire will be greater in the future than if a portion of such costs could be "locked in" today through the purchase of MEC. I will challenge both of these premises in my testimony.

II. MEC CAPACITY WILL NOT LIKELY BE REQUIRED

Q. HOW DOES NSP DEVELOP LEAST COST RESOURCE PLANS?

A. NSP uses industry standard modeling software, called Strategist, to help predict what a least cost generation portfolio is likely to consist of in the future. I understand that Strategist is able to model the cost of various generation portfolios based on fuel price forecasts. Strategist also allows users to input various constraints, such as load requirements, renewable portfolio standards, reserve requirements, and changes in generation portfolios (such as plant closures), into the model.

Q. DO YOU HAVE CONCERNS ABOUT THE STRATEGIST SOFTWARE?

A. I have no concerns about the Strategist software. However, like any other software, Strategist outputs are only as good as the forecasts and constraints input into it. Assumptions embedded in forecasts and constraints impact Strategist outputs.

Q. AND YOU HAVE CONCERNS ABOUT THE FORECASTS AND CONSTRAINTS INPUT INTO THE STRATEGIST MODEL?

A. Yes.

Q. WHAT IS NSP'S RATIONALE FOR RECOMMENDING AN ADVANCE DETERMINATION OF PRUDENCE FOR THE MEC PURCHASE?

A. NSP admits that MEC capacity is not currently needed, and that this excess capacity will result in customer cost increases until such time that MEC capacity is needed. However, NSP claims that the cost reductions available from MEC ownership over the long term will outweigh higher costs in the short term.[1]

Q. WHEN DOES THE STRATEGIST MODEL INDICATE AN MEC PURCHASE WILL BEGIN REDUCING COSTS TO CUSTOMERS?

A. Under NSP's "85 by 30" low carbon emissions generation plan, and based on NSP forecasts and constraints, the Strategist model indicates customer costs will begin to be lower as a result of the MEC purchase beginning in 2035.[2] The earlier customer costs begin to fall as a result of the purchase, the more likely the MEC purchase will be cost-effective for customers overall, as generating plants have finite lives. If customer costs fail to fall as a result of the purchase early enough, the projected savings from the purchase later in the plant's life will be insufficient to make up for the additional costs customers will incur early in the plant's life. The key determinant in the cost-effectiveness of the MEC purchase, therefore, is the timing of the transition of the plants from contributing to excess generation capacity (higher costs for customers) to satisfaction of needed capacity (lower costs for customers).

Q. WHAT NSP FORECASTS AND CONSTRAINTS WHICH JEAPORDIZE NSP'S FINDING THAT COSTS WILL BEGIN TO FALL IN 2035 CONCERN YOU?

A. I am concerned that NSP's forecasts assume higher load growth than is reasonable. I am also concerned that NSP assumes its nuclear plants will close in the early 2030s – a constraint I feel is unlikely to hold. Both of these assumptions contribute to a greater, and earlier, modeled need for capacity than would otherwise be the case. The need for greater, and earlier, capacity contributes directly to NSP's prediction that customer costs will begin to fall in 2035 if MEC is purchased. If the need for capacity is less, or later, than indicated by models employing these questionable NSP assumptions, the year in which customer costs begin to fall will be later. In fact it is possible, if not likely, that a delay in the transition from "contributing to excess capacity" to "satisfaction of needed capacity" will make the MEC purchase more costly for customers over the long term. It is also possible MEC capacity will

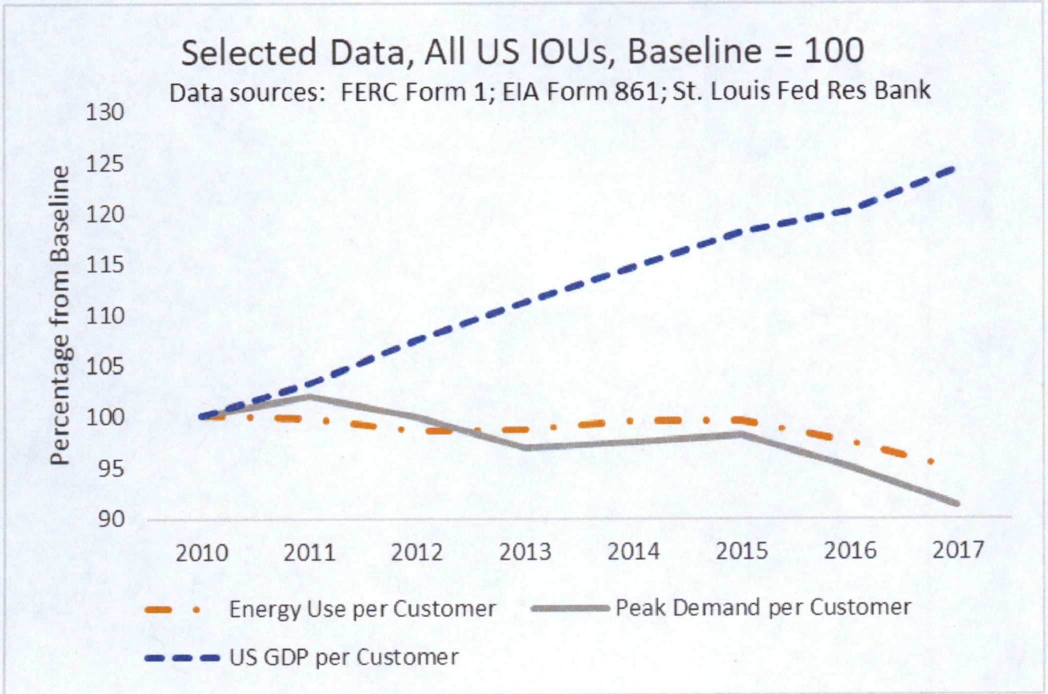
[1] ND PSC 18-403. Testimony of Philip Joseph Martin. Page 18, lines 19-24.
[2] ND PSC PU-18-403. Testimony of Philip Joseph Martin. Page 17, Figure 2.

never be needed to serve NSP loads when the existing PPAs expire. Many significant changes are happening quickly in the electric generation and distribution industries, and 2035 is more than 15 years away.

Q. WHY DO YOU BELIEVE NSP'S LOAD FORECASTS ARE HIGHER THAN REASONABLE?

A. Per capita demand for electric energy and capacity have been falling in the U.S. for about a decade. I will talk about the reasons for this trend, and why I expect it to continue, later in this testimony. Figure 1 below, sourced from data reported by U.S. investor-owned utilities from FERC Form 1 and EIA Form 861, illustrates the trend. Note that this trend is clear despite the growth in gross domestic product per US electric customer.

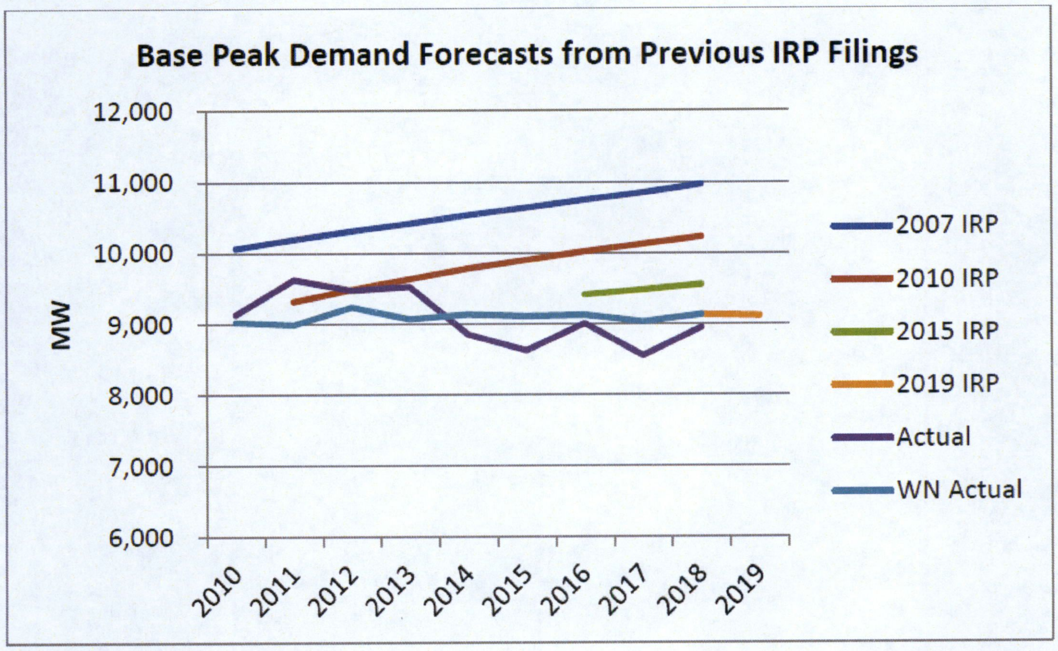
Figure 1: US Investor-Owned Utility Electric Energy and Demand Trend



Q. IS THE DEMAND FOR ELECTRIC ENERGY AND CAPACITY FALLING IN THE NSP SERVICE AREA?

A. Yes. In fact, all three of NSP's most recent resource plans, including plans developed in 2007, 2010, and 2015, dramatically over-estimated growth in peak demand. Figure 2 below compares the peak demand from recent NSP resource plans to actual peak demand.[3] One can see that peak demand is flat (weather normalized) to falling, and that NSP's three most recent load forecasts used for resource planning have failed to recognize this trend.

Figure 2: Comparison of NSP peak demand forecasts to actual NSP peak demand



Q. WHAT DOES LOAD GROWTH NEED TO BE FOR THE MEC PURCHASE TO DELIVER LONG TERM SAVINGS TO CUSTOMERS SUFFICIENT TO OUTWEIGH THE NEAR-TERM COST INCREASES INDICATED IN NSP'S APPLICATION?

A. Categorizing the cost increases as "near term" is a misnomer, as NSP's projections indicate that, under the Company's 85-by-30 Plan, cost increases will be borne by customers for 14 of the next 15 years if NSP purchases the plants and adds them to the rate base. Fifteen years sounds longer than near term to me. But to answer the question, if all other assumptions made by NSP hold, the load growth needs to be 0.8% compounded annually for the next four decades.[4] The Fall 2018 load growth forecast[5] is compared to historical

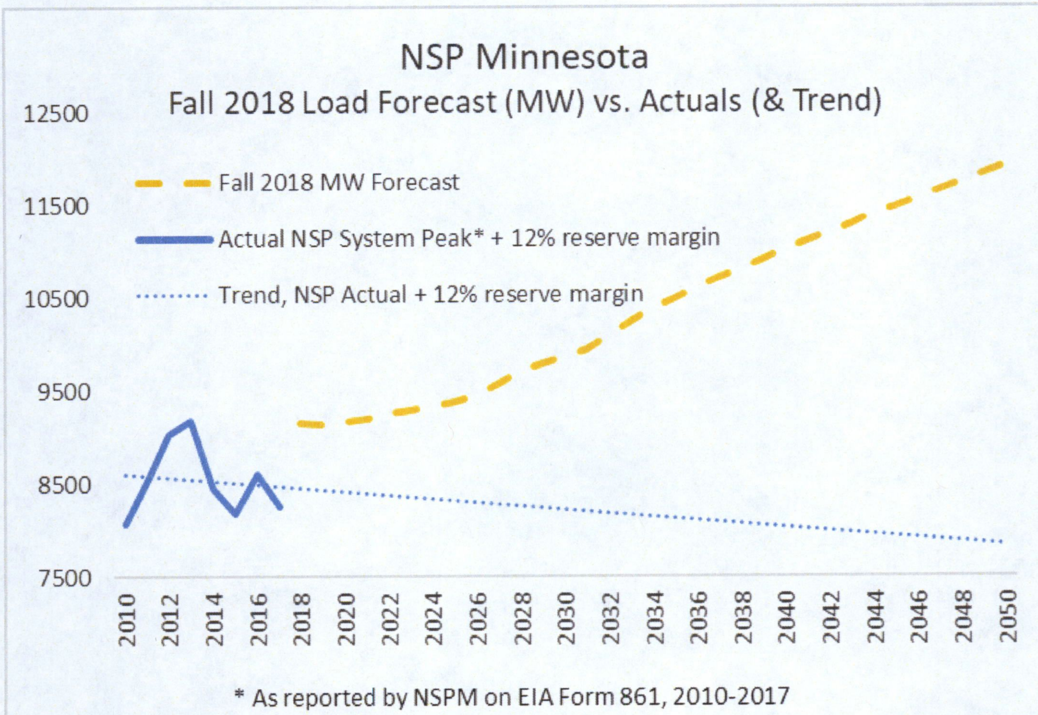
[3] ND PSC PU-18-403. NSP response to ND PSC IR 3-002.

[4] Witnesses' analysis of Martin testimony, Schedule 1, page 2, Table 3, column "Final w/EV Adjustments".

[5] Ibid.

load growth in recent years, and projected into the future using a line of best fit, in Figure 3 below.

Figure 3: NSP's Fall 2018 Load Forecast Compared to Trends Based on Historical Actual



Q. DO YOU HAVE ANY CONCERNS ABOUT THE "OTHER ASSUMPTIONS" YOU MENTION?

A. Yes. In addition to my concern that NSP's load growth forecast is sufficiently overstated to create a need for MEC capacity earlier than would otherwise be the case, I am concerned that NSP's generation capacity forecasts are understated. The combination of overstated load and understated generation capacity further reduces the likelihood that cost savings, if any, will be secured early enough for distant benefits to exceed incremental customer costs if MEC are purchased and added to the rate base.

Q. WHY DO YOU BELIEVE NSP GENERATION CAPACITY FORECASTS ARE UNDERSTATED?

A. NSP generation capacity forecasts include the assumption that all three of NSP's nuclear units, including Monticello (647 MW), Prairie Island I (522 MW), and Prairie Island II (519 MW) will be decommissioned when their current Nuclear Regulatory Commission (NRC) operating licenses expire, in 2031, 3033, and 2034, respectively. The role of these three nuclear units in NSP's system is significant, representing 22.4% of NSP's peak capacity requirement and 27.5% of energy distributed by NSP in 2018.[6] While I believe it is entirely appropriate for NSP to consider a worst-case scenario, these license expirations are twelve to fifteen years away. I do not believe it is prudent to incur certain cost increases for the next 12-15 years when the conditions leading to a need for MEC capacity are uncertain.

Q. WHY DO YOU BELIEVE NSP NUCLEAR UNITS MIGHT NOT BE DECOMMISSIONED AS THEIR OPERATING LICESNSES EXPIRE?

A. For three reasons. First, NSP has successfully secured operating license extensions for all three nuclear units in the past. Second, it is likely society's interest in operating electric generation plants featuring zero carbon-dioxide emissions will grow in the next 12-15 years, and that public pressure to keep nuclear plants open will therefore be strong in the 2030s. Third, the nuclear units are located in Minnesota, where carbon emissions and costs are considered in resource plans, making nuclear generation appear more cost-effective in these resource plans than they would otherwise be. In addition, the Minnesota legislature and Public Utilities Commission will exert significant influence over the fate of the three nuclear units, and these bodies are more likely than those in North Dakota to encourage continued nuclear unit operation. For these three reasons, I believe NSP's nuclear generating units will continue to operate beyond 2031, 2033, and 2034, respectively.

Q. WHAT EVIDENCE DO YOU CITE IN SUPPORT OF YOUR PREDICTIONS?

[6] NSP Minnesota 2018 FERC Form 1. Peak demand 7,540 MW per page 401a; nuclear supply 12,646,380 out of 45,983,726 MWh per page 400a.

A. Legislatures in several states are acting in ways which support my predictions. In recent years Connecticut[7] and New Jersey[8] passed legislation establishing zero emissions credit programs to compensate nuclear facilities for their low carbon emissions attributes. State regulators in New York established rules to the same effect.[9] Legislators in Illinois,[10] Ohio,[11] and Pennsylvania[12] are currently developing their own versions of such legislation. Legislation recently passed in Virginia authorizes accelerated cost recovery for investments utilities make in upgrading nuclear plants when such upgrades are associated with NRC operating license renewals.[13] Colorado legislators recently passed legislation which required that the social cost of carbon be set at $46 per short ton of carbon dioxide emissions for the purposes of resource planning, and included provisions for growth from that amount.[14]

Q. ARE YOU AWARE THAT NORTH DAKOTA LAW PRECLUDES THE NORTH DAKOTA PUBLIC SERVICE COMMISSION FROM CONSIDERING ENVIRONMENTAL COSTS IN RESOURCE PLANNING?

A. Yes. The language in the Century Code reads, "The commission may not use, require the use of, or allow electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service."[15] However, my testimony does not ask this Commission to consider environmental externality values in its decision regarding an advance determination of prudence for the MEC purchase. Rather, my testimony asks the Commission to consider whether generation capacity will be constrained to a degree which indicates a need for MEC capacity once

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7 Connecticut Legislature. S.B. 106/H.B. 1501

8 New Jersey Legislature. A.B. 3724/S.B. 2313

9 New York Public Service Commission. Case Nos. 15-E-0302 and 16-E-0270. Order dated August 1, 2016.

10 Illinois Legislature. HB 2861.

11 Ohio Legislature. HB 6.

12 Pennsylvania Legislature. HB 11.

13 Virginia Legislature. HB 2291.

14 Colorado Legislature. SB 19-236

15 North Dakota Century Code 49-02-23.

current PPAs expire. Irrespective of the rationale for my prediction that the Minnesota nuclear units will continue to operate past their current NRC license periods, the Commission's consideration that nuclear unit capacity is likely to be available past the 2031-2035 timeframe would be pragmatic, not unlawful.

Q. WHAT DO YOUR CONCERNS ABOUT NSP'S OVERSTATED LOAD GROWTH AND UNDERSTATED CAPACITY AVAILABILITY MEAN FOR CUSTOMERS?

A. In summary, NSP is asking its customers to pay more than they otherwise would for at least 15 years for the potential to receive benefits which might or might not be available beyond 15 years. The cost increases are certain, while the future benefits are uncertain and in fact, as my testimony to this point indicates, even unlikely. As a result, I do not consider an advance determination of prudence to be reasonable at this time.

Q. WHAT WOULD BE A MORE PRUDENT COURSE OF ACTION, IN YOUR OPINION?

A. I believe it would be more prudent to wait until the resource planning processes of the late 2020's or early 2030's to examine the need for additional capacity. In the interim, all parties will gain clarity on load growth and the availability (or lack thereof) of NSP nuclear unit capacity and energy. The relative merits of increases in owned, regulated generating capacity could be better estimated with the increased clarity time will bring to these issues.

Q. DOESN'T SUCH AN APPROACH EXPOSE CUSTOMERS TO ECONOMIC RISKS ASSOCIATED WITH HIGHER CAPACITY AND/OR ENERGY COSTS WHICH MIGHT EXIST IN THE FUTURE?

A. To an extent, yes. But I expect the economic risk to be low, and insufficient to justify the certainty of higher prices for customers over the next 15 years, at least. I will discuss the rationale for this expectation in the next section of my testimony.

III. IN THE FUTURE, MEC CAPACITY AND ENERGY IS NOT LIKELY TO BE SUFFICIENTLY LESS COSTLY THAN MARKET/PPA PRICES TO JUSTIFY ITS PURCHASE.

Q. EXPLAIN WHY YOU BELIEVE THAT FUTURE MEC CAPACITY AND ENERGY IS NOT LIKELY TO BE SUFFICIENTLY LESS COSTLY THAN MARKET/PPA PRICES TO JUSTIFY ITS PURCHASE.

A. I believe that future MEC capacity and energy is not likely to be significantly less costly than future market/PPA prices for three reasons. First, I believe that demand for capacity and energy are likely to continue to fall in the future, putting downward pressure on future market/PPA prices. Second, in the unlikely event that the demand for capacity and energy do not fall, market mechanisms will encourage adequate generation capacity such that market/PPA prices are unlikely to spike. Finally, marginal energy costs are (and will continue to be) driven primarily by natural gas costs, which impact both MEC and market/PPA prices for energy similarly. I would like to address these three issues in order.

Q. WHY DO YOU BELIEVE THE DEMAND FOR CAPACITY AND ENERGY ARE LIKELY TO CONTINUE TO FALL IN THE FUTURE?

A. As indicated in Figure 2 earlier in my testimony, per customer demand for capacity and energy have been falling in NSP's service area for some time. As indicated in Figure 1 earlier, this phenomenon is not limited to NSP, but applies to the United States generally despite steady growth in gross domestic product. I believe several trends explain falling demand for electric energy and capacity in the US, the MISO market geography, and the NSP service area, including increases in customer energy efficiency, demand response, and self-generation, as well as reductions in industrial electric energy intensity. In addition, as the price of electric storage (largely batteries) falls, the need for generating capacity will fall too.

Q. CAN YOU EXPLAIN THE TREND IN ENERGY EFFICIENCY?

A. A variety of factors contribute to improving energy efficiency in US homes and businesses. About 8% of US electricity is used to for lighting,[16] and LED lighting is a big part of efficiency gains to date. LED bulbs use about 80% less energy than incandescent bulbs and 25% less energy than florescent bulbs.[17] Yet the biggest lighting efficiency gains are yet to come, as LED adoption is but 12.6% of installations/replacements annually, and the use of lighting controls (via the Internet of Things) reportedly offers as much potential to reduce energy use than the conversion to LED bulbs.[18]

The improving efficiency of customer equipment is another big contributor. The efficiency of large electric loads like air conditioning (about 13% of US electricity use), refrigeration (10%), space heating (8%), and water heating (6%)[19] improves with each passing year. It is worthwhile to note that most of these loads are generally operating during coincident system peaks in either the winter or the summer, indicating that energy efficiency helps reduce generation capacity requirements as well as energy requirements.

Finally, the efficiency of US building stock is improving. As buildings age, they are either replaced or remodeled to ever-more stringent building codes, which often apply to building equipment as well as to building envelopes (windows, insulation, etc.).

Q. WHAT IS DRIVING THE GROWTH IN DEMAND RESPONSE?

A. The rise of capacity markets in the US has resulted in significant growth in demand response. Businesses have recognized the cost-reducing potential of demand response. They are participating in increasing numbers, at ever-higher levels of demand reduction. While the amount of capacity MISO is able to secure through demand response is strong at

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16 US Energy Information Administration. Accessed via Internet 5/13/19 at https://www.eia.gov/tools/faqs/faq.php?id=99&t=3

17 US Department of Energy. Accessed via Internet 5/14/19 at https://www.energy.gov/energysaver/save-electricity-and-fuel/lighting-choices-save-you-money/

18 US Department of Energy Efficiency and Renewable Energy. 2017 LED Adoption Report Summary. Page 2.

19 US Energy Information Administration. Accessed via Internet 5/13/19 at https://www.eia.gov/energyexplained/index.php?page=electricity_use

9.7% of peak load in 2017,[20] the size of MISO demand response capability continues to grow. Since 2012, MISO's demand response capability has grown at a compound annual growth rate of 4.9%,[21] showing no sign of slowing. Furthermore, demand response by the residential class, an enormous potential source of demand response capability, is largely untapped. One respected consultant estimates that adoption of time-of-use (TOU) rates amounted to less than 3% of residential customers in 2017.[22] The same consultant's review of 126 TOU rate impact studies found reductions in demand as high as 50% among populations of participating residential customers for TOU rates with certain features.[23]

Q. SELF-GENERATION IS GROWING TOO, CORRECT?

A. Yes, and very rapidly. As the price for PV solar panels, equipment, and installation falls, adoption of PV solar panels rises, reducing the need for centralized generation. The Solar Energy Industries Association reports that in the US, PV solar capacity installed by customers grew from less than 500 MW DC annually in 2010 to more than 4,500 MW DC annually by 2018 – a compound annual growth rate of about 31.5%.[24] (As a rule of thumb, 1.0 MW DC capacity is equivalent to about 0.75 MW of AC capacity, though the growth rate is still impressive).

Other forms of self-generation seem to be growing too. Industrial customers, in particular, seem to be installing combined heat and power (CHP) plants, known to many as cogeneration, at an increasing rate. General Electric reports that in North America, CHP

[20] *2017 MISO State of the Market Report.* Potomac Economics. June, 2018. Page 78. (DR capacity 11,682 MW in 2017).

[21] *Demand Response as a System Resource.* Synapse Energy Economics. May, 2013. (MISO DR capacity 9221 MW in 2012)

[22] Hledik R, Faruqui A, and Warner, C. *The National Landscape of Residential TOU Rates: A Preliminary Summary.* Slide 2. Accessed via Internet at http://www.brattle.com/news-and-knowledge/publications/archive/2017 on 5/14/19

[23] Faruqui A and Palmer J. *The Discovery of Price Responsiveness – A Survey of Experiments Involving the Dynamic Pricing of Electricity.* EDI Quarterly. Volume 4, No. 1. April, 2012.

[24] Solar Energy Industries Association. Accessed via Internet 5/14/2019 at https://www.seia.org/sites/default/files/inline-images/SIDP-2018YIR-Fig1_0.png

capacity installed by customers grew from less than 100 MW annually in 2010 to about 500 MW annually by 2016 – a compound annual growth rate similar to PV solar (31%).[25]

Q. WHAT DO YOU MEAN BY THE "REDUCTION IN INDUSTRIAL ENERGY INTENSITY"?

A. Industrial customers consume 25% of US energy today,[26] but this number has been falling for almost a decade. By 2018, US industrial electric use had fallen 5% from its peak in 2010.[27] Electric-intensive industrial processes are being converted to take advantage of low-cost natural gas, or being moved overseas to take advantage of lower electric rates. Electric rates per kilowatt hour in India and China are 2/3 the cost of a kilowatt hour in the US.[28] US gross domestic product is growing through the so-called knowledge economy, and is no longer driven by industrial growth. Thus, industry no longer drives growth in the demand for electric capacity or energy.

Q. YOU ALSO MENTIONED THAT ELECTRIC STORAGE IS LIKELY TO GROW?

A. Yes, in an industry-changing way. As with PV Solar, falling electric storage costs will result in increasing customer adoption. Business customers are particularly interested in electric storage and its value in reducing utility demand charges without impacting operations. Growth in electric storage, particularly among business customers, will be responsible for a significant reduction in generation capacity requirements in coming decades. This, in turn, will reduce peak capacity requirements, as many business customers' demand peaks are consistent with system demand peaks. McKinsey reports that battery costs fell 77% per kilowatt hour in just six years (2010-2016), and that customer-sited storage capacity grew at a

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[25] Liefman, Michael. Now is the time (for Combined Heat and Power). General Electric whitepaper. Undated. Page 5.

[26] US Energy Information Administration. Accessed via Internet 5/13/19 at https://www.eia.gov/energyexplained/index.php?page=electricity_use

[27] Ibid.

[28] OVO Energy. Accessed via Internet 5/13/19 at https://www.ovoenergy.com/guides/energy-guides/average-electricity-prices-kwh.html

staggering compound annual growth rate of 69% from 2013-2016 as a result.[29] McKinsey calculates that the use of batteries for reducing demand charges is cost effective at demand charges as low as $9 per kW today, and predicts the break-even point could fall to a demand charge as low as $4 or $5 per kW as soon as 2020.[30] (I note that NSP's demand charge is around $10 per kW in North Dakota and Minnesota in the winter, and almost 50% higher in the summer.)

Based on the demand charge management opportunity and falling battery prices, and augmented by the increasingly common pairing of batteries with PV solar, McKinsey believes the market for customer-sited batteries will grow an astounding 50% annually in coming years.[31] These data points encourage skepticism for any forecast growth in peak demand.[32]

Q. DO YOU EXPECT THESE TRENDS TO CONTINUE?

A. Yes. I expect all these trends to continue throughout the United States, the MISO market's geography, and NSP's service area. I foresee no reason why these trends would abate, and therefore no reason the demand for energy or capacity will reverse their downward trend. I am not alone in my assessment; electric industry prognosticators across the globe, from investment bankers to utility regulators, are concerned about how electric utilities will fund investments in times of flat or falling sales.[33]

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[29] Noffsinger J, Rogers M, and Wagner A. *Why the future of commercial battery storage looks bright.* McKinsey article summary. 2018. Page 2.

[30] D'Aprile, P, Newman J, and Pinner D. *The New Economics of Battery Storage.* McKinsey whitepaper. 2016. Page 3.

[31] McKinsey article summary, page 2.

[32] The comments of Xcel Energy CEO Ben Fowke in a May 22 appearance before the Minnesota PUC reinforces falling battery costs. An Internet article quoted him as saying "We are very interested in nurturing batteries, but today batteries with storage don't quite meet the economic (test). But in five years, they might." Accessed via Internet on 5/24/19 at https://www.energycentral.com/news/ceo-xcel-will-likely-need-gas-or-nuclear-power-reach-carbon-free-goals?utm_medium=eNL&utm_campaign=DAILY_NEWS&utm_content=400384&utm_source=2019_05_24

[33] Roberts, D. *After risicng for 100 years, electric demand is flat. Utilities are freaking out.* Article published on Vox.com February 27, 2018. Accessed via Internet on 5/14/19 at https://www.vox.com/energy-and-environment/2018/2/27/17052488/electricity-demand-utilities

Q. BUT WHAT ABOUT ELECTRIC VEHICLES? WON'T THEY INCREASE DEMAND FOR ENERGY AND CAPACITY?

A. Yes, they will. But the growth in demand for energy and capacity resulting from electric vehicles may not be enough to offset reductions resulting from energy efficiency, demand response, self-generation, reduced industrial electric intensity, and electric storage, let alone result in growth in demand for energy and capacity.

Most people assume the growth in energy and capacity resulting from electric vehicles will be large. But electric motors are much more efficient than internal combustion engines, requiring much less energy per mile. Automated driving/traffic flow control offer dramatic additional efficiencies. In a presentation at GridConnect 2017, former US Federal Communications Commission Chairman and Internet of Things proponent Reed Hundt presented calculations on growth in electricity use in a city with 100% electric passenger cars. Mr. Hundt calculated that electric sales would only increase about 13% in such an instance. But by adding automated driving/traffic flow control, Mr. Hundt calculated that the same city with 100% electric passenger cars would increase electric use by only about 3%.[34]

Estimates by others confirm Mr. Hundt's assessment. McKinsey estimates electric energy for electric vehicles will represent only 6.5% of global electric energy sales in 2050,[35] while the London-based consultancy Redburn estimates 5% of global electric energy sales will result from electric vehicle charging by 2040.[36] Furthermore, the use of time-of-use rates with critical peak price features for electric vehicle owners can be very effective at avoiding increases in peak demand.

Q. DIDN'T NSP TAKE ALL THESE TRENDS INTO ACCOUNT IN THE STRATEGIST MODEL WHICH SHOWS EVIDENCE OF A NEED FOR MEC CAPACITY?

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[34] Hundt, R. *Building Our Nation's Next-Gen Infrastructure*. Keynote address at GridConnext 2017. December 5, 2017, Washington DC. Proceeding slide deck page 45.

[35] Engel H. et al. *The potential impact of electric vehicles on global energy systems*. McKinsey whitepaper. July, 2018. Page 2.

[36] Sioshansi, F. *The impact of electric vehicles on electricity demand*. Blog post dated 11/6/18 summarizing a report by Redburn. Accessed via Internet 5/14/2019 at https://energypost.eu/the-impact-of-electric-vehicles-on-electricity-demand/

A. NSP accounted for trends indicating load growth to a greater extent than it accounted for trends leading to load reductions. For example, while the NSP load forecast does reflect increases in demand for energy and capacity resulting from electric vehicles, it does not reflect any anticipated decreases in demand from customer adoption of energy storage.[37] While the NSP load forecast does reflect reductions in demand for energy and capacity resulting from NSP's own demand-side management programs, it does not reflect energy efficiency and demand response actions customers may take outside of NSP programs, or in the broader MISO market.[38] Higher-than-expected growth in customer self-generation is only reflected in NSP's "low load growth" scenario,[39] to which NSP assigns only a 15% probability,[40] and which NSP did not use to justify the MEC purchase.

Q. YOU HAVE PROVIDED MUCH EVIDENCE FOR THE IDEA THAT THE DEMAND FOR ENERGY AND CAPACITY WILL FALL IN COMING DECADES. BUT THIS ONLY SUPPORTS HALF OF YOUR ARGUMENT THAT THE FUTURE RISK OF HIGH MARKET PRICES FOR ENERGY AND CAPACITY IS LOW. WHAT EVIDENCE DO YOU HAVE THAT CAPCITY SUPPLY WILL NOT BE LIMITED IN THE FUTURE?

A. Free markets are effective at ensuring that suppliers will react to changes in demand, and MISO's capacity market is a free market. If the supply of generation capacity tightens, market capacity prices will rise, and potential investors will be provided with the economic incentive to build new plants. New plants will be built, the supply of generation capacity will grow, and market capacity prices will subsequently fall. Market mechanisms should be adequate to keep market prices for capacity and energy in check, particularly in times of falling demand. In summary, free markets are effective in mitigating long-term price increases.

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37 ND PSC PU-18-403. NSP response to ND PSC IR 2-011(b).

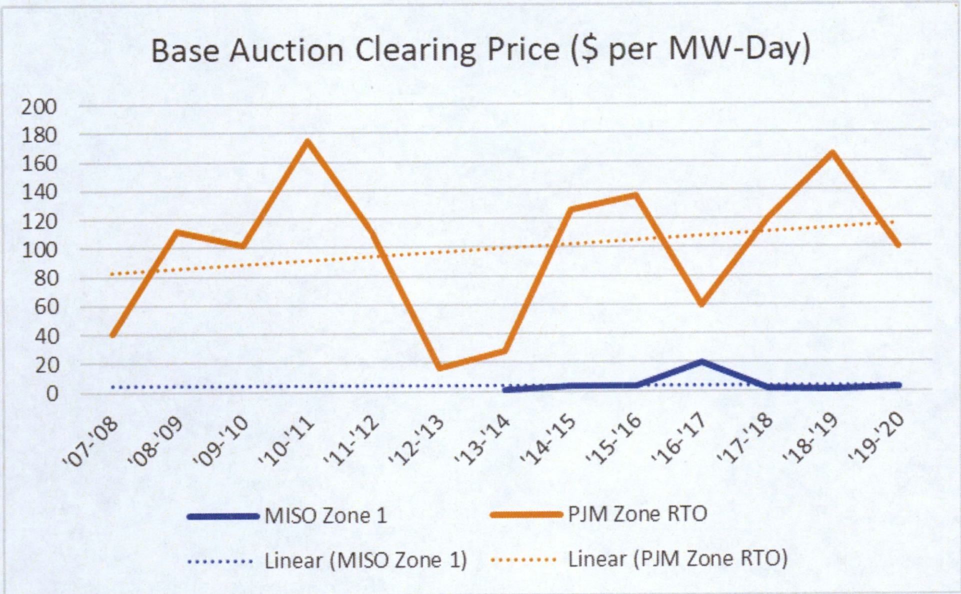
38 ND PSC PU-18-403. NSP response to ND PSC IR 2-011(d).

39 ND PSC PU-18-403. NSP response to ND PSC IR 2-011(a).

40 ND PSC PU-18-403. NSP response to ND PSC IR 2-007, Attachments B and C.

Actual experience in capacity markets bears this out. As shown in Figure 4, market prices for capacity in MISO have been flat since the market was established in 2013. Yet new plants, such as MEC II, are still being built, and old, inefficient plants are being shut down and replaced. The story is the same in PJM, which has the oldest capacity market. Since initiated in 2007, PJM capacity markets have exhibited a slight growth trend over time, with alternating periods of price drops and price increases. During this time dozens of plants have closed while dozens of others have been built. Figure 4 shows the average clearing prices of capacity per MW day in PJM and MISO over time.[41]

Figure 4: PJM and MISO Capacity Market Price History



While the trend in PJM prices indicates an increase of just under 3% compounded annually, this is not dramatically different than US Consumer Price Index inflation rate of just under 2% compounded annually over the same time period.[42] Furthermore, the pattern exhibited by the PJM price history, consisting of price drops following price increases, reinforces my

[41] PJM capacity clearing price history available at www.pjm.org; MISO capacity clearing price history available at www.misoenergy.org.

[42] Compound annual growth rate in US CPI sourced from the US CPI Inflation Calculator (using US Bureau of Labor Statistics Consumer Price Index data). Accessed via Internet on 5/20/19 at www.in2013dollars.com.

claim that suppliers do react to market price increases by increasing market supply, mitigating long-term price increases as predicted by the law of supply and demand.

Q. PROVIDE SUPPORT FOR YOUR THIRD ARGUMENT, THAT NATURAL GAS PRICES WILL IMPACT THE COST OF ENERGY FROM MEC IN A WAY THAT IS SIMILAR TO THE WAY THEY WILL IMPACT MARKET/PPA PRICES. WON'T THE MORE EFFICIENT DESIGN OF MEC REDUCE THE ULTIMATE COSTS CUSTOMERS WILL HAVE TO PAY RELATIVE TO THE MARKET/PPA PRICES WHICH WILL PREVAIL IN THE FUTURE?

A. I agree that the efficiency with which a plant translates natural gas into electricity, called a heat rate, plays a role in the ultimate costs customers will have to pay. MEC, which employs a combined-cycle (CC) plant design, is more efficient than the more common combustion turbine (CT) plant design. According to NSP testimony, a generic CC plant is about 37% more efficient than a generic CT plant on average.[43] However, the CC design advantage diminishes as utilization rates (the percentage of time a unit is operated) fall. In addition, the fixed costs of a CC are higher than the fixed cost of a CT. The question remains, is the higher cost of the MEC purchase over at least 15 years worth the potential fuel efficiency benefits the plants will offer if and when the plant's capacity is required?

While the MEC design features more efficient conversion of natural gas into electricity than the more common CT design, higher efficiency alone cannot answer this question. If the capacity available from MEC turns out not to be needed when the associated PPAs expire, the fact that MEC uses less natural gas per unit of electricity generated is moot.

Q. YOUR CHALLENGES TO THE NSP PREMISES RELY HEAVILY ON YOUR PREDICTION THAT DEMAND FOR CAPACITY AND ENERGY WILL CONTINUE TO FALL IN THE FUTURE. DO YOU HAVE ANY OTHER

[43] ND PSC PU-18-403. Testimony of Philip Joseph Martin. Schedule 1, page 14, Table 10.

INFORMATION TO SHARE WHICH INSPIRES CONFIDENCE IN THAT PREDICTION?

A. One thing that comes to mind is the question of why the current owner of MEC put the plant up for sale. The current owner has two PPAs in place which, thanks to the recent cut in the federal corporate income tax rate, are delivering a return on investment that is much higher than the owner originally anticipated. Further, those returns appear to be virtually locked in for the next 7 to 20 years, depending on the PPA. I ask, why would a corporation in this situation sell the plant now? In my estimation, the only reason would be a belief that the plant will never be worth more than it is right now. I then ask, in what situation would such a belief be true? Such a belief would be true in a situation in which demand for the plant's output is expected to fall over time, without the possibility it will return. In such a situation, who would be the most interested buyer for such a plant? I believe a regulated utility which can pass the risk for future obsolescence off on customers by placing the asset into rate base would be the most interested buyer. I recognize that these are hypothetical questions, to which I have provided hypothetical answers. But I believe they inspire confidence in my prediction that the demand for energy and capacity will be lower in the future than they are today, and I believe the current plant owner, though it would not admit it, probably agrees with my assessment of the situation.

Q. ARE THERE ANY OTHER REASONS YOU BELIEVE NSP'S APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE MEC PURCHASE SHOULD BE DENIED?

A. Yes. In highly similar circumstances which are basically unchanged, the Commission has already denied NSP's application for an advance determination of prudence for a PPA associated with MEC-II, stating:

"After considering all of the testimony and other evidence, the Commission finds NSP has not established the Calpine PPA is prudent. There is little or no dispute that there is not a need for this project until at least 2023 and the potential need at that time is largely based on NSP ceasing coal operations at Sherco. Approval of this project now would require customers to pay for unneeded capacity for a significant portion of the 20-year contract term. However, load forecasts and other assumptions underlying NSP's integrated resource plan are continually subject to change. The conclusions about prudence on which NSP relies to support this application may or may not occur. It is premature for the Commission to base an advance determination of prudence on such evidence."[44]

Given that the Commission has already denied NSP's advance determination of prudence application for a PPA associated with MEC-II in the same circumstances, I believe a precedent has been set. In NDPSC PU-15-96, the Commission's ruling implies that if the conditions required for prudence may or may not exist in the future, and customers are being asked to pay higher costs than necessary in the meantime, an advance determination of prudence would be premature. I agree with the Commission's Order in PU-15-96, and believe the wisdom demonstrated in that Order applies precisely to the present application.

IV. REVIEW, CONCLUSIONS, AND RECOMMENDATIONS

Q. PLEASE REVIEW YOUR TESTIMONY

A. In this testimony I challenged NSP witness Martin's claim that the cost reductions available from MEC ownership over the long term will outweigh higher costs in the short term. NSP's claim is based on two premises: 1) the load NSP will need to serve in the future, when compared to a future projection of NSP's generation portfolio, indicates a need for MEC capacity once the purchased power agreements (PPAs) these plants currently satisfy expire; and 2) the cost of any capacity and energy which might be needed when the current PPAs expire will be greater in the future than if a portion of such costs could be "locked in" today through the purchase of MEC.

I refuted the first premise in part by demonstrating that the growth in peak load NSP forecasts is unlikely to materialize. I compared the peak load forecasts from NSP's most recent three resource plans to NSP's actual peak load history, finding that NSP had

[44] NDPSC Case No. PU-15-96. Commission Order dated March 23, 2016. Page 4.

significantly overestimated peak load requirements in all three plans. I also found that NSP peak demand is flat (weather normalized) to falling over the past 8 years, which stands in stark contrast to the load growth NSP forecasts in its application. Later in my testimony I presented evidence that falling demand for capacity and energy is systemic and long-term due to continuing improvements in energy efficiency, and increasing customer use of demand response, self-generation, and electric storage (batteries), as well as falling energy intensity among industrial customers.

I also refuted the first premise by demonstrating that NSP's generation capacity forecasts are unreasonably pessimistic. Specifically, NSP's generation capacity forecasts assume the closure of nuclear plants which currently fulfill 22.4% of NSP's peak capacity requirement and 27.5% of its energy requirement with no carbon emissions. Citing activity in other states, I demonstrated why it is unlikely NSP's nuclear plants will close when their NRC operating licenses expire, between 2031 and 2035. I explained that the combination of over-estimated load growth and under-estimated generation capacity creates a forecasted need for MEC capacity which is much nearer and greater than is realistic, thereby reducing if not eliminating the likelihood that the MEC purchase will reduce costs to customers over time.

My testimony also challenged the second premise (that the cost of any capacity and energy which might be needed when the current PPAs expire will be greater in the future than if a portion of such costs could be "locked in" today through the MEC purchase). I described why I believe the risk of higher capacity and energy prices when the current PPAs expire is low. I cited the aforementioned rationale for systemic, long-term reductions in demand for capacity and energy as evidence that upward pressure on prices is apt to be low in the future. I also cited historical experience in MISO and PJM capacity markets as evidence that open wholesale markets will continue to ensure an adequate supply of generation capacity, reducing the likelihood of exceptional growth in capacity and energy prices in the long term. The fact that capacity prices in MISO have been flat since the market's inception, and the fact that the trend in PJM capacity price is growing at a compound annual growth rate of less than 3%, supports my arguments that markets work to mitigate long-term price increases.

I agreed with NSP's claim that MEC is more efficient than other natural gas-fueled plants. However, I disputed the implication that this feature will be sufficient to outweigh higher customer costs over a minimum of 15 years. I also noted that this feature fails to deliver benefits to customers if the plant's output is not needed when the current PPAs expire. Finally, I put myself in the place of the current plant owner, hypothesizing that now is the time to sell if the plant owner believes demand for the plant's output will fall in the future. I also noted that the Commission has already ruled against an advance determination of prudence in instances in which uncertain future conditions are required before prudence can be demonstrated.

Q. BASED ON THIS TESTIMONY, WHAT ARE YOUR CONCLUSIONS?

A. I conclude that MEC capacity is unlikely to be necessary in a timeframe which is sufficiently early to ensure the incremental benefits late in the plant's life, if any, exceed the incremental costs of the purchase to customers early in the plant's life. Furthermore, I conclude the uncertain and even unlikely future benefits to customers of an MEC purchase do not justify the certainty of higher costs in the near term.

While on the subject of conclusions, I believe it is important to note that mine are based on the assumption that NSP's rate impact estimates and associated present value calculations are accurate. The testimony of Advocacy Staff witness Michael Majoros casts doubt on this assumption, lending further credence to my recommendations.

Q. BASED ON YOUR TESTIMONY AND CONCLUSIONS, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. Based on my testimony and conclusions, I recommend the Commission deny NSP's application for an advance determination of prudence in the purchase of MEC. I also recommend the Commission revisit the need for additional rate-based generation capacity in future resource planning cycles, giving significant attention to 1) the accuracy of NSP's load forecasts; 2) the systemic, long-term electric wholesale and retail market changes likely to impact those forecasts; and 3) the likely future status of NSP's nuclear generating plants.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. However, I reserve the right to revise my testimony based on NSP responses to outstanding discovery or new information which may become public relevant to subject matter covered herein.

ATTACHMENT A

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 150963, Lakewood, CO 80215 palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Appearances and Research Projects in Regulatory Proceedings

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017.

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Grid Modernization in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators.* Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company **Advance Prudence –Mankato Energy Center** **Application**	**Case No. PU-18-403**

VERIFICATION

STATE OF Colorado)
) **ss.**
COUNTY OF Jefferson)

Paul J. Alvarez, being first duly sworn on oath, deposes and states that he has read the testimony and any exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Paul J. Alvarez

Subscribed and sworn to before me this 28th day of May, 2019.

WILLIAM F HEIN
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184009209
MY COMMISSION EXPIRES 02/26/2022

Notary Public
My Commission Expires: 2/26/2022