Diller, Michael R.

From: Diller, Michael R.
nt: Thursday, December 11, 2014 5:03 PM
dave.sederquist@xcelenergy.com
Cc: Schock, Victor F.
Subject: Requests for Information
Attachments: RFI's for NSP's Solar Farms.docx

Dave,

Attached are 5 general questions relating to your proposed solar portfolio ADP, Case No. PU-14-810.

If you have any questions, please advise. Mike

Northern States Power Company
Advance Determination of Prudence for 187 MW's of Solar
Case No. PU-14-810
December 11, 2014
Requests for Information from Mike Diller

1. Questions concerning Minnesota statute 216B.1691:

a) Provide NSP's understanding of legislative rationale for excluding iron mining extraction and processing facilities as well as paper mills, wood products manufacturers, sawmills and strand board manufacturers from paying for any costs associated with satisfying Minnesota's solar standard of 1.5% by 2020 and its goal of 10% by 2030.

b) The statute indicates that a solar photovoltaic device "installed and generating electricity in Minnesota" may be used to meet Minnesota's solar energy standard by 2020. Could solar PV devices located in North Dakota be used to meet Minnesota's standard and if so please explain?

c) According to the statute, at least ten percent of the 1.5% solar goal must be met by solar energy generated or procured from PV devices with a nameplate capacity of 20 kilowatts or less. How far along is NSP in meeting this requirement? Provide the average levelized cost of energy for these facilities and indicate if any of the costs are being assigned to North Dakota?

2. Questions concerning NSP's Request for Proposals for up to 100 MW's of PV Solar Generation Resources:

a) Please explain what you mean by NSP has an "interest in partnering in the ownership of the project through an affiliate of ours" (Page 43 of Schedule 2 of application). Include in your explanation how this would benefit ratepayers compared to ownership by the utility company rather than an affiliate and disclose any and all agreements related to ownership possibilities in the future by an affiliate.

b) Of the more than 100 proposals, how many were from different states and were the out-of-Minnesota state proposals given equal and fair consideration given what appears to be a Minnesota location preference? Provide the Levelized Energy Cost for the two lowest out-of-Minnesota state proposals received and indicate why they were not selected.

c) Interconnection to the grid appears to be a very important element to the cost of a solar project yet little is provided by NSP to potential bidders in this regard. In fact they are discouraged from requesting information from MISO and the Company. Describe how the bidders coped with submitting bids with little knowledge of interconnectivity and how this resulted in an unbiased process. It appears to me that companies familiar with NSP's operation would have a leg up on other bidders given the lack of system information available for bidding.

3. Questions concerning NSP's Application:

a) Based on the three solar proposals, it takes about 7 to 8 acres of land per MW. How much of these solar footprints can be farmed or used for other purposes?

b) There have been tremendous solar efficiency gains in recent years in terms of cost and solar collection. What efficiency gains did you assume going forward when determining to acquire solar now rather than 2019 or later when capacity and energy might be needed? In other words, if industry is expecting to experience a 7% efficiency gain each year in the near future, how does the proposed PVRR compare to the PVRR if solar is not installed until 2020, assuming a 10% ITC rather than a 30% ITC?

c) Provide all material assumptions used in developing Table 1. In regards to Table 1, please explain the importance of "Markets Off" modeling as I see no reason to assume market electricity will not be available. Explain what the Capacity Factor columns are and its importance to evaluating this proposal as it appears that a 2.5% increase in capacity factor (presumably the solar farms) increases the overall PVRR. Less appears to better than more.

d) Provide all material assumptions and support for the assumptions used in developing Table 2.

e) It appears from Table 3 that a 50 cent increase in the assumed cost of gas or a .5 cent increase per kWh in market energy would eliminate the net cost of adding these solar projects. Please provide a more precise break-even point for each. Provide reference material considered for establishing cost of gas and market energy prices in graphical form to show differences between the projected prices by various entities and the assumed prices for planning purposes. Include average actual prices for gas and market energy for the last 10 years to give the chart some historical perspective.

4. Questions concerning Laura McCarten's testimony:

a) Laura's testimony states that NSP is purchasing this energy "primarily" to comply with Minnesota's solar energy standards (SES) but that it would also provide a hedge against purchasing gas and market energy. Prior to the passage of SES, please provide all solar projects selected by NSP's resource planners for integrated resource planning purposes.

b) How much cost associated with behind-the-meter solar generation and community solar gardens are currently being assigned to North Dakota?

c) What is the current market value of solar Renewable Energy Credits? What does NSP project for the value of REC's in the future and what is included in the resource model?

5. Questions concerning Kurt Haeger's testimony:

a) Please reconcile the 300 MW's of solar power necessary per testimony to meet the 2020 SES and the 100 MW's of solar power described as needed by the Leidos' Audit Report given the Minnesota banking rules for REC's (Page 19, Schedule 2 of Application).

b) What indications have you received from your tax people concerning the possibility that the 30% ITC might be extended beyond 2016.

c) Please describe your observations about technology improvements in the solar industry including pricing efficiencies during the past 10 years and how and to what extent future efficiencies will occur and how such is incorporated into integrated resource modeling and planning.

d) Does NSP give any consideration to the societal cost of removing agricultural land from food production when acquiring solar generation? Why not?

e) All three purchase power agreements are for 25 years. Please provide any information you have concerning the expected life of a solar farm. Discuss the potential longevity and cost decline of these solar units beyond the 25 contract period.

f) If the sun is above the horizon an average of 12 hours a day; the sky is only clear about half the time; the project owners must only meet 85% of the Committed Solar Energy; and NSP can curtail production under a number of scenarios, how can the expected capacity accreditation be 52%? Provide assumptions and calculation. How does this calculation support or detract from the use of 12CP for allocating generation resources among the various state jurisdictions? How have the rules for determining accreditation changed since the inception of MISO and what changes are expected in the future? Is this accreditation calculation applied similarly to other types of resources?

g) Because PV technology directly converts sunlight to energy, sunlight reaching the ground is critical. Provide the ten top bidders in terms of sunlight availability. For those with better sunlight availability than the chosen projects, please explain why those bids were rejected. Provide the resources that were used to determine whether a project's sunlight availability assumptions were reasonable.

h) Please provide the rationale for arguing that "conditional" Generator Interconnect Agreements should qualify as capacity resources.

i) Provide the monthly peak demand of NSP and the expected contribution to meeting those peaks by resource including capacity factors of each resource during those peak times for the next 5 years.

j) Please clarify and explain Answer on Page 19 of Mr. Haeger's Direct Testimony.

k) Provide NSP's required planning reserve margin since the inception of MISO, how the calculations have changed under MISO and why you believe the current calculation is stable and conservative. Provide the impact to capacity requirements for any changes that have occurred.

Diller, Michael R.

From:	Hedlund, Amber R <Amber.R.Hedlund@xcelenergy.com>
nt:	Monday, December 29, 2014 4:32 PM
:	Diller, Michael R.
Cc:	Sederquist, Dave
Subject:	Xcel Energy's Responses to NDPSC Data Request Nos. 1, 2 Public, 3 Public, and 4_Case No. PU-14-810
Attachments:	Cvr Letter NDPSC DRs 1-4.pdf; NDPSC-001.pdf; NDPSC-002 PUBLIC.pdf; NDPSC-003 PUBLIC.pdf; NDPSC-004.pdf

Dear Diller:

Enclosed please find a cover letter and responses to Data Request Nos. 1, 2 Public, 3 Public and 4 concerning Xcel Energy's Solar Portfolio ADP.

The Non-Public responses to NDPSC Data Request Nos. 2 and 3 will be sent under separate cover following the Commission's approval of an order for trade secret protection pursuant to N.D.C.C. § 69-02-09-01.

Please contact me if you have any questions regarding this submission. Thank you.

Amber Hedlund
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Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

December 29, 2014

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—Via Electronic Filing—

Michael Diller
North Dakota Public Service Commission
State Capitol Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: RESPONSES TO DATA REQUEST NOS. 1, 2 PUBLIC, 3 PUBLIC, AND 4
SOLAR PORTFOLIO ADP
CASE NO. PU-14-810

Dear Mr. Diller:

Enclosed please find our responses to the referenced North Dakota Public Service Commission staff Data Requests in the above noted case. The Non-Public responses to NDPSC Data Request Nos. 2 and 3 will be sent under separate cover following the Commission's approval of an order for trade secret protection pursuant to N.D.C.C. § 69-02-09-01.

Please note, we anticipate sending our response to NDPSC Data Request No. 5 this week.

Sincerely,

/s/

AMBER HEDLUND
REGULATORY CASE SPECIALIST

cc: Dave Sederquist

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☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	1
Requestor:	Michael Diller		
Date Received:	December 15, 2014		

Question:

Questions concerning Minnesota statute 216B.1691:

a) Provide NSP's understanding of legislative rationale for excluding iron mining extraction and processing facilities as well as paper mills, wood products manufacturers, sawmills and strand board manufacturers from paying for any costs associated with satisfying Minnesota's solar standard of 1.5% by 2020 and its goal of 10% by 2030.

b) The statute indicates that a solar photovoltaic device "installed and generating electricity in Minnesota" may be used to meet Minnesota's solar energy standard by 2020. Could solar PV devices located in North Dakota be used to meet Minnesota's standard and if so please explain?

c) According to the statute, at least ten percent of the 1.5% solar goal must be met by solar energy generated or procured from PV devices with a nameplate capacity of 20 kilowatts or less. How far along is NSP in meeting this requirement? Provide the average levelized cost of energy for these facilities and indicate if any of the costs are being assigned to North Dakota?

Response:

a) Minn. Stat. § 216B.1691, subdivision 2f (Solar Energy Standard or SES Statute) exempts retail sales to (i) iron mining extraction and processing facilities (including scram mining), and (ii) paper mills, wood products manufacturers, sawmills, and oriented strand board manufacturers from a utility's calculation of its SES requirement (1.5 percent of total retail electric sales), and further provides that the costs of the SES requirement not be reflected in the rates charged to these customers. While the Minnesota Legislature excluded these industry groups from the SES requirement, the statute does not provide specific rationale.

b) We do not interpret this section to restrict the use of solar produced in North Dakota from counting toward the SES.

c) The 1.5 percent SES will be met through the recording of Renewable Energy Credits (REC) in the Midwest Renewable Energy Tracking System (M-RETS®). The Company plans to meet the under 20KW PV system generation requirement through Minnesota customer's participation in the Company's Solar*Rewards program, and the Minnesota Department of Commerce's Made in Minnesota program. The programs provide incentive dollars to qualifying participants who install small PV systems. Both programs are funded solely by Minnesota customers via rate riders. Solar*Rewards is funded through Renewable Development Fund (RDF) rider, and the Made in Minnesota program is funded from the Conservation Improvement Program rider and the RDF rider. A key term of these programs is the receipt of the RECs for each unit of the participant's energy production.

   For "first generation" 20KW PV systems installed in 2013 as part of the Solar*Rewards program, the Company acquired 12 Solar RECs (SREC). We note that many systems were commissioned and began producing only in the final weeks of the year. The 2014 second generation solar energy and SREC data for the Solar*Rewards and Made in Minnesota programs is not yet available.

   Customers who participate in Solar*Rewards or Made in Minnesota programs install, operate and fund the PV system, metering and interconnection costs. Customer installing the PV systems also benefit by offsetting their system energy usage. Should these customer's PV systems produce more power than the customer uses in a given period, that customer would receive a payment or bill credit for the excess production under the tariff they have elected to receive excess energy payments. In 2013, the Company paid out a total of $103,690 for excess energy purchases and recovered the cost through the Fuel Cost Rider. North Dakota's share of the excess energy purchases was approximately 5 percent of that total.

Preparer:	Rick Evans / Nick Paluck
Title:	Director*Regional Government Affairs / Rate Consultant
Department:	NSPM State Public Affairs / Regulatory Analysis
Telephone:	612.337.2256 / 612.330.2905
Date:	December 29, 2014

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Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	2
Requestor:	Michael Diller		
Date Received:	December 15, 2014		

Question:

Questions concerning NSP's Request for Proposals for up to 100 MW's of PV Solar Generation Resources:

a) Please explain what you mean by NSP has an "interest in partnering in the ownership of the project through an affiliate of ours" (Page 43 of Schedule 2 of application). Include in your explanation how this would benefit ratepayers compared to ownership by the utility company rather than an affiliate and disclose any and all agreements related to ownership possibilities in the future by an affiliate.

b) Of the more than 100 proposals, how many were from different states and were the out-of-Minnesota state proposals given equal and fair consideration given what appears to be a Minnesota location preference? Provide the Levelized Energy Cost for the two lowest out-of-Minnesota state proposals received and indicate why they were not selected.

c) Interconnection to the grid appears to be a very important element to the cost of a solar project yet little is provided by NSP to potential bidders in this regard. In fact they are discouraged from requesting information from MISO and the Company. Describe how the bidders coped with submitting bids with little knowledge of interconnectivity and how this resulted in an unbiased process. It appears to me that companies familiar with NSP's operation would have a leg up on other bidders given the lack of system information available for bidding.

Response:

a) Our Request for Proposals (RFP) was structured to allow bidders to propose any and all structures for their projects. This included, but was not limited to, power purchase agreements (PPA), Company ownership, and affiliated ownership. Our selection ultimately resulted in just PPAs being pursued. That said, an ownership

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structure through an affiliate rather than through Company ownership may have provided additional tax advantages related to the Investment Tax Credit, and we wanted to make that option available to bidders. Since no affiliate ownership projects were selected, however, we have not fully explored the benefits and trade offs that affiliate ownership would have provided compared to Company ownership.

b) There were six out-of-Minnesota project proposals, for all of which the Company evaluated bid completeness and price, as well as conducted due diligence on siting and transmission risks. Only two of these proposals had levelized pricing below the initial pricing screening threshold of $85/MWh levelized. The two lowest cost out-of-Minnesota state proposals were (i) Heliosage's 50 MW Leder Solar Center with a levelized cost of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** to be sited in Stuttgart, Arkansas, and (ii) PRC Solar LLC's 50 MW North Dakota Project with a levelized cost of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** to be sited in Stanton, ND. The Leder Solar Center project was rejected from the short list as it did not make arrangements for delivery of energy to our Local Resource Zone 1 in the MISO footprint. This project is located in MISO South, and the contract limit of 1000 MW between MISO regions is currently being exceeded by existing transfers.

PRC Solar LLC was rejected from the short list because it proposed a Net Zero interconnection with MISO. MISO's proposed Net Zero process would have required GRE (the owner of the transmission system to which the PRC Solar project would interconnect) to post for the availability of a Net Zero interconnection. To our knowledge, this has not occurred. Although we support the use of Net Zero Interconnection, given the complexity of the proposed arrangement and the fact that GRE's desire to allow for the Net Zero Interconnection was not known, we decided not to pursue this project.

c) The Company is limited in the amount of detail it can disclose regarding its transmission and distribution system because much of that information is deemed to be Critical Energy Infrastructure Information. Consequently, bidders were required to use their industry expertise and experience to make their own assessment of potential interconnection sites and related costs.

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This process did not bias any particular bidders, and to our knowledge, did not prohibit any potential bidders from preparing and submitting a complete proposal inclusive of estimated interconnection costs. This was confirmed by the auditors hired to monitor the RFP.

Preparer:	Mary Morrison / Paul Johnson / Randy Oye
Title:	Resource Planning Analyst II / Resource Planning Director / Transmission Analyst
Department:	Resource Planning / Resource Planning / Market Operations
Telephone:	612.330.5862 / 612.330.6238 / 612.330.2886
Date:	December 29, 2014

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Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	3
Requestor:	Michael Diller		
Date Received:	December 15, 2014		

Question:

Questions concerning NSP's Application:

a) Based on the three solar proposals, it takes about 7 to 8 acres of land per MW. How much of these solar footprints can be farmed or used for other purposes?

b) There have been tremendous solar efficiency gains in recent years in terms of cost and solar collection. What efficiency gains did you assume going forward when determining to acquire solar now rather than 2019 or later when capacity and energy might be needed? In other words, if industry is expecting to experience a 7% efficiency gain each year in the near future, how does the proposed PVRR compare to the PVRR if solar is not installed until 2020, assuming a 10% ITC rather than a 30% ITC?

c) Provide all material assumptions used in developing Table 1. In regards to Table 1, please explain the importance of "Markets Off" modeling as I see no reason to assume market electricity will not be available. Explain what the Capacity Factor columns are and its importance to evaluating this proposal as it appears that a 2.5% increase in capacity factor (presumably the solar farms) increases the overall PVRR. Less appears to better than more.

d) Provide all material assumptions and support for the assumptions used in developing Table 2.

e) It appears from Table 3 that a 50 cent increase in the assumed cost of gas or a .5 cent increase per kWh in market energy would eliminate the net cost of adding these solar projects. Please provide a more precise break-even point for each. Provide reference material considered for establishing cost of gas and market energy prices in graphical form to show differences between the projected prices by various entities and the assumed prices for planning purposes. Include average actual prices for gas and market energy for the last 10 years to give the chart some historical perspective.

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Response:

a) The solar developers intend to purchase the land sites identified in their bid proposals for the purposes of installing and operating a solar energy site. Aerial diagrams of land plots and panel layout indicate the land's primary use will be for support of the panel structures. However, this does not preclude the developer from seeking a secondary use of this land.

b) With respect to future solar efficiency gains, we reviewed IHS Energy's October 2014 Market Brief entitled "Outlook for US Solar PV Capital Costs and Prices, 2014-2030." Based on its research, IHS expects solar PV capital costs to fall approximately 45 percent by 2030. Whether this is the result of a constant gradual reduction or stepped reduction in cost is not known. IHS also projects the following efficiency gains from 2009 to 2030 for three module types: 11 percent to 21.5 percent for Thin film-Cd-Te TF modules; 14.5 percent to 22 percent for c-Si modules; and 17.5 percent to 26 percent for Super-monocrystalline modules. By 2020, the respective efficiencies of these module types are projected to be 18.5 percent, 19.5 percent and 24 percent. A copy of the IHS Market Brief is included as Attachment A to this response to provide additional information and support.

As for the PVRR difference between a project with a 30 percent Investment Tax Credit (ITC) benefit and the same project with a 10 percent ITC benefit, we are unable to provide that information. The Company did not receive bid data for non-ITC projects such that it would be able to develop a basis for projecting power purchase agreement (PPA) prices under a 10 percent ITC scenario.

c) The material assumptions and support for the Strategist modeling of the solar portfolio is included as Attachment B to this response.

The "Markets Off" sensitivity was provided to illustrate the benefits/costs of the solar PPAs to the system when considered in isolation rather than as part of the regional market. The Company makes no assertion as to the importance of this sensitivity.

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The "Capacity Factor" columns are additional sensitivity cases provided to illustrate the impacts of varying actual PPA output vs. the base capacity factor assumptions. Because these PPAs are structured as a cost per MWH generated, an increase or decrease in project capacity factor will change both the avoided energy benefit/cost as well as the PPA costs. In the respective sensitivity cases, the generation output of the PPA projects was increased or decreased by adjusting the annual expected capacity factor by +/- 2.5%. The Company makes no assertion as to the importance of these sensitivity cases.

d) See Attachment B provided in response to 3c above.

e) The Company used a spreadsheet-derived approximation to determine the requested breakeven PVRRs for the solar PPA portfolio compared to the Base Case. In this approximation methodology, a fixed adder was applied to the base gas or power costs in $2014 and escalated at inflation (1.66 percent). This adder was multiplied by the avoided gas or power volumes per year and iteratively changed until the NPV of the avoided gas or power costs were equal to the PVRR cost delta for the solar PPA ($14.3M). From this analysis, the breakeven cost adder was <u>$0.84 per MMBTU</u> for gas, or <u>$7.17 per MWH</u> (0.72 ¢ per kWh) for power.

The requested historical and forecast information for gas and power are provided as Trade Secret Attachment C to this response. Due to copyright and license restrictions, this material is trade secret and may only be released to regulatory agencies and their staff without individual licenses being obtained from the data sources themselves (PIRA, CERA, Wood McKenzie).

Preparer:	Mary Morrison / Paul Johnson / Jon Landrum
Title:	Resource Planning Analyst II / Resource Planning Director / Resource Planning Analytics Manager
Department:	Resource Planning / Resource Planning / Resource Planning
Telephone:	612.330.5862 / 612.330.6238 / 303.571.2765
Date:	December 29, 2014

IHS ENERGY

Market Brief

North America Renewable Power Advisory

Outlook for US Solar PV Capital Costs and Prices, 2014–2030

7 October 2014

ihs.com

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Contents

Summary

IHS Energy expects solar PV benchmark capital costs to fall approximately 45% by 2030.

- Utility-scale solar PV benchmark capital costs are anticipated to fall to US$1.21/WattDC by 2030 (nominal), with lower-cost modules and inverters accounting for 60% of the expected cost improvement.
- Residential solar PV systems have the potential for the greatest percentage cost reduction by 2030, falling below US$2/Watt by 2030.

Improving solar PV module efficiencies underpin solar PV system cost declines.

- Leading OEMs are focused on driving up module efficiency to increase power density for distributed solar applications.
- Module efficiency gains also contribute to lower balance of system (BoS), installation, and development costs per watt.
- Average module prices are projected to fall below US$0.40/WattDC in 2030, down from US$0.70/WattDC in 2014.

The required price for distributed solar PV reaches parity with retail power prices in the US Southwest before 2020 without the 30% investment tax credit (ITC).

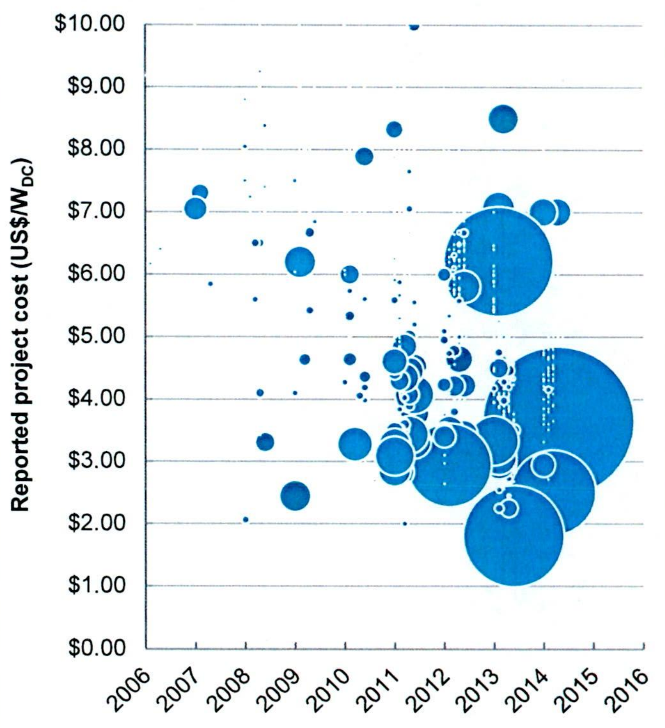
- Required prices for residential-scale solar systems are expected to reach between US$140/MWh and US$200/MWh (nominal) by 2030, depending on solar resource, without the federal ITC.
- A long-term extension of the 30% ITC would put residential solar PV prices below retail power prices in most states by 2025.

Utility-scale solar PV power reaches parity with wholesale power prices in California by 2020, but rising solar penetration thereafter creates price risk for developers.

- California will become the first US state where utility-scale solar PV can compete with wholesale power prices.
- Utility-scale solar PV power prices reach projected on-peak wholesale power prices in West Texas and the Southwest by 2025.

Benchmark capital costs

Reported project cost data in the US



Notes: Bubbles denote project nameplate capacity (MW$_{DC}$).
Source: IHS, state and federal registries

Historical solar PV benchmark capital costs for residential, commercial, and utility-scale projects are derived from component pricing and validated with project data.

- IHS tracks system, component, and customer acquisition costs through various public sources and surveys of key suppliers, and validates its estimates through industry discussions.
- IHS has analyzed cost data for over 200,000 distributed solar projects (3 GWDC total capacity) installed between 2003 and Q2 2014. Data is sourced from the US Treasury 1603 cash grant program; state reporting registries in California, Massachusetts, New York, Arizona, and Connecticut; and tracked through IHS Energy's project database.

IHS's outlook for benchmark capital costs is based on expectations for continued improvement in module efficiencies and individual solar system components.

- Benchmark capital cost outlooks reflect assumptions for both technology learning curves and expectations for commodity costs.
- Benchmark capital cost outlooks are broken down to module, inverter, balance of system (BoS), single-axis tracking equipment, and development costs including grid interconnection.
- Outlooks assume that the relative costs of regional project development will stay constant over the outlook period.
- All costs are nominal and reported in US$/WattDC unless otherwise indicated and reflect total capitalized costs (owner's costs plus overnight capital costs).

Modeling solar PV's required price

Methodology and assumptions	
Model outputs and methodology	**IHS Energy has modeled for each region a levelized nominal required price of power for new solar PV projects installed each year through 2030, and calculated the gap between the wholesale power price and the levelized required solar PV price. The following items are included in the regional charts that follow:** 1) **Levelized required solar price:** Estimated nominal unit cost (US$/MWh) over the life of a project required to bring new solar PV generation online in a given year and region; price does not include transmission or integration costs; represents a fundamental, cost-based assessment and does not reflect the effects of potential regional supply/demand imbalances. 2) **Levelized wholesale power price:** Estimated nominal base power price (US$/MWh) that could be realized by a solar project for its power sold on the wholesale market; built up from forecasts of annual average wholesale on-peak prices with the additional assumption that a solar project generates 100% of its output on peak; forecasts are based on IHS's reference case and reflect regional hub prices. 3) **Levelized required solar price differential:** Difference between (1) and (2).
Model inputs and assumptions	**Capital costs:** IHS Energy forecasts benchmark capital costs for solar PV to 2030, and, based on historical cost differentials, has established a projection for benchmark costs on a segment basis (residential, commercial, and utility-scale projects); trends reflect assumptions for both technology learning curves and expectations for commodity costs and other market factors; all costs are nominal unless otherwise indicated and reflect total capitalized costs (owner's costs plus overnight capital costs). **Capacity factors:** Capacity factor estimates are regionally specific and reflect IHS Energy's assessment of representative regional solar resource data; capacity factors represent net generation delivered to the grid. **Cost of capital:** All modeling is done on a nominal basis with a target unlevered return of 6.99%; this target represents an equity hurdle rate of 11%, a debt rate of 7%, and a debt-to-equity ratio of 60:40. **Tax incentives (ITC, MACRS):** IHS Energy's base forecast, which serves as the foundation for this analysis, assumes that the federal investment tax credit (ITC) is worth 30% of project capital costs, and remains in place through the end of 2016 and falls to 10% of project capital costs beginning in 2017; the ITC remains at 10% through the remainder of the forecast period. Five-year modified accelerated cost recovery (MACRS) tax depreciation schedules hold throughout the period. All tax benefits are assumed to be realizable by a corporate parent; any need for a tax equity partner would raise the cost of capital and thus the price or power required for a given project. **Required prices:** Required solar power prices are quoted on a US$/MWh basis in nominal terms and represent the long-term levelized price that IHS Energy estimates will be required to bring a new benchmark project online in a given year and region. Detailed modeling assumptions are presented at the end of this report and in the accompanying data sheets.

Source: IHS

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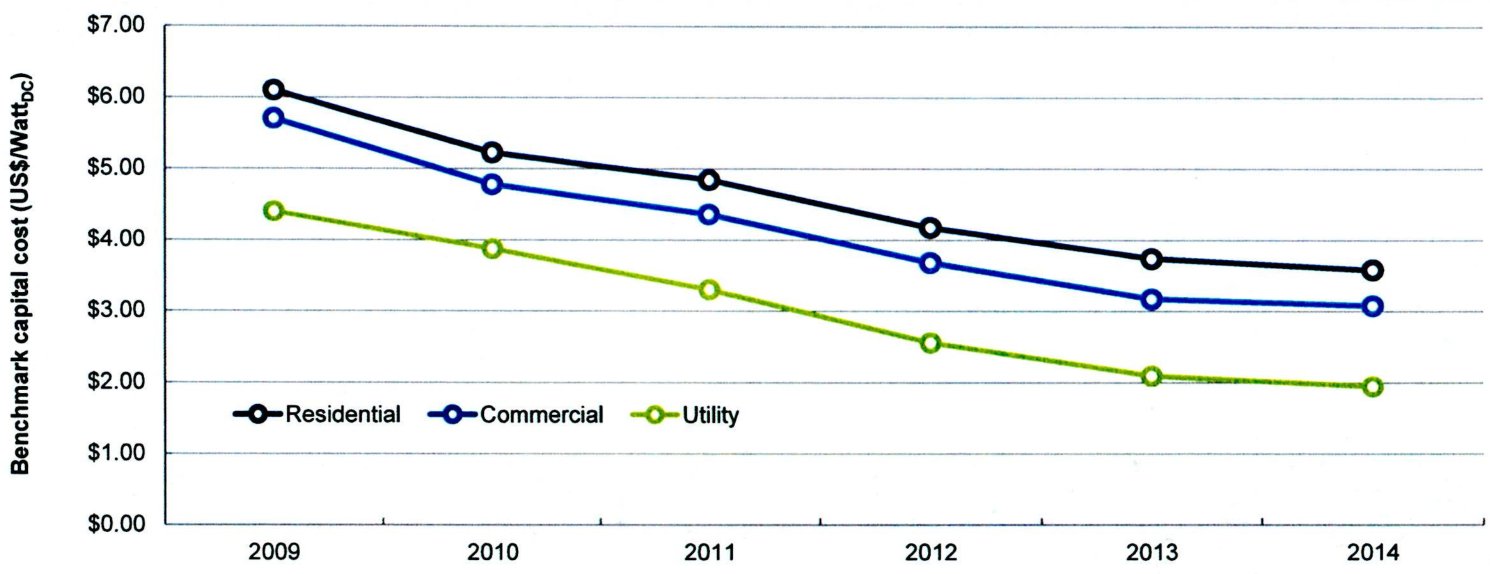
Historical trends in solar PV capital costs

Solar PV benchmark capital costs by segment

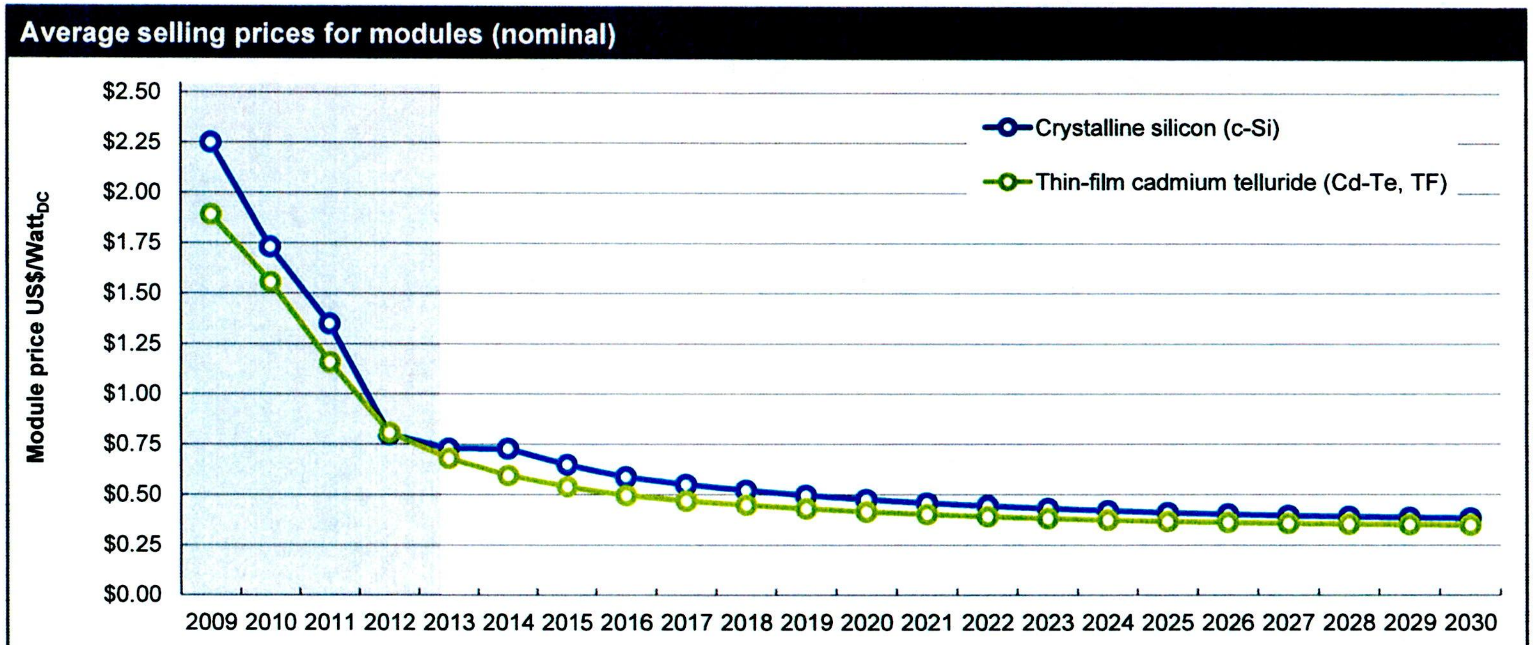


Notes: Historical benchmark residential and commercial capital costs reflect the average of the least-cost quartile of project costs in California, Arizona, Massachusetts, New York, and Connecticut.
Source: IHS, state registries

Benchmark solar PV capital costs have fallen by about half since 2009, a 10% average annual cost improvement.

Solar PV module trends

US solar PV module price outlook, 2009–2030



Notes: Average historical c-Si module prices based on tier-one Chinese manufacturers. Prices for 2014-2030 reflect global average module selling prices for Western manufacturers. Cd-Te module prices reflect estimated global average selling price.
Source: IHS

c-Si module prices are expected to fall below US$0.40/Watt by 2022, down from over US$4/Watt in 2005.

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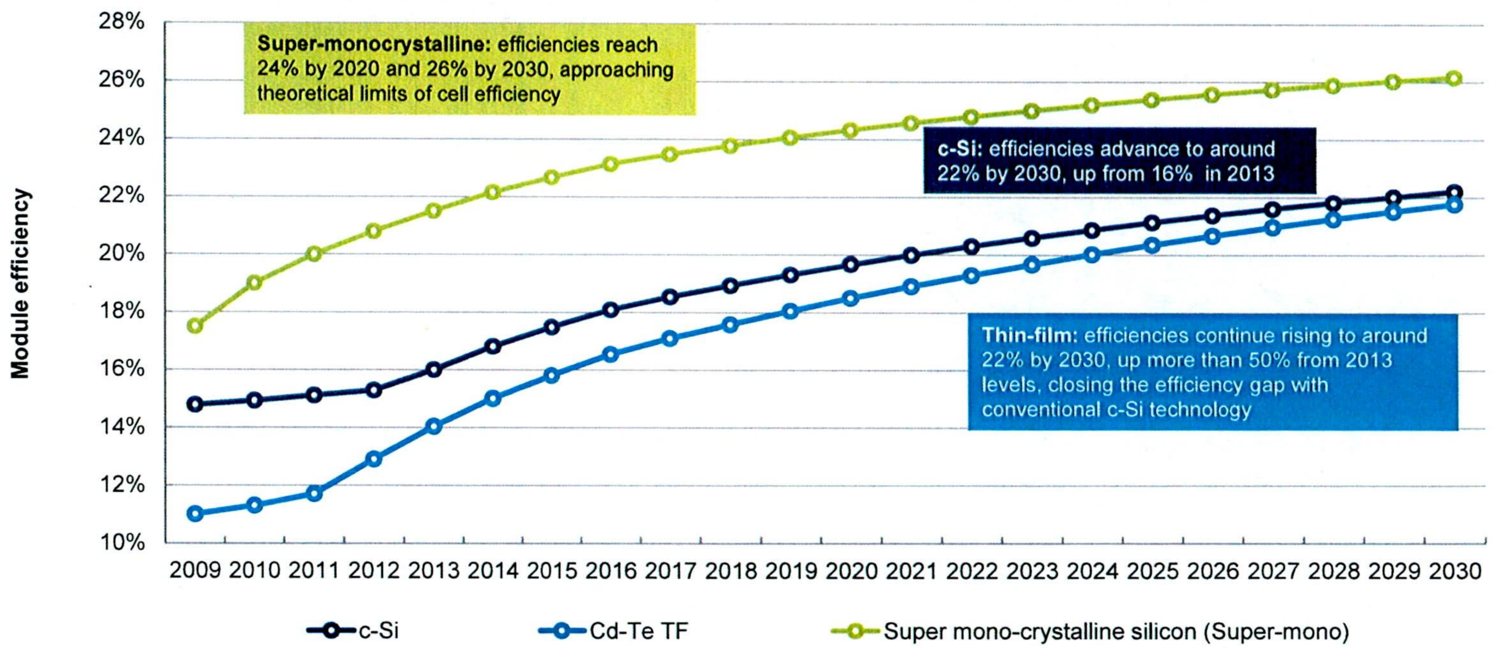
Outlook for solar PV module efficiency, 2009–2030

Outlook for module efficiencies

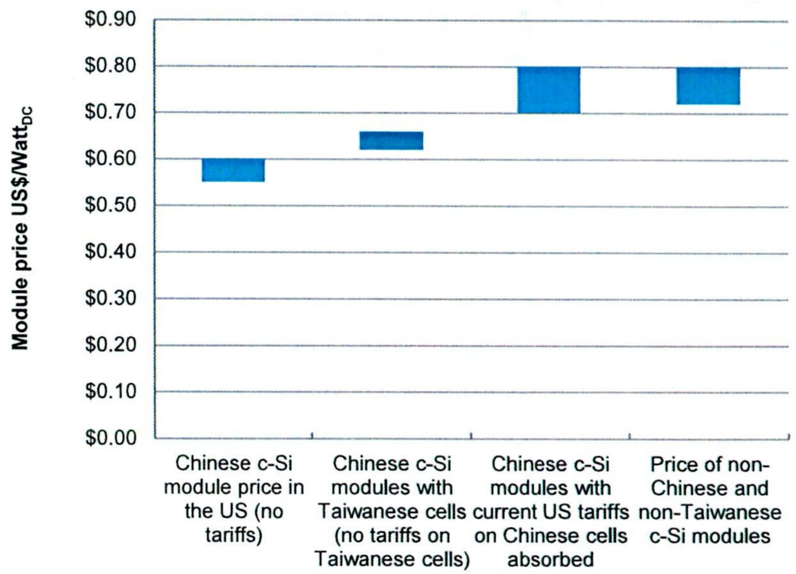


Source: IHS

Improving solar PV module efficiencies underpin solar capital cost declines.

Effect of US tariffs on imported Chinese c-Si module prices

Comparative price of c-Si modules after impact of US preliminary tariffs



Notes: For additional details please see IHS Energy's 29 April 2014 On Point, Spring Tariffs Cast Shadow Over US Solar Industry.
Source: IHS

Anti-dumping tariffs and countervailing duties issued by the US Department of Commerce (DOC) have driven up module prices.

- Preliminary anti-dumping tariffs announced in July 2014 add 26% to 59% to the price of imported Chinese modules, and compound preliminary countervailing tariffs of 19% to 35%, which were previously imposed on 3 June 2014.
- IHS estimates the latest tariffs have increased average module prices by 12% this year.
- See IHS Energy's 29 April 2014 On Point, Spring Tariffs Cast Shadow Over US Solar Industry for more details.

Tariffs erode the cost advantage held by Chinese players, but do not completely undermine their price competitiveness.

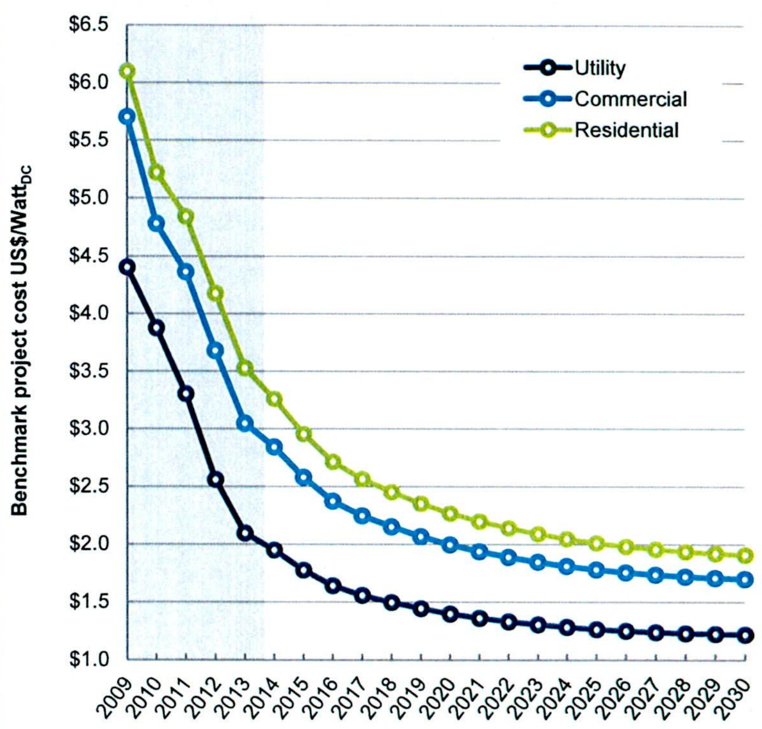
- Chinese modules supplied to the US had been selling as low as US$0.62–0.65/WattDC earlier in 2014, including the premium from sourcing cells from Taiwan.
- With the preliminary tariffs, average Chinese module prices in 2014 are estimated to range from US$0.70 to US$0.80/WattDC assuming companies elect to ship modules with Chinese cells, which is on par with modules imported from other regions.

US tariffs imposed on imported Chinese modules have slowed declines in solar capital costs.

Solar PV capital cost trends

Solar PV capital cost outlook, 2009–2030

Benchmark solar PV capital costs outlook (nominal)



Notes: Costs are based on projects using c-Si modules.
Source: IHS

Solar PV benchmark capital costs are expected to fall 35% by 2020 and 45% by 2030.

- Module efficiency gains yield lower balance of system (BoS), installation, and development costs per watt for all project sizes.
- Inverter price improvements, which bring US prices in line with Europe, also contribute to future cost reductions.
- Residential systems show the greatest reduction in percentage terms, falling 47% by 2030.

Utility-scale benchmark capital costs will fall from US$1.95/WattDC in 2014 to US$1.21/WattDC in 2030.

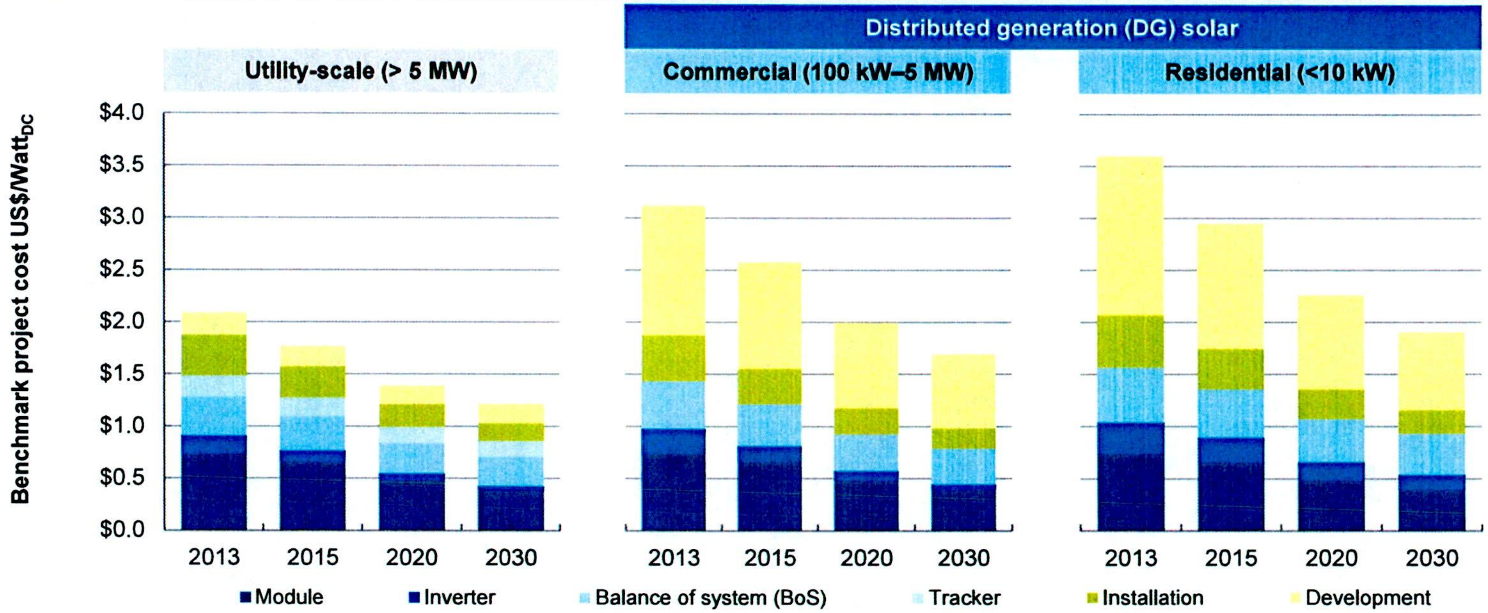
- Module and inverter price declines account for 60% of total cost reductions expected by 2020.
- Falling installation costs—resulting from greater plant standardization and higher efficiency modules—account for most of the remaining gains.

Commercial and residential benchmark capital costs reach US$1.69/WattDC and US$1.90/WattDC, respectively, in 2030.

- Module and inverter price declines account for 41% of total cost reductions by 2020.
- Industry consolidation and scale-up drive down development and customer acquisition costs by half.
- Installation costs also fall by half due to a combination of more efficient modules and more streamlined installation procedures.

Trends in solar PV capital cost compression

Solar PV benchmark capital costs (nominal)

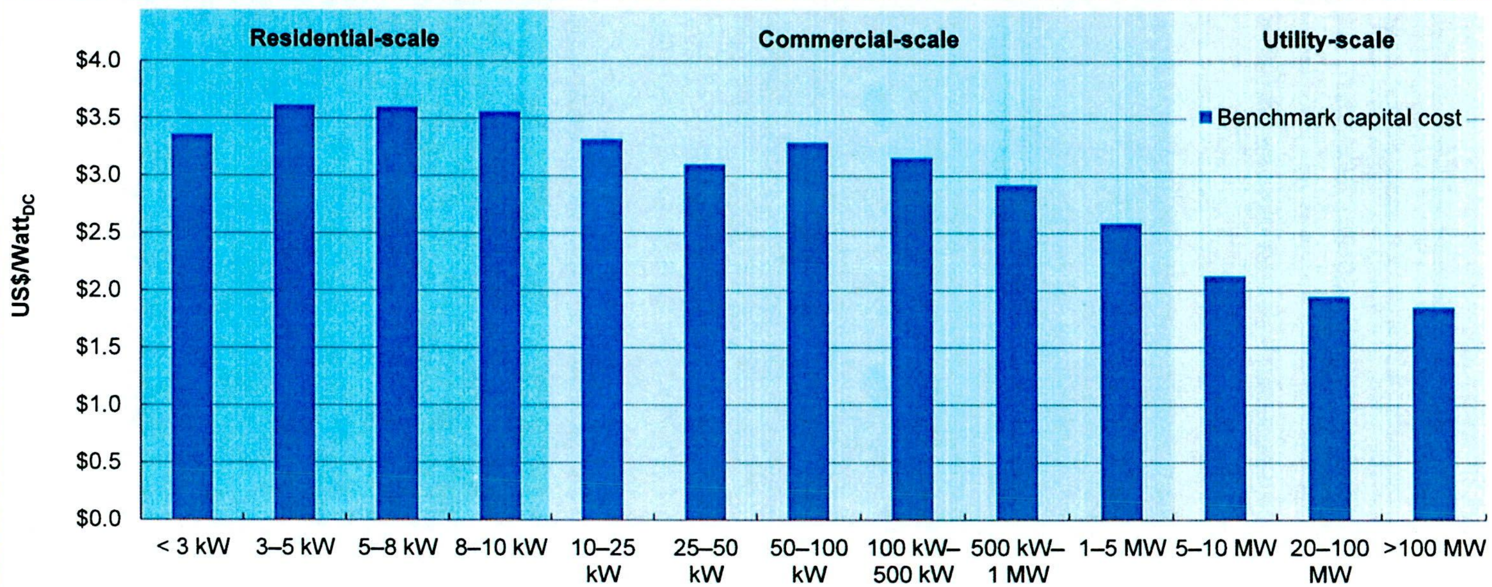


Notes: Costs are based on projects using c-Si modules. Development includes customer acquisition, developer overhead, permitting, and interconnection costs.
Source: IHS

The cost of equipment and installation is converging across system types, with DG solar technology's higher overall capital cost mainly a function of customer acquisition and more expensive inverters.

Solar PV capital costs by project size

Solar PV benchmark capital costs by project size, 2014



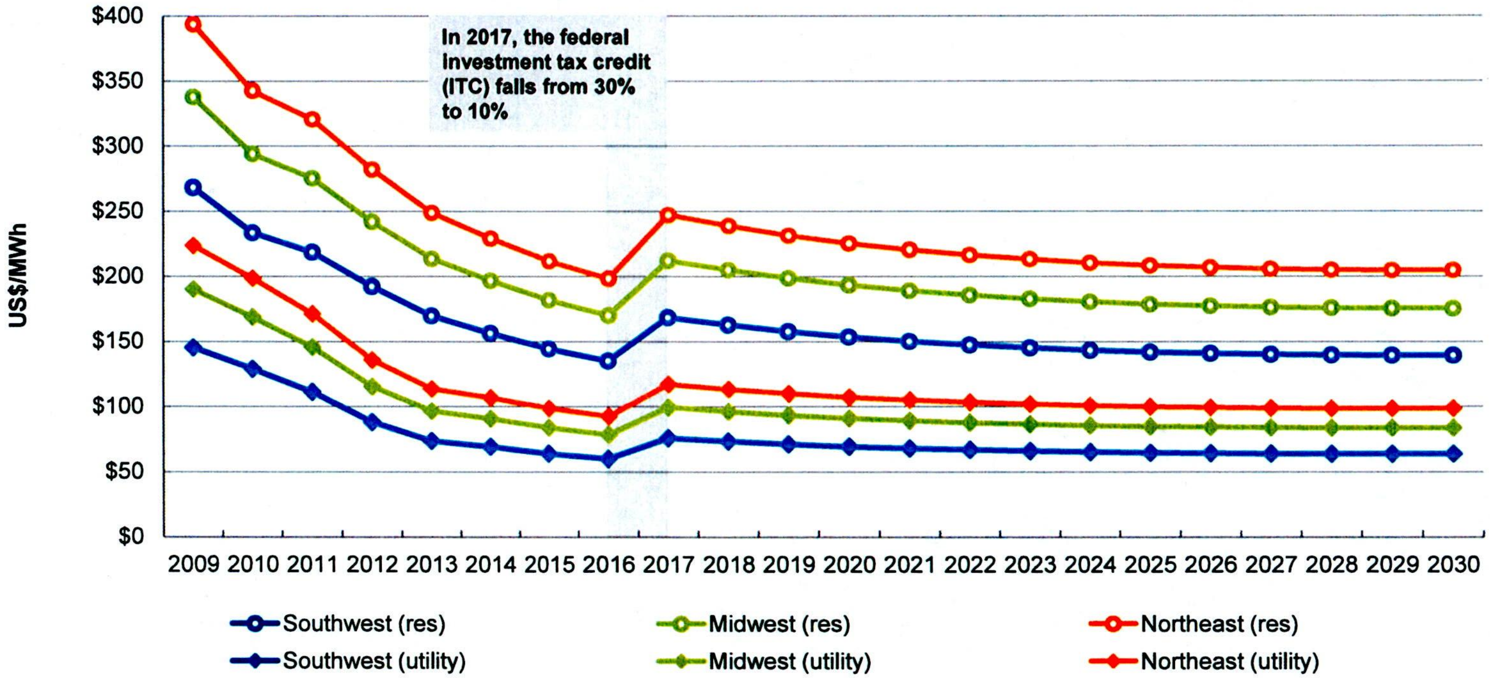
Notes: Residential and commercial capital costs are the average of the least-cost quartile of reported project costs in California, Arizona, Massachusetts, New York, and Connecticut reported in Q1–Q2 2014 (estimated to account for about 28% of total distributed capacity installed in the US over this time period). Project cost estimates for projects between 20–100 MW and >100 MW are IHS Energy's benchmark capital costs for utility-scale projects using c-Si technology.
Source: IHS, state registries

Solar PV system costs exhibit improving economies of scale mostly above 100 kW.

Solar PV power price trends

Solar PV power price comparison: utility-scale vs. residential-scale, 2009–2030

Required price for solar PV power (including federal ITC)



Notes: Southwest solar power prices based on solar resources in Phoenix, Arizona; Northeast solar power prices based on solar resources in Boston, MA. See appendix for regional capacity factor and finance assumptions. Prices shown are based on solar projects using c-Si technology. Federal ITC reverts from 30% to 10% in 2017.
Source: IHS

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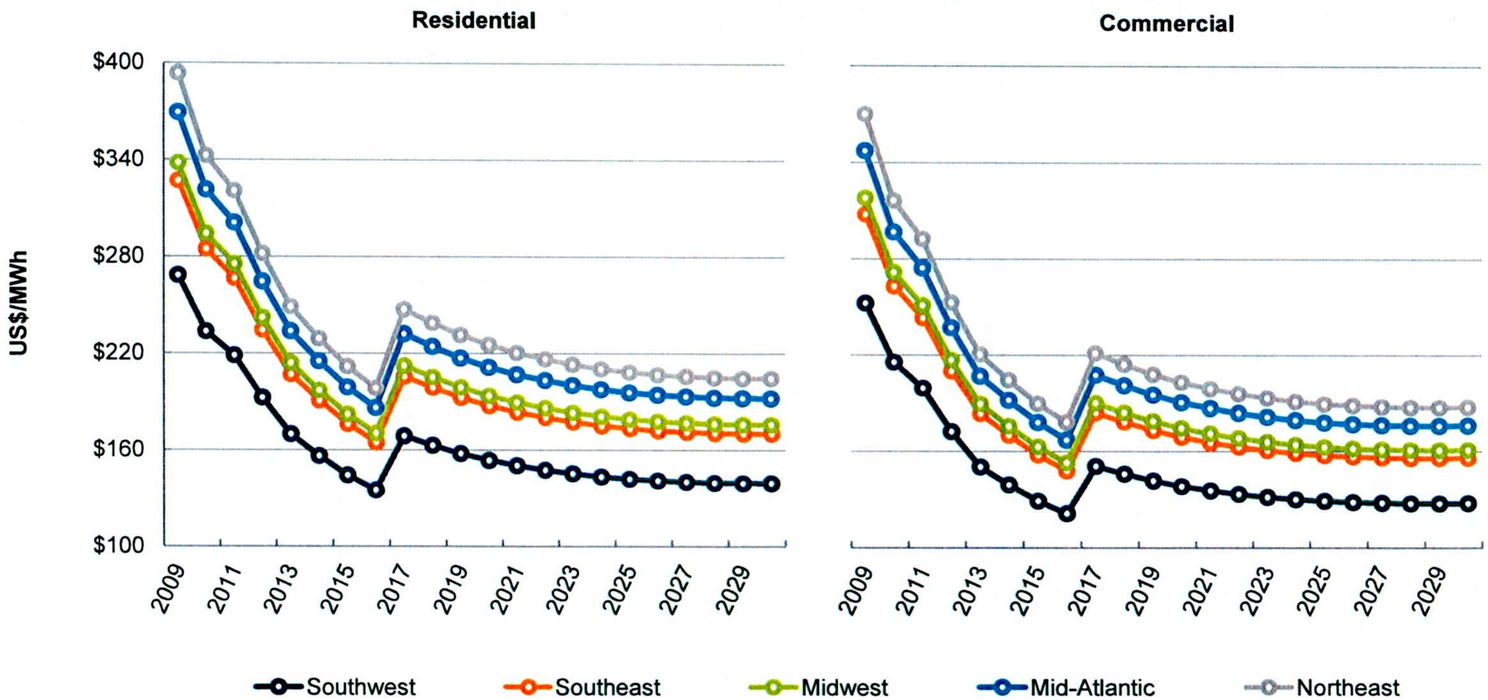
Residential and commercial-scale solar PV power prices by region

Required price for solar PV power (including federal ITC)



Notes: See appendix for regional capacity factor and finance assumptions: prices shown are based on solar projects using c-Si technology. Federal ITC reverts from 30% to 10% in 2017.
Source: IHS

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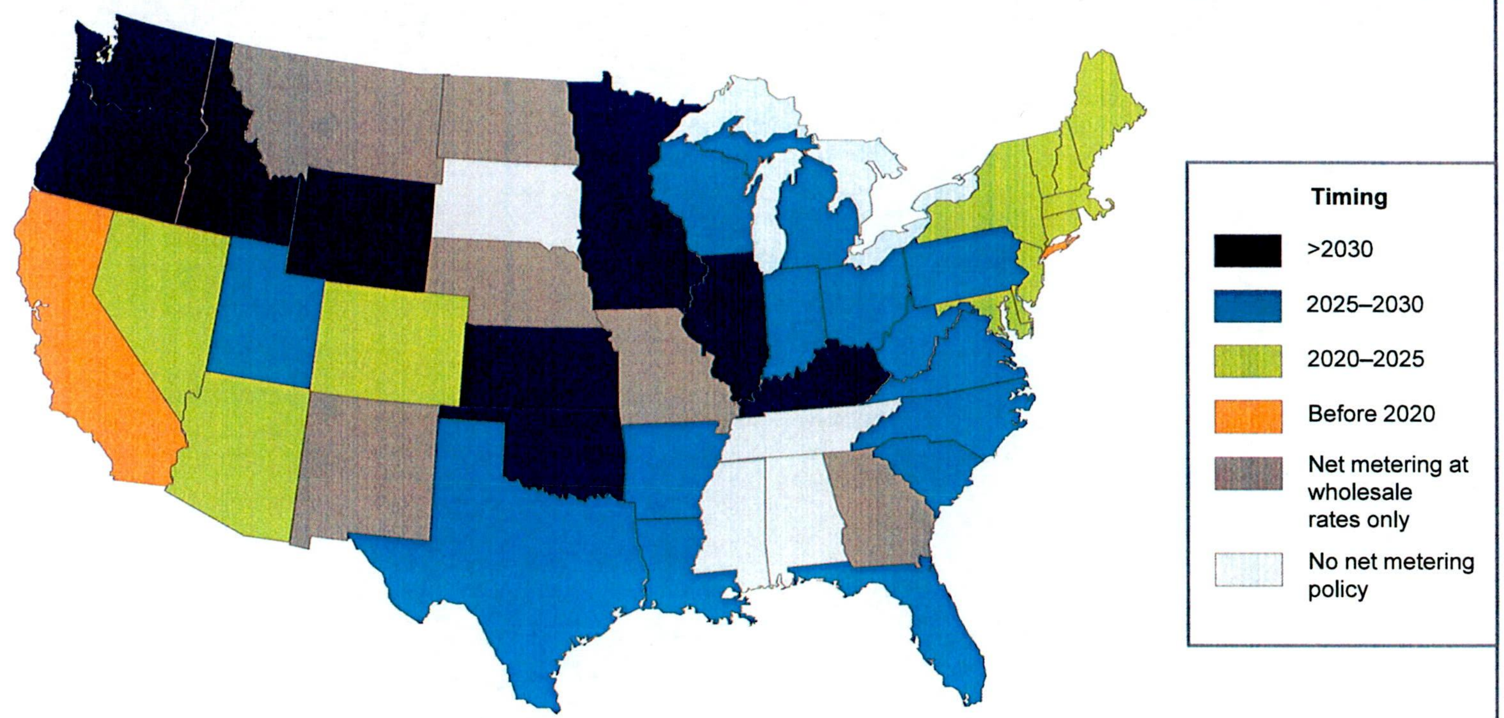
Residential solar PV retail rate parity with 10% ITC

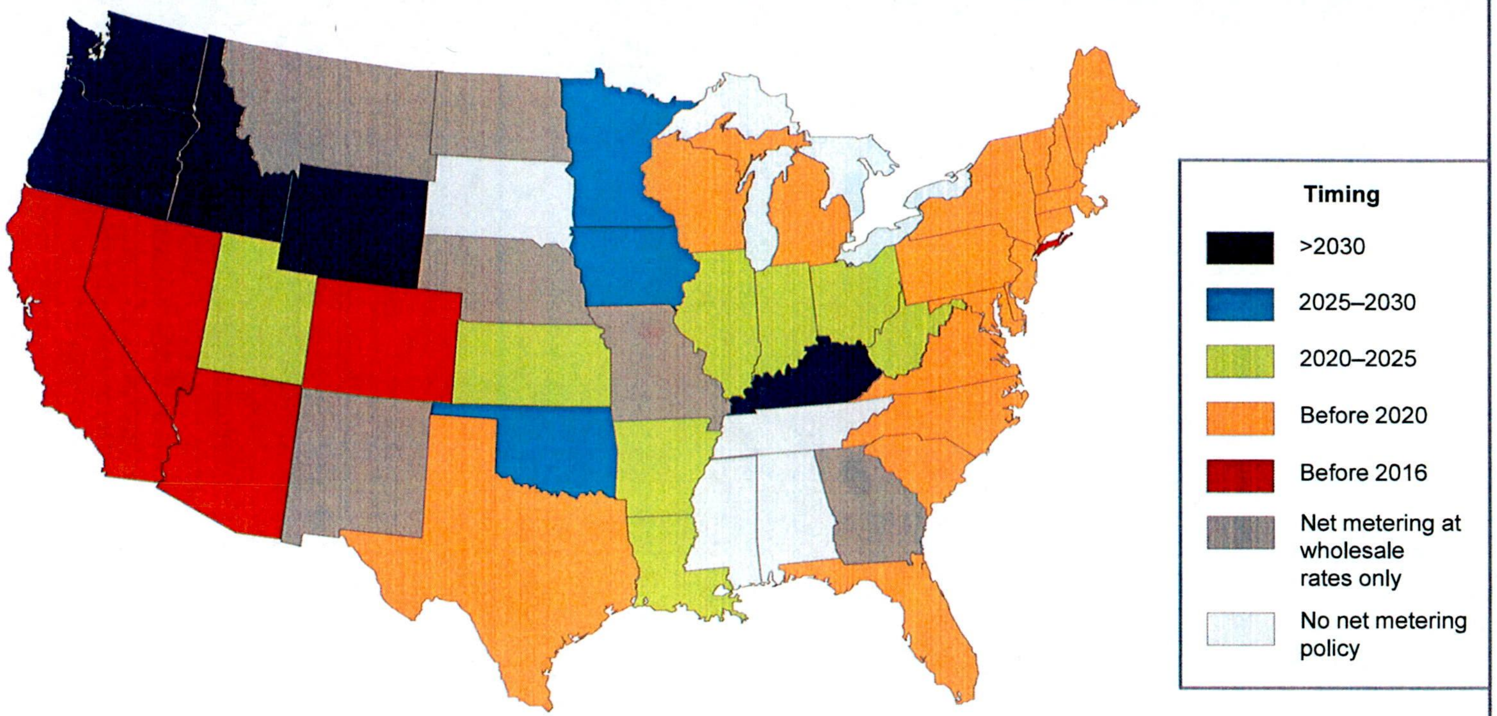
Residential solar retail rate parity timing with 10% federal investment tax credit



Notes: Based on the assumption of a federal ITC of 10% for all years. The above map shows the approximate timing of parity between the retail price of power outlook from the US EIA and IHS's forecast required price of solar PV power in each respective year. Required solar PV power prices is based on solar projects using c-Si technology.
Source: IHS, EIA

Residential solar PV retail rate parity with 30% ITC

Residential solar retail rate parity timing with 30% federal investment tax credit



Notes: Based on the assumption of a federal ITC of 30% for all years. The above map shows the approximate timing of parity between the retail price of power outlook from the US EIA and IHS's forecast required price of solar PV power in each respective year. Required solar PV power prices is based on solar projects using c-Si technology.
Source: IHS, EIA

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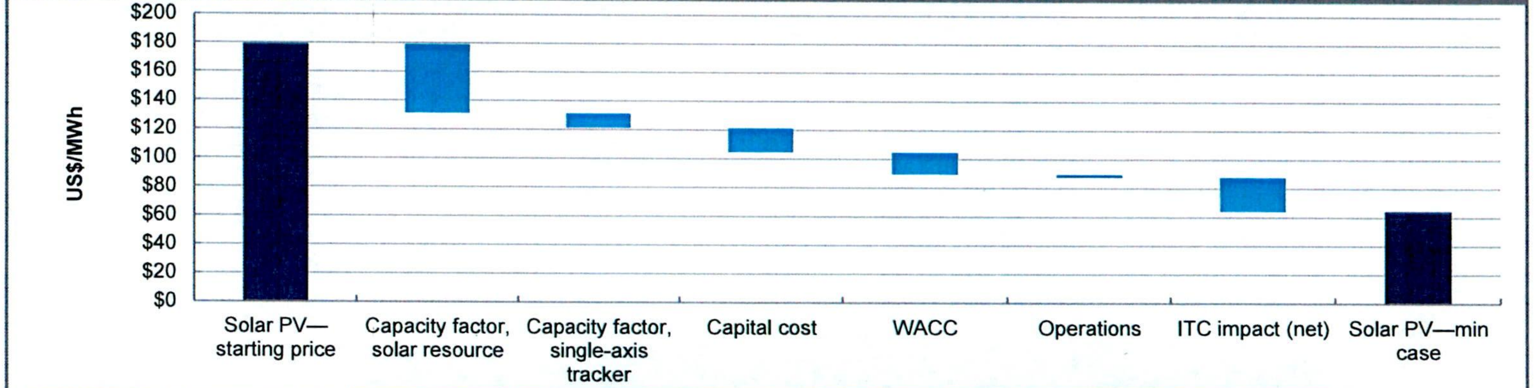
Drivers of utility-scale solar PV's required price

Sensitivity of utility-scale solar PV's required power price

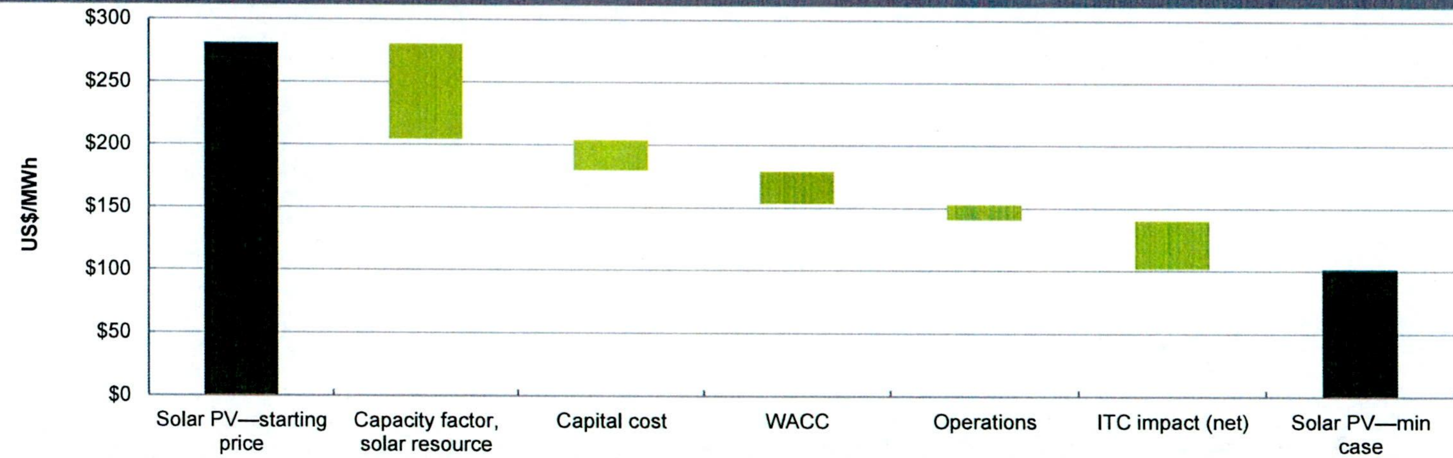


	Solar PV—starting price	Capacity factor, solar resource	Capacity factor, single-axis tracker	Capital cost	WACC	Operations	ITC impact (net)	Solar PV—min case
Average capacity factor* (AC)	18.6%	25.4%						
Average capacity factor* (AC) from trackers	None	None	30.1%	30.1%	30.1%	30.1%	30.1%	30.1%
Capital cost (AC)	$2,288/kW	US$2,288/kW	US$2,530/kW	US$2,160/kW	US$2,160/kW	US$2,160/kW	US$2,160/kW	US$2,160/kW
After-tax WACC	9%	9%	9%	9%	7%	7%	8%	8%
Operating cost (real US$2013)	US$20/kW-yr	US$20/kW-yr	US$20/kW-yr	US$20/kW-yr	US$20/kW-yr	US$16/kW-yr	US$16/kW-yr	US$16/kW-yr
Federal ITC	None	None	None	None	None	None	30%	30%
Comment	Mid-Atlantic solar resource (Newark, NJ)	Southwest solar resource (Phoenix, AZ)	Single-axis trackers increase capital cost by 11%, but lower the required power price by 8%	Chinese modules without tariffs and larger project capacity could unlock savings	Low interest rate environment and falling technology risks can lower WACC	Larger portfolios and experience lowers operating expense for leading players	Net ITC benefit includes 100 basis point cost to access 3rd party tax equity	With the ITC, solar out-competes wind in the Southwest, and challenges natural gas

Notes: *Average capacity factor is the 20-year average capacity factor for the respective project, taking into account an annual degradation rate of 0.8%/year (see Appendix).
Source: IHS

Drivers of commercial-scale solar PV's required price

Sensitivity of commercial-scale solar PV's required power price



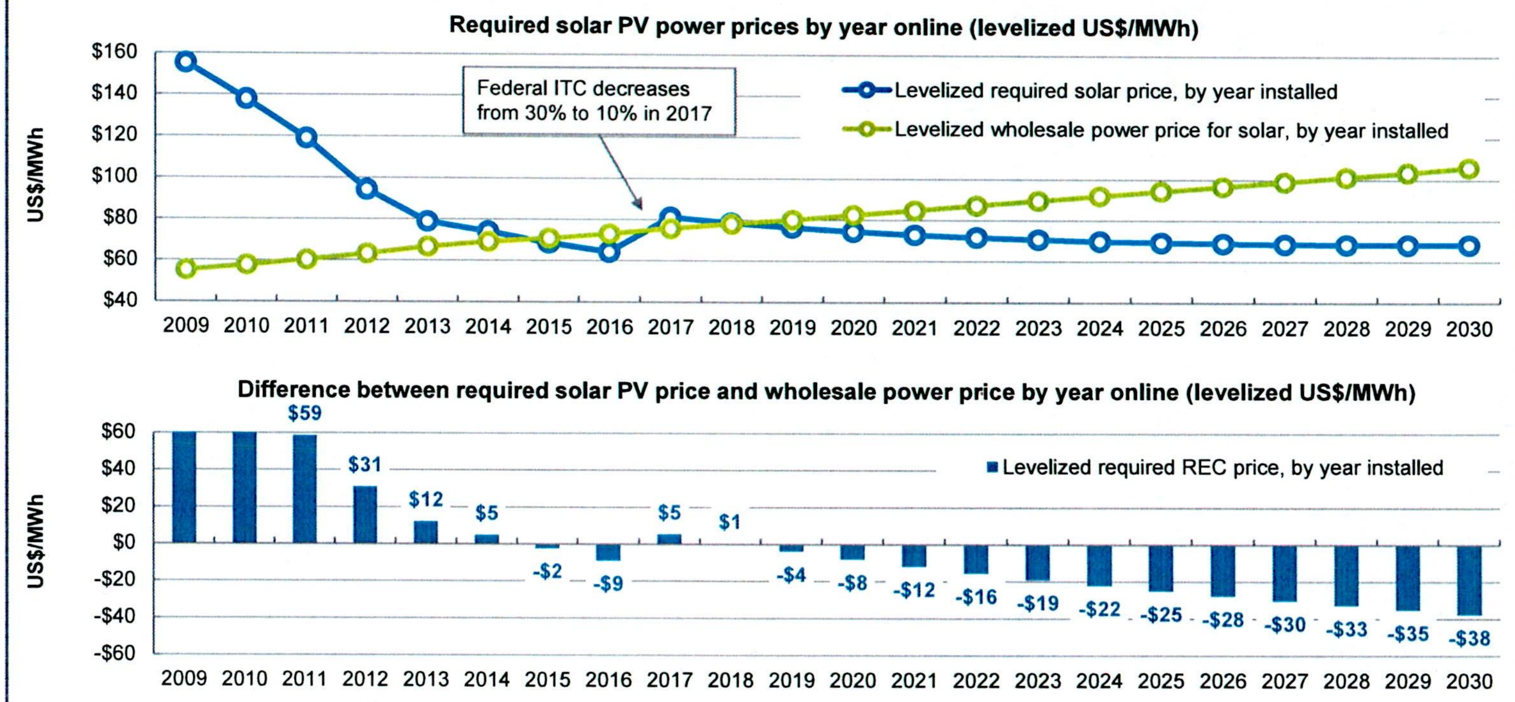
	Solar PV—starting price	Capacity factor, solar resource	Capital cost	WACC	Operations	ITC impact (net)	Solar PV—min case
Average capacity factor* (AC)	15.0%	20.7%	20.7%	20.7%	20.7%	20.7%	20.7%
Capital cost (AC)	US$3,268/kW	US$3,268/kW	US$2,820/kW	US$2,820/kW	US$2,820/kW	US$2,820/kW	US$2,820/kW
After-tax WACC	7%	7%	7%	5%	5%	6%	6%
Operating cost (real US$2013)	US$40/kW-yr	US$40/kW-yr	US$40/kW-yr	US$40/kW-yr	US$20/kW-yr	US$20/kW-yr	US$20/kW-yr
Federal ITC	None	None	None	None	None	30%	30%
Comment	Mid-Atlantic solar resource (Newark, NJ)	Southwest solar resource (Phoenix, AZ)	Chinese modules without tariffs and more experienced developers could lead to lower CAPEX	Low interest rate environment and falling technology risks can lower WACC	Larger portfolios and greater experience converge O&M expenses with utility-scale solar PV	Net ITC benefit includes 100 basis point cost to access 3rd party tax equity	With the ITC, solar PV challenges retail rates in the Southwest, including CO

Notes: *Average capacity factor is the 20-year average capacity factor for the respective project, taking into account an annual degradation rate of 0.8%/year (see Appendix).
Source: IHS

Required prices for utility-scale solar

California

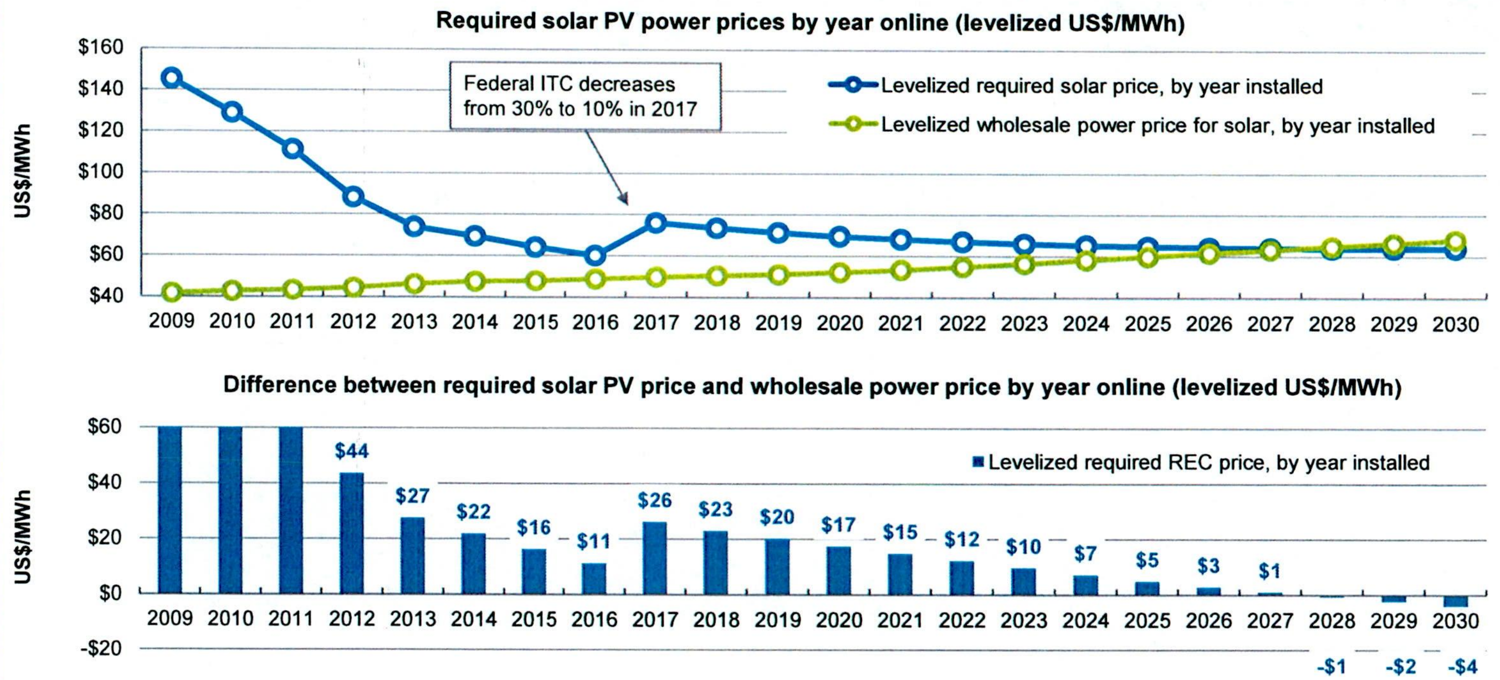
Required prices for utility-scale solar PV power in California, by year online



Notes: California solar prices based on resources in Santa Maria, CA; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

Southwest

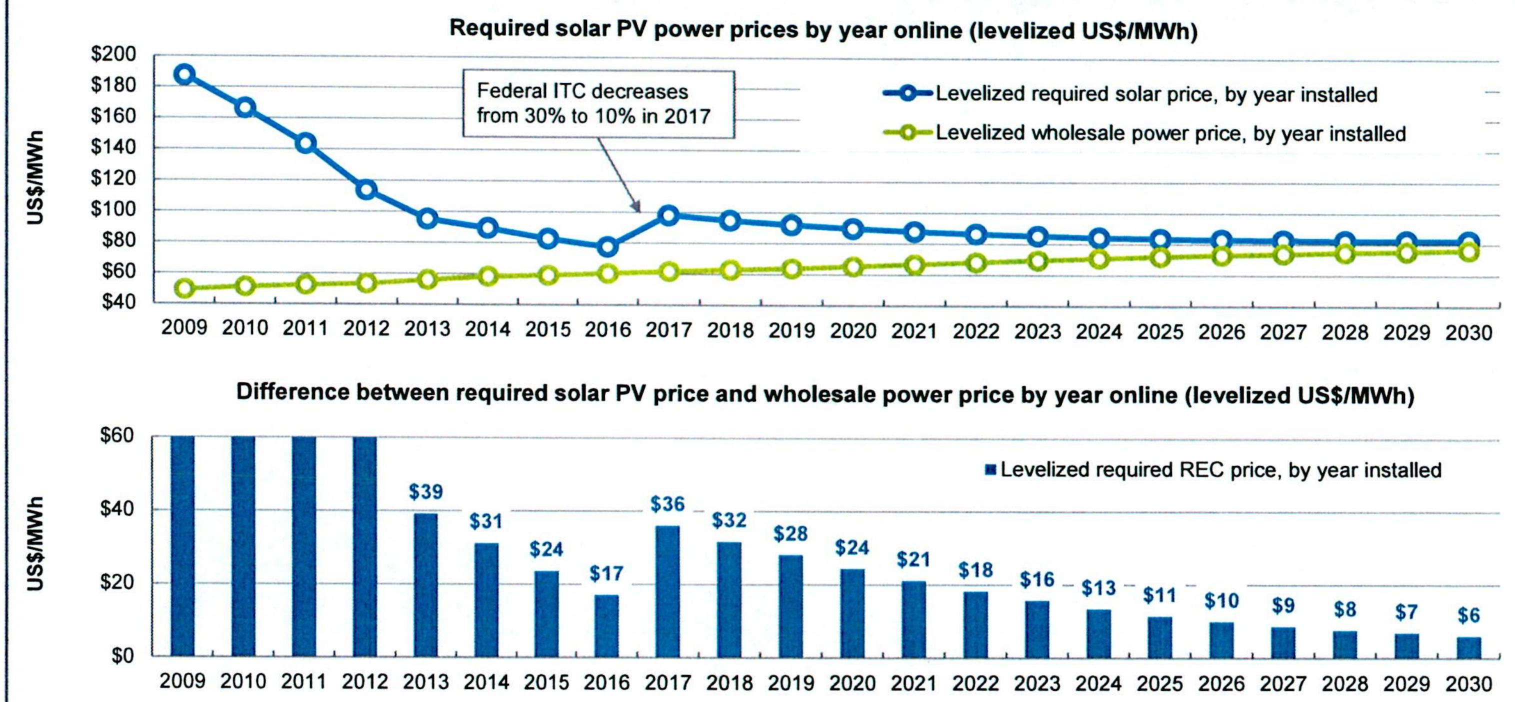
Required prices for utility-scale solar PV power in the Southwest, by year online



Notes: Southwest solar prices based on resources in Phoenix, AZ; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

Southeast

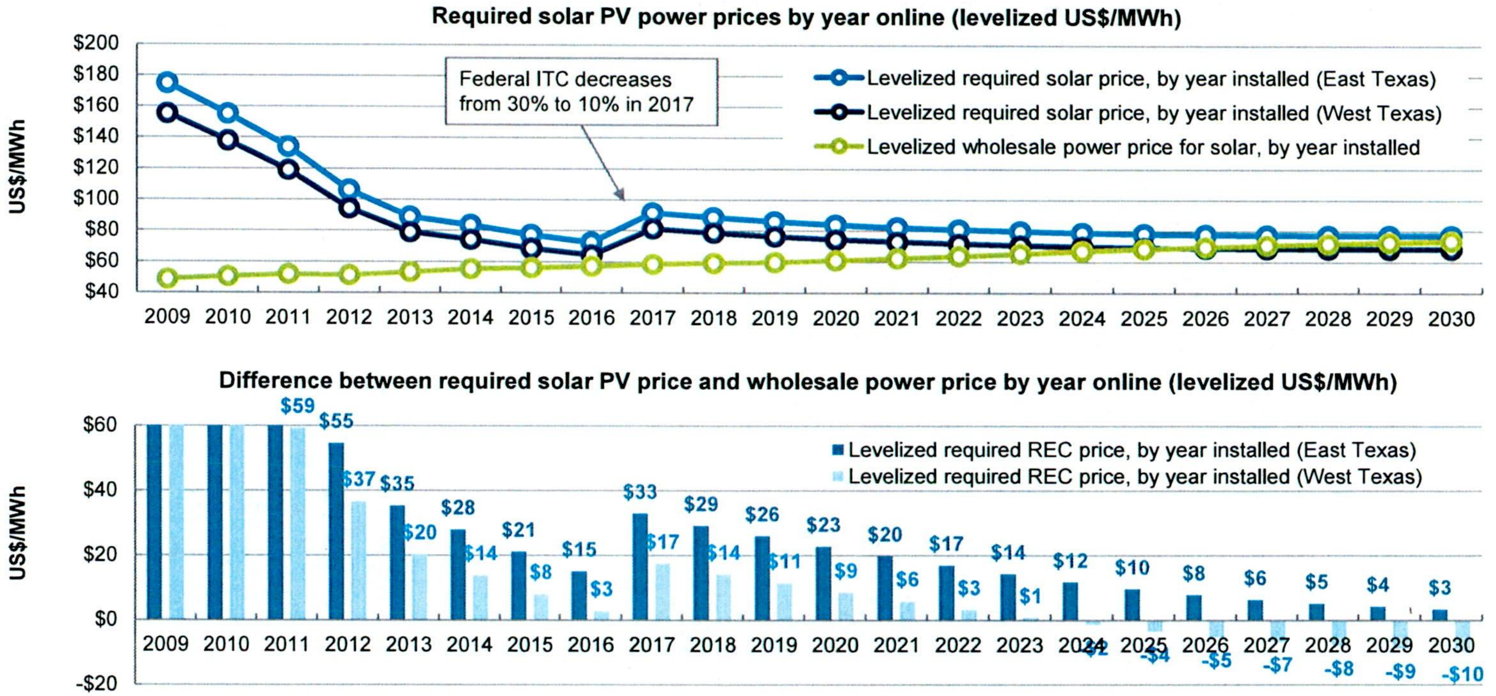
Required prices for utility-scale solar PV power in the Southeast, by year online



Notes: Southeast solar prices based on resources in Macon, GA; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

Texas

Required prices for utility-scale solar PV power in Texas, by year online



Notes: East Texas solar prices based on resources in Austin, TX. West Texas solar prices based on resources in El Paso, TX; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

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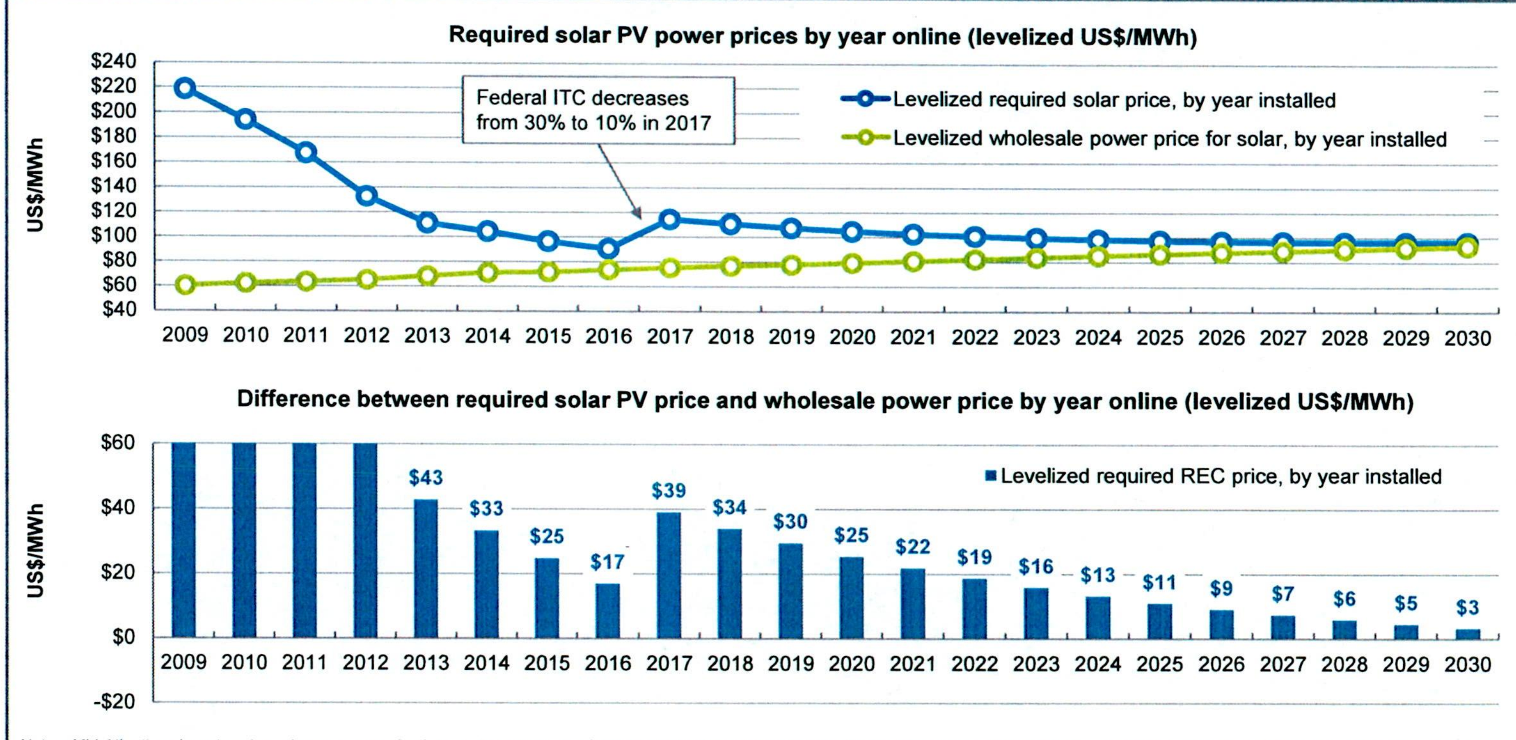
Mid-Atlantic

Required prices for utility-scale solar PV power in the Mid-Atlantic, by year online



Notes: Mid-Atlantic solar prices based on resources in Newark, NJ; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

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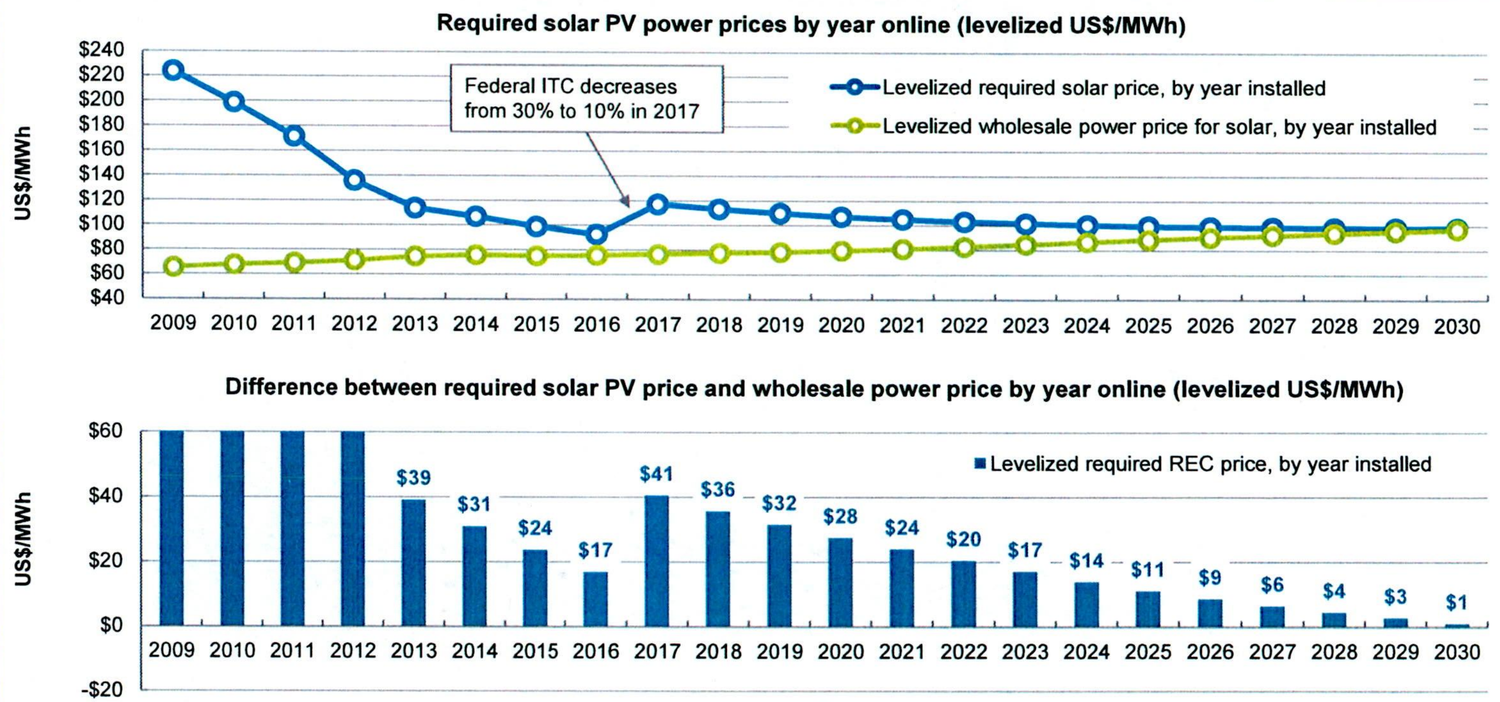
Northeast

Required prices for utility-scale solar PV power in the Northeast, by year online



Notes: Northeast solar prices based on resources in Boston, MA; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

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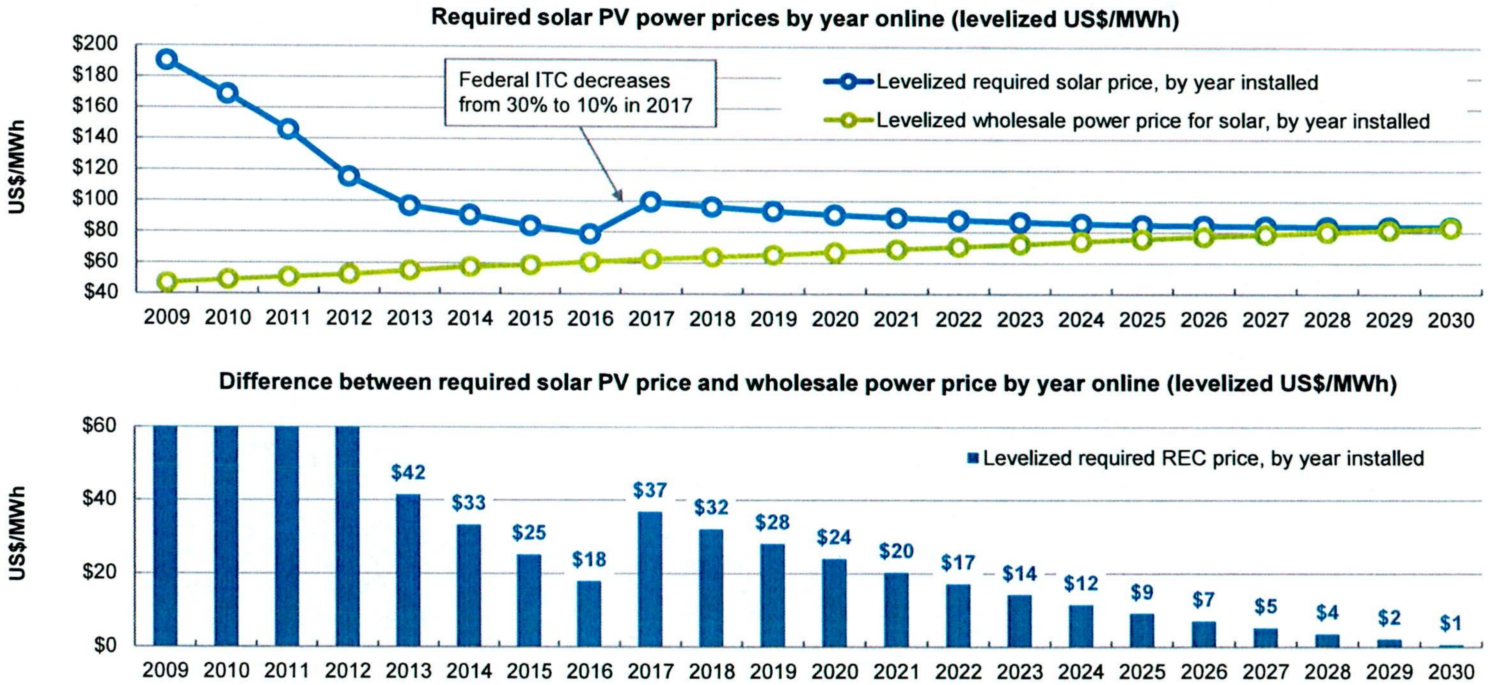
Midwest

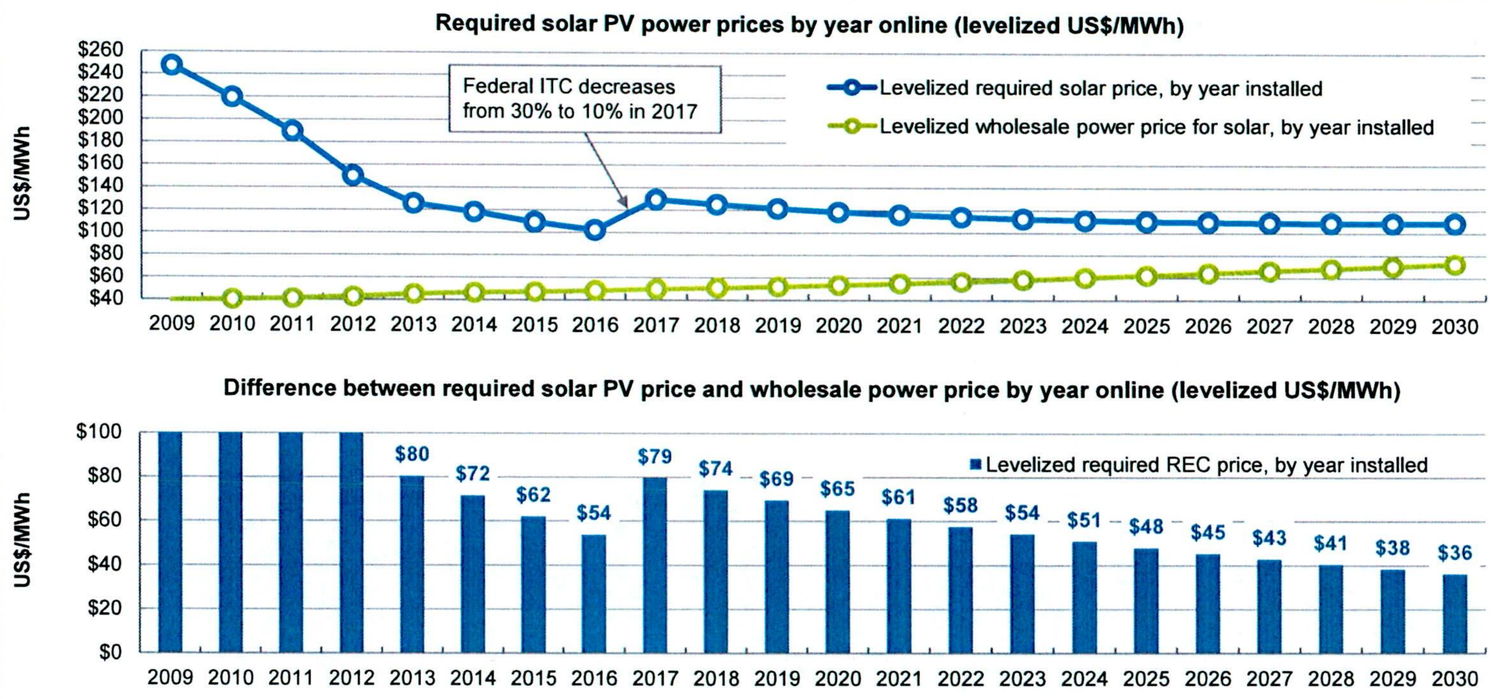
Required prices for utility-scale solar PV power in the Midwest, by year online



Notes: Midwest solar prices based on resources in Springfield, IL; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

Northwest

Required prices for utility-scale solar PV power in the Northwest, by year online



Notes: Northwest solar prices based on resources in Seattle, WA; required solar PV power prices and required solar PV REC prices are based on solar PV benchmark capital costs using c-Si module technology
Source: IHS

Appendix

Definitions and assumptions

Base modeling assumptions*

Operating and capital cost assumptions		Tax assumptions and other assumptions	
Plant life	20 years**	Federal tax rate	35%
Degradation rate	0.8%/year	State tax rate	5%
Target IRR, unlevered	6.99%	Combined net tax rate	38.3%
Equity rate	11.00%	Depreciation	5 year MACRS
Debt rate	7.00%	Property tax	0.5% of net book value
Debt-to-equity ratio	60:40	Insurance	0.15% of initial capital cost
Debt term	18 years		

Notes: *Assumptions common to all projects in all regions. **Projects are assumed to realize full value within 20-year timeframe of an industry-standard PPA; continuing value beyond 20 years is assumed to at least cover decommissioning costs, but no continuing value is included in the levelized required price of power. See the following slides and the accompanying data sheet for regional assumptions.

Source: IHS

Regional definitions and assumptions

Regional definitions and assumptions

Region	Representative city, state	Starting capacity factor/ 20-year average capacity factor**	Pricing zone*
Southwest (WECC)	Phoenix, Arizona	Commercial and residential: 22.3% / 20.7% Utility-scale fixed-tilt: 27.4% / 25.4% Utility-scale single-axis tracking: 32.5% / 30.2%	Southwest (Palo Verde)
California (CAISO)	Santa Maria, California	Commercial and residential: 21.4% / 19.9% Utility-scale fixed-tilt: 26.6% / 24.6% Utility-scale single-axis tracking: 30.4% / 28.2%	Southern California (South Path 15)
Texas (ERCOT)	Austin, Texas	Commercial and residential: 19.4% / 18.0% Utility-scale fixed-tilt: 23.3% / 21.6% Utility-scale single-axis tracking: 27.0% / 25.0%	ERCOT North
Southeast	Macon, Georgia	Commercial and residential: 18.3% / 17.0% Utility-scale fixed-tilt: 22.2% / 20.6% Utility-scale single-axis tracking: 25.2% / 23.3%	SERC-East
Midwest (MISO)	Springfield, Illinois	Commercial and residential: 17.7% / 16.4% Utility-scale fixed-tilt: 21.9% / 20.3% Utility-scale single-axis tracking: 24.8% / 23.0%	Illinois Hub (MISO)
Mid-Atlantic (PJM)	Newark, New Jersey	Commercial and residential: 16.2% / 15.0% Utility-scale fixed-tilt: 20.1% / 18.6% Utility-scale single-axis tracking: 21.6% / 20.0%	PJM Western Hub

Notes: *Pricing zones are those forecast and published by IHS Energy's North American Power advisory. **Average capacity factor is the 20-year average capacity factor for the respective project, taking into account an annual degradation rate of 0.8%/year.

Source: IHS

Regional definitions and assumptions (cont.)

Regional definitions and assumptions

Region	Representative city, state	Starting capacity factor/ 20-year average capacity factor	Pricing zone*
Northeast (ISONE)	Boston, Massachusetts	Commercial and residential: 15.2% / 14.1% Utility-scale fixed-tilt: 19.1% / 17.7% Utility-scale single-axis tracking: 21.1% / 19.5%	Massachusetts Hub
Northwest	Seattle, Washington	Commercial and residential: 14.0% / 13.0% Utility-scale fixed-tilt: 17.3% / 16.0% Utility-scale single-axis tracking: 19.2% / 17.8%	Pacific Northwest (Mid-Columbia)

Notes: *Pricing zones are those forecast and published by IHS Energy's North American Power advisory. **Average capacity factor is the 20-year average capacity factor for the respective project, taking into account an annual degradation rate of 0.8%/year.

Source: IHS

Sensitivities, California

2016 Commercial-scale c-Si in California (fixed-tilt)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$2,455 -10%	$2,592 -5%	$2,728 (base)	$2,865 +5%	$3,001 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$104	$108	$113	$117	$121	
6%	-1%	$110	$115	$119	$124	$128	
7%	(base)	$117	$122	$126	$131	$136	
8%	+1%	$124	$129	$134	$140	$145	
9%	+2%	$131	$137	$143	$148	$154	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in California (tracker)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$1,917 -10%	$2,023 -5%	$2,130 (base)	$2,236 +5%	$2,343 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$52	$54	$56	$59	$61	
6%	-1%	$55	$58	$60	$63	$65	
7%	(base)	$59	$61	$64	$67	$70	
8%	+1%	$63	$66	$69	$71	$74	
9%	+2%	$67	$70	$73	$76	$79	

Source: IHS © 2014 IHS

2016 Commercial-scale c-Si in California (fixed-tilt)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	23.5% +10%	22.5% +5%	21.4% (base)	20.3% -5%	19.3% -10%	Capacity factor Δ from base
5%	-2%	$102	$107	$113	$119	$125	
6%	-1%	$108	$113	$119	$125	$132	
7%	(base)	$115	$120	$126	$133	$141	
8%	+1%	$122	$128	$134	$141	$149	
9%	+2%	$130	$136	$143	$150	$158	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in California (tracker)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	33.4% +10%	31.9% +5%	30.4% (base)	28.9% -5%	27.4% -10%	Capacity factor Δ from base
5%	-2%	$51	$54	$56	$59	$63	
6%	-1%	$55	$57	$60	$63	$67	
7%	(base)	$58	$61	$64	$68	$71	
8%	+1%	$62	$65	$69	$72	$76	
9%	+2%	$66	$70	$73	$77	$81	

Source: IHS © 2014 IHS

Sensitivities, Southwest

2016 Commercial-scale c-Si in Southwest (fixed-tilt)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$2,455 -10%	$2,592 -5%	$2,728 (base)	$2,865 +5%	$3,001 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$100	$104	$108	$112	$116	
6%	-1%	$105	$110	$114	$119	$123	
7%	(base)	$112	$117	$121	$126	$131	
8%	+1%	$119	$124	$129	$134	$139	
9%	+2%	$126	$131	$137	$142	$148	

Source: IHS

2016 Utility-scale c-Si in Southwest (tracker)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$1,917 -10%	$2,023 -5%	$2,130 (base)	$2,236 +5%	$2,343 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$48	$51	$53	$55	$57	
6%	-1%	$51	$54	$56	$59	$61	
7%	(base)	$55	$57	$60	$63	$65	
8%	+1%	$59	$61	$64	$67	$70	
9%	+2%	$62	$65	$68	$71	$74	

Source: IHS

2016 Commercial-scale c-Si in Southwest (fixed-tilt)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	24.5% +10%	23.4% +5%	22.3% (base)	21.2% -5%	20.1% -10%	Capacity factor Δ from base
5%	-2%	$98	$103	$108	$114	$120	
6%	-1%	$104	$109	$114	$120	$127	
7%	(base)	$110	$116	$121	$128	$135	
8%	+1%	$117	$123	$129	$136	$143	
9%	+2%	$124	$130	$137	$144	$152	

Source: IHS

2016 Utility-scale c-Si in Southwest (tracker)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	35.8% +10%	34.1% +5%	32.5% (base)	30.9% -5%	29.3% -10%	Capacity factor Δ from base
5%	-2%	$48	$50	$53	$56	$59	
6%	-1%	$51	$54	$56	$59	$62	
7%	(base)	$55	$57	$60	$63	$67	
8%	+1%	$58	$61	$64	$67	$71	
9%	+2%	$62	$65	$68	$72	$76	

Source: IHS

Sensitivities, Southeast

2016 Commercial-scale c-Si in Southeast (fixed-tilt)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$2,455 -10%	$2,592 -5%	$2,728 (base)	$2,865 +5%	$3,001 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$122	$127	$132	$137	$142	
6%	-1%	$129	$134	$139	$145	$150	
7%	(base)	$136	$142	$148	$154	$160	
8%	+1%	$145	$151	$157	$163	$170	
9%	+2%	$153	$160	$167	$173	$180	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Southeast (tracker)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$1,917 -10%	$2,023 -5%	$2,130 (base)	$2,236 +5%	$2,343 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$62	$65	$68	$71	$74	
6%	-1%	$66	$69	$72	$76	$79	
7%	(base)	$71	$74	$77	$81	$84	
8%	+1%	$76	$79	$83	$86	$90	
9%	+2%	$80	$84	$88	$92	$96	

Source: IHS © 2014 IHS

2016 Commercial-scale c-Si in Southeast (fixed-tilt)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	20.1% +10%	19.2% +5%	18.3% (base)	17.4% -5%	16.5% -10%	Capacity factor Δ from base
5%	-2%	$120	$125	$132	$139	$146	
6%	-1%	$127	$133	$139	$147	$155	
7%	(base)	$134	$141	$148	$156	$164	
8%	+1%	$143	$150	$157	$165	$175	
9%	+2%	$152	$159	$167	$175	$185	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Southeast (tracker)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	27.7% +10%	26.5% +5%	25.2% (base)	23.9% -5%	22.7% -10%	Capacity factor Δ from base
5%	-2%	$62	$65	$68	$72	$76	
6%	-1%	$66	$69	$72	$76	$81	
7%	(base)	$70	$74	$77	$81	$86	
8%	+1%	$75	$79	$83	$87	$92	
9%	+2%	$80	$84	$88	$93	$98	

Source: IHS © 2014 IHS

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Sensitivities, Mid-Atlantic

2016 Commercial-scale c-Si in Mid-Atlantic (fixed-tilt)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$2,455 -10%	$2,592 -5%	$2,728 (base)	$2,865 +5%	$3,001 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$138	$143	$149	$154	$160	
6%	-1%	$145	$151	$157	$163	$169	
7%	(base)	$154	$161	$167	$174	$180	
8%	+1%	$163	$170	$177	$185	$192	
9%	+2%	$173	$181	$188	$196	$204	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Mid-Atlantic (tracker)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$1,917 -10%	$2,023 -5%	$2,130 (base)	$2,236 +5%	$2,343 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$73	$76	$79	$83	$86	
6%	-1%	$77	$81	$85	$88	$92	
7%	(base)	$83	$86	$90	$94	$98	
8%	+1%	$88	$92	$96	$101	$105	
9%	+2%	$94	$98	$103	$107	$112	

Source: IHS © 2014 IHS

2016 Commercial-scale c-Si in Mid-Atlantic (fixed-tilt)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	17.8% +10%	17.0% +5%	16.2% (base)	15.4% -5%	14.6% -10%	Capacity factor Δ from base
5%	-2%	$135	$142	$149	$157	$165	
6%	-1%	$143	$150	$157	$166	$175	
7%	(base)	$152	$159	$167	$176	$186	
8%	+1%	$161	$169	$177	$187	$197	
9%	+2%	$171	$179	$188	$198	$209	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Mid-Atlantic (tracker)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	23.8% +10%	22.7% +5%	21.6% (base)	20.5% -5%	19.4% -10%	Capacity factor Δ from base
5%	-2%	$72	$76	$79	$84	$88	
6%	-1%	$77	$81	$85	$89	$94	
7%	(base)	$82	$86	$90	$95	$100	
8%	+1%	$88	$92	$96	$102	$107	
9%	+2%	$93	$98	$103	$108	$114	

Source: IHS © 2014 IHS

Sensitivities, Northeast

2016 Commercial-scale c-Si in Northeast (fixed-tilt)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$2,455 -10%	$2,592 -5%	$2,728 (base)	$2,865 +5%	$3,001 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$147	$153	$159	$165	$171	
6%	-1%	$155	$161	$168	$174	$181	
7%	(base)	$164	$171	$178	$185	$192	
8%	+1%	$174	$182	$189	$197	$204	
9%	+2%	$184	$193	$201	$209	$217	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Northeast (tracker)
Capital cost and IRR sensitivities

Target IRR	Δ from base	$1,917 -10%	$2,023 -5%	$2,130 (base)	$2,236 +5%	$2,343 +10%	Cost ($/kW$_{AC}$) Δ from base
5%	-2%	$75	$78	$81	$85	$88	
6%	-1%	$79	$83	$87	$90	$94	
7%	(base)	$85	$89	$92	$96	$100	
8%	+1%	$90	$94	$99	$103	$107	
9%	+2%	$96	$101	$105	$110	$114	

Source: IHS © 2014 IHS

2016 Commercial-scale c-Si in Northeast (fixed-tilt)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	16.7% +10%	16.0% +5%	15.2% (base)	14.4% -5%	13.7% -10%	Capacity factor Δ from base
5%	-2%	$144	$151	$159	$167	$176	
6%	-1%	$152	$160	$168	$177	$186	
7%	(base)	$162	$170	$178	$187	$198	
8%	+1%	$172	$180	$189	$199	$210	
9%	+2%	$182	$191	$201	$211	$223	

Source: IHS © 2014 IHS

2016 Utility-scale c-Si in Northeast (tracker)
Capacity factor and IRR sensitivities

Target IRR	Δ from base	23.2% +10%	22.2% +5%	21.1% (base)	20.0% -5%	19.0% -10%	Capacity factor Δ from base
5%	-2%	$74	$78	$81	$86	$90	
6%	-1%	$79	$82	$87	$91	$96	
7%	(base)	$84	$88	$92	$97	$103	
8%	+1%	$90	$94	$99	$104	$110	
9%	+2%	$96	$100	$105	$111	$117	

Source: IHS © 2014 IHS

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ND Solar PPA Modeling Assumptions

1. Capital Structure and Discount Rate

The rates shown in Table 1 were calculated by taking a weighted average of MN (85%) and WI (15%) information from the January 2014 Corporate Assumptions Memo. The after tax WACC of 6.62% is used to calculate the capital revenue requirements of generic resources. It is also used as the discount rate to determine the present value of revenue requirements.

Table 1 – Capital Structure

	Capital Structure	Allowed Return	Before tax Elec. WACC	After tax Elec. WACC
L-T Debt	45.24%	5.12%	2.33%	1.37%
Common Equity	52.56%	9.89%	5.24%	5.24%
S-T Debt	2.20%	0.64%	0.01%	0.01%
Total			7.58%	6.62%

2. Inflation Rates

The inflation rates are developed based on the long-term forecasts from Global Insight of labor and non-labor inflation rates.

- Variable O&M inflation - 50% labor and 50% non-labor inflation – 1.80%
- Fixed O&M inflation - 75% labor and 25% non-labor inflation – 2.18%
- General inflation – 40% labor and 60% non-labor inflation – 1.66%

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.1%. The coincidence factor between the NSP and MISO peak is 5%. Therefore, the effective reserve margin is:

(1 - 5%) * (1 + 7.1%) - 1 = 1.75%.

Table 2 – Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.10%
Effective RM Based on Non-coincident Peak	1.75%

4. CO_2 Price Forecasts

Emission rates for existing and planned resources consistent with historical and expected performance. No emissions costs for CO2 or any other pollutant were included in the ND analysis.

5. Externality Prices

No externality costs were included

6. Demand and Energy Forecast

The Fall 2014 Load Forecast, developed by the Xcel Energy Load Forecasting group, was used in the Resource Plan. The table below shows the annual energy and demand.

Table 3 – Demand and Energy Forecast

Demand (MW)				Energy (GWh)			
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2014	9,894	8,851	8,776	2014	50,353	45,119	44,682
2015	10,494	9,466	9,325	2015	51,186	46,054	45,210
2016	10,624	9,656	9,442	2016	51,806	46,930	45,635
2017	10,723	9,812	9,525	2017	52,057	47,518	45,775
2018	10,824	9,972	9,597	2018	52,382	48,199	46,008
2019	10,914	10,118	9,649	2019	52,705	48,824	46,185
2020	11,008	10,241	9,674	2020	53,170	49,457	46,362
2021	11,091	10,364	9,694	2021	53,438	49,868	46,325
2022	11,178	10,518	9,754	2022	53,664	50,460	46,520
2023	11,259	10,614	9,748	2023	53,971	50,826	46,488
2024	11,348	10,715	9,766	2024	54,395	51,322	46,659
2025	11,428	10,817	9,798	2025	54,651	51,778	46,810
2026	11,513	10,947	9,868	2026	54,867	52,261	47,083
2027	11,594	11,086	9,962	2027	55,152	52,889	47,520
2028	11,682	11,222	10,136	2028	55,591	53,639	48,522
2029	11,763	11,268	10,151	2029	55,878	53,811	48,566
2030	11,855	11,367	10,251	2030	56,160	54,215	48,779

7. Demand Side Management Forecasts

The goals for both 2014 and 2015 are as filed in our most recent DSM Triennial Plan (2013-2015) Docket No. E,G002/CIP-12-447. Beginning in 2016, a scenario based on a March 2014 update to the 2011 Minnesota DSM Potential Study was used. This scenario assumes impacts expected at a 75% rebate level for DSM. The annual average of impact from this scenario equals roughly 1.5% of the sales metric used in the DSM Plans and has been called the "1.5% scenario."

Table 4 – Base DSM Forecast (with 1.5% scenario beginning 2016)

Year	Energy (MWh)	Demand (MW)
2014	438	75
2015	845	141
2016	1,295	214
2017	1,743	287
2018	2,191	375
2019	2,639	469
2020	3,095	567
2021	3,543	670
2022	3,941	764
2023	4,338	866
2024	4,663	949
2025	4,968	1,019
2026	5,178	1,079
2027	5,369	1,124
2028	5,117	1,087
2029	5,246	1,116
2030	5,436	1,116

8. Demand Response Forecast

The 2014 Load Management Forecast developed by the Xcel Energy Load Research group was used in the Resource Plan. The table below shows the July demand.

Table 5 – Load Management Forecast

July Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022
LMF	933	942	953	964	975	986	996	1,007

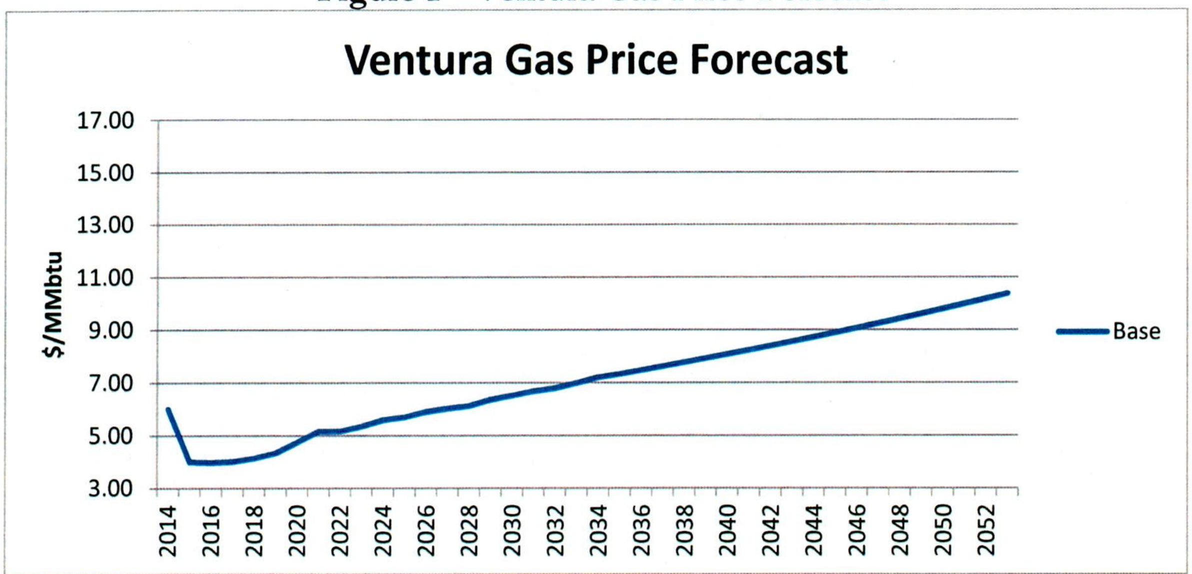
July Demand (MW)	2023	2024	2025	2026	2027	2028	2029	2030
LMF	1,017	1,028	1,030	1,025	1,021	1,017	1,013	1,009

9. Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of the latest market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates ("CERA") and Petroleum Industry Research Associates ("PIRA").

Gas Prices from September 8th were used.

Figure 1 – Ventura Gas Price Forecast



10. Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted ("FL&U") for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 12 contains gas transportation charges for generic thermal resources.

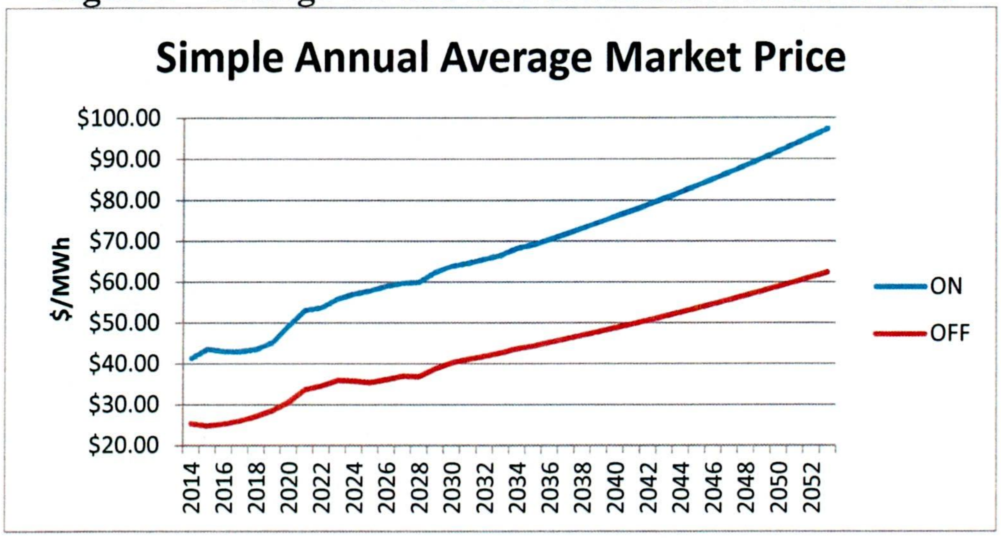
11. Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 12 contains gas demand charges for generic thermal resources.

12. Market Prices

In addition to resources that exist within NSP, the Company has access to markets located outside its service territory. Market power prices are developed using a blend of market information from the Intercontinental Exchange ("ICE") for near-term prices and long-term fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 7 below shows the market prices under no CO2 assumptions.

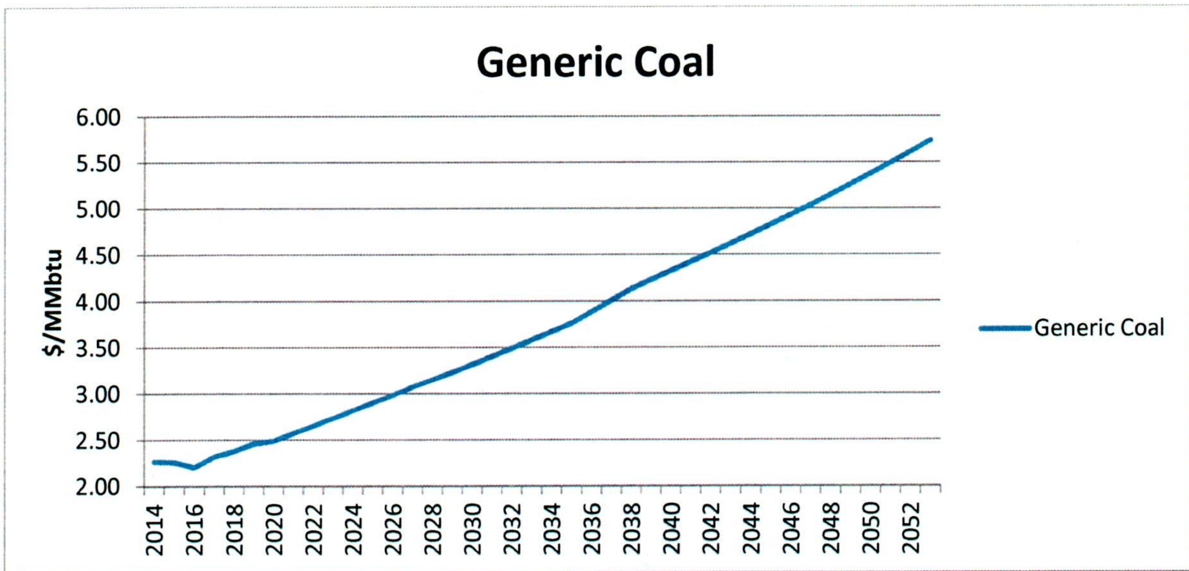
Figure 2 – Average On and Off Peak Market Price. No CO2.



13. Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent RFP responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

Figure 3 – Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 6 – Surplus Capacity Credit

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$/kw-mo	4.60	4.71	4.81	4.92	5.03	5.14	5.26	5.37	5.50	5.62
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
$/kw-mo	5.74	5.87	6.00	6.14	6.28	6.42	6.56	6.71	6.86	7.01
	2034	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
$/kw-mo	7.17	7.33	7.49	7.66	7.83	8.00	8.18	8.37	8.55	8.75
	2044	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**
$/kw-mo	8.94	9.14	9.35	9.55	9.77	9.99	10.21	10.44	10.67	10.91

15. Transmission Delivery Costs

Generic 2x1 combined cycle, generic CTs, generic wind and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kw basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs. The averages were $152/kW for combustion turbines and $406/kW for 2X1 combined cycles. Wind costs were based on 25% of capital construction costs, which were based on transmission analyses for the Buffalo Ridge area. Solar costs were developed from inputs from the Transmission Access group that indicated cost of around $150/kWac based on utility scale projects that are connecting at the 115kV transmission level.

Table 7 – Transmission Delivery Costs

	$/kw
CC	$ 406.0
CT	$ 152.2
Solar	$ 150.0
Wind	$ 437.5

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability ("ELCC") Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions were given a capacity credit equal to 14.8% of their nameplate rating per MISO 2012/2013 Wind Capacity Report.

18. Effective Load Carrying Capability ("ELCC") Capacity Credit for Utility Scale Solar PV Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 52.3% of the AC nameplate capacity. This value is from the May 2013 ELCC Study. In this study, it was estimated what capacity accreditation solar might receive based on the methodology that MISO prescribes under its Resource Adequacy Business Practices Manual.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 94MW and is based on a recent 12 month rolling average of spinning reserves carried by the NSP system within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 MMBtu/MWh. Emergency energy occurs only in rare instances.

21. Dump Energy / Wind Curtailment

Estimates of wind curtailment were represented in the Strategist model by the "dump energy" variable. Dump energy occurs whenever generation cannot be reduced enough to balance with load, a situation that occurs primarily due to the non-dispatchable nature of wind generation resources combined with minimum turn-down capabilities of must-run units under low load hours. In NSP, it is assumed that the excess generation can be sold into the MISO market. To approximate the price the excess energy could be sold for, the all-hours average market price modeled in Strategist was used.

22. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP Wind Integration Cost Study. Wind integration costs contain five components:

1) MISO Contingency Reserves
2) MISO Regulating Reserves
3) MISO RSG Charges
4) Coal Cycling Costs
5) Gas Storage Costs

The results of the study as used in Strategist are shown below.

Table 8 – Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2014	0.39	0.40	0.72	1.20
2015	0.40	0.41	0.73	1.22
2016	0.41	0.42	0.75	1.24
2017	0.41	0.42	0.76	1.26
2018	0.42	0.43	0.77	1.28
2019	0.43	0.44	0.78	1.31
2020	0.43	0.45	0.80	1.33
2021	0.44	0.45	0.81	1.35
2022	0.45	0.46	0.82	1.37
2023	0.46	0.47	0.84	1.39
2024	0.46	0.48	0.85	1.42
2025	0.47	0.48	0.87	1.44
2026	0.48	0.49	0.88	1.47
2027	0.49	0.50	0.89	1.49
2028	0.50	0.51	0.91	1.51
2029	0.50	0.51	0.92	1.54
2030	0.51	0.52	0.94	1.56

23. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource. Table 10 below shows company owned unit retirement date, ICAP, current UCAP (calculated by Resource Planning), and long term UCAP (2017) based on a five year average of historical EFORd's.

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Table 9 – Thermal Owned Unit Information

Unit	Retirement Date	ICAP	RP Current UCAP	Long Term UCAP
AS KING 1	12/31/2037	541	514	519
BLACKDOG 3	5/31/2015	92	83	83
BLACKDOG 4	5/31/2015	166	135	135
SHERCO 1	12/31/2040	709	695	694
SHERCO 2	12/31/2040	694	676	667
SHERCO 3	12/31/2040	527	491	515
MONTI 1	* 9/30/2030	624	593	608
P ISLAND 1	8/31/2033	522	518	520
P ISLAND 2	10/31/2034	516	508	516
BDOG_CC 52	12/31/2031	285	189	247
HB_CC 1	5/31/2048	544	525	515
RS_CC 1	3/31/2049	470	445	443
ANSON 2	12/31/2030	93	88	83
ANSON 3	12/31/2030	93	80	76
ANSON 4	5/31/2035	149	145	144
BLUELAKE 7	5/31/2035	154	151	154
BLUELAKE 8	5/31/2035	155	146	150
FLAMBEAU 1	12/31/2018	13	12	11
GRANITE 1	12/31/2023	13	9	9
GRANITE 2	12/31/2023	14	12	12
GRANITE 3	12/31/2023	14	11	12
GRANITE 4	12/31/2023	13	10	11
INVERHIL 1	12/31/2026	48	40	41
INVERHIL 2	12/31/2026	48	45	46
INVERHIL 3	12/31/2026	48	44	44
INVERHIL 4	12/31/2026	48	41	40
INVERHIL 5	12/31/2026	47	38	41
INVERHIL 6	12/31/2026	48	42	39
KEY CITY 2	3/31/2015	16	16	16
KEY CITY 3	3/31/2015	16	13	13
KEY CITY 4	3/31/2015	17	16	16
WHEATON 1	12/31/2025	46	38	40
WHEATON 2	12/31/2025	55	42	48
WHEATON 3	12/31/2025	46	40	42
WHEATON 4	12/31/2025	47	38	45
BAYFRONT 4	12/31/2023	20	19	19
BLUELAKE 1	12/31/2023	39	35	35
BLUELAKE 2	12/31/2023	39	39	39
BLUELAKE 3	12/31/2023	38	38	38
BLUELAKE 4	12/31/2023	41	41	41
FCH ISLD 3	12/31/2023	-	-	56
FCH ISLD 4	12/31/2023	61	59	56
WHEATON 5	12/31/2025	53	42	42
WHEATON 6	12/31/2025	51	33	31
INVERDSL 78	8/31/2017	-	-	-
BAYFRONT 5	12/31/2023	21	20	20
BAYFRONT 6	12/31/2023	26	25	25
FCH ISLD 12	12/31/2023	16	15	15
RED WING 12	12/31/2027	21	19	20
WILMARTH 12	12/31/2027	19	17	17

**Assumed retirement of 12/31/2030 for modeling purposes.*

24. Thermal PPA Operating Characteristics and Costs

Power Purchase Agreements are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal purchase power contract. Table 11 below shows each thermal PPA's type, expiration date and maximum capacity.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Table 10 – Thermal PPA Information

Name of Contract	Type	Strategist Expiration Date	Max Capacity (MW)
LS Power - Cottage Grove	CC	9/30/2027	262.0
Mankato Energy Center	CC	7/31/2026	357.0
Invenergy 1	CT	3/31/2025	179.0
Invenergy 2	CT	3/31/2025	179.0
Minnkota Power Cooperative (Coyote)	COAL	10/31/2015	100.0
Laurentian	BIO	12/31/2026	35.0
Koda Energy	BIO	5/31/2019	12.0
Fibrominn	BIO	8/31/2028	55.0
St Paul Cogen	BIO	4/30/2023	25.0
Burnsville (MN Methane)	LND	3/31/2020	4.7
PineBend	LND	12/31/2025	12.0
Gunderson	LND	NA	1.1
Barron	RDF	12/31/2022	1.9
HERC	RDF	12/31/2017	33.7
Diamond K Diary	DGT	12/31/2023	0.4
Greenwhey	DGT	NA	3.2
Heller Dairy	DGT	NA	0.5

25. Renewable Energy PPA and Owned Operating Characteristics and Costs

Power Purchase Agreements are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy purchase power contract and owned unit. Table 12 below shows the type, retirement date, and nameplate capacity for each owned and PPA renewable.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2009-2014 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the Fall 2013 update to the May 2013 ELCC study. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

Table 11 – Owned and PPA Renewable Information

Name of Contract/Unit	Type	Owned or PPA	Retirement Date	Nameplate Capacity (MW)
Byllesby	Hydro	PPA	2/28/2021	2.36
Hastings	Hydro	PPA	6/30/2033	4
StCloud	Hydro	PPA	10/31/2021	8.8
EauGalle	Hydro	PPA	7/31/2026	0.3
DG Hydro	Hydro	PPA		0.43
LCO_Hydro	Hydro	PPA	12/31/2021	3.1
Neshonoc	Hydro	PPA	12/31/2020	0.4
Rapidan	Hydro	PPA	4/30/2017	5
SAF_Hydr	Hydro	PPA	12/31/2031	9.2
WTC_Angelo Dam	Hydro	PPA	3/31/2024	0.205
Hennipine Island-St. Anthony Falls	Hydro	Owned		13.9
WI Owned Hydro Grouped	Hydro	Owned		260.2
Manitoba	Hydro	PPA	4/30/2015	500
Manitoba	Hydro	PPA	4/30/2021	375
Manitoba	Hydro	PPA	4/30/2025	500
Slayton	Solar	PPA	1/31/2033	1.66
StJohns	Solar	PPA	5/31/2030	0.4
Existing DG	Solar	PPA		4.81 (2020)
New DG	Solar	PPA		67.74 (2020)
Utility Scale Solar	Solar	PPA		187 (2017)
Solar Gardens Community	Solar	PPA		30.01 (2020)
Adams	Wind	PPA	3/31/2031	19.8
Agassiz	Wind	PPA	2/28/2031	1.98
BigBlue	Wind	PPA	12/31/2032	36
Boeve	Wind	PPA	8/31/2028	1.9
Carlton	Wind	PPA	9/30/2024	1.65
Chanaram	Wind	PPA	12/31/2023	85.5
Cisco	Wind	PPA	5/31/2028	8
CommWndNorth	Wind	PPA	5/31/2031	30
CommWndSouth	Wind	PPA	12/31/2032	30.75
Courtnay	Wind	PPA	12/31/2035	200
Danielsn	Wind	PPA	3/31/2031	19.8
DG Wind	Wind	PPA	12/31/2031	5.73
Ewington	Wind	PPA	5/31/2028	19.95
Fenton1	Wind	PPA	11/30/2032	205.5
Fey	Wind	PPA	9/30/2028	1.9
FPL Mower County	Wind	PPA	12/31/2026	98.9
GrantCo	Wind	PPA	8/31/2030	20

Table 12 – Owned and PPA Renewable Information Continued

Name of Contract/Unit	Type	Owned or PPA	Retirement Date	Nameplate Capacity (MW)
Hilltop	Wind	PPA	2/28/2029	2
Jeffers	Wind	PPA	10/31/2028	50
JJN	Wind	PPA	12/31/2029	1.5
KasBros	Wind	PPA	12/31/2031	1.5
KBrink	Wind	PPA	2/28/2028	1.9
LkBnton1	Wind	PPA	12/31/2028	105.75
LkBnton2	Wind	PPA	5/31/2025	103.5
Metro	Wind	PPA	2/28/2031	0.66
MNDakota	Wind	PPA	12/31/2022	150
Moraine1	Wind	PPA	12/31/2018	51
Moraine2	Wind	PPA	2/28/2019	49.5
NAELakot	Wind	PPA	4/30/2034	11.25
NAEShak	Wind	PPA	10/31/2033	1.65
NAEShakH	Wind	PPA	4/30/2034	11.88
Odell	Wind	PPA	12/31/2035	200
Olsen	Wind	PPA	12/31/2031	1.5
Prairie Rose	Wind	PPA	12/31/2032	200
Ridgewind	Wind	PPA	1/31/2031	25.3
Rock Ridge	Wind	PPA	4/30/2021	1.8
Shanes	Wind	PPA	8/31/2026	2
South Ridge	Wind	PPA	4/30/2021	1.8
StOlaf	Wind	PPA	10/31/2028	1.65
Tholen	Wind	PPA	9/30/2025	13.2
Uilk	Wind	PPA	1/31/2030	4.5
Valley View	Wind	PPA	11/30/2031	10
Velva	Wind	PPA	1/31/2026	11.88
Wind Current	Wind	PPA	5/31/2028	1.9
Wind Power Partners	Wind	PPA	5/31/2019	25
Windvest	Wind	PPA	4/30/2021	1.8
Winona	Wind	PPA	10/31/2031	1.5
WoodStkH	Wind	PPA	4/30/2034	10.2
WoodStkM	Wind	PPA	6/30/2030	0.75
East Ridge group	Wind	PPA	4/30/2026	10
Garwin McNeilus group	Wind	PPA	2/28/2028	36.75
Minwind group	Wind	PPA	2/28/2025	11.55
Norgaard North	Wind	PPA	5/31/2026	5
Norgaard South	Wind	PPA	5/31/2026	3.75
Ruthton Ridge Group	Wind	PPA	1/31/2031	15.84
North Shaokatan	Wind	PPA	2/28/2031	11.88
Stahl Wind group	Wind	PPA	1/31/2025	8.25
Viking Wind group	Wind	PPA	12/31/2018	12
Westridge Group	Wind	PPA	12/31/2028	9.5
Border	Wind	Owned		150
GrandMed	Wind	Owned		100.5
Nobles	Wind	Owned		201
PlsntVly	Wind	Owned		200

26. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource. Tables 13-15 below show the assumptions for the generic renewable and thermal resources.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table 12 – Thermal Generic Information (Costs in 2014 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,621	5,287	926	1,167	602	1,515	4,558
Electric Transmission Delivery ($/kw)	NA	NA	406	NA	152	NA	NA
Gas Demand ($/kw-yr)	0	0	8.44	11.28	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,343	24,598	7,510	4,139	591	853	5,183
Variable O&M Cost ($/MWh)	2.80	10.56	3.08	1.75	2.27	1.81	4.68
Ongoing Capital Expenditures ($/kw-yr)	9.59	23.42	4.32	4.79	5.87	1.86	14.13
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 13 – Renewable Generic Information (Costs in 2014 Dollars)

Resource	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
Nameplate Capacity (MW)	200	200	50	50
ELCC Capacity Credit (MW)	29.6	29.6	26.15	26.15
Capital Cost ($/kw)	$1,700	$1,700	$1,563	$1,140
Electric Transmission Delivery ($/kw)	$150	$150	$85	$62
Book life	25	25	25	25
Fixed O&M Cost ($000/yr)	$1,828	$1,828	$1,235	$1,235
Variable O&M Cost ($/MWh)	$0.63	$0.63	$0.00	$0.00
Ongoing Capital Expenditures ($000/yr)	$2,466	$2,466	$0	$0
Land Lease Payments ($000/yr)	$1,172	$1,172	$0	$0

Table 14– Renewable Generic ECC Costs

Year	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
2014	25.71	45.46	75.00	95.00
2015	26.28	46.48	75.00	95.00
2016	26.87	47.52	75.00	95.00
2017	27.48	48.58	75.00	95.00
2018	28.09	49.67	75.00	95.00
2019	28.72	50.78	75.00	95.00
2020	29.36	51.92	75.00	95.00
2021	30.02	53.08	75.00	95.00
2022	30.69	54.27	75.00	95.00
2023	31.38	55.49	75.00	95.00
2024	32.08	56.73	75.00	95.00
2025	32.80	58.00	75.00	95.00
2026	33.54	59.30	75.00	95.00
2027	34.29	60.63	75.00	95.00
2028	35.06	61.99	75.00	95.00
2029	35.84	63.38	75.00	95.00
2030	36.65	64.80	75.00	95.00

27. Renewable Energy Expansion Plan

The base renewable energy expansion plan (not including the PPA solar portfolios being analyzed) included:

- Addition of 750 MW of wind through 2016 as already approved by regulators.
- Generic addition of 200MW of wind in 2028, 2030, 2032 and 2034 to ensure meeting MN renewable energy standard.
- No extension of the Federal Production Tax Credit or 30% Investment Tax Credit past the expiration dates as per current law.
- Distributed solar additions sufficient, when combined with the utility-scale solar being contemplated, to meet the MN 1.5% standard and small-solar carve-out by 2020. Distributed solar additions end after 2020.

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Year	Month	Historical Ventura	Forecast Ventura
2005	1/1/2005	5.96	
2005	2/1/2005	5.82	
2005	3/1/2005	6.62	
2005	4/1/2005	6.91	
2005	5/1/2005	6.05	
2005	6/1/2005	6.53	
2005	7/1/2005	7.08	
2005	8/1/2005	8.54	
2005	9/1/2005	10.14	
2005	10/1/2005	11.15	
2005	11/1/2005	8.25	
2005	12/1/2005	11.83	
2006	1/1/2006	7.90	
2006	2/1/2006	7.18	
2006	3/1/2006	6.15	
2006	4/1/2006	6.20	
2006	5/1/2006	5.55	
2006	6/1/2006	5.78	
2006	7/1/2006	5.71	
2006	8/1/2006	6.84	
2006	9/1/2006	4.70	
2006	10/1/2006	5.73	
2006	11/1/2006	7.20	
2006	12/1/2006	6.81	
2007	1/1/2007	6.39	
2007	2/1/2007	8.04	
2007	3/1/2007	6.76	
2007	4/1/2007	7.09	
2007	5/1/2007	7.09	
2007	6/1/2007	6.69	
2007	7/1/2007	5.86	
2007	8/1/2007	5.86	
2007	9/1/2007	5.50	
2007	10/1/2007	6.53	
2007	11/1/2007	6.65	
2007	12/1/2007	7.07	
2008	1/1/2008	8.05	
2008	2/1/2008	8.58	
2008	3/1/2008	9.32	
2008	4/1/2008	9.80	
2008	5/1/2008	9.95	
2008	6/1/2008	11.13	
2008	7/1/2008	10.18	
2008	8/1/2008	7.63	
2008	9/1/2008	6.27	
2008	10/1/2008	6.28	
2008	11/1/2008	6.24	
2008	12/1/2008	5.93	
2009	1/1/2009	5.42	
2009	2/1/2009	4.42	
2009	3/1/2009	3.70	
2009	4/1/2009	3.26	
2009	5/1/2009	3.35	
2009	6/1/2009	3.22	
2009	7/1/2009	3.22	
2009	8/1/2009	3.07	
2009	9/1/2009	2.98	

Year	Historical Ventura	Forecast Ventura
2005	7.91	
2006	6.31	
2007	6.63	
2008	8.28	
2009	3.85	
2010	4.38	
2011	4.03	
2012	2.77	
2013	3.79	
2014	4.55	
2015		4.01
2016		3.98
2017		4.02
2018		4.14
2019		4.35
2020		4.76
2021		5.16
2022		5.17
2023		5.35
2024		5.59
2025		5.70
2026		5.90
2027		6.03
2028		6.12
2029		6.36
2030		6.52
2031		6.68
2032		6.80
2033		7.00
2034		7.20
2035		7.32
2036		7.47
2037		7.61
2038		7.76
2039		7.91
2040		8.07
2041		8.23
2042		8.39

2009	10/1/2009	4.31	
2009	11/1/2009	3.71	
2009	12/1/2009	5.59	
2010	1/1/2010	5.89	
2010	2/1/2010	5.45	
2010	3/1/2010	4.41	
2010	4/1/2010	3.95	
2010	5/1/2010	4.05	
2010	6/1/2010	4.64	
2010	7/1/2010	4.47	
2010	8/1/2010	4.16	
2010	9/1/2010	3.81	
2010	10/1/2010	3.48	
2010	11/1/2010	3.87	
2010	12/1/2010	4.39	
2011	1/1/2011	4.62	
2011	2/1/2011	4.26	
2011	3/1/2011	4.03	
2011	4/1/2011	4.23	
2011	5/1/2011	4.26	
2011	6/1/2011	4.51	
2011	7/1/2011	4.39	
2011	8/1/2011	4.08	
2011	9/1/2011	3.91	
2011	10/1/2011	3.57	
2011	11/1/2011	3.34	
2011	12/1/2011	3.20	
2012	1/1/2012	2.77	
2012	2/1/2012	2.57	
2012	3/1/2012	2.08	
2012	4/1/2012	1.95	
2012	5/1/2012	2.37	
2012	6/1/2012	2.40	
2012	7/1/2012	2.94	
2012	8/1/2012	2.84	
2012	9/1/2012	2.85	
2012	10/1/2012	3.44	
2012	11/1/2012	3.63	
2012	12/1/2012	3.39	
2013	1/1/2013	3.50	
2013	2/1/2013	3.41	
2013	3/1/2013	3.92	
2013	4/1/2013	4.19	
2013	5/1/2013	4.01	
2013	6/1/2013	3.76	
2013	7/1/2013	3.63	
2013	8/1/2013	3.46	
2013	9/1/2013	3.63	
2013	10/1/2013	3.74	
2013	11/1/2013	3.68	
2013	12/1/2013	4.61	
2014	1/1/2014	7.86	
2014	2/1/2014	14.63	
2014	3/1/2014	10.39	
2014	4/1/2014	4.67	
2014	5/1/2014	4.51	
2014	6/1/2014	4.58	
2014	7/1/2014	4.06	
2014	8/1/2014	3.86	
2014	9/1/2014		3.89
2014	10/1/2014		3.99

2014	11/1/2014	4.16
2014	12/1/2014	4.38
2015	1/1/2015	4.52
2015	2/1/2015	4.50
2015	3/1/2015	4.29
2015	4/1/2015	3.82
2015	5/1/2015	3.75
2015	6/1/2015	3.73
2015	7/1/2015	3.76
2015	8/1/2015	3.79
2015	9/1/2015	3.78
2015	10/1/2015	3.83
2015	11/1/2015	4.11
2015	12/1/2015	4.23
2016	1/1/2016	4.34
2016	2/1/2016	4.31
2016	3/1/2016	4.22
2016	4/1/2016	3.78
2016	5/1/2016	3.77
2016	6/1/2016	3.78
2016	7/1/2016	3.81
2016	8/1/2016	3.82
2016	9/1/2016	3.81
2016	10/1/2016	3.83
2016	11/1/2016	4.04
2016	12/1/2016	4.22
2017	1/1/2017	4.37
2017	2/1/2017	4.35
2017	3/1/2017	4.27
2017	4/1/2017	3.75
2017	5/1/2017	3.74
2017	6/1/2017	3.77
2017	7/1/2017	3.86
2017	8/1/2017	3.87
2017	9/1/2017	3.86
2017	10/1/2017	3.88
2017	11/1/2017	4.16
2017	12/1/2017	4.34
2018	1/1/2018	4.48
2018	2/1/2018	4.46
2018	3/1/2018	4.39
2018	4/1/2018	3.89
2018	5/1/2018	3.88
2018	6/1/2018	3.91
2018	7/1/2018	3.97
2018	8/1/2018	3.99
2018	9/1/2018	3.99
2018	10/1/2018	4.03
2018	11/1/2018	4.29
2018	12/1/2018	4.47
2019	1/1/2019	4.60
2019	2/1/2019	4.58
2019	3/1/2019	4.51
2019	4/1/2019	4.03
2019	5/1/2019	4.03
2019	6/1/2019	4.06
2019	7/1/2019	4.24
2019	8/1/2019	4.26
2019	9/1/2019	4.26
2019	10/1/2019	4.30
2019	11/1/2019	4.55

2019	12/1/2019	4.75
2020	1/1/2020	4.86
2020	2/1/2020	4.85
2020	3/1/2020	4.78
2020	4/1/2020	4.37
2020	5/1/2020	4.38
2020	6/1/2020	4.42
2020	7/1/2020	4.77
2020	8/1/2020	4.82
2020	9/1/2020	4.80
2020	10/1/2020	4.82
2020	11/1/2020	5.02
2020	12/1/2020	5.18
2021	1/1/2021	5.26
2021	2/1/2021	5.28
2021	3/1/2021	5.21
2021	4/1/2021	4.88
2021	5/1/2021	4.94
2021	6/1/2021	5.02
2021	7/1/2021	5.07
2021	8/1/2021	5.15
2021	9/1/2021	5.14
2021	10/1/2021	5.15
2021	11/1/2021	5.32
2021	12/1/2021	5.47
2022	1/1/2022	5.52
2022	2/1/2022	5.49
2022	3/1/2022	5.38
2022	4/1/2022	4.96
2022	5/1/2022	4.96
2022	6/1/2022	4.99
2022	7/1/2022	4.99
2022	8/1/2022	5.01
2022	9/1/2022	4.98
2022	10/1/2022	5.01
2022	11/1/2022	5.26
2022	12/1/2022	5.47
2023	1/1/2023	5.57
2023	2/1/2023	5.57
2023	3/1/2023	5.50
2023	4/1/2023	5.10
2023	5/1/2023	5.13
2023	6/1/2023	5.17
2023	7/1/2023	5.19
2023	8/1/2023	5.23
2023	9/1/2023	5.21
2023	10/1/2023	5.27
2023	11/1/2023	5.55
2023	12/1/2023	5.75
2024	1/1/2024	5.87
2024	2/1/2024	5.85
2024	3/1/2024	5.73
2024	4/1/2024	5.32
2024	5/1/2024	5.34
2024	6/1/2024	5.39
2024	7/1/2024	5.43
2024	8/1/2024	5.47
2024	9/1/2024	5.46
2024	10/1/2024	5.52
2024	11/1/2024	5.77
2024	12/1/2024	5.97

2025	1/1/2025	6.05
2025	2/1/2025	6.01
2025	3/1/2025	5.85
2025	4/1/2025	5.43
2025	5/1/2025	5.46
2025	6/1/2025	5.50
2025	7/1/2025	5.53
2025	8/1/2025	5.57
2025	9/1/2025	5.54
2025	10/1/2025	5.59
2025	11/1/2025	5.84
2025	12/1/2025	6.05
2026	1/1/2026	6.16
2026	2/1/2026	6.13
2026	3/1/2026	6.02
2026	4/1/2026	5.60
2026	5/1/2026	5.65
2026	6/1/2026	5.70
2026	7/1/2026	5.75
2026	8/1/2026	5.81
2026	9/1/2026	5.79
2026	10/1/2026	5.85
2026	11/1/2026	6.09
2026	12/1/2026	6.30
2027	1/1/2027	6.38
2027	2/1/2027	6.38
2027	3/1/2027	6.20
2027	4/1/2027	5.76
2027	5/1/2027	5.79
2027	6/1/2027	5.85
2027	7/1/2027	5.86
2027	8/1/2027	5.89
2027	9/1/2027	5.85
2027	10/1/2027	5.90
2027	11/1/2027	6.16
2027	12/1/2027	6.36
2028	1/1/2028	6.48
2028	2/1/2028	6.44
2028	3/1/2028	6.25
2028	4/1/2028	5.82
2028	5/1/2028	5.86
2028	6/1/2028	5.92
2028	7/1/2028	5.94
2028	8/1/2028	5.97
2028	9/1/2028	5.94
2028	10/1/2028	5.99
2028	11/1/2028	6.32
2028	12/1/2028	6.57
2029	1/1/2029	6.71
2029	2/1/2029	6.68
2029	3/1/2029	6.50
2029	4/1/2029	6.06
2029	5/1/2029	6.10
2029	6/1/2029	6.16
2029	7/1/2029	6.18
2029	8/1/2029	6.23
2029	9/1/2029	6.20
2029	10/1/2029	6.26
2029	11/1/2029	6.52
2029	12/1/2029	6.77
2030	1/1/2030	6.93

2030	2/1/2030	6.90
2030	3/1/2030	6.64
2030	4/1/2030	6.19
2030	5/1/2030	6.23
2030	6/1/2030	6.28
2030	7/1/2030	6.31
2030	8/1/2030	6.36
2030	9/1/2030	6.32
2030	10/1/2030	6.39
2030	11/1/2030	6.71
2030	12/1/2030	6.98
2031	1/1/2031	7.11
2031	2/1/2031	7.07
2031	3/1/2031	6.81
2031	4/1/2031	6.35
2031	5/1/2031	6.39
2031	6/1/2031	6.45
2031	7/1/2031	6.47
2031	8/1/2031	6.52
2031	9/1/2031	6.48
2031	10/1/2031	6.54
2031	11/1/2031	6.83
2031	12/1/2031	7.14
2032	1/1/2032	7.24
2032	2/1/2032	7.18
2032	3/1/2032	6.92
2032	4/1/2032	6.46
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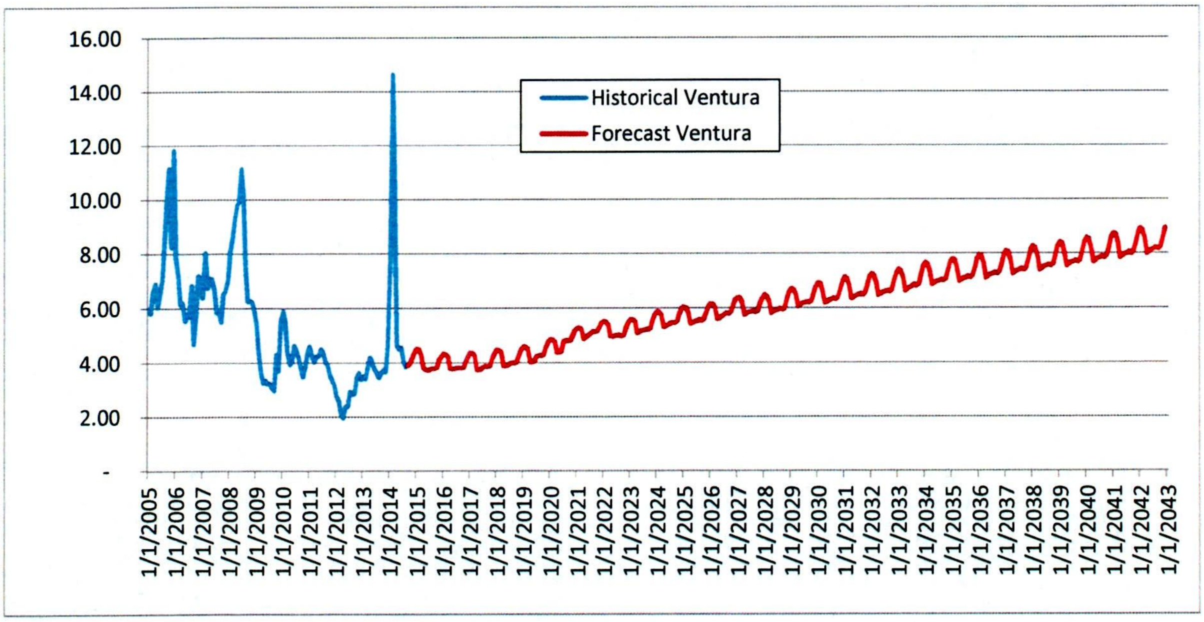
2032	7/1/2032	6.59
2032	8/1/2032	6.63
2032	9/1/2032	6.59
2032	10/1/2032	6.66
2032	11/1/2032	6.97
2032	12/1/2032	7.28
2033	1/1/2033	7.40
2033	2/1/2033	7.36
2033	3/1/2033	7.09
2033	4/1/2033	6.63
2033	5/1/2033	6.68
2033	6/1/2033	6.75
2033	7/1/2033	6.80
2033	8/1/2033	6.84
2033	9/1/2033	6.81
2033	10/1/2033	6.88
2033	11/1/2033	7.19
2033	12/1/2033	7.51
2034	1/1/2034	7.65
2034	2/1/2034	7.61
2034	3/1/2034	7.33
2034	4/1/2034	6.86
2034	5/1/2034	6.90
2034	6/1/2034	6.96
2034	7/1/2034	6.99
2034	8/1/2034	7.04
2034	9/1/2034	7.00
2034	10/1/2034	7.06
2034	11/1/2034	7.36
2034	12/1/2034	7.68
2035	1/1/2035	7.79
2035	2/1/2035	7.75

2035	3/1/2035	7.46
2035	4/1/2035	6.97
2035	5/1/2035	7.02
2035	6/1/2035	7.08
2035	7/1/2035	7.10
2035	8/1/2035	7.15
2035	9/1/2035	7.11
2035	10/1/2035	7.17
2035	11/1/2035	7.47
2035	12/1/2035	7.80
2036	1/1/2036	7.95
2036	2/1/2036	7.90
2036	3/1/2036	7.61
2036	4/1/2036	7.11
2036	5/1/2036	7.16
2036	6/1/2036	7.22
2036	7/1/2036	7.24
2036	8/1/2036	7.29
2036	9/1/2036	7.25
2036	10/1/2036	7.32
2036	11/1/2036	7.61
2036	12/1/2036	7.95
2037	1/1/2037	8.10
2037	2/1/2037	8.05
2037	3/1/2037	7.76
2037	4/1/2037	7.25
2037	5/1/2037	7.30
2037	6/1/2037	7.36
2037	7/1/2037	7.39
2037	8/1/2037	7.44
2037	9/1/2037	7.39
2037	10/1/2037	7.46
2037	11/1/2037	7.76
2037	12/1/2037	8.10
2038	1/1/2038	8.25
2038	2/1/2038	8.21
2038	3/1/2038	7.90
2038	4/1/2038	7.39
2038	5/1/2038	7.45
2038	6/1/2038	7.51
2038	7/1/2038	7.53
2038	8/1/2038	7.59
2038	9/1/2038	7.54
2038	10/1/2038	7.61
2038	11/1/2038	7.91
2038	12/1/2038	8.26
2039	1/1/2039	8.41
2039	2/1/2039	8.36
2039	3/1/2039	8.06
2039	4/1/2039	7.54
2039	5/1/2039	7.60
2039	6/1/2039	7.66
2039	7/1/2039	7.68
2039	8/1/2039	7.74
2039	9/1/2039	7.69
2039	10/1/2039	7.76
2039	11/1/2039	8.06
2039	12/1/2039	8.42
2040	1/1/2040	8.57
2040	2/1/2040	8.53
2040	3/1/2040	8.21

2040	4/1/2040	7.69
2040	5/1/2040	7.75
2040	6/1/2040	7.81
2040	7/1/2040	7.84
2040	8/1/2040	7.89
2040	9/1/2040	7.84
2040	10/1/2040	7.91
2040	11/1/2040	8.21
2040	12/1/2040	8.58
2041	1/1/2041	8.74
2041	2/1/2041	8.69
2041	3/1/2041	8.37
2041	4/1/2041	7.84
2041	5/1/2041	7.90
2041	6/1/2041	7.97
2041	7/1/2041	7.99
2041	8/1/2041	8.05
2041	9/1/2041	7.99
2041	10/1/2041	8.07
2041	11/1/2041	8.37
2041	12/1/2041	8.75
2042	1/1/2042	8.91
2042	2/1/2042	8.86
2042	3/1/2042	8.53
2042	4/1/2042	8.00
2042	5/1/2042	8.06
2042	6/1/2042	8.12
2042	7/1/2042	8.15
2042	8/1/2042	8.21
2042	9/1/2042	8.15
2042	10/1/2042	8.23
2042	11/1/2042	8.54
2042	12/1/2042	8.91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8.00
6.00
4.00
2.00
-
Historical Ventura
Forecast Ventura
1/1/2005
1/1/2006
1/1/2007
1/1/2008
1/1/2009
1/1/2010
1/1/2011
1/1/2012
1/1/2013
1/1/2014
1/1/2015
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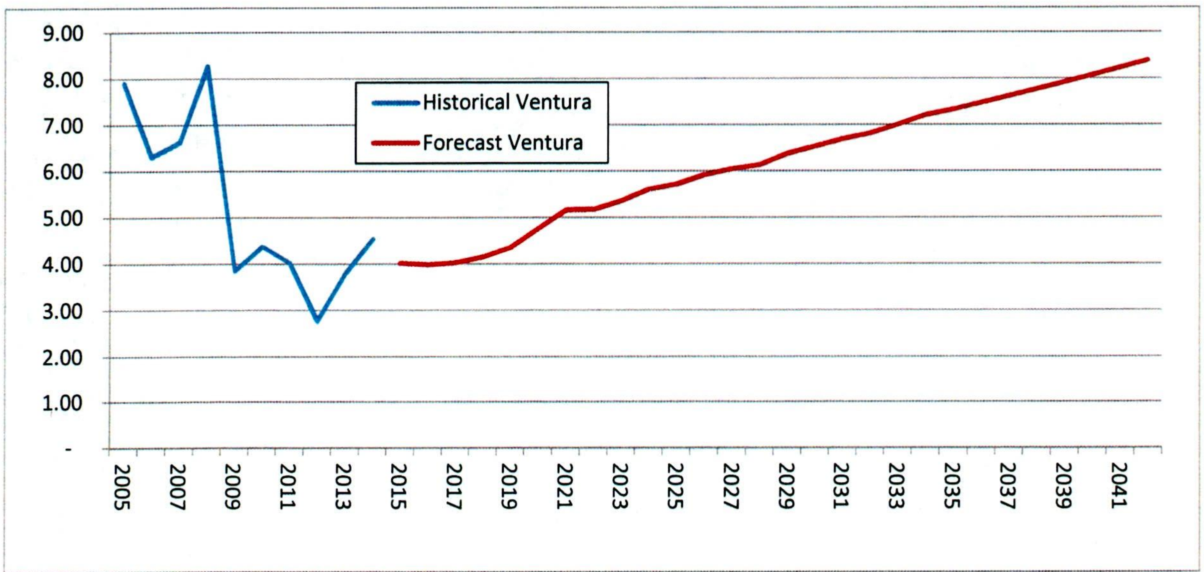
1/1/2042
1/1/2043


9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Historical Ventura
Forecast Ventura
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041

Henry Hub Gas Forecast Decomposition

TRADE SECRET DATA SHADED

Prices as of **9/8/2014** **[TRADE SECRET BEGINS...**

Date	NYMEX	PIRA	Wood Mac	CERA	4 Source Blend	Methodology	Final Henry Hub Gas Curve	Ventura Basis
10/1/2014	$ 3.876				$ 4.02	100% NYMEX	$ 3.876	$ 0.110
11/1/2014	$ 3.927				$ 4.03	100% NYMEX	$ 3.927	$ 0.233
12/1/2014	$ 4.015				$ 4.13	100% NYMEX	$ 4.015	$ 0.365
1/1/2015	$ 4.086				$ 4.15	100% NYMEX	$ 4.086	$ 0.430
2/1/2015	$ 4.076				$ 4.13	100% NYMEX	$ 4.076	$ 0.428
3/1/2015	$ 4.013				$ 4.09	100% NYMEX	$ 4.013	$ 0.275
4/1/2015	$ 3.803				$ 3.95	100% NYMEX	$ 3.803	$ 0.015
5/1/2015	$ 3.788				$ 3.98	100% NYMEX	$ 3.788	$ (0.040)
6/1/2015	$ 3.811				$ 4.02	100% NYMEX	$ 3.811	$ (0.085)
7/1/2015	$ 3.840				$ 4.06	100% NYMEX	$ 3.840	$ (0.085)
8/1/2015	$ 3.848				$ 4.10	100% NYMEX	$ 3.848	$ (0.063)
9/1/2015	$ 3.837				$ 4.09	100% NYMEX	$ 3.837	$ (0.058)
10/1/2015	$ 3.873				$ 4.14	100% NYMEX	$ 3.873	$ (0.043)
11/1/2015	$ 3.966				$ 4.19	100% NYMEX	$ 3.966	$ 0.145
12/1/2015	$ 4.112				$ 4.38	100% NYMEX	$ 4.112	$ 0.115
1/1/2016	$ 4.235				$ 4.58	100% NYMEX	$ 4.235	$ 0.103
2/1/2016	$ 4.216				$ 4.56	100% NYMEX	$ 4.216	$ 0.098
3/1/2016	$ 4.151				$ 4.52	100% NYMEX	$ 4.151	$ 0.070
4/1/2016	$ 3.928				$ 4.33	100% NYMEX	$ 3.928	$ (0.148)
5/1/2016	$ 3.930				$ 4.31	100% NYMEX	$ 3.930	$ (0.165)
6/1/2016	$ 3.957				$ 4.30	100% NYMEX	$ 3.957	$ (0.173)
7/1/2016	$ 3.985				$ 4.31	100% NYMEX	$ 3.985	$ (0.178)
8/1/2016	$ 3.993				$ 4.31	100% NYMEX	$ 3.993	$ (0.178)
9/1/2016	$ 3.981				$ 4.25	100% NYMEX	$ 3.981	$ (0.175)
10/1/2016	$ 4.010				$ 4.24	100% NYMEX	$ 4.010	$ (0.178)
11/1/2016	$ 4.092				$ 4.27	100% NYMEX	$ 4.092	$ (0.055)
12/1/2016	$ 4.263				$ 4.42	100% NYMEX	$ 4.263	$ (0.043)
1/1/2017	$ 4.391				$ 4.59	100% NYMEX	$ 4.391	$ (0.018)
2/1/2017	$ 4.371				$ 4.59	100% NYMEX	$ 4.371	$ (0.023)
3/1/2017	$ 4.306				$ 4.55	100% NYMEX	$ 4.306	$ (0.033)
4/1/2017	$ 4.048				$ 4.38	100% NYMEX	$ 4.048	$ (0.298)
5/1/2017	$ 4.058				$ 4.42	100% NYMEX	$ 4.058	$ (0.320)
6/1/2017	$ 4.091				$ 4.44	100% NYMEX	$ 4.091	$ (0.320)
7/1/2017	$ 4.128				$ 4.44	100% NYMEX	$ 4.128	$ (0.273)
8/1/2017	$ 4.142				$ 4.45	100% NYMEX	$ 4.142	$ (0.273)
9/1/2017	$ 4.137				$ 4.43	100% NYMEX	$ 4.137	$ (0.273)
10/1/2017	$ 4.162				$ 4.43	100% NYMEX	$ 4.162	$ (0.283)
11/1/2017	$ 4.239				$ 4.48	100% NYMEX	$ 4.239	$ (0.080)

12/1/2017	$	4.407		$	4.60	100% NYMEX	$	4.407	$	(0.063)
1/1/2018	$	4.537		$	4.74	100% NYMEX	$	4.537	$	(0.055)
2/1/2018	$	4.517		$	4.74	100% NYMEX	$	4.517	$	(0.060)
3/1/2018	$	4.455		$	4.70	100% NYMEX	$	4.455	$	(0.070)
4/1/2018	$	4.130		$	4.50	100% NYMEX	$	4.130	$	(0.240)
5/1/2018	$	4.143		$	4.53	100% NYMEX	$	4.143	$	(0.263)
6/1/2018	$	4.173		$	4.55	100% NYMEX	$	4.173	$	(0.265)
7/1/2018	$	4.207		$	4.55	2/3 NYMEX, 1/3 Blend	$	4.32	$	(0.273)
8/1/2018	$	4.221		$	4.57	2/3 NYMEX, 1/3 Blend	$	4.34	$	(0.273)
9/1/2018	$	4.218		$	4.55	2/3 NYMEX, 1/3 Blend	$	4.33	$	(0.270)
10/1/2018	$	4.244		$	4.56	2/3 NYMEX, 1/3 Blend	$	4.35	$	(0.255)
11/1/2018	$	4.330		$	4.59	2/3 NYMEX, 1/3 Blend	$	4.42	$	(0.073)
12/1/2018	$	4.504		$	4.73	2/3 NYMEX, 1/3 Blend	$	4.58	$	(0.058)
1/1/2019	$	4.622		$	4.85	2/3 NYMEX, 1/3 Blend	$	4.70	$	(0.050)
2/1/2019	$	4.602		$	4.85	2/3 NYMEX, 1/3 Blend	$	4.68	$	(0.055)
3/1/2019	$	4.541		$	4.82	2/3 NYMEX, 1/3 Blend	$	4.63	$	(0.065)
4/1/2019	$	4.221		$	4.62	2/3 NYMEX, 1/3 Blend	$	4.36	$	(0.235)
5/1/2019	$	4.235		$	4.69	2/3 NYMEX, 1/3 Blend	$	4.39	$	(0.258)
6/1/2019	$	4.265		$	4.73	2/3 NYMEX, 1/3 Blend	$	4.42	$	(0.260)
7/1/2019	$	4.299		$	4.76	1/3 NYMEX, 2/3 Blend	$	4.61	$	(0.268)
8/1/2019	$	4.313		$	4.79	1/3 NYMEX, 2/3 Blend	$	4.63	$	(0.268)
9/1/2019	$	4.310		$	4.79	1/3 NYMEX, 2/3 Blend	$	4.63	$	(0.265)
10/1/2019	$	4.339		$	4.81	1/3 NYMEX, 2/3 Blend	$	4.66	$	(0.255)
11/1/2019	$	4.438		$	4.84	1/3 NYMEX, 2/3 Blend	$	4.71	$	(0.073)
12/1/2019	$	4.635		$	5.01	1/3 NYMEX, 2/3 Blend	$	4.89	$	(0.058)
1/1/2020	$	4.755		$	5.10	1/3 NYMEX, 2/3 Blend	$	4.98	$	(0.050)
2/1/2020	$	4.735		$	5.10	1/3 NYMEX, 2/3 Blend	$	4.98	$	(0.055)
3/1/2020	$	4.674		$	5.05	1/3 NYMEX, 2/3 Blend	$	4.93	$	(0.065)
4/1/2020	$	4.374		$	4.88	1/3 NYMEX, 2/3 Blend	$	4.71	$	(0.235)
5/1/2020	$	4.392		$	4.94	1/3 NYMEX, 2/3 Blend	$	4.76	$	(0.258)
6/1/2020	$	4.422		$	5.00	1/3 NYMEX, 2/3 Blend	$	4.80	$	(0.260)
7/1/2020	$	4.456		$	5.04	100% B lend	$	5.04	$	(0.268)
8/1/2020	$	4.483		$	5.08	100% B lend	$	5.08	$	(0.268)
9/1/2020	$	4.480		$	5.07	100% B lend	$	5.07	$	(0.265)
10/1/2020	$	4.515		$	5.08	100% B lend	$	5.08	$	(0.255)
11/1/2020	$	4.610		$	5.09	100% B lend	$	5.09	$	(0.073)
12/1/2020	$	4.800		$	5.24	100% B lend	$	5.24	$	(0.058)
1/1/2021	$	4.910		$	5.31	100% B lend	$	5.31	$	(0.050)
2/1/2021	$	4.890		$	5.33	100% B lend	$	5.33	$	(0.055)
3/1/2021	$	4.826		$	5.27	100% B lend	$	5.27	$	(0.065)
4/1/2021	$	4.521		$	5.11	100% B lend	$	5.11	$	(0.235)
5/1/2021	$	4.547		$	5.20	100% B lend	$	5.20	$	(0.258)
6/1/2021	$	4.577		$	5.28	100% B lend	$	5.28	$	(0.260)
7/1/2021	$	4.614		$	5.34	100% B lend	$	5.34	$	(0.268)
8/1/2021	$	4.644		$	5.41	100% B lend	$	5.41	$	(0.268)
9/1/2021	$	4.641		$	5.41	100% B lend	$	5.41	$	(0.265)

10/1/2021	$	4.680	$	5.41	100% B lend	$	5.41	$ (0.255)
11/1/2021	$	4.770	$	5.39	100% B lend	$	5.39	$ (0.073)
12/1/2021	$	4.960	$	5.53	100% B lend	$	5.53	$ (0.058)
1/1/2022	$	5.062	$	5.57	100% B lend	$	5.57	$ (0.050)
2/1/2022	$	5.042	$	5.55	100% B lend	$	5.55	$ (0.055)
3/1/2022	$	4.974	$	5.44	100% B lend	$	5.44	$ (0.065)
4/1/2022	$	4.654	$	5.20	100% B lend	$	5.20	$ (0.235)
5/1/2022	$	4.649	$	5.22	100% B lend	$	5.22	$ (0.258)
6/1/2022	$	4.679	$	5.25	100% B lend	$	5.25	$ (0.260)
7/1/2022	$	4.717	$	5.26	100% B lend	$	5.26	$ (0.268)
8/1/2022	$	4.759	$	5.28	100% B lend	$	5.28	$ (0.268)
9/1/2022	$	4.769	$	5.24	100% B lend	$	5.24	$ (0.265)
10/1/2022	$	4.815	$	5.26	100% B lend	$	5.26	$ (0.255)
11/1/2022	$	4.903	$	5.34	100% B lend	$	5.34	$ (0.073)
12/1/2022	$	5.093	$	5.52	100% B lend	$	5.52	$ (0.058)
1/1/2023	$	5.193	$	5.62	100% B lend	$	5.62	$ (0.050)
2/1/2023	$	5.163	$	5.62	100% B lend	$	5.62	$ (0.055)
3/1/2023	$	5.083	$	5.56	100% B lend	$	5.56	$ (0.065)
4/1/2023	$	4.743	$	5.33	100% B lend	$	5.33	$ (0.235)
5/1/2023	$	4.728	$	5.39	100% B lend	$	5.39	$ (0.258)
6/1/2023	$	4.758	$	5.43	100% B lend	$	5.43	$ (0.260)
7/1/2023	$	4.799	$	5.46	100% B lend	$	5.46	$ (0.268)
8/1/2023	$	4.838	$	5.49	100% B lend	$	5.49	$ (0.268)
9/1/2023	$	4.848	$	5.48	100% B lend	$	5.48	$ (0.265)
10/1/2023	$	4.900	$	5.52	100% B lend	$	5.52	$ (0.255)
11/1/2023	$	4.990	$	5.62	100% B lend	$	5.62	$ (0.073)
12/1/2023	$	5.180	$	5.80	100% B lend	$	5.80	$ (0.058)
1/1/2024	$	5.275	$	5.92	100% B lend	$	5.92	$ (0.050)
2/1/2024	$	5.242	$	5.90	100% B lend	$	5.90	$ (0.055)
3/1/2024	$	5.159	$	5.79	100% B lend	$	5.79	$ (0.065)
4/1/2024	$	4.809	$	5.55	100% B lend	$	5.55	$ (0.235)
5/1/2024	$	4.794	$	5.60	100% B lend	$	5.60	$ (0.258)
6/1/2024	$	4.826	$	5.65	100% B lend	$	5.65	$ (0.260)
7/1/2024	$	4.871	$	5.69	100% B lend	$	5.69	$ (0.268)
8/1/2024	$	4.913	$	5.74	100% B lend	$	5.74	$ (0.268)
9/1/2024	$	4.926	$	5.72	100% B lend	$	5.72	$ (0.265)
10/1/2024	$	4.986	$	5.77	100% B lend	$	5.77	$ (0.255)
11/1/2024	$	5.076	$	5.84	100% B lend	$	5.84	$ (0.073)
12/1/2024	$	5.271	$	6.03	100% B lend	$	6.03	$ (0.058)
1/1/2025	$	5.366	$	6.10	100% B lend	$	6.10	$ (0.050)
2/1/2025	$	5.331	$	6.06	100% B lend	$	6.06	$ (0.055)
3/1/2025	$	5.246	$	5.92	100% B lend	$	5.92	$ (0.065)
4/1/2025	$	4.861	$	5.66	100% B lend	$	5.66	$ (0.235)
5/1/2025	$	4.846	$	5.71	100% B lend	$	5.71	$ (0.258)
6/1/2025	$	4.884	$	5.76	100% B lend	$	5.76	$ (0.260)
7/1/2025	$	4.932	$	5.79	100% B lend	$	5.79	$ (0.268)

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8/1/2025	$	4.976	$	5.83	100% B lend	$	5.83	$ (0.268)
9/1/2025	$	4.991	$	5.81	100% B lend	$	5.81	$ (0.265)
10/1/2025	$	5.053	$	5.85	100% B lend	$	5.85	$ (0.255)
11/1/2025	$	5.158	$	5.91	100% B lend	$	5.91	$ (0.073)
12/1/2025	$	5.368	$	6.11	100% B lend	$	6.11	$ (0.058)
1/1/2026	$	5.478	$	6.21	100% B lend	$	6.21	$ (0.050)
2/1/2026	$	5.441	$	6.18	100% B lend	$	6.18	$ (0.055)
3/1/2026	$	5.353	$	6.08	100% B lend	$	6.08	$ (0.065)
4/1/2026	$	4.963	$	5.83	100% B lend	$	5.83	$ (0.235)
5/1/2026	$	4.948	$	5.90	100% B lend	$	5.90	$ (0.258)
6/1/2026	$	4.986	$	5.96	100% B lend	$	5.96	$ (0.260)
7/1/2026	$	5.034	$	6.01	100% B lend	$	6.01	$ (0.268)
8/1/2026	$	5.078	$	6.08	100% B lend	$	6.08	$ (0.268)
9/1/2026	$	5.093	$	6.05	100% B lend	$	6.05	$ (0.265)
10/1/2026	$	5.155	$	6.10	100% B lend	$	6.10	$ (0.255)
11/1/2026	$	5.275	$	6.16	100% B lend	$	6.16	$ (0.073)
12/1/2026	$	5.505	$	6.36	100% B lend	$	6.36	$ (0.058)
1/1/2027	$	5.493	$	6.42	100% B lend	$	6.42	$ (0.050)
2/1/2027	$	5.569	$	6.42	100% B lend	$	6.42	$ (0.055)
3/1/2027	$	5.433	$	6.25	100% B lend	$	6.25	$ (0.065)
4/1/2027	$	5.139	$	6.00	100% B lend	$	6.00	$ (0.235)
5/1/2027	$	5.103	$	6.05	100% B lend	$	6.05	$ (0.258)
6/1/2027	$	5.159	$	6.11	100% B lend	$	6.11	$ (0.260)
7/1/2027	$	5.194	$	6.13	100% B lend	$	6.13	$ (0.268)
8/1/2027	$	5.153	$	6.15	100% B lend	$	6.15	$ (0.268)
9/1/2027	$	5.171	$	6.12	100% B lend	$	6.12	$ (0.265)
10/1/2027	$	5.204	$	6.15	100% B lend	$	6.15	$ (0.255)
11/1/2027	$	5.301	$	6.23	100% B lend	$	6.23	$ (0.073)
12/1/2027	$	5.505	$	6.41	100% B lend	$	6.41	$ (0.058)
1/1/2028	$	5.636	$	6.53	100% B lend	$	6.53	$ (0.050)
2/1/2028	$	5.617	$	6.49	100% B lend	$	6.49	$ (0.055)
3/1/2028	$	5.530	$	6.31	100% B lend	$	6.31	$ (0.065)
4/1/2028	$	5.176	$	6.05	100% B lend	$	6.05	$ (0.235)
5/1/2028	$	5.180	$	6.12	100% B lend	$	6.12	$ (0.258)
6/1/2028	$	5.214	$	6.17	100% B lend	$	6.17	$ (0.260)
7/1/2028	$	5.255	$	6.20	100% B lend	$	6.20	$ (0.268)
8/1/2028	$	5.270	$	6.24	100% B lend	$	6.24	$ (0.268)
9/1/2028	$	5.275	$	6.20	100% B lend	$	6.20	$ (0.265)
10/1/2028	$	5.319	$	6.24	100% B lend	$	6.24	$ (0.255)
11/1/2028	$	5.420	$	6.38	100% B lend	$	6.38	$ (0.073)
12/1/2028	$	5.636	$	6.62	100% B lend	$	6.62	$ (0.058)
1/1/2029	$	5.772	$	6.76	100% B lend	$	6.76	$ (0.050)
2/1/2029	$	5.752	$	6.74	100% B lend	$	6.74	$ (0.055)
3/1/2029	$	5.664	$	6.57	100% B lend	$	6.57	$ (0.065)
4/1/2029	$	5.273	$	6.29	100% B lend	$	6.29	$ (0.235)
5/1/2029	$	5.279	$	6.36	100% B lend	$	6.36	$ (0.258)

6/1/2029	$ 5.314		$ 6.42	100% B lend	$ 6.42	$ (0.260)
7/1/2029	$ 5.356		$ 6.45	100% B lend	$ 6.45	$ (0.268)
8/1/2029	$ 5.372		$ 6.49	100% B lend	$ 6.49	$ (0.268)
9/1/2029	$ 5.378		$ 6.46	100% B lend	$ 6.46	$ (0.265)
10/1/2029	$ 5.423		$ 6.51	100% B lend	$ 6.51	$ (0.255)
11/1/2029	$ 5.524		$ 6.59	100% B lend	$ 6.59	$ (0.073)
12/1/2029	$ 5.745		$ 6.82	100% B lend	$ 6.82	$ (0.058)
1/1/2030	$ 5.881		$ 6.99	100% B lend	$ 6.99	$ (0.050)
2/1/2030	$ 5.861		$ 6.96	100% B lend	$ 6.96	$ (0.055)
3/1/2030	$ 5.771		$ 6.71	100% B lend	$ 6.71	$ (0.065)
4/1/2030	$ 5.374		$ 6.42	100% B lend	$ 6.42	$ (0.235)
5/1/2030	$ 5.380		$ 6.48	100% B lend	$ 6.48	$ (0.258)
6/1/2030	$ 5.416		$ 6.54	100% B lend	$ 6.54	$ (0.260)
7/1/2030	$ 5.458		$ 6.58	100% B lend	$ 6.58	$ (0.268)
8/1/2030	$ 5.475		$ 6.62	100% B lend	$ 6.62	$ (0.268)
9/1/2030	$ 5.483		$ 6.59	100% B lend	$ 6.59	$ (0.265)
10/1/2030	$ 5.529		$ 6.64	100% B lend	$ 6.64	$ (0.255)
11/1/2030	$ 5.631		$ 6.77	100% B lend	$ 6.77	$ (0.073)
12/1/2030	$ 5.856		$ 7.03	100% B lend	$ 7.03	$ (0.058)
1/1/2031	$ 5.992		$ 7.16	100% B lend	$ 7.16	$ (0.050)
2/1/2031	$ 5.972		$ 7.13	100% B lend	$ 7.13	$ (0.055)
3/1/2031	$ 5.880		$ 6.87	100% B lend	$ 6.87	$ (0.065)
4/1/2031	$ 5.478		$ 6.58	100% B lend	$ 6.58	$ (0.235)
5/1/2031	$ 5.484		$ 6.65	100% B lend	$ 6.65	$ (0.258)
6/1/2031	$ 5.519		$ 6.71	100% B lend	$ 6.71	$ (0.260)
7/1/2031	$ 5.562		$ 6.74	100% B lend	$ 6.74	$ (0.268)
8/1/2031	$ 5.579		$ 6.78	100% B lend	$ 6.78	$ (0.268)
9/1/2031	$ 5.588		$ 6.74	100% B lend	$ 6.74	$ (0.265)
10/1/2031	$ 5.636		$ 6.79	100% B lend	$ 6.79	$ (0.255)
11/1/2031	$ 5.741		$ 6.90	100% B lend	$ 6.90	$ (0.073)
12/1/2031	$ 5.970		$ 7.19	100% B lend	$ 7.19	$ (0.058)
1/1/2032	$ 6.105		$ 7.30	100% B lend	$ 7.30	$ (0.050)
2/1/2032	$ 6.086		$ 7.24	100% B lend	$ 7.24	$ (0.055)
3/1/2032	$ 5.991		$ 6.99	100% B lend	$ 6.99	$ (0.065)
4/1/2032	$ 5.584		$ 6.70	100% B lend	$ 6.70	$ (0.235)
5/1/2032	$ 5.589		$ 6.77	100% B lend	$ 6.77	$ (0.258)
6/1/2032	$ 5.625		$ 6.83	100% B lend	$ 6.83	$ (0.260)
7/1/2032	$ 5.668		$ 6.86	100% B lend	$ 6.86	$ (0.268)
8/1/2032	$ 5.685		$ 6.90	100% B lend	$ 6.90	$ (0.268)
9/1/2032	$ 5.696		$ 6.86	100% B lend	$ 6.86	$ (0.265)
10/1/2032	$ 5.745		$ 6.91	100% B lend	$ 6.91	$ (0.255)
11/1/2032	$ 5.851		$ 7.03	100% B lend	$ 7.03	$ (0.073)
12/1/2032	$ 6.085		$ 7.33	100% B lend	$ 7.33	$ (0.058)
1/1/2033	$ 6.221		$ 7.45	100% B lend	$ 7.45	$ (0.050)
2/1/2033	$ 6.202		$ 7.42	100% B lend	$ 7.42	$ (0.055)
3/1/2033	$ 6.104		$ 7.16	100% B lend	$ 7.16	$ (0.065)

4/1/2033	$	5.693		$	6.86	100% B lend	$	6.86	$ (0.235)
5/1/2033	$	5.697		$	6.94	100% B lend	$	6.94	$ (0.258)
6/1/2033	$	5.733		$	7.01	100% B lend	$	7.01	$ (0.260)
7/1/2033	$	5.777		$	7.06	100% B lend	$	7.06	$ (0.268)
8/1/2033	$	5.795		$	7.11	100% B lend	$	7.11	$ (0.268)
9/1/2033	$	5.807		$	7.07	100% B lend	$	7.07	$ (0.265)
10/1/2033	$	5.858		$	7.13	100% B lend	$	7.13	$ (0.255)
11/1/2033	$	5.964		$	7.25	100% B lend	$	7.25	$ (0.073)
12/1/2033	$	6.200		$	7.56	100% B lend	$	7.56	$ (0.058)
1/1/2034	$	6.338		$	7.70	100% B lend	$	7.70	$ (0.050)
2/1/2034	$	6.318		$	7.66	100% B lend	$	7.66	$ (0.055)
3/1/2034	$	6.218		$	7.40	100% B lend	$	7.40	$ (0.065)
4/1/2034	$	5.804		$	7.09	100% B lend	$	7.09	$ (0.235)
5/1/2034	$	5.807		$	7.16	100% B lend	$	7.16	$ (0.258)
6/1/2034	$	5.844		$	7.23	100% B lend	$	7.23	$ (0.260)
7/1/2034	$	5.888		$	7.26	100% B lend	$	7.26	$ (0.268)
8/1/2034	$	5.905		$	7.30	100% B lend	$	7.30	$ (0.268)
9/1/2034	$	5.918		$	7.26	100% B lend	$	7.26	$ (0.265)
10/1/2034	$	5.971		$	7.31	100% B lend	$	7.31	$ (0.255)
11/1/2034	$	6.078		$	7.42	100% B lend	$	7.42	$ (0.073)
12/1/2034	$	6.318		$	7.73	100% B lend	$	7.73	$ (0.058)
1/1/2035	$	6.458		$	7.84	100% B lend	$	7.84	$ (0.050)
2/1/2035	$	6.439		$	7.80	100% B lend	$	7.80	$ (0.055)
3/1/2035	$	6.334		$	7.44	100% B lend	$	7.44	$ (0.065)
4/1/2035	$	5.918		$	7.29	100% B lend	$	7.29	$ (0.235)
5/1/2035	$	5.918		$	7.29	100% B lend	$	7.29	$ (0.258)
6/1/2035	$	5.956		$	7.34	100% B lend	$	7.34	$ (0.260)
7/1/2035	$	6.001		$	7.36	100% B lend	$	7.36	$ (0.268)
8/1/2035	$	6.016		$	7.42	100% B lend	$	7.42	$ (0.268)
9/1/2035	$	6.031		$	7.36	100% B lend	$	7.36	$ (0.265)
10/1/2035	$	6.086		$	7.43	100% B lend	$	7.43	$ (0.255)
11/1/2035	$	6.194		$	7.59	100% B lend	$	7.59	$ (0.073)
12/1/2035	$	6.438		$	7.79	100% B lend	$	7.79	$ (0.058)
1/1/2036	$	6.581		$	7.99	100% B lend	$	7.99	$ (0.050)
2/1/2036	$	6.562		$	7.95	100% B lend	$	7.95	$ (0.055)
3/1/2036	$	6.455		$	7.59	100% B lend	$	7.59	$ (0.065)
4/1/2036	$	6.033		$	7.43	100% B lend	$	7.43	$ (0.235)
5/1/2036	$	6.034		$	7.43	100% B lend	$	7.43	$ (0.258)
6/1/2036	$	6.072		$	7.48	100% B lend	$	7.48	$ (0.260)
7/1/2036	$	6.118		$	7.50	100% B lend	$	7.50	$ (0.268)
8/1/2036	$	6.130		$	7.57	100% B lend	$	7.57	$ (0.268)
9/1/2036	$	6.146		$	7.50	100% B lend	$	7.50	$ (0.265)
10/1/2036	$	6.201		$	7.57	100% B lend	$	7.57	$ (0.255)
11/1/2036	$	6.311		$	7.73	100% B lend	$	7.73	$ (0.073)
12/1/2036	$	6.560		$	7.94	100% B lend	$	7.94	$ (0.058)
1/1/2037	$	6.707		$	8.14	100% B lend	$	8.14	$ (0.050)

2/1/2037	$	6.689		$	8.11	100% B lend	$	8.11	$ (0.055)
3/1/2037	$	6.579		$	7.73	100% B lend	$	7.73	$ (0.065)
4/1/2037	$	6.149		$	7.57	100% B lend	$	7.57	$ (0.235)
5/1/2037	$	6.151		$	7.57	100% B lend	$	7.57	$ (0.258)
6/1/2037	$	6.190		$	7.62	100% B lend	$	7.62	$ (0.260)
7/1/2037	$	6.236		$	7.64	100% B lend	$	7.64	$ (0.268)
8/1/2037	$	6.246		$	7.71	100% B lend	$	7.71	$ (0.268)
9/1/2037	$	6.262		$	7.65	100% B lend	$	7.65	$ (0.265)
10/1/2037	$	6.317		$	7.72	100% B lend	$	7.72	$ (0.255)
11/1/2037	$	6.429		$	7.88	100% B lend	$	7.88	$ (0.073)
12/1/2037	$	6.683		$	8.09	100% B lend	$	8.09	$ (0.058)
1/1/2038	$	6.836		$	8.30	100% B lend	$	8.30	$ (0.050)
2/1/2038	$	6.819		$	8.26	100% B lend	$	8.26	$ (0.055)
3/1/2038	$	6.707		$	7.88	100% B lend	$	7.88	$ (0.065)
4/1/2038	$	6.268		$	7.72	100% B lend	$	7.72	$ (0.235)
5/1/2038	$	6.272		$	7.72	100% B lend	$	7.72	$ (0.258)
6/1/2038	$	6.312		$	7.77	100% B lend	$	7.77	$ (0.260)
7/1/2038	$	6.358		$	7.79	100% B lend	$	7.79	$ (0.268)
8/1/2038	$	6.364		$	7.86	100% B lend	$	7.86	$ (0.268)
9/1/2038	$	6.381		$	7.79	100% B lend	$	7.79	$ (0.265)
10/1/2038	$	6.435		$	7.86	100% B lend	$	7.86	$ (0.255)
11/1/2038	$	6.549		$	8.03	100% B lend	$	8.03	$ (0.073)
12/1/2038	$	6.808		$	8.24	100% B lend	$	8.24	$ (0.058)
1/1/2039	$	6.966		$	8.46	100% B lend	$	8.46	$ (0.050)
2/1/2039	$	6.952		$	8.42	100% B lend	$	8.42	$ (0.055)
3/1/2039	$	6.837		$	8.03	100% B lend	$	8.03	$ (0.065)
4/1/2039	$	6.391		$	7.87	100% B lend	$	7.87	$ (0.235)
5/1/2039	$	6.398		$	7.87	100% B lend	$	7.87	$ (0.258)
6/1/2039	$	6.437		$	7.92	100% B lend	$	7.92	$ (0.260)
7/1/2039	$	6.483		$	7.94	100% B lend	$	7.94	$ (0.268)
8/1/2039	$	6.486		$	8.01	100% B lend	$	8.01	$ (0.268)
9/1/2039	$	6.502		$	7.94	100% B lend	$	7.94	$ (0.265)
10/1/2039	$	6.556		$	8.01	100% B lend	$	8.01	$ (0.255)
11/1/2039	$	6.670		$	8.18	100% B lend	$	8.18	$ (0.073)
12/1/2039	$	6.934		$	8.40	100% B lend	$	8.40	$ (0.058)
1/1/2040	$	7.096		$	8.62	100% B lend	$	8.62	$ (0.050)
2/1/2040	$	7.084		$	8.58	100% B lend	$	8.58	$ (0.055)
3/1/2040	$	6.967		$	8.18	100% B lend	$	8.18	$ (0.065)
4/1/2040	$	6.509		$	8.02	100% B lend	$	8.02	$ (0.235)
5/1/2040	$	6.510		$	8.01	100% B lend	$	8.01	$ (0.258)
6/1/2040	$	6.554		$	8.07	100% B lend	$	8.07	$ (0.260)
7/1/2040	$	6.603		$	8.09	100% B lend	$	8.09	$ (0.268)
8/1/2040	$	6.614		$	8.16	100% B lend	$	8.16	$ (0.268)
9/1/2040	$	6.628		$	8.09	100% B lend	$	8.09	$ (0.265)
10/1/2040	$	6.684		$	8.17	100% B lend	$	8.17	$ (0.255)
11/1/2040	$	6.806		$	8.34	100% B lend	$	8.34	$ (0.073)

12/1/2040	$	7.075		$	8.56	100% B lend	$	8.56	$ (0.058)
1/1/2041	$	7.237		$	8.78	100% B lend	$	8.78	$ (0.050)
2/1/2041	$	7.216		$	8.75	100% B lend	$	8.75	$ (0.055)
3/1/2041	$	7.101		$	8.34	100% B lend	$	8.34	$ (0.065)
4/1/2041	$	6.629		$	8.17	100% B lend	$	8.17	$ (0.235)
5/1/2041	$	6.633		$	8.17	100% B lend	$	8.17	$ (0.258)
6/1/2041	$	6.676		$	8.22	100% B lend	$	8.22	$ (0.260)
7/1/2041	$	6.726		$	8.25	100% B lend	$	8.25	$ (0.268)
8/1/2041	$	6.742		$	8.32	100% B lend	$	8.32	$ (0.268)
9/1/2041	$	6.756		$	8.25	100% B lend	$	8.25	$ (0.265)
10/1/2041	$	6.814		$	8.33	100% B lend	$	8.33	$ (0.255)
11/1/2041	$	6.938		$	8.50	100% B lend	$	8.50	$ (0.073)
12/1/2041	$	7.213		$	8.73	100% B lend	$	8.73	$ (0.058)
1/1/2042	$	7.378		$	8.95	100% B lend	$	8.95	$ (0.050)
2/1/2042	$	7.357		$	8.91	100% B lend	$	8.91	$ (0.055)
3/1/2042	$	7.239		$	8.50	100% B lend	$	8.50	$ (0.065)
4/1/2042	$	6.756		$	8.33	100% B lend	$	8.33	$ (0.235)
5/1/2042	$	6.760		$	8.32	100% B lend	$	8.32	$ (0.258)
6/1/2042	$	6.804		$	8.38	100% B lend	$	8.38	$ (0.260)
7/1/2042	$	6.855		$	8.40	100% B lend	$	8.40	$ (0.268)
8/1/2042	$	6.871		$	8.48	100% B lend	$	8.48	$ (0.268)
9/1/2042	$	6.886		$	8.41	100% B lend	$	8.41	$ (0.265)
10/1/2042	$	6.945		$	8.48	100% B lend	$	8.48	$ (0.255)
11/1/2042	$	7.071		$	8.66	100% B lend	$	8.66	$ (0.073)
12/1/2042	$	7.351		$	8.90	100% B lend	$	8.90	$ (0.058)

...TRADE SECRET ENDS]

[TRADE SECRET BEGINS...

...TRADE SECRET ENDS]

Year	Month	Historical NSP.NSP DA (On Peak)	Forecast Power (On Peak)
2005	1/1/2005		
2005	2/1/2005		
2005	3/1/2005		
2005	4/1/2005	54.35	
2005	5/1/2005	41.70	
2005	6/1/2005	66.27	
2005	7/1/2005	80.04	
2005	8/1/2005	78.41	
2005	9/1/2005	71.61	
2005	10/1/2005	77.28	
2005	11/1/2005	67.01	
2005	12/1/2005	105.28	
2006	1/1/2006	54.28	
2006	2/1/2006	53.03	
2006	3/1/2006	48.34	
2006	4/1/2006	49.66	
2006	5/1/2006	53.20	
2006	6/1/2006	59.25	
2006	7/1/2006	102.37	
2006	8/1/2006	77.31	
2006	9/1/2006	45.29	
2006	10/1/2006	65.54	
2006	11/1/2006	75.16	
2006	12/1/2006	72.67	
2007	1/1/2007	65.24	
2007	2/1/2007	100.53	
2007	3/1/2007	67.53	
2007	4/1/2007	78.31	
2007	5/1/2007	71.57	
2007	6/1/2007	78.00	
2007	7/1/2007	79.61	
2007	8/1/2007	73.91	
2007	9/1/2007	52.98	
2007	10/1/2007	62.70	
2007	11/1/2007	70.99	
2007	12/1/2007	77.48	
2008	1/1/2008	72.14	
2008	2/1/2008	79.68	
2008	3/1/2008	83.38	
2008	4/1/2008	74.99	
2008	5/1/2008	58.33	
2008	6/1/2008	66.16	
2008	7/1/2008	92.85	
2008	8/1/2008	71.06	
2008	9/1/2008	53.29	
2008	10/1/2008	48.77	
2008	11/1/2008	49.55	
2008	12/1/2008	62.96	
2009	1/1/2009	50.68	

Year	Historical NSP.NSP DA (On Peak)	Forecast Power (On Peak)
2005	53.49	
2006	63.01	
2007	73.24	
2008	67.76	
2009	33.12	
2010	38.00	
2011	35.21	
2012	32.33	
2013	38.90	
2014	40.47	
2015		43.65
2016		43.05
2017		43.01
2018		43.59
2019		45.26
2020		49.23
2021		53.05
2022		53.71
2023		55.84
2024		57.09
2025		57.87
2026		58.97
2027		59.69
2028		59.95
2029		62.42
2030		63.87
2031		64.63
2032		65.60
2033		66.52
2034		68.26
2035		69.12
2036		70.45
2037		71.80
2038		73.17
2039		74.57
2040		76.00
2041		77.46
2042		78.94

2009	2/1/2009	38.39
2009	3/1/2009	31.10
2009	4/1/2009	28.31
2009	5/1/2009	28.28
2009	6/1/2009	28.14
2009	7/1/2009	26.11
2009	8/1/2009	28.94
2009	9/1/2009	28.52
2009	10/1/2009	35.17
2009	11/1/2009	29.82
2009	12/1/2009	43.97
2010	1/1/2010	48.08
2010	2/1/2010	45.10
2010	3/1/2010	32.65
2010	4/1/2010	32.55
2010	5/1/2010	37.09
2010	6/1/2010	36.36
2010	7/1/2010	44.17
2010	8/1/2010	46.83
2010	9/1/2010	30.51
2010	10/1/2010	32.71
2010	11/1/2010	33.01
2010	12/1/2010	36.92
2011	1/1/2011	37.63
2011	2/1/2011	33.20
2011	3/1/2011	32.68
2011	4/1/2011	35.29
2011	5/1/2011	31.13
2011	6/1/2011	30.55
2011	7/1/2011	50.14
2011	8/1/2011	41.18
2011	9/1/2011	30.88
2011	10/1/2011	33.94
2011	11/1/2011	32.26
2011	12/1/2011	33.69
2012	1/1/2012	27.70
2012	2/1/2012	26.31
2012	3/1/2012	23.32
2012	4/1/2012	25.46
2012	5/1/2012	31.54
2012	6/1/2012	36.37
2012	7/1/2012	50.80
2012	8/1/2012	34.34
2012	9/1/2012	28.75
2012	10/1/2012	31.56
2012	11/1/2012	34.39
2012	12/1/2012	37.43
2013	1/1/2013	36.57
2013	2/1/2013	33.80
2013	3/1/2013	37.87
2013	4/1/2013	42.54
2013	5/1/2013	38.04
2013	6/1/2013	35.92
2013	7/1/2013	41.12
2013	8/1/2013	40.28

2013	9/1/2013	42.00	
2013	10/1/2013	38.16	
2013	11/1/2013	36.93	
2013	12/1/2013	43.52	
2014	1/1/2014	70.65	
2014	2/1/2014	59.82	
2014	3/1/2014	48.90	
2014	4/1/2014	39.52	
2014	5/1/2014	43.03	
2014	6/1/2014	41.26	
2014	7/1/2014	35.15	
2014	8/1/2014	36.79	
2014	9/1/2014	32.74	28.63
2014	10/1/2014	39.16	37.62
2014	11/1/2014	38.61	39.71
2014	12/1/2014		48.42
2015	1/1/2015		58.37
2015	2/1/2015		43.12
2015	3/1/2015		39.42
2015	4/1/2015		40.06
2015	5/1/2015		37.86
2015	6/1/2015		38.50
2015	7/1/2015		49.53
2015	8/1/2015		52.19
2015	9/1/2015		41.04
2015	10/1/2015		37.87
2015	11/1/2015		38.14
2015	12/1/2015		47.75
2016	1/1/2016		55.42
2016	2/1/2016		45.62
2016	3/1/2016		36.55
2016	4/1/2016		41.44
2016	5/1/2016		36.10
2016	6/1/2016		36.93
2016	7/1/2016		53.04
2016	8/1/2016		55.64
2016	9/1/2016		38.66
2016	10/1/2016		36.25
2016	11/1/2016		36.19
2016	12/1/2016		44.73
2017	1/1/2017		61.86
2017	2/1/2017		52.61
2017	3/1/2017		34.58
2017	4/1/2017		37.95
2017	5/1/2017		35.33
2017	6/1/2017		36.69
2017	7/1/2017		51.87
2017	8/1/2017		53.66
2017	9/1/2017		40.13
2017	10/1/2017		34.77
2017	11/1/2017		35.29
2017	12/1/2017		41.44
2018	1/1/2018		60.21
2018	2/1/2018		54.21
2018	3/1/2018		35.60

2018	4/1/2018	37.17
2018	5/1/2018	35.65
2018	6/1/2018	36.15
2018	7/1/2018	52.37
2018	8/1/2018	53.09
2018	9/1/2018	39.31
2018	10/1/2018	37.75
2018	11/1/2018	38.78
2018	12/1/2018	42.85
2019	1/1/2019	55.84
2019	2/1/2019	53.14
2019	3/1/2019	39.91
2019	4/1/2019	37.99
2019	5/1/2019	36.81
2019	6/1/2019	39.03
2019	7/1/2019	55.41
2019	8/1/2019	54.81
2019	9/1/2019	41.83
2019	10/1/2019	41.05
2019	11/1/2019	42.18
2019	12/1/2019	45.15
2020	1/1/2020	53.05
2020	2/1/2020	51.70
2020	3/1/2020	43.52
2020	4/1/2020	41.01
2020	5/1/2020	40.60
2020	6/1/2020	44.37
2020	7/1/2020	62.13
2020	8/1/2020	61.32
2020	9/1/2020	48.47
2020	10/1/2020	46.92
2020	11/1/2020	46.98
2020	12/1/2020	50.66
2021	1/1/2021	54.63
2021	2/1/2021	53.15
2021	3/1/2021	49.32
2021	4/1/2021	46.01
2021	5/1/2021	46.85
2021	6/1/2021	52.37
2021	7/1/2021	65.93
2021	8/1/2021	65.20
2021	9/1/2021	51.00
2021	10/1/2021	49.74
2021	11/1/2021	49.51
2021	12/1/2021	52.92
2022	1/1/2022	56.74
2022	2/1/2022	54.64
2022	3/1/2022	50.89
2022	4/1/2022	46.72
2022	5/1/2022	45.99
2022	6/1/2022	52.93
2022	7/1/2022	66.63
2022	8/1/2022	64.74
2022	9/1/2022	50.26
2022	10/1/2022	50.07

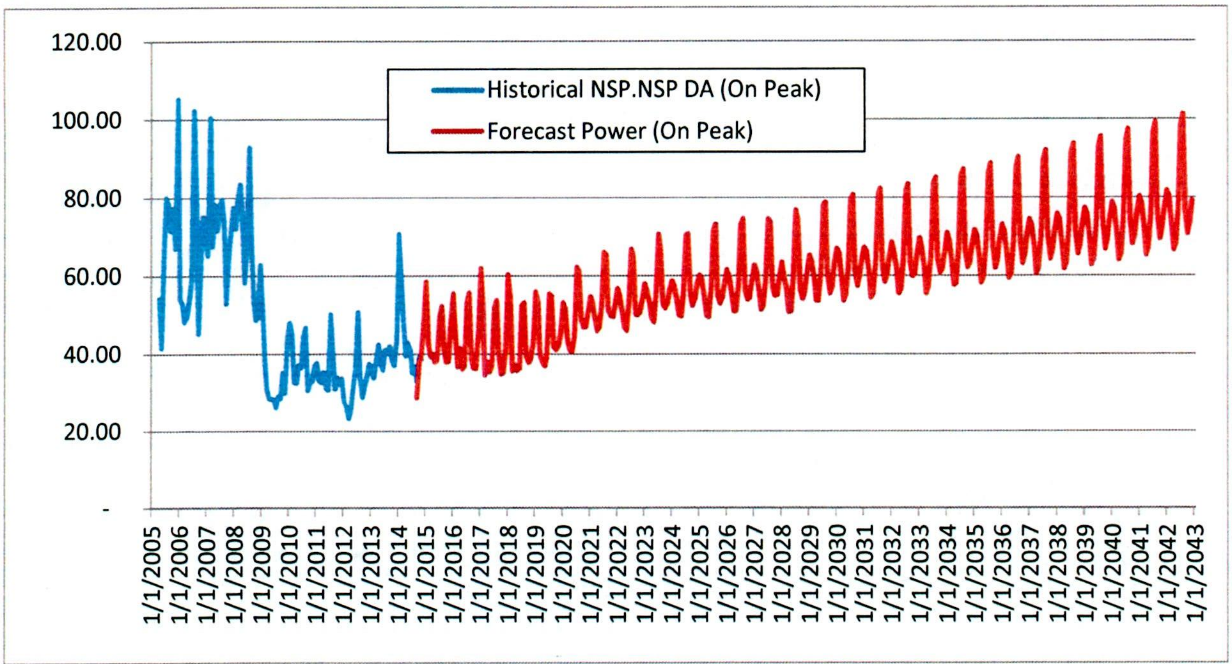
2022	11/1/2022	50.66
2022	12/1/2022	54.30
2023	1/1/2023	57.85
2023	2/1/2023	55.82
2023	3/1/2023	53.52
2023	4/1/2023	49.28
2023	5/1/2023	48.24
2023	6/1/2023	54.74
2023	7/1/2023	70.50
2023	8/1/2023	66.65
2023	9/1/2023	52.52
2023	10/1/2023	51.74
2023	11/1/2023	52.90
2023	12/1/2023	56.27
2024	1/1/2024	58.70
2024	2/1/2024	57.43
2024	3/1/2024	54.11
2024	4/1/2024	50.03
2024	5/1/2024	49.63
2024	6/1/2024	55.00
2024	7/1/2024	70.31
2024	8/1/2024	70.58
2024	9/1/2024	54.72
2024	10/1/2024	52.44
2024	11/1/2024	54.03
2024	12/1/2024	58.08
2025	1/1/2025	60.00
2025	2/1/2025	59.26
2025	3/1/2025	55.23
2025	4/1/2025	49.94
2025	5/1/2025	49.41
2025	6/1/2025	55.86
2025	7/1/2025	71.48
2025	8/1/2025	73.09
2025	9/1/2025	54.85
2025	10/1/2025	52.89
2025	11/1/2025	54.29
2025	12/1/2025	58.10
2026	1/1/2026	61.45
2026	2/1/2026	59.74
2026	3/1/2026	55.83
2026	4/1/2026	50.84
2026	5/1/2026	51.01
2026	6/1/2026	57.24
2026	7/1/2026	72.95
2026	8/1/2026	74.51
2026	9/1/2026	56.31
2026	10/1/2026	53.91
2026	11/1/2026	54.35
2026	12/1/2026	59.49
2027	1/1/2027	62.57
2027	2/1/2027	61.02
2027	3/1/2027	56.32
2027	4/1/2027	51.32
2027	5/1/2027	52.37

2027	6/1/2027	58.45
2027	7/1/2027	74.37
2027	8/1/2027	73.48
2027	9/1/2027	56.77
2027	10/1/2027	54.83
2027	11/1/2027	55.10
2027	12/1/2027	59.66
2028	1/1/2028	63.40
2028	2/1/2028	59.48
2028	3/1/2028	56.59
2028	4/1/2028	50.81
2028	5/1/2028	50.86
2028	6/1/2028	59.62
2028	7/1/2028	76.72
2028	8/1/2028	74.15
2028	9/1/2028	56.53
2028	10/1/2028	54.10
2028	11/1/2028	56.09
2028	12/1/2028	61.02
2029	1/1/2029	65.17
2029	2/1/2029	63.85
2029	3/1/2029	59.54
2029	4/1/2029	53.81
2029	5/1/2029	53.61
2029	6/1/2029	60.50
2029	7/1/2029	77.77
2029	8/1/2029	78.74
2029	9/1/2029	60.04
2029	10/1/2029	55.46
2029	11/1/2029	56.94
2029	12/1/2029	63.58
2030	1/1/2030	66.88
2030	2/1/2030	65.75
2030	3/1/2030	59.83
2030	4/1/2030	53.61
2030	5/1/2030	55.00
2030	6/1/2030	62.01
2030	7/1/2030	79.46
2030	8/1/2030	80.64
2030	9/1/2030	61.12
2030	10/1/2030	57.31
2030	11/1/2030	59.95
2030	12/1/2030	64.89
2031	1/1/2031	67.13
2031	2/1/2031	66.16
2031	3/1/2031	61.20
2031	4/1/2031	54.46
2031	5/1/2031	55.37
2031	6/1/2031	62.96
2031	7/1/2031	80.49
2031	8/1/2031	82.27
2031	9/1/2031	61.93
2031	10/1/2031	58.39
2031	11/1/2031	60.47
2031	12/1/2031	64.79

2032	1/1/2032	68.51
2032	2/1/2032	65.95
2032	3/1/2032	62.24
2032	4/1/2032	55.51
2032	5/1/2032	56.57
2032	6/1/2032	63.82
2032	7/1/2032	81.55
2032	8/1/2032	83.44
2032	9/1/2032	63.45
2032	10/1/2032	59.93
2032	11/1/2032	60.52
2032	12/1/2032	65.69
2033	1/1/2033	69.53
2033	2/1/2033	67.57
2033	3/1/2033	62.27
2033	4/1/2033	55.48
2033	5/1/2033	57.06
2033	6/1/2033	65.01
2033	7/1/2033	83.37
2033	8/1/2033	85.08
2033	9/1/2033	64.17
2033	10/1/2033	60.78
2033	11/1/2033	61.83
2033	12/1/2033	66.14
2034	1/1/2034	70.93
2034	2/1/2034	68.65
2034	3/1/2034	64.45
2034	4/1/2034	57.61
2034	5/1/2034	58.06
2034	6/1/2034	66.85
2034	7/1/2034	85.61
2034	8/1/2034	87.18
2034	9/1/2034	66.18
2034	10/1/2034	62.17
2034	11/1/2034	63.27
2034	12/1/2034	68.18
2035	1/1/2035	71.62
2035	2/1/2035	70.24
2035	3/1/2035	64.87
2035	4/1/2035	58.26
2035	5/1/2035	59.57
2035	6/1/2035	67.45
2035	7/1/2035	86.14
2035	8/1/2035	88.62
2035	9/1/2035	67.32
2035	10/1/2035	61.93
2035	11/1/2035	64.13
2035	12/1/2035	69.34
2036	1/1/2036	72.99
2036	2/1/2036	71.59
2036	3/1/2036	66.12
2036	4/1/2036	59.38
2036	5/1/2036	60.71
2036	6/1/2036	68.74
2036	7/1/2036	87.79

2036	8/1/2036	90.31
2036	9/1/2036	68.61
2036	10/1/2036	63.11
2036	11/1/2036	65.35
2036	12/1/2036	70.67
2037	1/1/2037	74.39
2037	2/1/2037	72.97
2037	3/1/2037	67.39
2037	4/1/2037	60.51
2037	5/1/2037	61.88
2037	6/1/2037	70.06
2037	7/1/2037	89.47
2037	8/1/2037	92.04
2037	9/1/2037	69.92
2037	10/1/2037	64.32
2037	11/1/2037	66.60
2037	12/1/2037	72.02
2038	1/1/2038	75.81
2038	2/1/2038	74.36
2038	3/1/2038	68.68
2038	4/1/2038	61.67
2038	5/1/2038	63.06
2038	6/1/2038	71.41
2038	7/1/2038	91.19
2038	8/1/2038	93.80
2038	9/1/2038	71.26
2038	10/1/2038	65.54
2038	11/1/2038	67.88
2038	12/1/2038	73.40
2039	1/1/2039	77.26
2039	2/1/2039	75.79
2039	3/1/2039	69.99
2039	4/1/2039	62.86
2039	5/1/2039	64.28
2039	6/1/2039	72.78
2039	7/1/2039	92.94
2039	8/1/2039	95.60
2039	9/1/2039	72.62
2039	10/1/2039	66.80
2039	11/1/2039	69.17
2039	12/1/2039	74.80
2040	1/1/2040	78.73
2040	2/1/2040	77.24
2040	3/1/2040	71.33
2040	4/1/2040	64.07
2040	5/1/2040	65.51
2040	6/1/2040	74.18
2040	7/1/2040	94.73
2040	8/1/2040	97.43
2040	9/1/2040	74.01
2040	10/1/2040	68.07
2040	11/1/2040	70.49
2040	12/1/2040	76.23
2041	1/1/2041	80.24
2041	2/1/2041	78.70

2041	3/1/2041	72.69
2041	4/1/2041	65.29
2041	5/1/2041	66.77
2041	6/1/2041	75.60
2041	7/1/2041	96.54
2041	8/1/2041	99.31
2041	9/1/2041	75.43
2041	10/1/2041	69.38
2041	11/1/2041	71.85
2041	12/1/2041	77.70
2042	1/1/2042	81.78
2042	2/1/2042	80.21
2042	3/1/2042	74.09
2042	4/1/2042	66.54
2042	5/1/2042	68.04
2042	6/1/2042	77.04
2042	7/1/2042	98.39
2042	8/1/2042	101.21
2042	9/1/2042	76.88
2042	10/1/2042	70.71
2042	11/1/2042	73.23
2042	12/1/2042	79.19


Historical NSP.NSP DA (On Peak)
Forecast Power (On Peak)
120.00
100.00
80.00
60.00
40.00
20.00
-
1/1/2005
1/1/2006
1/1/2007
1/1/2008
1/1/2009
1/1/2010
1/1/2011
1/1/2012
1/1/2013
1/1/2014
1/1/2015
1/1/2016
1/1/2017
1/1/2018
1/1/2019
1/1/2020
1/1/2021
1/1/2022
1/1/2023
1/1/2024
1/1/2025
1/1/2026
1/1/2027
1/1/2028
1/1/2029
1/1/2030
1/1/2031
1/1/2032
1/1/2033
1/1/2034
1/1/2035
1/1/2036
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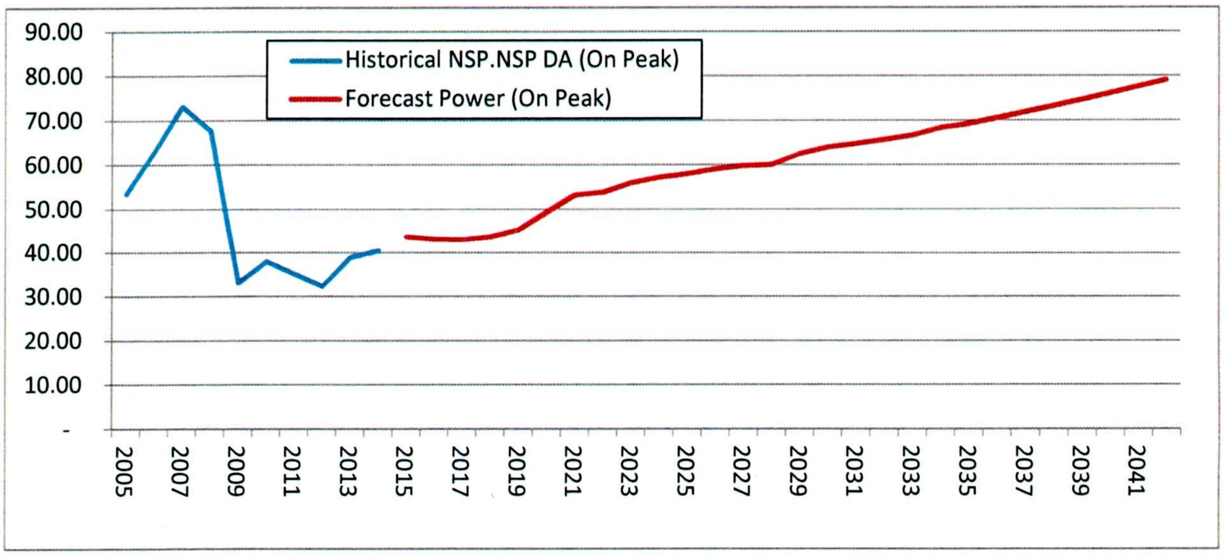
1/1/2042
1/1/2043


Historical NSP.NSP DA (On Peak)
Forecast Power (On Peak)
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041

PUBLIC DOCUMENT -
TRADE SECRET DATA EXCISED

Case No. PU-14-810
NDPSC Data Request No. 3E
Attachment C - Page 29 of 36

Minnesota Hub On-Peak Power Forecast Decomposition

TRADE SECRET DATA SHADED

Prices as of 9/8/2014 [TRADE SECRET BEGINS...

Date	PIRA	Wood Mac	CERA	Final MN Hub On Peak Forecast
10/1/2014				$ 37.62
11/1/2014				$ 39.71
12/1/2014				$ 48.42
1/1/2015				$ 58.37
2/1/2015				$ 43.12
3/1/2015				$ 39.42
4/1/2015				$ 40.06
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...TRADE SECRET ENDS]

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	4
Requestor:	Michael Diller		
Date Received:	December 15, 2014		

Question:

Questions concerning Laura McCarten's testimony:

a) Laura's testimony states that NSP is purchasing this energy "primarily" to comply with Minnesota's solar energy standards (SES) but that it would also provide a hedge against purchasing gas and market energy. Prior to the passage of SES, please provide all solar projects selected by NSP's resource planners for integrated resource planning purposes.

b) How much cost associated with behind-the-meter solar generation and community solar gardens are currently being assigned to North Dakota?

c) What is the current market value of solar Renewable Energy Credits? What does NSP project for the value of REC's in the future and what is included in the resource model?

Response:

a) Prior to the passage of the Minnesota Solar Energy Standard, no utility-scale solar projects were selected by the Company's resource planners. As regards the hedge value of the renewables added to date, our evaluation has shown that their carbon free energy contribution limited the Company's exposure to price spikes in natural gas and market energy prices during the 2000 to 2010 period.

b) Customers who install behind-the-meter solar generation systems are solely responsible for installation and associated metering and interconnection costs. Customers who install PV systems benefit by offsetting their system energy usage. Some customers that have installed small PV systems participate in the Solar*Reward or Made in Minnesota programs and receive production-based incentive payments. These programs are funded via rate riders from Minnesota customers. Solar*Rewards is funded by the Renewable Development Fund (RDF) rider, and Made in Minnesota is funded by the Conservation Improvement Program rider and the RDF rider.

Customers installing larger PV systems also have received grant funding from the RDF. Should these customers' PV systems produce more power than the customer uses in a given period, the customers receive a payment or bill credit for the excess production pursuant to the tariff under which they elected to receive the excess energy payments. In 2013, the Company paid out a total of $103,690 for excess energy purchases and recovered the cost through the Fuel Cost Rider. North Dakota's share of the excess energy purchases was approximately 5 percent of that total.

The Community Solar Garden (CSG) program just recently began accepting applications on December 12, 2014, and has not made any bill credit payments as of the date of this response.

c) There are several Renewable Energy Credit (REC) markets in the United States, and the current market value of solar renewable energy credits varies greatly in those markets. For example, according to the U.S. Department of Energy website on REC prices in the eastern U.S. market (http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5), solar REC (SREC) prices range between $50 and $450 per REC, depending on the state and the vintage of the solar. The East Coast SREC prices are high due to high demand. The Company does not have access to the East Coast market because NSP's service territory is not located in that region, or in a state that is contiguous to that region.

In contrast, the REC market in the MRETs region is not yet developed because there are limited solar resources available. According to broker quotes that Xcel Energy received recently, North Carolina's out-of-state SRECs range between bids of $2 and offers of $4 per SREC. Pricing in the Midwest may develop to levels comparable to or beyond North Carolina's, but the Company has not sold any SRECs from its MRETs account to date and thus there is no established price for them. Currently, we see the value of RES RECs or MN SRECs at about $1. The Company does not know what the future prices of SRECs will be.

Preparer:	Paul Johnson / Nick Paluck / Jeff Haskins
Title:	Resource Planning Director / Rate Consultant / Rotational Position
Department:	Resource Planning / NSPM Regulatory / Purchased Power
Telephone:	612.330.6238 / 612.330.2905 / 303.571.6454
Date:	December 29, 2014

Diller, Michael R.

From:	Hedlund, Amber R <Amber.R.Hedlund@xcelenergy.com>
›nt:	Friday, January 02, 2015 1:58 PM
›:	Diller, Michael R.
Cc:	Sederquist, Dave
Subject:	Xcel Energy's Response to NDPSC Data Request No. 5 Public_Case No. PU-14-810
Attachments:	Cvr Letter NDPSC DR 5 Public.pdf; NDPSC-005 PUBLIC.pdf

Dear Mr. Diller:

Enclosed please find a cover letter and response to Data Request No. 5 Public concerning Xcel Energy's Solar Portfolio ADP.

The Non-Public response to NDPSC Data Request No. 5 will be sent under separate cover following the Commission's approval of an order for trade secret protection pursuant to N.D.C.C. § 69-02-09-01.

Please contact me if you have any questions regarding this submission. Thank you.

Amber Hedlund
Xcel Energy
Regulatory Case Specialist
414 Nicollet Mall, 7th Floor, Minneapolis, MN 55401
P: 612.337.2268
E: amber.r.hedlund@xcelenergy.com

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

January 2, 2015

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—Via Electronic Filing—

Michael Diller
North Dakota Public Service Commission
State Capitol Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: RESPONSE TO DATA REQUEST NO. 5 PUBLIC
SOLAR PORTFOLIO ADP
CASE NO. PU-14-810

Dear Mr. Diller:

Enclosed please find our response to the referenced North Dakota Public Service Commission staff Data Request in the above noted case. The Non-Public response to NDPSC Data Request No. 5 will be sent under separate cover following the Commission's approval of an order for trade secret protection pursuant to N.D.C.C. § 69-02-09-01.

Sincerely,

/s/

AMBER HEDLUND
REGULATORY CASE SPECIALIST

cc: Dave Sederquist

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☐ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	5
Requestor:	Michael Diller		
Date Received:	December 15, 2014		

<u>Question:</u>

Questions concerning Kurt Haeger's testimony:

a) Please reconcile the 300 MW's of solar power necessary per testimony to meet the 2020 SES and the 100 MW's of solar power described as needed by the Leidos' Audit Report given the Minnesota banking rules for REC's (Page 19, Schedule 2 of Application).

b) What indications have you received from your tax people concerning the possibility that the 30% ITC might be extended beyond 2016.

c) Please describe your observations about technology improvements in the solar industry including pricing efficiencies during the past 10 years and how and to what extent future efficiencies will occur and how such is incorporated into integrated resource modeling and planning.

d) Does NSP give any consideration to the societal cost of removing agricultural land from food production when acquiring solar generation? Why not?

e) All three purchase power agreements are for 25 years. Please provide any information you have concerning the expected life of a solar farm. Discuss the potential longevity and cost decline of these solar units beyond the 25 contract period.

f) If the sun is above the horizon an average of 12 hours a day; the sky is only clear about half the time; the project owners must only meet 85% of the Committed Solar Energy; and NSP can curtail production under a number of scenarios, how can the expected capacity accreditation be 52%? Provide assumptions and calculation. How does this calculation support or detract from the use of 12CP for allocating generation resources among the various state jurisdictions? How have the rules for determining accreditation changed since the inception of MISO and what changes are expected in the future? Is this accreditation calculation applied similarly to other types of resources?

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g) Because PV technology directly converts sunlight to energy, sunlight reaching the ground is critical. Provide the ten top bidders in terms of sunlight availability. For those with better sunlight availability than the chosen projects, please explain why those bids were rejected. Provide the resources that were used to determine whether a project's sunlight availability assumptions were reasonable.

h) Please provide the rationale for arguing that "conditional" Generator Interconnect Agreements should qualify as capacity resources.

i) Provide the monthly peak demand of NSP and the expected contribution to meeting those peaks by resource including capacity factors of each resource during those peak times for the next 5 years.

j) Please clarify and explain Answer on Page 19 of Mr. Haeger's Direct Testimony.

k) Provide NSP's required planning reserve margin since the inception of MISO, how the calculations have changed under MISO and why you believe the current calculation is stable and conservative. Provide the impact to capacity requirements for any changes that have occurred.

Response:

a) Shortly after solar legislation was passed in Minnesota, the Company estimated that roughly 300 MW of solar generation would be required to produce 1.5 percent of the electric energy used by our customers in Minnesota beginning in 2020. That assessment is correct when only looking at the generation necessary to meet the 1.5 percent requirement from annual production. Subsequently, the Minnesota Commission put Solar Renewable Energy Credit (SREC) "banking" rules in place that allow solar generated electricity produced by new facilities in 2016 to 2020 to be used to meet the 2020 solar energy standard (SES). The rules also allow electricity produced in a year to be used to comply in subsequent years. The 100 MW reference in the Leidos report refers to needing a 100 MW utility scale solar resource in addition to our estimate of approximately 100 MW of small retail solar to meet the 2020 SES requirement, given the benefit of SREC banking prior to 2020.

b) We have no information indicating any imminent congressional action to change current Investment Tax Credit provisions of the tax code.

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c) See our response to Data Request No. 3B.

d) No. We have not attempted to assign a societal cost to solar project installations to reflect land removed from agricultural production. We would expect little, if any, impact at this early stage in the development of utility scale solar generation in our region.

e) As solar penetration in the Upper Midwest is just beginning, we have not analyzed the full expected life of a solar facility in this region. We have relied on the fact that the developers have proposed 25 year power purchase agreements (PPA). Most developers, including those who proposed the top three projects, require financing to implement their projects. The longest proposed term common to most of the PPAs was 25 years. Assuming developers obtained preliminary support from their financing sources for at least a 25-year term PPA, it appears reasonable to conclude the projects should have a minimum life of 25 years. As regards degradation, most of the projects assumed a 0.5 percent per year loss in panel efficiency during the 25-year term. As is common with wind projects that have been operating for 20-25 years, the project owners face the decision of continuing operation with outdated older technology or repowering with the latest vintage technology that provides the potential benefits of improved performance and reduced costs.

f) The nature of the question may indicate some confusion regarding the difference between "capacity accreditation" and "capacity factor." The former is essentially the expected capacity contribution from solar resources during the MISO system peak. The latter is the anticipated energy production of a facility or resource relative to its maximum generating capabilities. While solar receives a 52 percent accreditation from MISO, its capacity factor is more in the range of 18 to 20 percent, depending on the technology. This is analogous to wind energy's capacity accreditation of around 10 to 15 percent and a capacity factor ranging from 30 to 40 percent, depending on the wind resource.

The Company has evaluated solar capacity accreditation through a study completed by the Company in the Solar Effective Load Carrying Capability (ELCC) Study docket (Docket No. E002/CI-13-315). The study analyzed the contribution of distributed solar electric generation to electric system reliability and the capacity value of solar on the NSP System. The Company also estimated accredited capacity for large solar systems using the methodology for intermittent resources prescribed by the Midcontinent Independent System Operator, Inc. (MISO). Assumptions and calculations are detailed in the study.

These calculations do not address allocation of generation resources among various state jurisdictions.

The MISO methodology, using the typical meteorological year (TMY) data, estimated a 52 percent accreditation factor. The MISO methodology for accreditation of intermittent resources, of which solar, wind, and hydro are typical examples, is defined in the MISO Business Practices Manual (BPM) on Resource Adequacy.

> Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours 1500 – 1700 EST from June, July and August.

MISO has modified this section in the BPM multiple times in the past years to identify how and when new resources will be accredited.

> Non-wind powered Intermittent Generation and Dispatchable Intermittent Resources that are new, upgraded or returning from extended outages shall submit all operating data for the prior Summer with a minimum of 30 consecutive days, in order to have their capacity registered with MISO.

The original study (May 1, 2013) and update (October 31, 2013) filings can be found via the Minnesota Commission's website at http://mn.gov/puc/. Select "Search eDockets," enter the year (13) and the docket number (315), then select "Search."

g) All but 6 of over 100 proposals were sited in Minnesota; review of the solar energy production map below confirms that the most of the Minnesota sited projects were located in the darker yellow areas assessed to have better solar energy production. The map also shows that the solar resource differences are not significant across the state, but are generally better in the southwestern areas of Minnesota. Therefore the decision not to select projects was not due to a significant difference in their projected energy output, but mainly due to price. Each bidder provided an energy output projection for their project reflecting their specific site. For similarly sized projects using similar technology, the energy output projections were not significantly different, but their prices were in many cases significantly higher than the lowest cost proposals.

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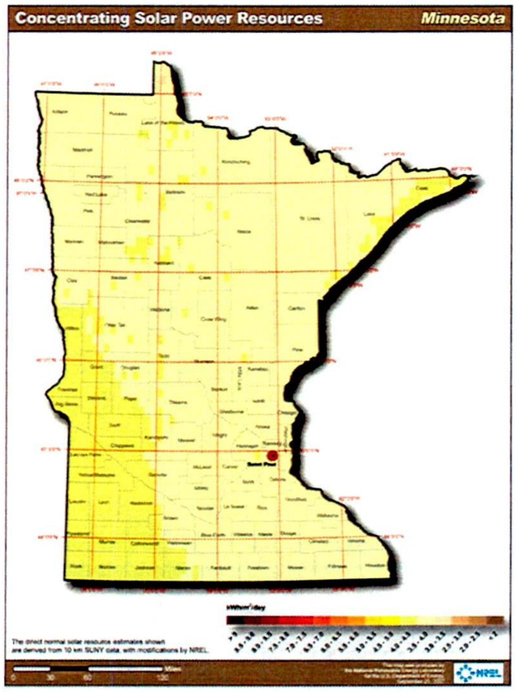

h) Company witness Mr. Kurtis J. Haeger indicated in his Direct Testimony that the Company will receive the capacity accreditation around 2018. Capacity accreditation is somewhat of a moving target and a number of events could impact the date that they are accredited.

The earliest the projects could qualify for capacity accreditation is the MISO 2018/2019 Planning Year (June 2018 through May 2019). This is because a solar project must provide 30 Consecutive days' worth of historical data during June, July or August for the hours of 1500 – 1700 EST (per MISO BPM 11 Resource Adequacy, Section 4.2.2, Intermittent Generation and Dispatchable Intermittent Resources) prior to participating in the Planning Resource Auction (PRA) which happens in March of every year. The projects have a planned in-service date of December 31, 2016, which means they would have to perform testing in June, July or August of 2017, and could participate in the March 2018 PRA.

In addition, solar or any other type of generation interconnecting in MISO will only be eligible to qualify as a capacity resource when all network upgrades required under the interconnection agreement are in-service. As Mr. Haeger pointed out in his Direct Testimony, it is possible that the solar projects' generation interconnection agreements could be conditioned on the completion of

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the North La Crosse to Madison 345 kV line in December 2018. This would mean that the projects could not receive capacity accreditation until the MISO 2019/2020 Planning Year (June 2019 through May 2020). The projects would still be able to meet the 30 consecutive days' worth of testing data in 2017 since a generating project is allowed to operate prior to completion of all transmission upgrades. The Company will not know if the solar projects are conditional based on the North La Crosse to Madison 345 kV line until all MISO generator interconnection studies are completed in 2015.

MISO is also working to improve their generator interconnection and resource adequacy process to allow projects to become eligible to qualify as a capacity resource prior to completion of all required network upgrades. MISO has discussed a plan to accomplish this in a number of MISO shareholder venues and is working on implementation. A successful outcome from this process could allow the solar projects to receive capacity accreditation for the MISO 2018/2019 Planning Year as discussed above.

i) See Trade Secret Attachment A to this response.

j) The benefits of the fixed pricing of the solar PPAs will become more apparent over time. With solar having no fossil fuel price risk and a fixed energy price over time, energy from these resources will provide an ever greater hedge against increases in on-peak market energy prices, which are projected to be driven by increases in natural gas prices.

k) The following list provides Module E PRM Targets for MISO, and the corresponding NSP required levels of PRM for the next planning period, and six prior periods.

- 2015/2016 – 7.1% - 522.8 MW
- 2014/2015 – 7.3% - 446.5 MW
- 2013/2014 – 6.2% - 493.3 MW
- 2012/2013 – 3.79% - 349.3 MW
- 2011/2012 – 3.81% - 317.7 MW
- 2010/2011 – 4.5% - 370.3 MW
- 2009/2010 – 5.35% - 454.9 MW

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The annual MISO Loss of Load Expectation (LOLE) Study determines the PRM on an unforced capacity (UCAP) basis for the MISO system. This report provides an overview of the LOLE process and results of this study, in addition to a summary of historical PRM's and a 10-year forecast of future PRM's. The following tables, from the 2015/2016 LOLE Study, detail the calculation methodology and 10-year forecast for PRM.

MISO Planning Reserve Margin (PRM)	2016/2017 PY (June 2016 - May 2017)	2017/2018 PY (June 2017 - May 2018)	2024/2025 PY (June 2024 - May 2025)	Formula Key
MISO System Peak Demand (MW)	129,367	130,690	138,091	[A]
Time of System Peak (EST)	8/3/2016 16:00	8/2/2017 16:00	7/31/2024 16:00	
Installed Capacity (ICAP) (MW)	148,909	150,398	151,620	[B]
Unforced Capacity (UCAP) (MW)	138,598	140,061	141,187	[C]
Firm External Support (MW)	3,155	3,155	3,155	[D]
Adjustment to ICAP (MW)	-4,030	-3,958	2,970	[E]
Adjustment to UCAP (MW)	-3,188	-3,135	2,803	[F]
ICAP PRM Requirement (PRMR) (MW)	148,034	149,595	157,745	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	138,565	140,081	147,145	[H]=[C]+[D]+[F]
MISO PRM ICAP	**14.4%**	**14.5%**	**14.2%**	[I]=([G]-[A])/[A]
MISO PRM UCAP	**7.1%**	**7.2%**	**6.6%**	[J]=([H]-[A])/[A]

Table 5.3-1: Future Planning Year MISO System Planning Reserve Margins

Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PRM $_{ICAP}$	14.3%	14.4%	14.5%	14.5%	14.4%	14.4%	14.3%	14.3%	14.2%	14.2%
PRM $_{UCAP}$	7.1%	7.1%	7.2%	7.1%	7.0%	6.9%	6.9%	6.8%	6.7%	6.6%

Table 5.3-2: MISO System Planning Reserve Margins 2015 through 2024

The LOLE Study Report for the 2015/2016 Planning Year is provided at the following link:
https://www.misoenergy.org/Library/Repository/Study/LOLE/2015%20LOLE%20Study%20Report.pdf

MISO's determination of PRM is based on UCAP (unforced capacity ratings of generation resources). This differs from a methodology based on ICAP (installed capacity ratings) used by MAPP. The Company participated in MAPP until 2009.

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Preparer:	Mary Morrison / Paul Johnson / Jon Landrum / Randy Oye
Title:	Resource Planning Analyst II / Resource Planning Director / Resource Planning Analytics Manager / Transmission Analyst
Department:	Resource Planning / Resource Planning / Resource Planning/ Market Operations
Telephone:	612.330.5862 / 612.330.6238 / 303.571.2765 / 612.330.2886
Date:	January 2, 2015

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Case No. PU-14-810
NDPSC Data Request No. 51
Attachment A - 1 of 2

NSP Load Balance	**2015**	**2016**	**2017**	**2018**	**2019**
Non-Coincident Peak Demand	9,325	9,442	9,525	9,597	9,649
Coincident Factor with MISO	5.0%	5.0%	5.0%	5.0%	5.0%
Demand Coincident with Peak	8,858	8,970	9,048	9,117	9,167
Transmission Loss Correction to Tranmission	2.62%	2.62%	2.62%	2.62%	2.62%
	8,633	8,741	8,818	8,884	8,933
Demand Resources	933	942	953	964	975
Demand at Transmission	7,700	7,800	7,864	7,920	7,958
Transmission Loss Correction to Generator	2.62%	2.62%	2.62%	2.62%	2.62%
Demand at Generator	7,901	8,004	8,070	8,127	8,166
Reserve Planning Margin	7.1%	7.1%	7.1%	7.1%	7.1%
Native Load Obligation	**8,462**	**8,572**	**8,643**	**8,704**	**8,746**

Resources	**2015**	**2016**	**2017**	**2018**	**2019**
Existing (including current PPAs)					
Owned Generation	6,803	6,870	6,913	6,913	6,902
Purchased Generation	1,885	1,968	2,070	2,053	2,023
Sales	(50)	(50)	(25)	-	-
Resources	**8,639**	**8,788**	**8,958**	**8,966**	**8,925**
Long/(Short) Position	**177**	**216**	**315**	**262**	**179**

Resources By Fuel Type & Ownership	2015	2016	2017	2018	2019
	[Trade Secret Begins ...				
Coal					
Nuclear					
NG - CC					
G - CT					
Oil - CT					
NG - Steam - BF					
RDF					
Biomass					
Hydro					
Wind					
NG - CC - PPA					
NG - CT - PPA					
Hydro - PPA - Assorted					
Hydro - PPA System					
Biomass - PPA - Assorted					
Wind - PPA - Assorted					
Solar - PPA's - Assorted					
					... Trade Secret Ends]

Individual Assets and PPA Sets	Fuel Type/ Ownership	Nameplate or EC	EFOR	2015	2016	2017	2018	2019
		[Trade Secret Begins ...						
AS KING 1	Coal							
SHERCO 1	Coal							
SHERCO 2	Coal							
SHERCO 3	Coal							
MONTI 1	Nuclear							
P ISLAND 1	Nuclear							
P ISLAND 2	Nuclear							
BDOG_CC 52	NG - CC							
_CC 1	NG - CC							
_CC 1	NG - CC							

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Case No. PU-14-810
NDPSC Data Request No. 51
Attachment A - 2 of 2

ividual Assets and PPA Sets	Fuel Type/ Ownership	Nameplate or EC	EFOR	2015	2016	2017	2018	2019
.SON 2	NG - CT							
ANSON 3	NG - CT							
ANSON 4	NG - CT							
BLUELAKE 7	NG - CT							
BLUELAKE 8	NG - CT							
FLAMBEAU 1	NG - CT							
GRANITE 1	NG - CT							
GRANITE 2	NG - CT							
GRANITE 3	NG - CT							
GRANITE 4	NG - CT							
INVERHIL 1	NG - CT							
INVERHIL 2	NG - CT							
INVERHIL 3	NG - CT							
INVERHIL 4	NG - CT							
INVERHIL 5	NG - CT							
INVERHIL 6	NG - CT							
WHEATON 1	NG - CT							
WHEATON 2	NG - CT							
WHEATON 3	NG - CT							
WHEATON 4	NG - CT							
BAYFRONT 4	NG - Steam - BF							
BLUELAKE 1	Oil - CT							
BLUELAKE 2	Oil - CT							
BLUELAKE 3	Oil - CT							
BLUELAKE 4	Oil - CT							
FCH ISLD 3	Oil - CT							
H ISLD 4	Oil - CT							
..HEATON 5	Oil - CT							
WHEATON 6	Oil - CT							
INVERDSL 78	Oil - CT							
BAYFRONT 5	Biomass							
BAYFRONT 6	Biomass							
FCH ISLD 12	RDF							
RED WING 12	RDF							
WILMARTH 12	RDF							
WI_HYD	Hydro							
GRANDMED	Wind							
NOBLES	Wind							
PLSNTVLY	Wind							
BORDER	Wind							
INVENERG 1	NG - CT - PPA							
INVENERG 2	NG - CT - PPA							
LSCOTGRV 1	NG - CC - PPA							
CALPMNKT 1	NG - CC - PPA							
Manitoba Hydro 375/500	Hydro - PPA System							
Manitoba Hydro Divers Agrmnt 2	Hydro - PPA System							
Manitoba Hydro Divers Agrmnt 3	Hydro - PPA System							
Biomass PPA's - Assorted	Biomass - PPA							
Hydro PPA's - Assorted	Hydro - PPA							
Wind PPA's - Assorted	Wind - PPA							
Solar PPA's - Assorted	Solar - PPA							

... Trade Secret Ends]

Diller, Michael R.

From:	Diller, Michael R.
›nt:	Monday, January 05, 2015 4:01 PM
›:	dave.sederquist@xcelenergy.com
Subject:	Follow-up Questions Concerning RFI's 1-5.docx
Attachments:	Follow-up Questions Concerning RFI's 1-4.docx

January 5, 2015

Dave Sederquist
Northern States Power Company
Fargo, ND

RE: Responses 1-5 Received on December 29, 2014 and January 2, 2015
Solar Portfolio ADP, Case No. PU-14-810

Dave:

The data responses submitted on December 29, 2014, need more work and I am writing to get additional information and clarification. I intend to attach all data responses to my testimony and make them a part of the official record so full and complete answers are appreciated. As such, it is important to not only answer the written word of the question but the clear intent and spirit of the question so that everyone has good information to analyze and reach good decisions. Please have your people respond to the following questions seeking clarification and in some instances...additional information.

1b) 216B at least infers that out-of-state solar generation may not be used to meet Minnesota's solar energy standard (SES) and thus the reason for my question asking for clarification as to whether devices located in ND would qualify to meet MN's SES. NSP responded that "we do not interpret this section" to restrict the use of ND solar power towards meeting the MN SES. Please provide an explanation of your interpretation as was originally requested and further, provide any and all restrictions elsewhere in MN law, rules, practices or otherwise that may restrict the use of ND solar in meeting the MN SES.

1c) Thank you for the detailed information about the various MN plans and funding sources for solar, however my concern and fundamental question was how much are these programs costing ND consumers on average. Provide the average cost per kWh for excess solar energy sold to NSP which is then allocated to ND. The 2013 amount paid by ND consumers is immaterial but if these programs are expected to exceed 2,400 MW's by 2030 according to your recent news release, the cost to North Dakota will become material.

2b) I believe that it would be in the best interest of NSP to provide more information concerning why the ND solar project was rejected from the short list. As it stands, it appears the project was rejected because the proposal was complex and NSP did not know if Great

River Energy would post for the availability of a Net Zero interconnection for PRC Solar's proposal. Given the sensitivity of project locations between states, a fuller explanation beyond "it's hard and we don't know" is suggested. Whether you determine to add to the record or not by providing additional details, provide a copy of the bid proposal from PRC Solar and NSP's evaluation of the proposal so we can review your decisions on the complexities and the price of the proposal. Also, provide NSP's reason for not contacting GRE about their willingness to post for a Net Zero interconnection.

3c) A curious sentence is added to the end of both paragraphs stating that NSP "makes no assertion as to the importance" of the "Markets Off" or the "Capacity Factor" sensitivity cases. If I asked the same question of the importance of the "Reference Case" or the "Low Gas Cost" sensitivity case in Table 1 of your application, would the same curious statement be included? Is this statement intended to suggest that these sensitivities are irrelevant and of little or no consequence? Why is this sentence included? Just want to understand.

Thanks Dave for the follow-up.

Sincerely,

Mike Diller
Director of Economic Regulation

Diller, Michael R.

From:	Hedlund, Amber R <Amber.R.Hedlund@xcelenergy.com>
nt:	Thursday, January 15, 2015 3:05 PM
.	Diller, Michael R.
Cc:	Sederquist, Dave
Subject:	Xcel Energy's Response to NDPSC Data Request Nos. 6, 7 Public, 8 and 9_Case No. PU-14-810
Attachments:	Cvr Letter NDPSC DRs 6, 7 Public, 8, and 9.pdf; NDPSC-006.pdf; NDPSC-007 PUBLIC.pdf; NDPSC-008.pdf; NDPSC-009.pdf

Dear Mr. Diller:

Enclosed please find a cover letter and our responses to Data Request Nos. 6, 7 Public, 8 and 9 concerning Xcel Energy's Solar Portfolio ADP.

The Non-Public response to NDPSC Data Request No. 7 has been sent to you under separate cover via overnight Federal Express.

Please contact me if you have any questions regarding this submission. Thank you.

Amber Hedlund
Xcel Energy
Regulatory Case Specialist
414 Nicollet Mall, 7th Floor, Minneapolis, MN 55401
P: 612.337.2268
`: amber.r.hedlund@xcelenergy.com

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

January 15, 2015

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—Via Email—

Michael Diller
North Dakota Public Service Commission
State Capitol Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: RESPONSES TO DATA REQUEST NOS. 6, 7 PUBLIC, 8 AND 9
SOLAR PORTFOLIO ADP
CASE NO. PU-14-810

Dear Mr. Diller:

Enclosed please find our responses to the referenced North Dakota Public Service Commission staff Data Requests in the above noted case. The Non-Public response to NDPSC Data Request No. 7 has been sent under separate cover via Federal Express.

Sincerely,

/s/

AMBER HEDLUND
REGULATORY CASE SPECIALIST

cc: Dave Sederquist

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	6
Requestor:	Michael Diller		
Date Received:	January 5, 2015		

Question:

Reference NDPSC Data Request No. 1C

Thank you for the detailed information about the various MN plans and funding sources for solar, however my concern and fundamental question was how much are these programs costing ND consumers on average. Provide the average cost per kWh for excess solar energy sold to NSP which is then allocated to ND. The 2013 amount paid by ND consumers is immaterial but if these programs are expected to exceed 2,400 MW's by 2030 according to your recent news release, the cost to North Dakota will become material.

Response:

The 2,400 MW of solar resources referenced in a recent News Release was from the Preferred Plan we proposed in our 2016-2030 Integrated Resource Plan. We clarify that approximately 80 percent of that total (1,887 MW) is driven by utility-scale solar that we would secure directly (we have already selected and proposed three projects for approval totaling 187 MW, and we plan to secure an additional 1,700 MW during the 2016-2030 planning period). Per our previous commitment, we would submit Applications for Advance Determinations of Prudence to the North Dakota Commission for these significant additions to the NSP System.

The remaining approximately 500 MW of solar power we plan to add by 2030 is customer-based solar additions through the Company's various solar tariffs and programs in Minnesota, which Table 18 from our Resource Plan breaks down as follows:

Table 18: Distributed Solar Additions (AC MW), Preferred Plan

Distributed Solar Additions (AC MW), Preferred Plan				
	Solar Rewards	Made In MN Small	Made In MN Large	Solar Gardens
2014	3.9	1.2	3.7	2.5
2015	3.9	1.2	3.7	5.0
2016	3.9	1.2	3.7	5.0
2017	3.9	1.2	3.7	5.0
2018	3.9	1.2	3.7	5.0
2019	3.9	1.2	3.7	5.0
2020	3.9	1.2	3.7	5.0
2021	10.5	-	-	6.0
2022	12.6	-	-	7.2
2023	15.2	-	-	8.6
2024	18.2	-	-	10.4
2025	21.8	-	-	12.4
2026	26.2	-	-	14.9
2027	31.4	-	-	17.9
2028	37.7	-	-	21.5
2029	45.2	-	-	25.8
2030	54.3	-	-	31.0
	300.5	8.3	25.7	188.3

We intend to fully recover the costs associated with the Minnesota Solar*Rewards Community (Solar Gardens) program from Minnesota customers, per our May 7, 2014 Compliance filing, and the Minnesota Commission's September 17, 2014 Order in Docket No. E002/M-13-867, as follows:

Xcel Energy May 7 Compliance filing:

> *To ensure Minnesota customers receive the full benefit from the additional solar energy created by the Minnesota Solar*Rewards Community program, we propose to directly assign its associated energy to Minnesota customers. To accomplish this task, the Company proposes to separately account for Minnesota Solar*Rewards Community energy and bill credits that are generated on behalf of and credited to Minnesota subscribers and for payments to garden operators for unsubscribed energy. The energy and associated bill credits will then be added into the accounts that are used to determine the Minnesota fuel clause.*

Minnesota Commission's September 17 Order at page 18:

> *Xcel stated that it intends to recover the cost of the solar-garden program, including subscriber bill credits and REC payments, through the fuel clause rider. The Department supported this proposal.*
>
> *The Commission concurs. Minn. Stat. § 216B.16, subd. 7, allows Xcel to request the automatic adjustment of charges for the costs of fuel used in the generation of electricity. Here, Xcel will be purchasing energy from solar gardens under contract in much the same way it purchases renewable energy from large wind facilities through a power purchase agreement. The Commission has approved Xcel's recovery of such costs through the fuel clause rider.*
>
> *The Commission will approve Xcel's proposal to recover community-solar-garden program costs, including customer bill credits, additional REC credits, and unsubscribed energy, through the fuel clause rider. The Commission will further require Xcel to include information about its bill credits (as reported in its annual reports in this docket) in the Company's Annual Automatic Adjustment (AAA) Report, reflecting the same time period covered by the AAA report.*

This leaves approximately 330 MW of net metering-eligible small-scale systems. The Solar Rewards and Made in MN programs fall under the Under 40 kW net metering category, which is eligible for the A50 tariff rate (which is based on retail rates) on excess system production. If a customer puts up a system that is larger than 40kW, they would fall within the 40 kW to 1 MW category and would be eligible to receive avoided cost rates (approximately $0.03 to $0.05) for excess production under our A51 or A52 tariffs.

For the most part, customers with these distributed generation systems are eligible to net meter their system's production. Depending on weather conditions and customer usage, these customer systems may produce more energy than they consume, and if they do, they may sell their excess production to the Company. However, customers installing solar PV systems are limited by Minnesota Statute to sizing the output of their system to 120 percent of their previous year's energy usage (Minn Statute § 216B.164, Subd. 4C), so we expect any future excess sold to the Company to be constrained by this requirement as well. I discuss each of these categories below:

(1) *Under 40 kW.* Customers installing distributed generation facilities with an AC capacity of under 40kW and who choose the *A50 Net Energy Billing Service* tariff are able sell their excess solar production at rates based on retail rates ranging from approximately $0.06 to $0.10. This category includes participants in the

Company's Solar Rewards and Made in Minnesota programs. The specific rates that have been in effect in 2013, 2014 and 2015 are as follows:

	Residential & Sm. Commercial		**Demand Billed Commercial**	
	Oct-May	Jun-Sept	Oct-May	Jun-Sept
Mar. 2014 to Feb. 2015	0.10575	0.11334	0.06266	0.06593
Mar. 2013 to Feb. 2014	0.10170	0.10647	0.06009	0.06177
Mar. 2012 to Feb. 2013	0.10042	0.10700	0.05855	0.06145

(2) *40 kW to 1 MW.* Customers with distributed generation facilities with an AC capacity of 40 kW to 1 MW can sell their excess solar PV production at avoided cost rates of approximately $0.03 to $0.05 on the Company's *A51 Purchase and Sale Service* tariff or its *A52 Time-of-Day Purchase Service* tariff. These tariff payment rates are designed at avoided cost levels, so non-participating customers are not paying incremental costs for this energy.

Based on our current experience, we estimate that payments for excess production to customers for the approximately 330 MW of AC solar capacity in the Under 40kW category could total roughly $3 million annually by the end of 2030, of which approximately 5 percent ($150,000) would be allocated to North Dakota. We additionally note that based upon the recent launch of our Community Solar Gardens program, we believe participation in that program will likely exceed the 188 MW estimate in our Resource Plan and will likely comprise the greatest proportion of the customer-based solar resources on the NSP System.

Preparer: Nick Paluck
Title: Rate Consultant
Department: NSPM Regulatory
Telephone: 612.330.2905
Date: January 15, 2015

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☐ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	7
Requestor:	Michael Diller		
Date Received:	January 5, 2015		

Question:

Reference NDPSC Data Request No. 2B

I believe that it would be in the best interest of NSP to provide more information concerning why the ND solar project was rejected from the short list. As it stands, it appears the project was rejected because the proposal was complex and NSP did not know if Great River Energy would post for the availability of a Net Zero interconnection for PRC Solar's proposal. Given the sensitivity of project locations between states, a fuller explanation beyond "it's hard and we don't know" is suggested. Whether you determine to add to the record or not by providing additional details, provide a copy of the bid proposal from PRC Solar and NSP's evaluation of the proposal so we can review your decisions on the complexities and the price of the proposal. Also, provide NSP's reason for not contacting GRE about their willingness to post for a Net Zero interconnection.

Response:
We provide a copy of PRC's Solar North Dakota Bid Proposal as Trade Secret Attachment A.

We performed a full transmission and interconnection analysis on PRC Solar's 50 MW North Dakota Project as outlined in the Auditor's Report, included as Exhibit___(KJH-1), Schedule 2, to our initial filing submitted on November 7, 2014. This analysis lead to our conclusion that this project did not qualify to proceed to the Final Short List of fully-compliant and lowest costs projects, for the reasons we outline below:

- *PRC's proposal did not provide a credible interconnection plan.* While they stated that they intended to utilize a Net Zero Interconnection (NZI), they did not provide any documentation that they had taken any steps in obtaining an NZI or that Great River Energy (GRE), who was the proposed "partner" in the

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NZI, was interested in participating in an NZI at their Stanton Generating Station.

The MISO tariff defines the process for obtaining an NZI under Section 3.2.3 of Attachment X, which also makes any proposal publicly apparent. Specifically, the MISO NZI process requires that an existing generator start the process by notifying MISO that they are willing to enter into a Net Zero arrangement with a suitable proposal. Upon receipt of the NZI notification, MISO will post the information on their website. At the time we evaluated the PRC Solar bid, MISO had not posted any information that GRE was interested in a NZI at their Stanton Plant. This is a critical step in evaluating an NZI proposal, since a MISO NZI can only happen if the existing generator has publicly indicated it is willing to enter into an NZI agreement with a new generator.

- *Under an NZI, the project would not have been eligible to provide any capacity credit, which was required by the RFP.*[1] An NZI is a MISO generation interconnection that allows a new generator to *share* interconnection rights with an existing generator, and is a restricted service interconnection in that it is not eligible for Network Resource Interconnection Service (NRIS), or Network Integration Transmission Service (NITS), one of which is required to obtain capacity credit.

During the due diligence process, we investigated these issues and did not find any evidence that PRC had taken any necessary steps to initiate the NZI process.

In addition, even if GRE had affirmed interest in an NZI, the NZI process affords the existing generator the right to choose the "winning NZI" and allows an unlimited number of generators to apply. In addition to an NZI taking significant time, which we believe would have put at risk a 2016 in-service date, there is no guarantee that if GRE had been interested in an NZI at Stanton that PRC Solar would have been chosen.

For these reasons, PRC Solar's North Dakota Project did not proceed to the Final Short List of fully compliant and lowest cost projects.

Please note that portions of Attachment A are marked "Non-Public" as they contain information described in the Company's Trade Secret Application in this Case.

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[1] Northern States Power Company 2014 Solar Resource Solicitation Request for Proposals dated April 2014, page 4, included in Exhibit___(KJH-1), Schedule 2, to our initial filing submitted on November 7, 2014, beginning at Page 46 of the Exhibit.

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PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED

Preparer:	Paul B. Johnson
Title:	Director, Resource Planning and Bidding
Department:	Resource Planning
Telephone:	612-330-6238
Date:	January 15, 2015

50MW North Dakota Solar Project Proposal

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LIST OF APPENDICIES

Tab 1 - Executive Summary

[TRADE SECRET BEGINS

PRC Solar, LLC

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Developer

Project Resources Corp and affiliates (together "PRC") have successfully developed 2 GWs of currently operating wind capacity in the Midwest over the last 17 years, including almost 1 GW for Xcel Energy. PRC is currently moving more than 800 MW of additional new wind and solar capacity toward construction. The team represents deep-domain experience in development, construction, operation, and financing of renewable energy projects and an excellent track record. PRC works with together with partners & local communities to deliver innovative, high quality, home-grown renewable electric projects.

PRC's strategic partner, SolarWorld, is the first and oldest photovoltaic manufacturer in the United States. With about 3,200 employees globally, the SolarWorld group is also one of the world's largest solar energy businesses – and the largest U.S. solar manufacturer. Its innovation, performance and environmental track record make the company an industry leader. SolarWorld is one of the very few companies who have been in business longer than the length of their warranty, and therefore have real-world experience and proven technology backed by case studies and independent third party testing. Furthermore, as a quality American made product SolarWorld is not subject to tariffs ranging from 19 to 35 percent and can be relied upon as a safe reliable supplier of modules and systems

Tab 2 – Project Description and Supporting Information

[TRADE SECRET BEGINS

2.1 Project Description

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2.2 Development Experience

Project Resources Corp and affiliates (together "PRC") have successfully developed 2 GWs of currently operating wind capacity in the Midwest over the last 17 years, including almost 1 GW for Xcel Energy. PRC is currently moving more than 800 MW of additional new wind and solar capacity toward construction. The team represents deep-domain experience in development, construction, operation, and financing of renewable energy projects and an excellent track record. PRC's experience includes:

- 42.4 MW operating portfolio including the 5.4MW MN Windshare project and 25MW Ridgewind project successfully delivering power to Xcel Energy
- 50 MW wind project in Minnesota that reached COD in 2014
- 795 MW of development projects, including the 20 MW Rock Aetna C-BED project in late-stage development with PPA and GIA signed with Xcel Energy

PRC enjoys a strong reputation of delivering results.

"As head of enXco Development since 2000, I have worked directly with PRC in developing enXco's fleet of projects in the Midwest USA during formative years of enXco's wind business.

PRC assisted in evaluation, siting and development of market opportunities that resulted in an enXco project pipeline to serve much of that market, resulting in almost 1,200 MW of current operating capacity, with an additional 400 MW under construction by enXco, as of year-end 2010.

PRC has demonstrated an ability to adapt to market changes and new challenges that deliver results such as they are doing now with the Wind Share program in MN.

We have been pleased with their performance in support of enXco's needs over the years."

Joseph B. Fahrendorf
Executive Vice President
Development Origination
enXco Development Corp.

Figure 1

Brief History of PRC

1997	PRC Founded by Paul White. Development of Viking project initiated.
2000-2003	PRC engaged as enXco's exclusive Midwest development lead. Developed 2,000+ MWs of project pipeline.
2003	Construction of Viking project completed.
2004-2006	PRC engaged by enXco to develop and annually review enXco's development strategy for the Midwestern U.S.
2004-2006	Development and construction of Windshare project.
2006	Strategy to develop PRC's proprietary pipeline initiated.
2007-2010	Development and construction of Ridgewind 25 MW project.
2011-2013	Development and construction of Lakeswind 50 MW project.

The PRC team carries with it more than 70 years of cumulative experience in various aspects of renewable energy and real estate development. PRC is led by Paul White: a proven leader in the wind power industry with more than 17 years of experience developing utility-scale wind power projects for Xcel Energy and other Midwest utilities. Mr. White is recognized in the sector for his ability to develop creative solutions to multi-faceted challenges, as demonstrated by positioning development assets for clients and PRC-owned projects.

Paul White, President
Paul White has been actively involved in the wind power industry for 20+ years working closely with numerous wind turbine manufacturers, developers, and other suppliers to the wind industry. In 1991 Paul began working on energy policy issues in Minnesota and California, and through the 1990's he sold and built wind turbines for Vestas-American Wind Technology. In 1997 Paul started his own business, Project Resources Corporation (PRC), a wind development company based in Minneapolis to develop projects throughout the Midwest. PRC has successfully originated over 1,700 megawatts of operating wind capacity throughout the Midwest. Paul has championed PRC's MN Windshare program to enhance community participation and economic benefits from wind energy projects. He earned a Bachelor's degree from St. Olaf College, and a Master's degree from the University of Minnesota. He lives in Minneapolis with his wife and two daughters.

Scott Nelson, Business Development Leader
Scott Nelson is a senior executive manager with successful international experience in management, operations, project development, engineering and construction of power generating assets. He is a business entrepreneur with a bachelor's degree in accounting and extensive executive business management education, including receiving his Certified Management Accounting designation (CMA). He has been the Vice President of a large international power operations company. He has extensive international experience in both wind power and

solar project development, procurement, construction, and operations. Scott's abilities have enabled him to increase profits of an international renewable developer over the last 19 years. He has profitably managed over 4000 MW's of project development and construction projects.
Until June of 2011, Scott was Vice-President of enXco, an international renewable energy company. During his tenure in that office, he most recently directed the wind business arm of the company's North American business operations. Prior to this position with enXco, he managed both the solar and wind businesses at enXco and implemented many on-budget and on-schedule projects. Under his direction, this company profitably developed, constructed, managed, and operated over 4,000MW's of wind and solar projects.

Lee Glover, General Manager
Lee Glover has over 20 years of experience in business management with an emphasis in real estate development and related industries. Her specialty is assisting entrepreneurs with the organization and operations of privately-held companies. Her knowledge includes business and management principles involved in strategic planning, resource allocations, human resources, leadership technique, accounting, customer and personal service, sales and marketing, and administration. Prior to joining PRC's team, Lee assisted three partners in creating and managing First Construction Finance, a start-up interim construction finance company, where she served in multiple capacities as Loan Officer, Business Manager and Vice President. During her 10 years as Business Manager and Vice President with Residential Development, Inc., a small residential land development company, she assisted the owner with all aspects of the business. Lee has managed her own real estate sales business and is a licensed Real Estate Broker.

Ryan Ammermann, Project Development Manager
Ryan Ammermann has recently joined PRC performing the duties of the Development Manager overseeing project schedules, deliverables and resources to bring projects to completion. Ryan manages and coordinates the planning and acquisition of required local, state and federal permits. With his experience in the industry, he has permitted numerous projects and constructed over 250MW of renewable energy in the Midwest. Ryan studied Geography and Aviation at the University of North Dakota, earning a Bachelor of Science degree in 2004. As a pilot, he enjoys flying when time permits and helping on the farm. Ryan lives in Minneapolis with his wife.

Eric Anderson, Technical Specialist
Eric Anderson has been with PRC for 6 years, managing wind assessment, project design, policy analysis, regulatory compliance, transmission & interconnection planning. Eric manages turbine micrositing, road and electrical design, other assistance with project construction, and supports development strategy and power marketing efforts. Eric studied physics at Gustavus Adolphus College, earning a Bachelor of Arts degree in 2008. He studied international business and economics at the Danish Institute for Study Abroad in 2007. An Eagle Scout, Eric enjoys leading wilderness trips in the Boundary Waters Canoe Area.

Munce Tronsgard-White, Special Projects Coordinator
Munce Tronsgard-White has 8 years of experience in wind development, including 5 years with PRC and 3 years with enXco Development Corporation. Munce has a broad range of experience coordinating project development activities, including but not limited to project site selection, land acquisition, power sales bids, development expense accounting, contractor coordination, company marketing activities, general office management, and human resource management. Munce lives in Minneapolis with her husband and two children.

Lisa Hammer, Land Title Specialist
Lisa Hammer has over 10 years of real estate and title experience. In 2011 Lisa joined the PRC team as the title clearance administrator where her primary duties are to insure that PRC's Leases and Easements are insurable by the title insurance company. Lisa was admitted to the Minnesota State Bar Association in 1994. After earning her law degree she worked for over 8 years with a law firm in Minneapolis where her practice area was almost exclusively in real estate related matters including drafting real estate documents, real estate related litigation and foreclosure work. In 2003 Lisa opened her own closing and title insurance company, Title Excellence LLC, where she is the title examiner, closer, claims manager and marketing representative. Lisa earned a Bachelor of Arts from St. Cloud State University and Juris Doctorate from William Mitchell College of Law. Lisa is a Board Certified Real Property Law Specialist certified by the Minnesota State Bar Association. Lisa lives in Minneapolis with her husband and two children.

Angeli Modjeski, Administrative Assistant
Angeli Modjeski has worked as an Administrative Assistant for over 14 years. Prior to joining PRC in June of 2013, Angeli worked in a range of business segments – health care, financial to advertising. She manages projects including generating and formatting reports, processing data, managing the PRC data site, providing technical and accounting support and facilities management. Resident of Minneapolis.

PRC Developed Projects

Name	Location	Size (MW)	Online	Location	Status
Lakeswind Project	Rollag, Minnesota	48	2014*	2 miles E of Rollag, MN	Construction
Lakefield Wind Project	Lakefield, Minnesota	205.5	2011	3 miles NE of Lakesfield, MN	Operating
Ridgewind Project	Woodstock, MN	25.3	2010	1 mile E of Woodstock, MN	Operating
Nobles Wind Project	Nobles, Minnesota	201	2010	7 miles NE of Fowner, IN	Operating
Crane Creek Wind Project	Riceville, IA	99	2009	3 miles E of Riceville, IA	Operating
Pomeroy	Pomeroy, IA	198	2008	1 mile North of Pomeroy, IA	Operating
Pomeroy 3	Pomeroy, IA	58.5	2008		Operating
Grand Meadow	Dexter, MN	100.5	2008	3 miles S of Dexter, MN	Operating
Wapsi	Dexter, MN	100.5	2008	3 miles N of Dexter, MN	Operating
Hoosier Wind Project	Goodland, IN	106	2008	5 miles SE of Goodland, IN	Operating
Fenton Wind Project	Fenton, MN	205.5	2007	5 miles SE of Chandler, MN	Operating
Spearville Wind Project	Spearville, KS	100.5	2006	1 mile North of Spearville, KS	Operating
Spearville 2 Wind Project	Spearville, KS	48	2010		Operating
Spearville 3 Wind Project	Spearville, KS	100.8	2012		Operating
Windshare Projects	Lake Wilson, MN	5.4	2005	2 miles SW of Lake Wilson, MN	Operating
Century Wind Project	Blairsburg, IA	150	2005	5 miles N of Blairsburg, IA	Operating
Chanarambie Wind Project	Lake Wilson, MN	85.5	2003	3 miles NW of Lake Wilson	Operating
Viking Wind Projects	Lake Wilson, MN	12	2003	2 miles SW of Lake Wilson, MN	Operating
Moulton & Champepadan Wind Projects	Chandler, MN	4	2000	1 mile south of Chandler	Operating
Peetz Wind Project	Peetz, CO	30	1999	5 miles west of Peetz, CO	Operating
Chandler Wind Project	Chandler, MN	1.98	1998	1 mile south of Chandler	Operating

TOTAL	1885.98

* contracted, under construction, or otherwise not yet commissioned

Figure 2

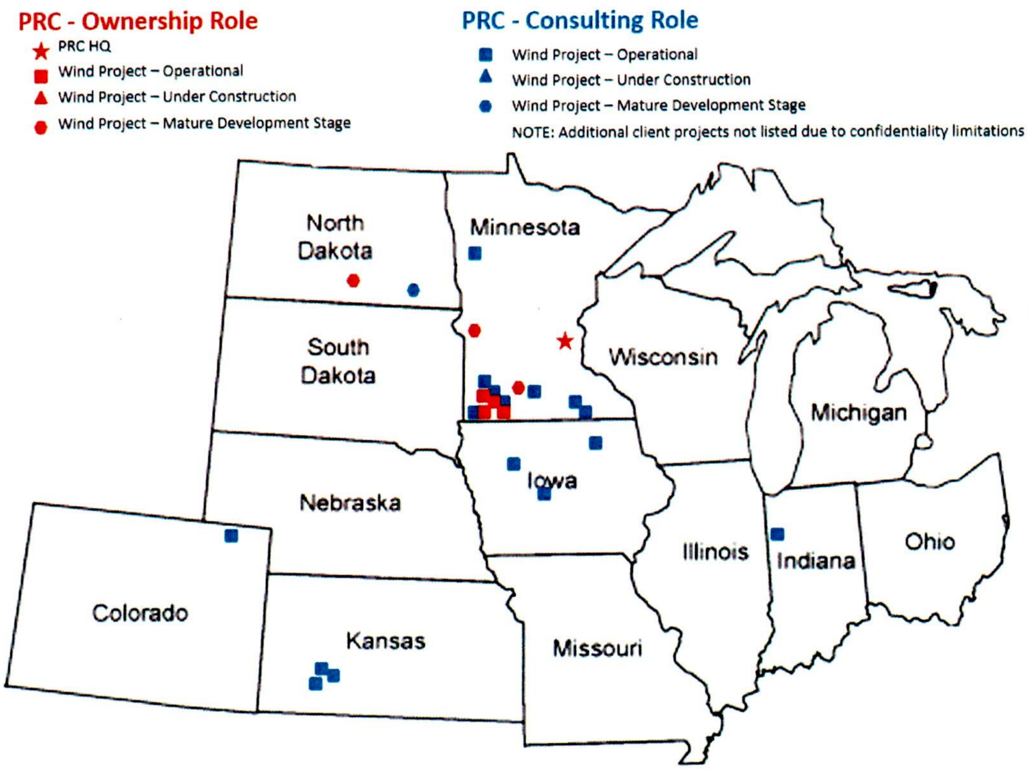

Figure 3

PRC's experience is augmented by a set of diverse partnerships within the solar industry, including engineering, construction, and finance expertise in developing thousands of MW's of solar projects throughout the United States. Final selection of project-specific partners and the EPC team will be completed after completion of PPA negotiations with Xcel Energy, in preparation for 2016 project COD.

The PRC Team has worked extensively with manufacturer SolarWorld and their EPC team in preparing this bid. SolarWorld has extensive industry experience in constructing and operating solar projects on a global scale. The SolarWorld team's experience within the industry is detailed further below. Overall, the North Dakota project team which PRC has built to see this project to a successful COD is unparalleled in the industry.

Ardes Johnson, Vice President Sales and Marketing
Mr. Johnson has held roles in sales and sales leadership with General Electric's GE Energy division, where he managed teams involved in power generation, power delivery and project development for the renewable energy, utility, industrial and oil and gas markets. He holds a bachelor's degree in mechanical engineering from Texas Tech University and an MBA from Southern Methodist University. Mr. Johnson also served in the U.S. Navy as a nuclear power surface warfare officer aboard the U.S.S. Harry S. Truman.

Josh Corbin, Manager of Projects
Mr. Corbin brings over 20 years of experience managing large industrial and commercial projects. In addition, Mr. Corbin has overseen or been involved in the installation of over 50 MWs of large commercial and utility PV systems, from the project development phase through implementation, concluding with commissioning and operations of the solar facility. Experienced in negotiating PPA's, EPC's and financial solutions, Mr. Corbin can provide all levels of service and support for large scale projects.

James Gahan, Design Engineer Supervisor
Mr. Gahan brings eight years of photovoltaic design experience. Designs completed cover the full spectrum of photovoltaic systems including, but not limited to, 25MW+ ground-mount utility-scale systems, 1MW+ industrial, 10-100kW rooftop commercial, and 2-20kW rooftop and ground-mount residential. James' broad knowledge of electrical power systems includes protection and coordination, grounding, medium voltage distribution circuitry and familiarity with SCADA and communication systems. Experienced with roof, ground mounts and trackers and interconnecting to high voltage systems. James holds a B.S. in Electrical Engineering from Cal Poly, San Luis Obispo concentrating in Power Systems. He is a registered professional engineer in the state of California.

Chris Biller, Construction Manager

Mr. Biller has more than 15 years of experience in commercial and residential construction and over 50MWs of photovoltaic (PV) design and installation. His background also includes project and field management, business development, site specific project strategy, and development. Mr. Biller specializes in installation of PV on large-scale residential, commercial and utility projects and has worked extensively with utilities, big box retail customers and government agencies.

Alex Martinez, Technical Analyst

Mr. Martinez obtained his B.A in Environmental Studies at the University of California, Santa Cruz with an emphasis on renewable energy implementation and sustainable design. With over three years of experience in the renewable energy and energy efficiency industry, Mr. Martinez is knowledgeable in project requirements, proposal development and risk analysis. As a Technical Analyst for SolarWorld's Project Development Team, Mr. Martinez's roles and responsibilities range from completion of project conceptual designs to turnkey project estimation. Prior to working at SolarWorld, he served as a lead residential project engineer at solar integrator and completed over a hundred designs for residential and light commercial projects located in Northern California.

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2.3 Equipment Description

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[TRADE SECRET BEGINS

2.4 Energy Production Profile

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2.5 Operations and Maintenance Plan

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2.6 Permitting Status

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2.7 Environmental Impact and Profile

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2.8 Community/State Reaction Assessment

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ENDS]

[TRADE SECRET BEGINS

2.9 Development Schedule & Milestones

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[TRADE SECRET BEGINS

2.10 Community-Based Energy Development (C-BED)

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Tab 3 – Pricing

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Tab 4 - Site Control

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Tab 5 – Transmission, Distribution and Interconnection

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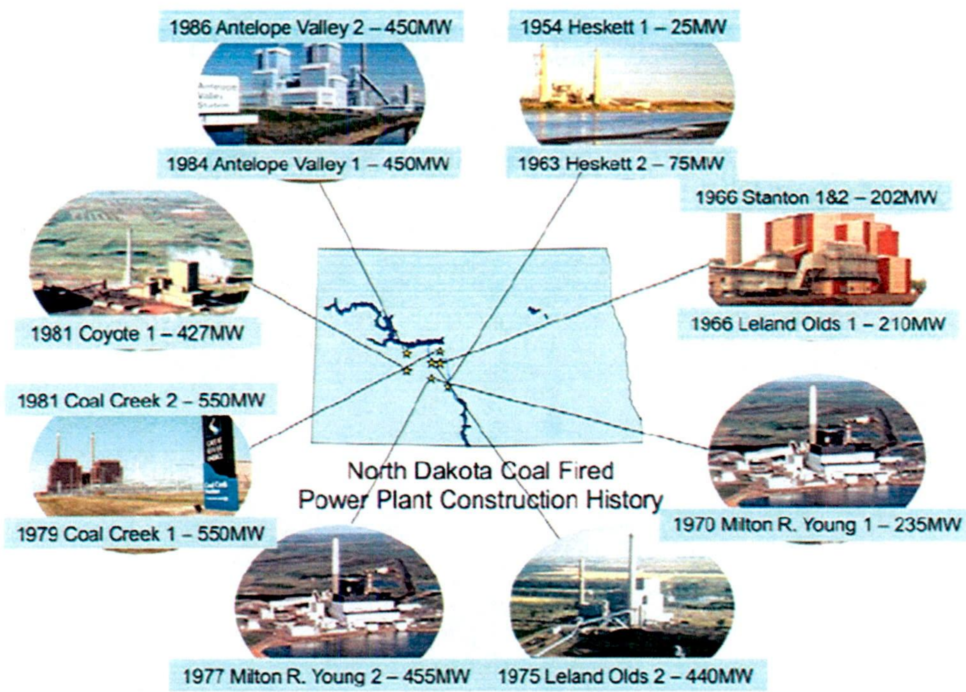
Central North Dakota is home to 4000 MW of coal plants within a 50 mile radius. These plants were built from 1954-1986 and have extensive export capability to Minnesota. PRCS sees a large opportunity for Xcel Energy to repurpose this transmission to renewables, as regional utilities move away from coal because of aging facilities, energy margins, and EPA rules. Besides terrific wind and solar resources, central North Dakota also has large hydro capabilities to assist in integration, which will be under market dispatch for the first time as WAPA joins SPP over the next few years.



ND Coal Plant	Utility	Year Built	Size (MW)	NET ZERO Targets
Heskett 1	Montana-Dakota Utilities Co	1954	25	*
Heskett 2	Montana-Dakota Utilities Co	1963	75	*
Stanton 1 & 2	Great River Energy	1966	202	**

Leland Olds 1	Basin Electric Power Cooperative	1966	210	*
Milton R Young	Minnkota Power Cooperative	1970	235	
Leland Olds 2	Basin Electric Power Cooperative	1975	440	
Milton R Young 2	Minnkota Power Cooperative	1977	455	
Coal Creek 1	Great River Energy	1979	550	*
Coyote 1	Otter Tail Power Company, MDU, Northnern Municipal Power Agency & Northwestern Energy	1981	427	
Coal Creek 2	Great River Energy	1981	550	*
Antelope Valley 1	Basin Electric Power Cooperative	1984	450	
Antelope Valley 2	Basin Electric Power Cooperative	1986	450	
		TOTAL:	**4069**	**1612 MW**

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Tab 6 – Financial Information

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Tab 7 - Exceptions to Model PPA

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Conclusion

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Tab 8 – Standard Proposal Forms

All proposals must also include completion of the following standard proposal forms:

Form A Bid Certification
Form B Bid Cover Sheet
Form C PPA Pricing and Committed Energy
Form D Construction Milestones
Form E Technical Description
Form F Energy Production Profile – Annual and Monthly
Form G Representation Authorization and Consent
Form H Electric Interconnection Details

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	8
Requestor:	Michael Diller		
Date Received:	January 5, 2015		

Question:
Reference NDPSC Data Request No. 3C

A curious sentence is added to the end of both paragraphs stating that NSP "makes no assertion as to the importance" of the "Markets Off" or the "Capacity Factor" sensitivity cases. If I asked the same question of the importance of the "Reference Case" or the "Low Gas Cost" sensitivity case in Table 1 of your application, would the same curious statement be included? Is this statement intended to suggest that these sensitivities are irrelevant and of little or no consequence? Why is this sentence included? Just want to understand.

Response:
Yes, for all sensitivity cases we would say the same thing with regard to their importance. We note, however, that we do not consider the Reference Case to be a sensitivity case, but rather what could be assumed as a base case or "normal" scenario. The statement was simply meant to convey that we do not mean to imply or give higher credibility to any sensitivity case over the Reference Case. Rather, we leave the determination of whether a specific sensitivity is more appropriate for guiding decision-making up to the Commission.

The supplied sensitivity cases, including the "Markets Off" and "Capacity Factor" cases, were intended to provide information that might be useful to regulators in determining how the costs/benefits of the portfolio might differ from the base analysis if some of the key underlying assumptions that went into the base projections turned out to be different over the life of the projects.

Preparer:	Jon Landrum
Title:	Manager, Resource Planning Analytics
Department:	Resource Planning
Telephone:	303-571-2765
Date:	January 15, 2015

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☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	9
Requestor:	Michael Diller		
Date Received:	January 5, 2015		

Question:
Reference NDPSC Data Request No. 1B

216B at least infers that out-of-state solar generation may not be used to meet Minnesota's solar energy standard (SES) and thus the reason for my question asking for clarification as to whether devices located in ND would qualify to meet MN's SES. NSP responded that "we do not interpret this section" to restrict the use of ND solar power towards meeting the MN SES. Please provide an explanation of your interpretation as was originally requested and further, provide any and all restrictions elsewhere in MN law, rules, practices or otherwise that may restrict the use of ND solar in meeting the MN SES.

Response:
NSP objects to this question as it calls for a legal conclusion. Subject to the foregoing objection and in the interests of being responsive to Mr. Diller's request, the Company provides the following response:

Minnesota Statutes 216B.1691 Subd. 2f(f) reads as follows:

> Notwithstanding any law to the contrary, a solar renewable energy credit associated with a solar photovoltaic device installed and generating electricity in Minnesota after August 1, 2013, but before 2020 may be used to meet the solar energy standard established under this subdivision.

This statute is new and its interpretation has not been ruled upon by any court or regulatory agency with jurisdiction over it. Consequently, the Company's interpretation is the only basis upon which the Company can operate until a more binding interpretation of the statue is provided.

That said, the statute is permissive in nature ("may be used") and we are not aware of any contradictory statutory language that would inform any interpretation other than that solar resources located outside of the State of Minnesota could also qualify to meet the Minnesota SES. By starting with the phrase, "Notwithstanding any law to the contrary…" the most likely interpretation of the plain words is that it is intended to ensure that the energy described in the provision is not excluded. This interpretation is also consistent with Minnesota Statutes Section 645.44 Subd. 15 which provides that the word "may" is permissive.

We also note that in cases where the Minnesota Legislature has intended for energy produced in Minnesota to have a preference or be a requirement with respect to any mandate or goal, it has done that in a straightforward manner with clear rules and procedures. See for example, Minnesota Statute Section 216B.2423, included as Attachment A, and Minnesota Statute Section 216B.1612, included as Attachment B. Subd. 2f(f) does not contain any such specific preference or requirement for energy to be produced in Minnesota for it to qualify for the SES.

The Company may be taking a minority position regarding the appropriate interpretation of this statute. However, we believe that customers will benefit if all potential locations for solar energy facilities are carefully considered in future requests for proposals, including sites in North Dakota and South Dakota. While the language mentions devices generating in Minnesota, we do not interpret this statute to exclude solar energy produced in a state other than Minnesota for the reasons described above.

We are not aware of any other Minnesota law, rule, or practice that may restrict the use of North Dakota solar in meeting the Minnesota SES.

Preparer: James R Alders
Title: Strategy Consultant
Department: NSPM Regulatory
Telephone: 612-330-6732
Date: January 15, 2015

216B.2423 WIND POWER MANDATE.

Subdivision 1. **Mandate.** A public utility, as defined in section 216B.02, subdivision 4, that operates a nuclear-powered electric generating plant within this state must construct and operate, purchase, or contract to construct and operate: (1) 225 megawatts of electric energy installed capacity generated by wind energy conversion systems within the state by December 31, 1998; and (2) an additional 200 megawatts of installed capacity so generated by December 31, 2002.

For the purpose of this section, "wind energy conversion system" has the meaning given it in section 216C.06, subdivision 19.

Subd. 2. **Resource planning mandate.** The Public Utilities Commission shall order a public utility subject to subdivision 1, to construct and operate, purchase, or contract to purchase an additional 400 megawatts of electric energy installed capacity generated by wind energy conversion systems by December 31, 2002, subject to resource planning and least cost planning requirements in section 216B.2422.

Subd. 2a. **Site preference.** The Public Utilities Commission shall ensure that a utility subject to the requirements of subdivision 1, clause (2), shall implement that clause with a preference for wind energy conversion systems within the state. This preference shall not prevent the utility from constructing or contracting to construct wind energy conversion systems outside the state, if the Public Utilities Commission determines that selection of a facility within the state conflicts with the requirements of section 216B.03.

Subd. 3. **Standard contract for wind energy conversion systems.** The Public Utilities Commission shall require a public utility subject to subdivision 1 to develop and file in a form acceptable to the commission by October 1, 1997, a standard form contract for the purchase of electricity from wind conversion systems with installed capacity of two megawatts and less. For purposes of applying the two megawatts limit, the installed capacity sold to the public utility from a single seller or affiliated group of sellers shall be cumulated. The standard contract shall include all the terms and conditions for purchasing wind-generated power by the utility, except for price and any other specific terms necessary to ensure system reliability and safety, which shall be separately negotiable.

History: *1994 c 641 art 3 s 2; 1997 c 216 s 123; 1999 c 200 s 3*

216B.1612 COMMUNITY-BASED ENERGY DEVELOPMENT; TARIFF.

Subdivision 1. **Tariff establishment.** A tariff shall be established to optimize local, regional, and state benefits from renewable energy development and to facilitate widespread development of community-based renewable energy projects throughout Minnesota.

Subd. 2. **Definitions.** (a) The terms used in this section have the meanings given them in this subdivision.

(b) "C-BED tariff" or "tariff" means a community-based energy development tariff.

(c) "Qualifying beneficiary" means:

(1) a Minnesota resident individually or as a member of a Minnesota limited liability company organized under chapter 322B and formed for the purpose of developing a C-BED project;

(2) a Minnesota nonprofit organization organized under chapter 317A;

(3) a Minnesota cooperative association organized under chapter 308A or 308B, including a rural electric cooperative association or a generation and transmission cooperative on behalf of and at the request of a member distribution utility;

(4) a Minnesota political subdivision or local government including, but not limited to, a municipal electric utility, or a municipal power agency on behalf of and at the request of a member distribution utility; the office of the commissioner of Iron Range resources and rehabilitation; a county, statutory or home rule charter city, town, school district, or public or private higher education institution; or any other local or regional governmental organization such as a board, commission, or association;

(5) a tribal council; or

(6) a legal entity (i) formed for a purpose other than to participate in C-BED projects; (ii) whose principal place of business or principal executive office is located in Minnesota; and (iii) that provides labor, services, equipment, components, or debt financing to a C-BED project.

A public utility, as defined in section 216B.02, subdivision 4, is not a qualifying beneficiary.

(d) "Qualifying revenue" includes, but is not limited to:

(1) royalties, distributions, dividends, and other payments flowing directly or indirectly to individuals who are qualifying beneficiaries;

(2) reasonable fees for consulting, development, professional, construction, and operations and maintenance services paid to qualifying beneficiaries;

(3) interest and fees paid to financial institutions that are qualifying beneficiaries;

(4) the value-added portion of payments for goods manufactured in Minnesota; and

(5) production taxes.

(e) "Discount rate" means the ten-year United States Treasury Yield as quoted in the Wall Street Journal as of the date of application for determination under subdivision 10, plus five percent; except that the discount rate applicable to any qualifying revenues contingent upon an equity investor earning a specified internal rate of return is the ten-year United States Treasury Yield, plus eight percent.

(f) "Standard reliability criteria" means:

(1) can be safely integrated into and operated within the utility's grid without causing any adverse or unsafe consequences; and

(2) is consistent with the utility's resource needs as identified in its most recent resource plan submitted under section 216B.2422.

(g) "Renewable" refers to a technology listed in section 216B.1691, subdivision 1, paragraph (a).

(h) "Community-based energy development project" or "C-BED project" means a new renewable energy project that either as a stand-alone project or part of a partnership under subdivision 8:

(1) has no single qualifying beneficiary, including any parent company or subsidiary of the qualifying beneficiary, owning more than 15 percent of a C-BED wind energy project unless: (i) the C-BED wind energy project consists of only one or two turbines; or (ii) the qualifying beneficiary is a public entity listed under paragraph (c), clause (4);

(2) demonstrates that at least 51 percent of the net present value of the gross revenues from a power purchase agreement over the life of the project are qualifying revenues; and

(3) has a resolution of support adopted by the county board of each county in which the project is to be located, or in the case of a project located within the boundaries of a reservation, the tribal council for that reservation.

(i) "Value-added portion" means the difference between the total sales price and the total cost of components, materials, and services purchased from or provided outside of Minnesota.

Subd. 3. **Tariff rate.** (a) The tariff described in subdivision 4 must provide for a rate that is higher in the first ten years of the power purchase agreement than in the last ten years.

(b) The commission shall consider mechanisms to encourage the aggregation of C-BED projects.

(c) The commission shall require that C-BED projects provide sufficient security to secure performance under the power purchase agreement, and shall prohibit transfer of a C-BED project during the initial term of a power purchase agreement if the transfer will result in the project no longer qualifying under subdivision 2, paragraph (h).

Subd. 4. **Utilities to offer tariff.** By December 1, 2007, each public utility providing electric service at retail shall file for commission approval a community-based energy development tariff consistent with subdivision 3. Within 90 days of the first commission approval order under this subdivision, each municipal power agency and generation and transmission cooperative electric association shall adopt a community-based energy development tariff as consistent as possible with subdivision 3.

Subd. 5. **Priority for C-BED projects.** (a) A utility subject to section 216B.1691 that needs to construct new generation, or purchase the output from new generation, as part of its plan to satisfy its good faith objective and standard under that section must take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements, applying standard reliability criteria, to fulfill some or all of the identified need at minimal impact to customer rates.

Nothing in this section shall be construed to obligate a utility to enter into a power purchase agreement under a C-BED tariff developed under this section.

(b) Each utility shall include in its resource plan submitted under section 216B.2422 a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.

(c) The commission shall consider the efforts and activities of a utility to purchase energy from C-BED projects when evaluating its good faith effort towards meeting the renewable energy objective under section 216B.1691.

(d) A municipal power agency or generation and transmission cooperative shall, when issuing a request for proposals for C-BED projects to satisfy its standard obligation under section 216B.1691, provide notice to its member distribution utilities that they may propose, in partnership with other qualifying beneficiaries, a C-BED project for the consideration of the municipal power agency or generation and transmission cooperative.

Subd. 6. **Property owner participation.** To the extent feasible, a developer of a C-BED project must provide, in writing, an opportunity to invest in the C-BED project to each property owner on whose property a high-voltage transmission line is constructed that will transmit the energy generated by the C-BED project to market. This subdivision applies if the property is located and the owner resides in the county where the C-BED project is located.

Subd. 7. **Other C-BED tariff issues.** (a) A community-based project developer and a utility shall negotiate the rate and power purchase agreement terms consistent with the tariff established under subdivision 4.

(b) At the discretion of the developer, a community-based project developer and a utility may negotiate a power purchase agreement with terms different from the tariff established under subdivision 4.

(c) A C-BED project may be jointly developed with a non-C-BED project. However, the terms of the C-BED tariff may only apply to the portion of the energy production of the total project that is directly proportional to the energy produced by the C-BED project. A project that is operating under a power purchase agreement under a C-BED tariff is not eligible for net energy billing under section 216B.164, subdivision 3, or for production incentives under section 216C.41.

(d) A public utility must receive commission approval of a power purchase agreement for a C-BED tariffed project. The commission shall provide the utility's ratepayers an opportunity to address the reasonableness of the proposed power purchase agreement. Unless a party objects to a contract within 30 days of submission of the contract to the commission the contract is deemed approved.

Subd. 8. **Community energy partnerships.** A utility providing electric service to retail or wholesale customers in Minnesota and an independent power producer may, subject to the limits specified in this section, participate in a community-based energy project, including as an owner, equity partner, or provider of technical or financial assistance.

Subd. 9. **Local government and political subdivision powers.** A Minnesota political subdivision or local government may plan, develop, purchase, acquire, construct, and own a C-BED project and may sell output from that project as provided for in this section. A Minnesota political subdivision or local government may not acquire property under this subdivision through eminent domain. A Minnesota political subdivision or local government may operate, maintain, improve, and expand the C-BED project subject to any restrictions in this section.

Subd. 10. **C-BED eligibility determination.** (a) A developer of a C-BED project may seek a predetermination of C-BED eligibility from the commissioner of commerce at any time, and must obtain a determination of C-BED eligibility from the commissioner of commerce, based on the project's final financing terms, before construction may begin. In seeking a determination of eligibility under this subdivision, a developer of a C-BED project must submit to the commissioner of commerce detailed financial projections demonstrating that, based on a net present value analysis, and applying the discount rate to qualifying revenues and gross revenues from a power purchase agreement, the project meets the requirements of subdivision 2, paragraph (h), clause (2).

(b) A project is not required to obtain a determination of C-BED eligibility under paragraph (a) if it has received, prior to May 18, 2010, an opinion letter from the commissioner indicating that the project qualifies as a C-BED project under this section.

(c) The commissioner's determination of C-BED eligibility of a project that obtained its initial opinion letter regarding C-BED eligibility from the commissioner or written notification from the Midwest Independent Systems Operator (MISO) that the project retains a position in the interconnection queue before May 18, 2010, must be based on the laws applicable at the time the initial opinion letter of C-BED eligibility was issued or the Midwest Independent System Operator interconnection queue position was obtained. A project subject to this paragraph may elect to have the determination of eligibility governed by the law in effect at the time of the determination.

History: *2005 c 97 art 2 s 1; 2006 c 212 art 1 s 11; 2007 c 136 art 4 s 1-7; 2008 c 303 s 1; 2009 c 78 art 6 s 21; 2010 c 358 s 1-5*

Diller, Michael R.

From:	Diller, Michael R.
Sent:	Wednesday, January 07, 2015 5:08 PM
To:	dave.sederquist@xcelenergy.com
Subject:	RFI's for NSP's Solar Farms.docx
Attachments:	RFI's for NSP's Solar Farms.docx

Dave,
Attached are a few more RFI's. Thanks for your attention to these. Mike

Northern States Power Company
Advance Determination of Prudence for 187 MW's of Solar
Case No. PU-14-810
January 7, 2015
Requests for Information from Mike Diller

6. In regards to NDPSC Data Request No. 3C, Attachment B:

a) If Figure 1 – Ventura Gas Price Forecast of NDPSC Data Request No. 3C, Attachment B, is intended to display the cost of natural gas assumed for modeling purposes, please update to include the historical annual cost of natural gas for the last 30 years. Given the new technology of horizontal drilling and fracking and the abundance of natural gas reserves and production, explain why the forecast seems to mimic the long-term historic price increases rather than the prices of the last 5 years under a new paradigm of production.

b) In regards to Figure 2 – Average On and Off Peak Market Price forecast of NDPSC Data Request No. 3c, Attachment B, provide the earliest year in which the least expensive solar contract proposed is projected to be less than the simple projected average On Peak market price for electricity. It looks like it might be around 2032 if I draw a line on the chart but want a more exact date for testimonial purposes.

c) Update Figure 3 – Coal Price Forecast to include the historical cost of coal for the last 30 years and explain the significant difference between historical prices and the prices forecasted. Similar to a) above, the environmental concerns over coal and EPA's 111(d) would suggest a paradigm shift in lower coal prices given less demand for coal in the future. Provide rationale for the steep upward projected cost of coal prices.

7. a) Please redo NDPSC Data Response No. 5i, Attachment A to make it non-trade secret and more useful for the hearing. Redo the non-trade secret section to only include "existing resources" to determine a baseline Long / (Short) Position. Make sure that this new schedule includes NSP's most recent capacity needs projections and reference the date of the projection. Below the baseline Position, include a separate line for each new resource's expected capacity to meet system capacity requirements including the date each is expected to come on line. The new resources section should include 3 segments, one for new resources already approved by the MN commission; another for resources that are expected to be approved by the MN commission; and a third section for resources that are not included in the first two but are preferred by NSP. Given this approach, the trade secret portion can be dropped from the schedule and the hearing will not be impeded by dealing with non-disclosure requirements. Last, add 5 more years to the worksheet to include years out to 2024.

b.) Provide the same thing except on a North Dakota basis. In other words, instead of Non-Coincident Peak Demand for NSP's system, the first line would include North Dakota's projected NCPD and a calculated diversity factor on the second line to coincide with North Dakota's projected Demand Coincident with Peak number on the third line. Include North Dakota's share of Demand Resources then work through the applicable transmission adjustments and the MISO reserve planning margin to determine a Native Load Obligation for ND. This would then be followed with ND's share of existing resources and its share of purchased generation and sales to determine ND's share of resources and its Long / (Short) Position. Again, each future projected resource will be shown displaying only ND's share of the projected capacity. I understand that this may not be readily available. However, this is important to my analysis of ND's needs and this proceeding. Make a good effort in developing the information.

Diller, Michael R.

From:	Hedlund, Amber R <Amber.R.Hedlund@xcelenergy.com>
Sent:	Monday, January 19, 2015 3:49 PM
To:	Diller, Michael R.
Cc:	Sederquist, Dave
Subject:	Xcel Energy's Response to NDPSC Data Request Nos. 10 and 11_Case No. PU-14-810
Attachments:	Cvr Letter NDPSC DRs 10 and 11.pdf; NDPSC-010.pdf; NDPSC-011.pdf; NDPSC-011_Attachments A and B.xlsx

Dear Mr. Diller:

Enclosed please find a cover letter and our responses to Data Request Nos. 10 and 11 concerning Xcel Energy's Solar Portfolio ADP. Please note, the attachments to Data Request No. 11 are being provided in PDF format attached to the response, as well as in live, spreadsheet format for convenience.

Please contact me if you have any questions regarding this submission. Thank you.

Amber Hedlund
Xcel Energy
Regulatory Case Specialist
414 Nicollet Mall, 7th Floor, Minneapolis, MN 55401
P: 612.337.2268
E: amber.r.hedlund@xcelenergy.com

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

January 19, 2015

—Via Email—

Michael Diller
North Dakota Public Service Commission
State Capitol Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: RESPONSES TO DATA REQUEST NOS. 10 AND 11
SOLAR PORTFOLIO ADP
CASE NO. PU-14-810

Dear Mr. Diller:

Enclosed please find our responses to the referenced North Dakota Public Service Commission staff Data Requests in the above noted case.

Sincerely,

/s/

AMBER HEDLUND
REGULATORY CASE SPECIALIST

cc: Dave Sederquist

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	10
Requestor:	Michael Diller		
Date Received:	January 7, 2015		

Question:

Reference NDPSC Data Request No. 3C, Attachment B

a) If Figure 1 – Ventura Gas Price Forecast of NDPSC Data Request No. 3C, Attachment B, is intended to display the cost of natural gas assumed for modeling purposes, please update to include the historical annual cost of natural gas for the last 30 years. Given the new technology of horizontal drilling and fracking and the abundance of natural gas reserves and production, explain why the forecast seems to mimic the long-term historic price increases rather than the prices of the last 5 years under a new paradigm of production.

b) In regards to Figure 2 – Average On and Off Peak Market Price forecast of NDPSC Data Request No. 3c, Attachment B, provide the earliest year in which the least expensive solar contract proposed is projected to be less than the simple projected average On Peak market price for electricity. It looks like it might be around 2032 if I draw a line on the chart but want a more exact date for testimonial purposes.

c) Update Figure 3 – Coal Price Forecast to include the historical cost of coal for the last 30 years and explain the significant difference between historical prices and the prices forecasted. Similar to a) above, the environmental concerns over coal and EPA's 111(d) would suggest a paradigm shift in lower coal prices given less demand for coal in the future. Provide rationale for the steep upward projected cost of coal prices.

Response:

a) The Ventura Price Forecast of NSPSC Data Request No. 3C is based on the anticipation of increased demand, this is why we see the price of natural gas increasing over time. The increase in domestic demand is primarily credited to coal plant retirements, new petro-chemical and fertilizer projects, and LNG projects. In addition, it is expected that U.S. exports to Mexico will increase, while U.S.

imports from Canada will decrease. Given these factors, the price forecast more closely mimics the long-term historic price increases rather than the prices of the last five years. Included in Attachment A are the requested historical prices. However, the market did not exist until 1992. Prior to that, there is no data that exists for Ventura.

b) In comparing the prices for the various PPAs in a given year to the market price forecasted in the same year, the market price is always lower based on energy price alone. To affect a true comparison, an economic value for the capacity contribution of each PPA needs to be included as the market forecast is for an energy-only product and the PPAs contribute both energy and capacity. Supporting data is included as Attachment B.

c) The Xcel Energy Fuel Supply organization subscribes to 3 publications prepared by industry consultants that provide long-term (20 to 25 year) coal price forecasts. They are the John T. Boyd Company, JD Energy, and Hanou Energy. These forecasts are limited exclusively to the cost of the commodity, and do not consider the cost of transportation from the mine to the power plant. The forecasts are based on the consultants' knowledge of the coal industry and the influence of external factors such as environmental regulations and economic conditions.

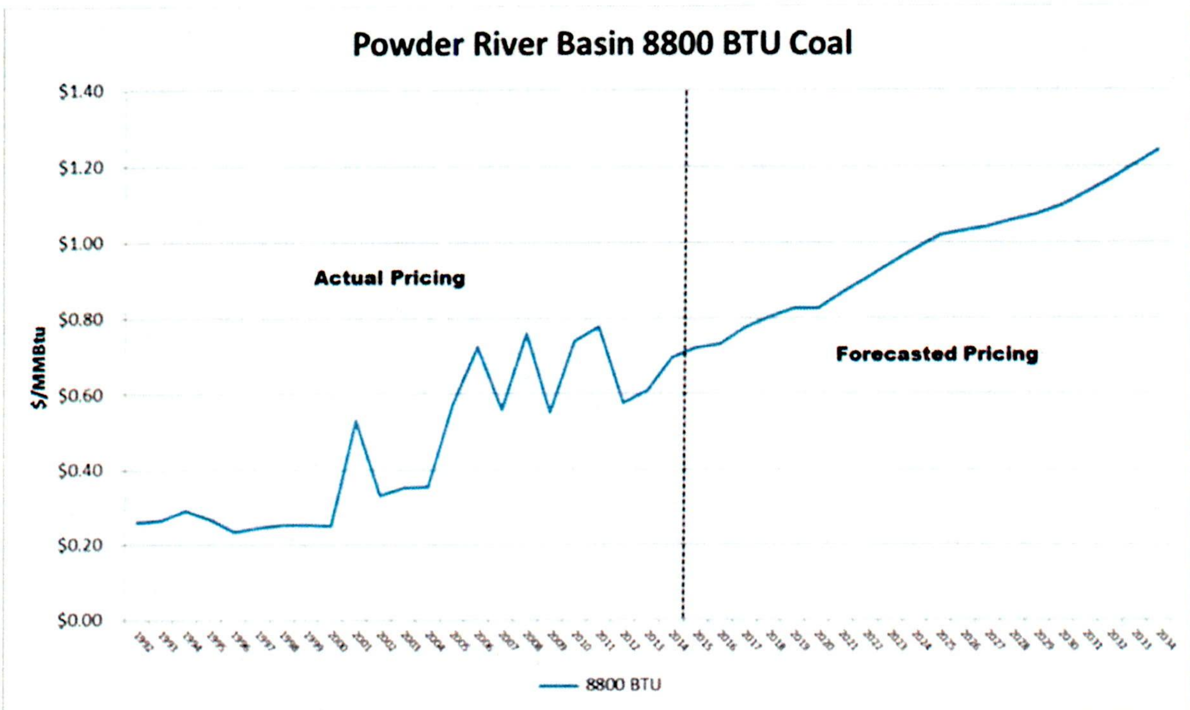
The JD Energy Company provides 3 variations on the forecasts. First is a Base Case, which is the consultant's view of the most likely scenario. Second is an accelerated regulation case, which assumes more stringent regulation of CO_2, SO_2, NO_x, and mercury/air toxics. The third is a deregulation case which assumes that a change in Administration will lead to loosening of regulatory impacts. For the purposes of planning future coal purchases, Fuel Supply has consistently chosen to use the Base Case scenario. In general, the alternative scenarios yield forecasts that demonstrate relative extremes, either up or down. The Base Case has served to provide realistic assumptions of what we would expect to pay for coal in the near term.

An arithmetic average of the base case scenarios from each of the 3 consultants is used to determine the forecasted coal prices. Because the NSP plants all burn 8,800 Btu/lb, Powder River Basin (PRB) coal, the forecasts for PRB 8800 coal was used. It is important to note that the coal price forecasts are presented in Nominal dollars, which are adjusted for inflation.

With respect to the forecasted rise in prices, the consultant's narratives indicate that the over-the-counter price of PRB coal is currently near the cost of production. The cost of production will act as a floor for prices and if the prices will not support production over the long-term, the mines will close. Over time, as labor and the costs of goods and services rise, so will the costs of mining the coal as reflected in the forecast. Further influencing the cost of production in the PRB, is that as the mines move westward into the reserves, the coal seams are deeper underground. This requires the removal of more overburden material to expose the coal, further increasing the cost of production.

For these reasons, the cost of coal is forecasted to rise over time. Until additional regulations are imposed on the industry, the economic impacts on the price of coal are purely speculative.

Note that the forecast uses escalations rates based on the All-inclusive index less fuel from the Association of American Railroads. The annual percentage of these escalation rates are used and gradually increase the price to ship coal to market from 2015 through 2053.



Preparer:	Ramsay Sawaya / Jon Landrum / Jim Witt
Title:	Risk Analytics Director / Resource Planning Analytics Manager / Principal Fuel Portfolio Coordinator
Department:	Risk Management / Resource Planning / Coal Supply
Telephone:	303.571.6917 / 303.571.2765 / 303.571.7158
Date:	January 19, 2015

Year	Month	Ventura Gas Historical	Ventura Gas Forecast
1992	4/1/1992	1.41	
1992	5/1/1992	1.44	
1992	6/1/1992	1.54	
1992	7/1/1992	1.59	
1992	8/1/1992	1.89	
1992	9/1/1992	1.98	
1992	10/1/1992	2.11	
1992	11/1/1992	2.08	
1992	12/1/1992	2.15	
1993	1/1/1993	1.97	
1993	2/1/1993	1.89	
1993	3/1/1993	2.03	
1993	4/1/1993	2.13	
1993	5/1/1993	1.96	
1993	6/1/1993	1.76	
1993	7/1/1993	1.84	
1993	8/1/1993	1.85	
1993	9/1/1993	1.91	
1993	10/1/1993	1.76	
1993	11/1/1993	2.14	
1993	12/1/1993	1.98	
1994	1/1/1994	2.04	
1994	2/1/1994	2.35	
1994	3/1/1994	1.83	
1994	4/1/1994	1.77	
1994	5/1/1994	1.63	
1994	6/1/1994	1.64	
1994	7/1/1994	1.62	
1994	8/1/1994	1.53	
1994	9/1/1994	1.31	
1994	10/1/1994	1.31	
1994	11/1/1994	1.45	
1994	12/1/1994	1.48	
1995	1/1/1995	1.30	
1995	2/1/1995	1.27	
1995	3/1/1995	1.27	
1995	4/1/1995	1.38	
1995	5/1/1995	1.35	
1995	6/1/1995	1.29	
1995	7/1/1995	1.16	
1995	8/1/1995	1.22	
1995	9/1/1995	1.44	
1995	10/1/1995	1.47	
1995	11/1/1995	1.69	
1995	12/1/1995	1.82	
1996	1/1/1996	1.99	
1996	2/1/1996	3.08	
1996	3/1/1996	2.34	
1996	4/1/1996	2.04	
1996	5/1/1996	1.90	
1996	6/1/1996	1.93	
1996	7/1/1996	2.08	
1996	8/1/1996	1.81	
1996	9/1/1996	1.62	
1996	10/1/1996	2.16	
1996	11/1/1996	2.90	
1996	12/1/1996	3.62	
1997	1/1/1997	3.32	
1997	2/1/1997	2.08	

Year	Ventura Gas Historical	Ventura Gas Forecast
1992	1.80	
1993	1.93	
1994	1.66	
1995	1.39	
1996	2.29	
1997	2.35	
1998	2.02	
1999	2.20	
2000	4.26	
2001	3.94	
2002	3.17	
2003	5.32	
2004	5.57	
2005	7.91	
2006	6.31	
2007	6.63	
2008	8.28	
2009	3.85	
2010	4.38	
2011	4.03	
2012	2.77	
2013	3.79	
2014	5.83	
2015		3.96
2016		3.98
2017		4.02
2018		4.14
2019		4.35
2020		4.76
2021		5.16
2022		5.17
2023		5.35
2024		5.59
2025		5.70
2026		5.90
2027		6.03
2028		6.12
2029		6.36
2030		6.52
2031		6.68
2032		6.80
2033		7.00
2034		7.20
2035		7.32
2036		7.47
2037		7.61
2038		7.76
2039		7.91
2040		8.07
2041		8.23
2042		8.39

Year	Month	Ventura Gas Historical	Ventura Gas Forecast	Year	Ventura Gas Historical	Ventura Gas Forecast
1997	3/1/1997	1.73				
1997	4/1/1997	1.87				
1997	5/1/1997	2.00				
1997	6/1/1997	2.00				
1997	7/1/1997	2.05				
1997	8/1/1997	2.35				
1997	9/1/1997	2.76				
1997	10/1/1997	2.98				
1997	11/1/1997	2.92				
1997	12/1/1997	2.19				
1998	1/1/1998	2.06				
1998	2/1/1998	2.13				
1998	3/1/1998	2.21				
1998	4/1/1998	2.34				
1998	5/1/1998	2.05				
1998	6/1/1998	2.06				
1998	7/1/1998	2.11				
1998	8/1/1998	1.78				
1998	9/1/1998	1.87				
1998	10/1/1998	1.83				
1998	11/1/1998	2.03				
1998	12/1/1998	1.72				
1999	1/1/1999	1.91				
1999	2/1/1999	1.73				
1999	3/1/1999	1.70				
1999	4/1/1999	2.02				
1999	5/1/1999	2.16				
1999	6/1/1999	2.19				
1999	7/1/1999	2.23				
1999	8/1/1999	2.68				
1999	9/1/1999	2.51				
1999	10/1/1999	2.69				
1999	11/1/1999	2.28				
1999	12/1/1999	2.32				
2000	1/1/2000	2.34				
2000	2/1/2000	2.56				
2000	3/1/2000	2.70				
2000	4/1/2000	2.94				
2000	5/1/2000	3.38				
2000	6/1/2000	4.14				
2000	7/1/2000	3.95				
2000	8/1/2000	4.28				
2000	9/1/2000	4.98				
2000	10/1/2000	5.04				
2000	11/1/2000	5.46				
2000	12/1/2000	9.34				
2001	1/1/2001	8.43				
2001	2/1/2001	5.86				
2001	3/1/2001	5.22				
2001	4/1/2001	5.15				
2001	5/1/2001	4.11				
2001	6/1/2001	3.54				
2001	7/1/2001	2.97				
2001	8/1/2001	2.91				
2001	9/1/2001	2.11				
2001	10/1/2001	2.33				
2001	11/1/2001	2.28				
2001	12/1/2001	2.35				
2002	1/1/2002	2.19				

Year	Month	Ventura Gas Historical	Ventura Gas Forecast	Year	Ventura Gas Historical	Ventura Gas Forecast
2002	2/1/2002	2.23				
2002	3/1/2002	3.01				
2002	4/1/2002	3.25				
2002	5/1/2002	3.20				
2002	6/1/2002	2.87				
2002	7/1/2002	2.79				
2002	8/1/2002	2.85				
2002	9/1/2002	3.23				
2002	10/1/2002	3.96				
2002	11/1/2002	3.95				
2002	12/1/2002	4.44				
2003	1/1/2003	5.16				
2003	2/1/2003	6.95				
2003	3/1/2003	6.79				
2003	4/1/2003	4.97				
2003	5/1/2003	5.35				
2003	6/1/2003	5.52				
2003	7/1/2003	4.90				
2003	8/1/2003	4.89				
2003	9/1/2003	4.50				
2003	10/1/2003	4.50				
2003	11/1/2003	4.47				
2003	12/1/2003	5.85				
2004	1/1/2004	6.00				
2004	2/1/2004	5.24				
2004	3/1/2004	5.11				
2004	4/1/2004	5.36				
2004	5/1/2004	5.92				
2004	6/1/2004	5.85				
2004	7/1/2004	5.68				
2004	8/1/2004	5.26				
2004	9/1/2004	4.60				
2004	10/1/2004	5.50				
2004	11/1/2004	5.88				
2004	12/1/2004	6.46				
2005	1/1/2005	5.96				
2005	2/1/2005	5.82				
2005	3/1/2005	6.62				
2005	4/1/2005	6.91				
2005	5/1/2005	6.05				
2005	6/1/2005	6.53				
2005	7/1/2005	7.08				
2005	8/1/2005	8.54				
2005	9/1/2005	10.14				
2005	10/1/2005	11.15				
2005	11/1/2005	8.25				
2005	12/1/2005	11.83				
2006	1/1/2006	7.90				
2006	2/1/2006	7.18				
2006	3/1/2006	6.15				
2006	4/1/2006	6.20				
2006	5/1/2006	5.55				
2006	6/1/2006	5.78				
2006	7/1/2006	5.71				
2006	8/1/2006	6.84				
2006	9/1/2006	4.70				
2006	10/1/2006	5.73				
2006	11/1/2006	7.20				
2006	12/1/2006	6.81				

Year	Month	Ventura Gas Historical	Ventura Gas Forecast	Year	Ventura Gas Historical	Ventura Gas Forecast
2007	1/1/2007	6.39				
2007	2/1/2007	8.04				
2007	3/1/2007	6.76				
2007	4/1/2007	7.09				
2007	5/1/2007	7.09				
2007	6/1/2007	6.69				
2007	7/1/2007	5.86				
2007	8/1/2007	5.86				
2007	9/1/2007	5.50				
2007	10/1/2007	6.53				
2007	11/1/2007	6.65				
2007	12/1/2007	7.07				
2008	1/1/2008	8.05				
2008	2/1/2008	8.58				
2008	3/1/2008	9.32				
2008	4/1/2008	9.80				
2008	5/1/2008	9.95				
2008	6/1/2008	11.13				
2008	7/1/2008	10.18				
2008	8/1/2008	7.63				
2008	9/1/2008	6.27				
2008	10/1/2008	6.28				
2008	11/1/2008	6.24				
2008	12/1/2008	5.93				
2009	1/1/2009	5.42				
2009	2/1/2009	4.42				
2009	3/1/2009	3.70				
2009	4/1/2009	3.26				
2009	5/1/2009	3.35				
2009	6/1/2009	3.22				
2009	7/1/2009	3.22				
2009	8/1/2009	3.07				
2009	9/1/2009	2.98				
2009	10/1/2009	4.31				
2009	11/1/2009	3.71				
2009	12/1/2009	5.59				
2010	1/1/2010	5.89				
2010	2/1/2010	5.45				
2010	3/1/2010	4.41				
2010	4/1/2010	3.95				
2010	5/1/2010	4.05				
2010	6/1/2010	4.64				
2010	7/1/2010	4.47				
2010	8/1/2010	4.16				
2010	9/1/2010	3.81				
2010	10/1/2010	3.48				
2010	11/1/2010	3.87				
2010	12/1/2010	4.39				
2011	1/1/2011	4.62				
2011	2/1/2011	4.26				
2011	3/1/2011	4.03				
2011	4/1/2011	4.23				
2011	5/1/2011	4.26				
2011	6/1/2011	4.51				
2011	7/1/2011	4.39				
2011	8/1/2011	4.08				
2011	9/1/2011	3.91				
2011	10/1/2011	3.57				
2011	11/1/2011	3.34				

Year	Month	Ventura Gas Historical	Ventura Gas Forecast
2011	12/1/2011	3.20	
2012	1/1/2012	2.77	
2012	2/1/2012	2.57	
2012	3/1/2012	2.08	
2012	4/1/2012	1.95	
2012	5/1/2012	2.37	
2012	6/1/2012	2.40	
2012	7/1/2012	2.94	
2012	8/1/2012	2.84	
2012	9/1/2012	2.85	
2012	10/1/2012	3.44	
2012	11/1/2012	3.63	
2012	12/1/2012	3.39	
2013	1/1/2013	3.50	
2013	2/1/2013	3.41	
2013	3/1/2013	3.92	
2013	4/1/2013	4.19	
2013	5/1/2013	4.01	
2013	6/1/2013	3.76	
2013	7/1/2013	3.63	
2013	8/1/2013	3.46	
2013	9/1/2013	3.63	
2013	10/1/2013	3.74	
2013	11/1/2013	3.68	
2013	12/1/2013	4.61	
2014	1/1/2014	7.86	
2014	2/1/2014	14.63	
2014	3/1/2014	10.39	
2014	4/1/2014	4.67	
2014	5/1/2014	4.51	
2014	6/1/2014	4.58	
2014	7/1/2014	4.06	
2014	8/1/2014	3.87	
2014	9/1/2014	3.87	
2014	10/1/2014	3.77	
2014	11/1/2014	4.32	
2014	12/1/2014	3.49	
2015	1/1/2015	3.30	
2015	2/1/2015		4.50
2015	3/1/2015		4.29
2015	4/1/2015		3.82
2015	5/1/2015		3.75
2015	6/1/2015		3.73
2015	7/1/2015		3.76
2015	8/1/2015		3.79
2015	9/1/2015		3.78
2015	10/1/2015		3.83
2015	11/1/2015		4.11
2015	12/1/2015		4.23
2016	1/1/2016		4.34
2016	2/1/2016		4.31
2016	3/1/2016		4.22
2016	4/1/2016		3.78
2016	5/1/2016		3.77
2016	6/1/2016		3.78
2016	7/1/2016		3.81
2016	8/1/2016		3.82
2016	9/1/2016		3.81
2016	10/1/2016		3.83

Year	Ventura Gas Historical	Ventura Gas Forecast

Year	Month	Ventura Gas Historical	Ventura Gas Forecast	Year	Ventura Gas Historical	Ventura Gas Forecast
2016	11/1/2016		4.04			
2016	12/1/2016		4.22			
2017	1/1/2017		4.37			
2017	2/1/2017		4.35			
2017	3/1/2017		4.27			
2017	4/1/2017		3.75			
2017	5/1/2017		3.74			
2017	6/1/2017		3.77			
2017	7/1/2017		3.86			
2017	8/1/2017		3.87			
2017	9/1/2017		3.86			
2017	10/1/2017		3.88			
2017	11/1/2017		4.16			
2017	12/1/2017		4.34			
2018	1/1/2018		4.48			
2018	2/1/2018		4.46			
2018	3/1/2018		4.39			
2018	4/1/2018		3.89			
2018	5/1/2018		3.88			
2018	6/1/2018		3.91			
2018	7/1/2018		3.97			
2018	8/1/2018		3.99			
2018	9/1/2018		3.99			
2018	10/1/2018		4.03			
2018	11/1/2018		4.29			
2018	12/1/2018		4.47			
2019	1/1/2019		4.60			
2019	2/1/2019		4.58			
2019	3/1/2019		4.51			
2019	4/1/2019		4.03			
2019	5/1/2019		4.03			
2019	6/1/2019		4.06			
2019	7/1/2019		4.24			
2019	8/1/2019		4.26			
2019	9/1/2019		4.26			
2019	10/1/2019		4.30			
2019	11/1/2019		4.55			
2019	12/1/2019		4.75			
2020	1/1/2020		4.86			
2020	2/1/2020		4.85			
2020	3/1/2020		4.78			
2020	4/1/2020		4.37			
2020	5/1/2020		4.38			
2020	6/1/2020		4.42			
2020	7/1/2020		4.77			
2020	8/1/2020		4.82			
2020	9/1/2020		4.80			
2020	10/1/2020		4.82			
2020	11/1/2020		5.02			
2020	12/1/2020		5.18			
2021	1/1/2021		5.26			
2021	2/1/2021		5.28			
2021	3/1/2021		5.21			
2021	4/1/2021		4.88			
2021	5/1/2021		4.94			
2021	6/1/2021		5.02			
2021	7/1/2021		5.07			
2021	8/1/2021		5.15			
2021	9/1/2021		5.14			

Year	Month	Ventura Gas Historical	Ventura Gas Forecast
2021	10/1/2021		5.15
2021	11/1/2021		5.32
2021	12/1/2021		5.47
2022	1/1/2022		5.52
2022	2/1/2022		5.49
2022	3/1/2022		5.38
2022	4/1/2022		4.96
2022	5/1/2022		4.96
2022	6/1/2022		4.99
2022	7/1/2022		4.99
2022	8/1/2022		5.01
2022	9/1/2022		4.98
2022	10/1/2022		5.01
2022	11/1/2022		5.26
2022	12/1/2022		5.47
2023	1/1/2023		5.57
2023	2/1/2023		5.57
2023	3/1/2023		5.50
2023	4/1/2023		5.10
2023	5/1/2023		5.13
2023	6/1/2023		5.17
2023	7/1/2023		5.19
2023	8/1/2023		5.23
2023	9/1/2023		5.21
2023	10/1/2023		5.27
2023	11/1/2023		5.55
2023	12/1/2023		5.75
2024	1/1/2024		5.87
2024	2/1/2024		5.85
2024	3/1/2024		5.73
2024	4/1/2024		5.32
2024	5/1/2024		5.34
2024	6/1/2024		5.39
2024	7/1/2024		5.43
2024	8/1/2024		5.47
2024	9/1/2024		5.46
2024	10/1/2024		5.52
2024	11/1/2024		5.77
2024	12/1/2024		5.97
2025	1/1/2025		6.05
2025	2/1/2025		6.01
2025	3/1/2025		5.85
2025	4/1/2025		5.43
2025	5/1/2025		5.46
2025	6/1/2025		5.50
2025	7/1/2025		5.53
2025	8/1/2025		5.57
2025	9/1/2025		5.54
2025	10/1/2025		5.59
2025	11/1/2025		5.84
2025	12/1/2025		6.05
2026	1/1/2026		6.16
2026	2/1/2026		6.13
2026	3/1/2026		6.02
2026	4/1/2026		5.60
2026	5/1/2026		5.65
2026	6/1/2026		5.70
2026	7/1/2026		5.75
2026	8/1/2026		5.81

Year	Ventura Gas Historical	Ventura Gas Forecast

Year	Month	Ventura Gas Historical	Ventura Gas Forecast	Year	Ventura Gas Historical	Ventura Gas Forecast
2026	9/1/2026		5.79			
2026	10/1/2026		5.85			
2026	11/1/2026		6.09			
2026	12/1/2026		6.30			
2027	1/1/2027		6.38			
2027	2/1/2027		6.38			
2027	3/1/2027		6.20			
2027	4/1/2027		5.76			
2027	5/1/2027		5.79			
2027	6/1/2027		5.85			
2027	7/1/2027		5.86			
2027	8/1/2027		5.89			
2027	9/1/2027		5.85			
2027	10/1/2027		5.90			
2027	11/1/2027		6.16			
2027	12/1/2027		6.36			
2028	1/1/2028		6.48			
2028	2/1/2028		6.44			
2028	3/1/2028		6.25			
2028	4/1/2028		5.82			
2028	5/1/2028		5.86			
2028	6/1/2028		5.92			
2028	7/1/2028		5.94			
2028	8/1/2028		5.97			
2028	9/1/2028		5.94			
2028	10/1/2028		5.99			
2028	11/1/2028		6.32			
2028	12/1/2028		6.57			
2029	1/1/2029		6.71			
2029	2/1/2029		6.68			
2029	3/1/2029		6.50			
2029	4/1/2029		6.06			
2029	5/1/2029		6.10			
2029	6/1/2029		6.16			
2029	7/1/2029		6.18			
2029	8/1/2029		6.23			
2029	9/1/2029		6.20			
2029	10/1/2029		6.26			
2029	11/1/2029		6.52			
2029	12/1/2029		6.77			
2030	1/1/2030		6.93			
2030	2/1/2030		6.90			
2030	3/1/2030		6.64			
2030	4/1/2030		6.19			
2030	5/1/2030		6.23			
2030	6/1/2030		6.28			
2030	7/1/2030		6.31			
2030	8/1/2030		6.36			
2030	9/1/2030		6.32			
2030	10/1/2030		6.39			
2030	11/1/2030		6.71			
2030	12/1/2030		6.98			
2031	1/1/2031		7.11			
2031	2/1/2031		7.07			
2031	3/1/2031		6.81			
2031	4/1/2031		6.35			
2031	5/1/2031		6.39			
2031	6/1/2031		6.45			
2031	7/1/2031		6.47			

Year	Month	Ventura Gas Historical	Ventura Gas Forecast
2031	8/1/2031		6.52
2031	9/1/2031		6.48
2031	10/1/2031		6.54
2031	11/1/2031		6.83
2031	12/1/2031		7.14
2032	1/1/2032		7.24
2032	2/1/2032		7.18
2032	3/1/2032		6.92
2032	4/1/2032		6.46
2032	5/1/2032		6.51
2032	6/1/2032		6.57
2032	7/1/2032		6.59
2032	8/1/2032		6.63
2032	9/1/2032		6.59
2032	10/1/2032		6.66
2032	11/1/2032		6.97
2032	12/1/2032		7.28
2033	1/1/2033		7.40
2033	2/1/2033		7.36
2033	3/1/2033		7.09
2033	4/1/2033		6.63
2033	5/1/2033		6.68
2033	6/1/2033		6.75
2033	7/1/2033		6.80
2033	8/1/2033		6.84
2033	9/1/2033		6.81
2033	10/1/2033		6.88
2033	11/1/2033		7.19
2033	12/1/2033		7.51
2034	1/1/2034		7.65
2034	2/1/2034		7.61
2034	3/1/2034		7.33
2034	4/1/2034		6.86
2034	5/1/2034		6.90
2034	6/1/2034		6.96
2034	7/1/2034		6.99
2034	8/1/2034		7.04
2034	9/1/2034		7.00
2034	10/1/2034		7.06
2034	11/1/2034		7.36
2034	12/1/2034		7.68
2035	1/1/2035		7.79
2035	2/1/2035		7.75
2035	3/1/2035		7.46
2035	4/1/2035		6.97
2035	5/1/2035		7.02
2035	6/1/2035		7.08
2035	7/1/2035		7.10
2035	8/1/2035		7.15
2035	9/1/2035		7.11
2035	10/1/2035		7.17
2035	11/1/2035		7.47
2035	12/1/2035		7.80
2036	1/1/2036		7.95
2036	2/1/2036		7.90
2036	3/1/2036		7.61
2036	4/1/2036		7.11
2036	5/1/2036		7.16
2036	6/1/2036		7.22

Year	Ventura Gas Historical	Ventura Gas Forecast

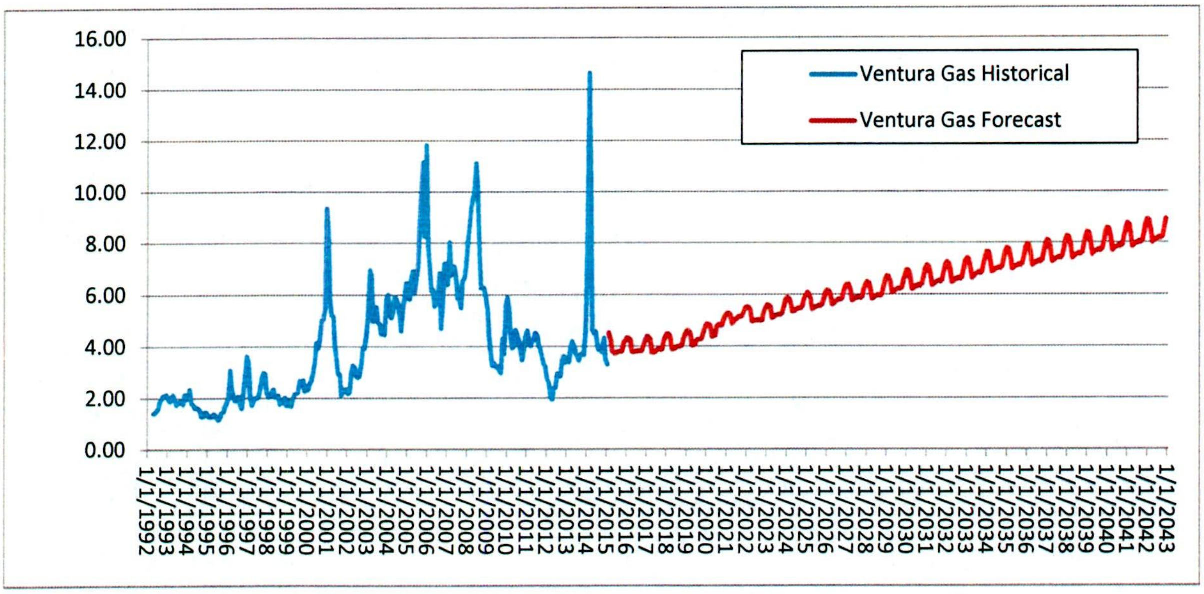
Year	Month	Ventura Gas Historical	Ventura Gas Forecast
2036	7/1/2036		7.24
2036	8/1/2036		7.29
2036	9/1/2036		7.25
2036	10/1/2036		7.32
2036	11/1/2036		7.61
2036	12/1/2036		7.95
2037	1/1/2037		8.10
2037	2/1/2037		8.05
2037	3/1/2037		7.76
2037	4/1/2037		7.25
2037	5/1/2037		7.30
2037	6/1/2037		7.36
2037	7/1/2037		7.39
2037	8/1/2037		7.44
2037	9/1/2037		7.39
2037	10/1/2037		7.46
2037	11/1/2037		7.76
2037	12/1/2037		8.10
2038	1/1/2038		8.25
2038	2/1/2038		8.21
2038	3/1/2038		7.90
2038	4/1/2038		7.39
2038	5/1/2038		7.45
2038	6/1/2038		7.51
2038	7/1/2038		7.53
2038	8/1/2038		7.59
2038	9/1/2038		7.54
2038	10/1/2038		7.61
2038	11/1/2038		7.91
2038	12/1/2038		8.26
2039	1/1/2039		8.41
2039	2/1/2039		8.36
2039	3/1/2039		8.06
2039	4/1/2039		7.54
2039	5/1/2039		7.60
2039	6/1/2039		7.66
2039	7/1/2039		7.68
2039	8/1/2039		7.74
2039	9/1/2039		7.69
2039	10/1/2039		7.76
2039	11/1/2039		8.06
2039	12/1/2039		8.42
2040	1/1/2040		8.57
2040	2/1/2040		8.53
2040	3/1/2040		8.21
2040	4/1/2040		7.69
2040	5/1/2040		7.75
2040	6/1/2040		7.81
2040	7/1/2040		7.84
2040	8/1/2040		7.89
2040	9/1/2040		7.84
2040	10/1/2040		7.91
2040	11/1/2040		8.21
2040	12/1/2040		8.58
2041	1/1/2041		8.74
2041	2/1/2041		8.69
2041	3/1/2041		8.37
2041	4/1/2041		7.84
2041	5/1/2041		7.90

Year	Ventura Gas Historical	Ventura Gas Forecast

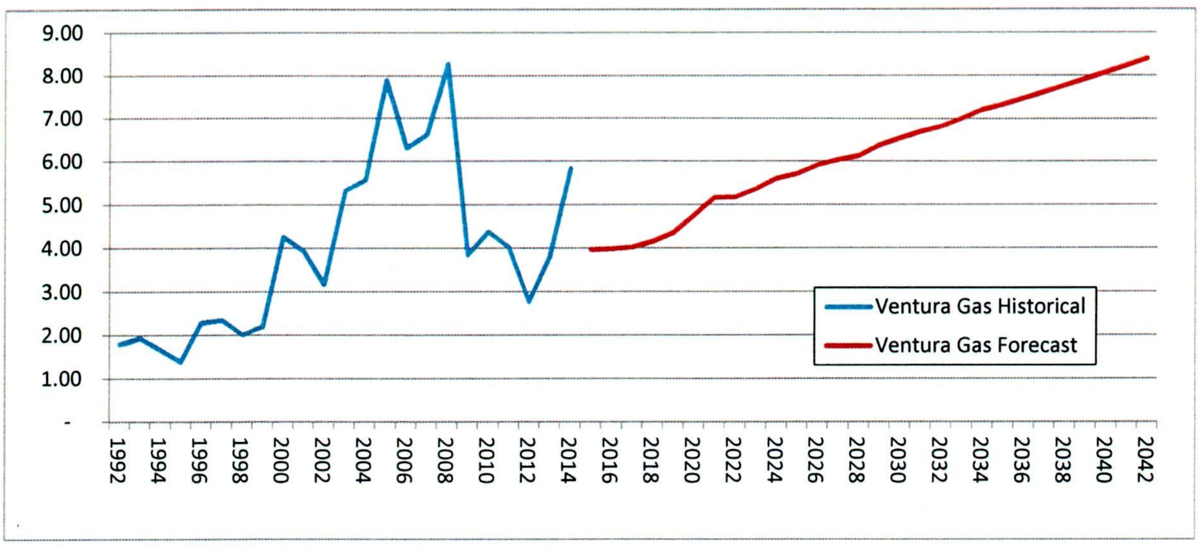
Year	Month	Ventura Gas Historical	Ventura Gas Forecast
2041	6/1/2041		7.97
2041	7/1/2041		7.99
2041	8/1/2041		8.05
2041	9/1/2041		7.99
2041	10/1/2041		8.07
2041	11/1/2041		8.37
2041	12/1/2041		8.75
2042	1/1/2042		8.91
2042	2/1/2042		8.86
2042	3/1/2042		8.53
2042	4/1/2042		8.00
2042	5/1/2042		8.06
2042	6/1/2042		8.12
2042	7/1/2042		8.15
2042	8/1/2042		8.21
2042	9/1/2042		8.15
2042	10/1/2042		8.23
2042	11/1/2042		8.54
2042	12/1/2042		8.91

Year	Ventura Gas Historical	Ventura Gas Forecast

Monthly Detail

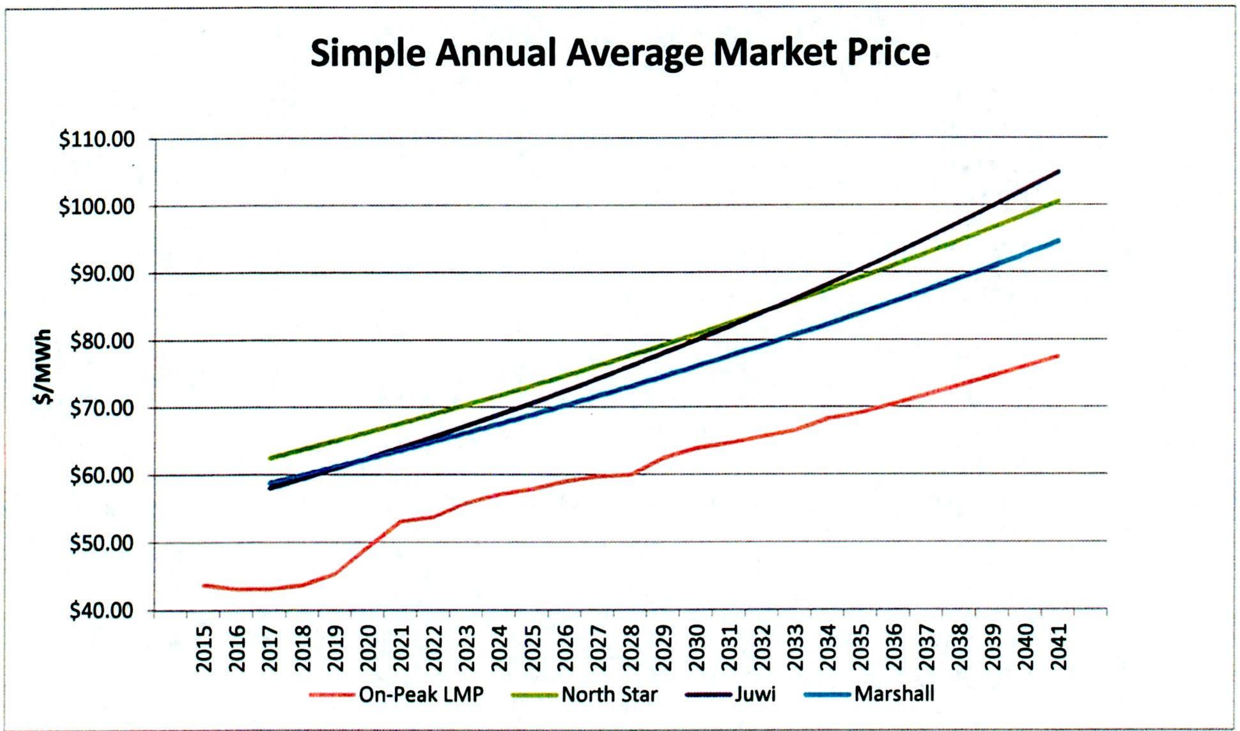


Annual Average



Simple Annual Average Market Price

	On-Peak LMP	Off-Peak LMP	North Star	Juwi	Marshall
2015	$43.65	$24.74			
2016	$43.05	$25.23			
2017	$43.01	$25.96	62.50	58.00	58.80
2018	$43.59	$27.07	63.75	59.45	59.98
2019	$45.26	$28.49	65.03	60.94	61.18
2020	$49.23	$30.50	66.33	62.46	62.40
2021	$53.05	$33.61	67.65	64.02	63.65
2022	$53.71	$34.52	69.01	65.62	64.92
2023	$55.84	$35.87	70.39	67.26	66.22
2024	$57.09	$35.77	71.79	68.94	67.54
2025	$57.87	$35.32	73.23	70.67	68.89
2026	$58.97	$36.06	74.69	72.43	70.27
2027	$59.69	$36.89	76.19	74.24	71.68
2028	$59.95	$36.80	77.71	76.10	73.11
2029	$62.42	$38.72	79.27	78.00	74.57
2030	$63.87	$40.18	80.85	79.95	76.06
2031	$64.63	$41.07	82.47	81.95	77.59
2032	$65.60	$41.80	84.12	84.00	79.14
2033	$66.52	$42.58	85.80	86.10	80.72
2034	$68.26	$43.61	87.52	88.25	82.33
2035	$69.12	$44.30	89.27	90.46	83.98
2036	$70.45	$45.15	91.05	92.72	85.66
2037	$71.80	$46.01	92.87	95.04	87.37
2038	$73.17	$46.89	94.73	97.42	89.12
2039	$74.57	$47.79	96.62	99.85	90.90
2040	$76.00	$48.71	98.56	102.35	92.72
2041	$77.46	$49.64	100.53	104.91	94.58
2042	$78.94	$50.59			
2043	$80.46	$51.56			
2044	$82.00	$52.55			
2045	$83.57	$53.55			
2046	$85.17	$54.58			
2047	$86.80	$55.62			
2048	$88.46	$56.69			
2049	$90.16	$57.78			
2050	$91.88	$58.88			
2051	$93.68	$60.03			
2052	$95.50	$61.20			
2053	$97.37	$62.39			


Simple Annual Average Market Price
$/MWh
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
On-Peak LMP
North Star
Juwi
Marshall

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	11
Requestor:	Michael Diller		
Date Received:	January 7, 2015		

Question:

Reference NDPSC Data Request No. 5I, Attachment A

a) Please redo NDPSC Data Response No. 5i, Attachment A to make it non-trade secret and more useful for the hearing. Redo the non-trade secret section to only include "existing resources" to determine a baseline Long / (Short) Position. Make sure that this new schedule includes NSP's most recent capacity needs projections and reference the date of the projection. Below the baseline Position, include a separate line for each new resource's expected capacity to meet system capacity requirements including the date each is expected to come on line. The new resources section should include 3 segments, one for new resources already approved by the MN commission; another for resources that are expected to be approved by the MN commission; and a third section for resources that are not included in the first two but are preferred by NSP. Given this approach, the trade secret portion can be dropped from the schedule and the hearing will not be impeded by dealing with non-disclosure requirements. Last, add 5 more years to the worksheet to include years out to 2024.

b) Provide the same thing except on a North Dakota basis. In other words, instead of Non-Coincident Peak Demand for NSP's system, the first line would include North Dakota's projected NCPD and a calculated diversity factor on the second line to coincide with North Dakota's projected Demand Coincident with Peak number on the third line. Include North Dakota's share of Demand Resources then work through the applicable transmission adjustments and the MISO reserve planning margin to determine a Native Load Obligation for ND. This would then be followed with ND's share of existing resources and its share of purchased generation and sales to determine ND's share of resources and its Long / (Short) Position. Again, each future projected resource will be shown displaying only ND's share of the projected capacity. I understand that this may not be readily available. However, this is important to my analysis of

ND's needs and this proceeding. Make a good effort in developing the information.

Response:

a) and b) Please see Attachments A and B for the requested analyses.

As shown in Attachments A and B, based on the 2014 forecast, the Company's current supply portfolio shows a modest amount of excess capacity (between 1 and 2.5%) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains a small amount of excess capacity by increasing our current Manitoba Hydro purchase from anticipated new capacity that is under development. In 2024, however, we again show a system deficit of 234 MW. This load balance profile suggests that we are at risk of capacity deficits beginning in 2019 and 2020 if our projected loads change by even a very small amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our assumed supply portfolio is modest given the normal forecast variability which can result in demand swings of 200 MW (2 percent) or more.

This data suggest that we are at risk of capacity shortfalls (both on a system-wide and North Dakota allocated share basis) in 2019-2020 due to small changes in customer loads. The normal variability we have experienced between load projections and actual results in recent years suggests that it may be appropriate to include additional generation as a hedge. While we recognize that we could potentially purchase short-term capacity from the MISO voluntary capacity market at then-prevailing rates for any capacity shortfall, we must also consider that existing and proposed retirements of baseload units in the MISO footprint may result in a shortfall of capacity across the footprint and higher capacity prices in the MISO voluntary short-term capacity market. Prudent planning includes balancing the risk of exposure to the capacity market in the next five years against the cost of building additional capacity in the 2019/2020 time-frame, which will be necessary by 2024, in any event.

As requested, Attachments A and B also includes a scenario where all of our currently contemplated resources have been included. This includes: (1) the 98 MW accreditable capacity (187 MW nameplate) solar portfolio purchase which is the subject of this Case; (2) the Calpine Mankato combined-cycle expansion project (345 MW accreditable capacity); (3) the up-to 71 MW accreditable capacity (up to 100 MW nameplate) Geronimo solar project; (4) the capacity for the Black Dog 6 combustion turbine unit (207 MW accreditable capacity), for which an ADP has already been issued by the Commission; (5) a new short-term (four year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated by our recently filed

Upper Midwest Resource Plan.[1] If all of the contemplated new generation is actually deployed, it will result in a system surplus in the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685 MW in 2020) and address our resource need in 2024.

Additionally, these resource additions will also position us well to address issues identified in our 2015 Resource Plan beyond 2024. This includes the impacts of pending environmental regulation such as NOx regulations that may impact the continued use of our Sherco Units 1 and 2 as well as EPA's proposed Clean Power Plan. Furthermore, these resources help position us to address known long-term changes to the NSP System beyond 2024. For example, from 2025 through 2034, the first phase of the Mankato Energy Center and the Cottage Grove power purchase agreements will expire, the Manitoba Hydro power purchase agreement will expire, and our nuclear plant licenses will reach their end dates. As a result, we must begin to address nearly 75 percent of the energy producing resources on the NSP System.

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[1] Please note, we intend to file ADP applications for the Calpine and Geronimo projects once the MPUC issues a written order approving their purchase. We expect to file for approval for the Manitoba Hydro contract from the Commission in the next several months. Because it is a short-term purchase, approval by the MPUC is not required.

NSP Load Balance	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NSP System Peak Demand, July (Fall 2014 Forecast) @ generator	9,325	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
Coincident Factor with MISO	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
NSP System Peak Demand Coincident with MISO @ generator	8,858	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
Transmission Loss Correction to Tranmission	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
NSP System Peak Demand Coincident with MISO @ transmission	8,633	8,741	8,818	8,884	8,933	8,956	8,975	9,030	9,025	9,042	9,071	9,136	9,223	9,384	9,398	9,490
NSP System Load Management Forecast, July @ transmission	933	942	953	964	975	986	996	1,007	1,017	1,028	1,030	1,025	1,021	1,017	1,013	1,009
NSP System Peak Demand, Net of LM, Coincident with MISO @ transmission	7,700	7,800	7,864	7,920	7,958	7,970	7,978	8,023	8,008	8,014	8,041	8,111	8,202	8,367	8,385	8,482
Transmission Loss Correction to Generator	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
NSP System Peak Demand, Net of LM, Coincident with MISO @ generator	7,901	8,004	8,070	8,127	8,166	8,178	8,187	8,233	8,217	8,224	8,251	8,323	8,416	8,586	8,604	8,703
MISO System Planning Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
NSP System Native Load Obligation @ generator	**8,462**	**8,572**	**8,643**	**8,704**	**8,746**	**8,759**	**8,768**	**8,817**	**8,800**	**8,808**	**8,837**	**8,914**	**9,014**	**9,195**	**9,215**	**9,321**
Existing Resources	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Owned Generation	6,803	6,870	6,913	6,913	6,902	6,902	6,954	6,954	6,954	6,566	6,566	6,317	6,066	6,029	6,029	6,029
Purchased Generation	1,885	1,894	1,997	1,882	1,852	1,857	2,045	2,046	2,009	2,008	862	593	570	309	324	361
Sales	(50)	(50)	(25)	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Resources @ generator	**8,639**	**8,714**	**8,885**	**8,795**	**8,754**	**8,760**	**8,999**	**9,000**	**8,963**	**8,574**	**7,427**	**6,910**	**6,636**	**6,339**	**6,353**	**6,391**
Long/(Short) Position @ generator	**177**	**142**	**242**	**91**	**8**	**0**	**231**	**182**	**163**	**(234)**	**(1,410)**	**(2,004)**	**(2,378)**	**(2,856)**	**(2,862)**	**(2,931)**
Additional Resources																
Resources Approved by the MPUC (Docket 12-1240)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Calpine Mankato - 2 (June 2019) (NG-CC-PPA)	-	-	-	-	308	308	308	308	308	308	308	308	308	308	308	308
Geronimo/Aurora (COD 12/2016, summer accreditation 6/2018) (Solar-PPA)	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72
Black Dog 6 - (June 2020) (NG-CT)	-	-	-	-	-	207	207	207	207	207	207	207	207	207	207	207
Total Resources Currently Approved	**-**	**-**	**-**	**72**	**380**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**
Resources Anticipating Approval by the MPUC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Manitoba Hydro - 75 MW Diversity Agreement (Period 6/1/2016-5/31/2020)	-	73	73	73	73	-	-	-	-	-	-	-	-	-	-	-
Solar Resource Acquisition (187 MW) docket 14-168 (COD 12/2016, summer accreditation 6/2018)	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98
Total Resources Anticipating Approval	**-**	**73**	**73**	**171**	**171**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**
Resources in the 2016 IRP Preferred Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Preferred Plan - Wind Additions	-	-	-	-	-	-	89	89	118	118	207	207	266	266	266	266
Preferred Plan - Solar Additions	-	-	-	-	-	-	-	-	-	52	261	418	523	784	784	889
Preferred Plan - CT Additions	-	-	-	-	-	-	-	-	-	-	877	1,316	1,535	1,755	1,755	1,755
Resources in the 2016 IRP Preferred Plan	**-**	**-**	**-**	**-**	**-**	**-**	**89**	**89**	**118**	**171**	**1,346**	**1,942**	**2,325**	**2,805**	**2,805**	**2,910**
Subsequent Impact of Additional Resources	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Resources Approved by the MPUC (Docket 12-1240)	-	-	-	72	380	587	587	587	587	587	587	587	587	587	587	587
Resources Anticipating Approval by the MPUC	-	73	73	171	171	98	98	98	98	98	98	98	98	98	98	98
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171	1,346	1,942	2,325	2,805	2,805	2,910
Additional Resources @ generator	-	73	73	243	551	684	773	773	803	855	2,030	2,626	3,009	3,490	3,490	3,594
Long/(Short) Position @ generator	**177**	**216**	**315**	**334**	**559**	**685**	**1,004**	**956**	**965**	**621**	**621**	**622**	**631**	**633**	**628**	**664**

Notes:
All resource capacity ratings represent MISO UCAP values.
Pending receipt of the written order in Docket 12-1240, the Commercial Operation Dates have been estimated.

NSP Load Balance - North Dakota - Summer	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
North Dakota Peak Demand, July (Fall 2014 Forecast) @ generator	480	490	496	502	508	513	519	525	535	539	543	547	551	555	559	563
Coincident Factor with MISO	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
North Dakota Peak Demand Coincident with MISO @ generator	456	466	471	477	482	487	493	499	508	512	516	520	523	527	531	535
Transmission Loss Correction to Transmission	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
North Dakota Peak Demand Coincident with MISO @ transmission	444	454	459	465	470	475	481	486	495	499	503	506	510	514	517	521
ND Load Management Forecast, July @ transmission	64	64	64	64	65	65	65	65	65	66	66	65	65	65	65	65
North Dakota Peak Demand, Net of LM, Coincident with MISO @ transmission	380	390	395	401	405	410	416	421	430	433	437	441	444	448	452	456
Transmission Loss Correction to Generator	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
North Dakota Peak Demand, Net of LM, Coincident with MISO @ generator	390	400	405	411	416	421	426	432	441	445	448	452	456	460	464	468
MISO System Planning Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
North Dakota Native Load Obligation @ generator	**418**	**428**	**434**	**440**	**446**	**451**	**457**	**462**	**472**	**476**	**480**	**485**	**489**	**493**	**497**	**501**
NSP System Obligation	8,462	8,572	8,643	8,704	8,746	8,759	8,768	8,817	8,800	8,808	8,837	8,914	9,014	9,195	9,215	9,321
ND Obligation	418	428	434	440	446	451	457	462	472	476	480	485	489	493	497	501
ND Obligation as a Percentage of NSP System Obligation	4.94%	5.00%	5.02%	5.06%	5.09%	5.15%	5.21%	5.24%	5.37%	5.41%	5.43%	5.44%	5.42%	5.36%	5.39%	5.38%

ND Share of Existing Resources, Summer	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Owned Generation	336	343	347	350	352	355	362	365	373	355	357	343	329	323	325	324
Purchased Generation	93	95	100	95	94	96	107	107	108	109	47	32	31	17	17	19
Sales	(2)	(2)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Resources, Summer	**427**	**436**	**446**	**445**	**446**	**451**	**469**	**472**	**481**	**464**	**404**	**376**	**360**	**340**	**343**	**344**
Position - Long (Short), Summer	**9**	**7**	**12**	**5**	**0**	**0**	**12**	**10**	**9**	**(13)**	**(77)**	**(109)**	**(129)**	**(153)**	**(154)**	**(158)**

Subsequent Impact of Additional Resources - ND Share	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Resources Approved by the MPUC (Docket 12-1240)	-	-	-	4	19	30	31	31	31	32	32	32	32	31	32	32
Resources Anticipating Approval by the MPUC	-	4	4	9	9	5	5	5	5	5	5	5	5	5	5	5
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	5	5	6	9	73	106	126	150	151	157
Additional Resources	-	4	4	12	28	35	40	41	43	46	110	143	163	187	188	193
Position - Long (Short), Summer with Additional Resources	9	11	16	17	28	35	52	50	52	34	34	34	34	34	34	36

Notes:
All resource capacity ratings represent MISO UCAP values.
Pending receipt of the written order in Docket 12-1240, the Commercial Operation Dates have been estimated.