DIRECT TESTIMONY AND SCHEDULES

JAMES A HEIDELL

**STATE OF NORTH DAKOTA**

**BEFORE THE**

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| NORTHERN STATES POWER COMPANY | CASE NOS. | **PU-17-270** |
| ADVANCE PRUDENCE – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING | | **PU-17-271** |
| | | **PU-17-322** |

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**Prefiled Direct Testimony of James A Heidell (Redacted)**

Public Service Commission Advocacy Counsel

Mitch Armstrong, SAAG

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# Introduction and Qualifications

**Q. Would you please state your name, affiliation, and address?**

A. My name is James A. Heidell. I am a Director at PA Consulting Group (PA). My business address is 1700 Lincoln Street, Suite 1550, Denver, CO 80203.

**Q. On whose behalf are you filing this testimony?**

A. I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public Service Commission (Commission).

**Q. Please summarize your qualifications and experience.**

A. I have worked in the energy industry for the past 35 years, primarily specializing in electricity and utilities. I have worked on issues related to resource planning, rates, analysis of electricity markets, and analysis of the economics of financial transactions for utilities and wholesale generation owners. My academic background includes a BSE in civil engineering from Tufts University, a MS in engineering economics from Stanford University, and an MBA in finance from the University of Washington. I am a Chartered Financial Analyst. My CV is provided in Exhibit JAH-1.

**Q. Have you testified before the North Dakota Public Service Commission previously?**

A. Yes. I testified on behalf of Montana-Dakota Utilities Co. in the matter of Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in Northern States Power Company's request for an Advanced Determination of Prudence (ADP) for 1,550 MW of Wind, Case Number PU-17-120. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in Otter Tail Power Company's request for an Advanced Determination of Prudence (ADP) for the Astoria CT and Merricourt Wind Project, Case Numbers PU-17-140, PU-17-141, and PU-17-143. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in the matter of Northern States Power Company, Case Nos. PU-12-813 et al.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to provide the Commission with my assessment of the Northern States Power Company's (NSP or the Company) requests for Advanced Determination of Prudence (ADP) related to the termination of two contracts and the extension of one contract with existing biomass plants located in Minnesota.
Specifically, NSP has requested:

- A seven year extension of the contract with the Hennepin Energy Recovery Center (HERC);

- To purchase and then shutdown the Benson / Fibrominn biomass project; and
- To restructure and create an early termination of the Pine Bend biomass project.

In addition, NSP has requested deferred accounting treatment including a return on the regulatory assets associated with:

- The termination of the PPA for the Laurentian biomass project,
- The termination of the PPA for the Pine Bend biomass project, and
- The purchase and shutdown of the Benson biomass project.

I have reviewed the Applications, supporting testimony, and responses to interrogatories in order to develop a recommendation regarding whether:

- Individually, the proposals to terminate purchases of electricity and capacity from each of these resources is appropriate;
- The proposed contract terminations will lower electricity costs for NSP's North Dakota customers; and
- Any conditions should be put on an approval of the ADPs.

Q. **Are the requests for the ADPs and deferred accounting separate decisions?**

A. Yes, each ADP request and each request for deferred accounting should be considered separately on their own merits.

Q. **Are there other considerations that the Commission should consider in evaluating the approval of ADPs/ deferred accounting for the individual contracts?**

A. Yes, the Commission should be aware that in NSP's rebuttal testimony in the Resource Treatment Framework Docket the Company has proposed to not allocate any of the costs of the four biomass projects to North Dakota as part of a larger proposed treatment of disputed legacy resources and the addition of 1,550 MW of wind.[1]

**Q. Would you please summarize the organization of your testimony?**

A. Yes. I start with presenting my findings and recommendations and then I discuss in detail the analysis conducted by NSP as well as my independent analysis to support my findings and recommendations. Finally, I address proposed conditions that should be included on approval of the ADPs. My analysis is separated into six sections:

- A review of the four biomass projects that are the subject of these proceedings;
- An evaluation of the Company's modeling of the savings based upon its mark-to-market methodology (Section VI);
- Additional evaluation of NSP's modeling of the savings for HERC and Benson (Sections VII & VIII);
- An evaluation of the energy prices used by NSP to estimate the savings based upon comparisons with independent forecasts (Section IX); and
- An independent assessment of the expected energy cost savings to the Company's North Dakota customers (Section X).

**Q. Are you sponsoring any exhibits to your testimony?**

A. Yes. I am sponsoring the following exhibits:

- Exhibit JAH-1: CV of James Heidell
- Exhibit JAH-2: Summary of Historical and Forecast Production (Confidential)
- Exhibit JAH-3: Comparison of Alternative Market Price Forecasts (Confidential)
- Exhibit JAH-4: Alternative Estimates of Savings for the Projects (Confidential)

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[1] Resource Treatment Framework in Case Nos. PU-12-813 et al. see Chandarana Rebuttal p 20. 1550 Wind refers to Case No. PU-17-120.

**Q. Are you sponsoring testimony related to the evaluation and approval of three applications for authority for deferred accounting requested by NSP?**

A. No, PA Witness Joel Jeanson will be relying upon my recommendations regarding the economics of the projects and will then address whether, and on what terms, deferred accounting treatment is appropriate. However, for the Commission's convenience, I have consolidated his recommendations along with mine in the next section.

# I. Summary of Recommendations

**Q. What is your recommendation with regards to approving the Company's Application for an ADP to terminate the Pine Bend Biomass PPA?**

A. My recommendation is that the transaction is in the interest of North Dakota rate payers. However, I defer to the Commission as to whether the transaction qualifies as an ADP under North Dakota statute 49-05-16. The agreement is to terminate an existing PPA and does not involve purchasing a new resource that provides either energy or capacity. The agreement is to terminate the PPA that currently expires at the end of 2025 in exchange of monthly payments that total $1,050,000. Based upon my independent analysis, I project the estimated cost of replacement energy and payments to Pine Bend to be less than the payments to Pine Bend that would otherwise be paid under the existing contract.

**Q. What is your recommendation with regards to approving the Company's Application for an ADP to purchase and shutdown the Benson biomass facility?**

A. My recommendation is that the Commission conditionally approve the ADP to purchase the Benson biomass facility, subject to a recommended adjustment to the approved purchase cost, as well as shut the facility down since the costs of owning and operating the facility exceed the cost of otherwise purchasing replacement electricity. The current PPA expires at the end of 2028. NSP is proposing to purchase and shut down the facility for $106.8M and I am recommending that NSP be allowed to recover $106.2M of those costs. As discussed later in my testimony, I have excluded $607K of costs related to the City of Benson. After accounting for the estimated cost of $127.1M, North Dakota customers are expected to save money compared to continuation of the contract.

**Q. What is your recommendation with regards to approving the Company's Application for an ADP to approve the terms of a seven year extension of the PPA with HERC?**

A. My recommendation is that the Commission deny the ADP regarding the financial terms of the contract extension. While NSP has a contractual commitment to extend the PPA at fair market value, my conclusion is that the payments as proposed are significantly above fair market value. My calculations show that the extension will cost $19 million above market value on a Net Present Value (NPV) basis. Furthermore, I question the prudence of providing a seven year extension in the initial contract.

**Q. What is your recommendation with regards to the Company's analysis of savings associated with terminating the Laurentian Biomass PPA?**

A. I concur with NSP that it makes economic sense to make the termination payment. The PPA currently expires at the end of 2026. NSP is proposing to pay $108,500,000 in return for terminating the PPA.[2] Based upon my independent analysis, the estimated cost of replacement energy and payments to the Laurentian Energy Authority will be less than the payments that would otherwise be paid under the existing contract.

**Q. What is your recommendation with regards to the request for deferred accounting with regards to the Laurentian termination payment?**

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[2] Laurentian will also receive an additional $34M out of the Minnesota Renewable Development Fund (RDF) but that is not a cost to North Dakota rate payers.

A. Based upon my review of the analysis completed by Witness Jeanson, my recommendation is that it should be approved; however, no return on the asset should be approved at this time.

**Q. What is your recommendation with regards to the request for deferred accounting with regards to the Pine Bend contract?**

A. Based upon my review of the analysis completed by Witness Jeanson, my recommendation is that it should be approved; however, no return on the asset should be approved at this time.

**Q. What is your recommendation with regards to the request for deferred accounting with regards to the purchase and shutdown of Benson?**

A. Based upon my review of the analysis completed by Witness Jeanson, my recommendation is that it should be approved; however, no return on the asset should be approved at this time.

# II. Findings

**Q. Would you please provide a summary of the findings in your testimony that support your recommendation regarding the Commission's treatment of the three ADPs?**

A. Based upon my review and analysis of the testimony filed in the Application, the exhibits contained within the Application, and the information produced in discovery, I conclude the following:

- The termination of the Laurentian and Pine Bend PPAs and the purchase and shut down of the Benson facility will - on an NPV basis - reduce power costs for North Dakota customers under three scenarios of forecast wholesale market electricity prices.

- The extension of the HERC PPA under the pricing negotiated by NSP is substantially above projected market pricing and will otherwise increase purchased power costs for North Dakota customers.
- The appropriate way to analyze saving potential savings of terminating contracts or extending the HERC contract is to evaluate contract costs against multiple projections of market prices.

**Q. Will the terminated / restructured contracts save rate payers money on an NPV basis?**

A. Yes, my analysis projects that the proposed termination of the three PPAs will save rate payers money on a NPV basis. However, I also project that the pricing terms for the HERC contract extension will not save rate payers money. Table 1 provides a comparison of the NSP estimates of savings with savings I have estimated using an alternative forecast of MISO prices. I summarize three scenarios: an expected natural gas cost case and high and low natural gas cost cases. The savings shown in the table are for the entire NSP system.

**Table 1. NPV Expected Savings ($ Millions)**

| Project | NPV Savings – NSP | NPV Savings – PA Base | NPV Savings – PA High Gas Case | NPV Savings – PA Low Gas Case |
|---|---|---|---|---|
| Pine Bend | $5.2M | $4.3M | $3.2M | $5.3M |
| Laurentian | $87M | $80.1M | $70.5M | $89.5M |
| Benson / Fibrominn | $345.6M | $332.3M | $312.9M | $351.5M |
| HERC | $26.6M | $(15.8)M | $(11.4)M | $(19.9)M |

**Q. Have you calculated the share of savings for NSP's North Dakota customers?**

A. Yes, the North Dakota share is approximately 5.49 percent of the total NSP savings.[3] The North Dakota savings are summarized in Table 2.

**Table 2. NPV of Expected North Dakota Savings ($ Thousands)**

| Project | NPV Savings – NSP[4] | NPV Savings – PA Base | NPV Savings – PA High Gas Case | NPV Savings – PA Low Gas Case |
|---|---|---|---|---|
| Pine Bend | $277K | $235K | $175K | $293K |
| Laurentian | $4,772K | $4,400K | $3,872K | $4,911K |
| Benson / Fibrominn | $18,970K | $18,241K | $17,176K | $19,295K |
| HERC | $1,460K | $(865)K | $(627)K | $(1,094)K |

**Q. Would you please summarize why your base case estimate of savings for the HERC contract differs significantly from NSP's estimate?**

A. Yes, as I discuss later in my testimony, NSP has calculated the savings based upon the pricing structure in the contract that expires at the end of 2017. The pricing structure in the contract that expires in 2017 uses a pricing formula based upon the operating costs of the Sherburne County Generating Station (Sherco) and includes a very high capacity cost component. My calculation is based upon the market value of energy, a calculation similar to what NSP used for the evaluation of savings from terminating the Pine Bend, Laurentian, and Benson PPAs.

## III. Overview of the NSP Application and Requests

**Q. Would you please provide a summary of the four biomass plants that are the subject of these proceedings?**

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[3] North Dakota share of savings based upon the total savings to North Dakota from Table 1 of application.

[4] Table 1, NSP Biomass Application

A. Yes. NSP is asking the Commission to make a determination of four biomass power plants. I have summarized their characteristics in Table 3.

**Table 3. Summary of Biomass Projects**

| Biomass Project | Size | Fuel | Contract |
|---|---|---|---|
| Pine Bend | 12 MW | Landfill gas | Contract through 12/31/2025 |
| Laurentian | 35 MW | 75% wood / 25% coal | Contract through 12/31/2026 |
| Benson / Fibrominn | 55 MW | 35% poultry litter / 65% wood | Contract through 9/10/2028 |
| HERC | 33.7 MW | Solid waste | 7 Year extension of PPA that expires in 12/31/2017 |

**Q. Would you please summarize NSP's requests with regard to the treatment of four of its existing biomass contracts?**

**A.** Yes, NSP is requesting ADP's for Pine Bend, Laurentian, and HERC. NSP is also requesting deferred accounting treatment for Pine Bend, Benson, and Laurentian. These requests are summarized in Table 4.

**Table 4. NSP Requested Action**

| Project | NSP Proposed Action | Approval(s) Sought by NSP |
|---|---|---|
| Pine Bend | Buy out of existing contract with monthly payments over a three year period | ADP & Deferred Accounting |
| Benson / Fibrominn | Buy-out of project and shut-down project | ADP & Deferred Accounting |
| HERC | Extend existing contract for seven years at pricing below 2017 expiring contract pricing | ADP |
| Laurentian | Buy out of existing contract with payments over six years | Deferred Accounting |

**Q. What is the status of the four biomass projects?**

A. All four projects are currently operating.

**Q. Would you please provide a brief description of the Pine Bend facility?**

A. Gas Recovery Systems (GRS) owns and operates this 12 MW landfill gas system. The facility is located in Inver Grove Heights in Dakota County in Minnesota. In 1994, NSP entered into a thirty year energy and capacity contract to buy the output of this project as a Qualified Facility under the PURPA legislation. The pricing structure of the contract was amended in 2010.

**Q. What is the structure of the existing Pine Bend contract?**

A. Under the 2010 contract amendment, NSP is obligated to purchase all energy from the facility based upon an energy-only rate. The energy price escalates annually at 1.5% and the contract end date is December 31, 2025.

**Q. How is NSP proposing to restructure the Pine Bend Contract?**

A. NSP is proposing to terminate the PPA and make alternative monthly payments for three years based upon the difference between the contract rate and the average monthly marginal cost at the NSP.NSP node plus an adder of $10 per megawatt-hour (MWh). The total payments are capped at $1,050,000. NSP estimates that the cap will be reached in approximately two years.

**Q. Would you please provide a brief description of the HERC facility?**

A. Hennepin County owns and operates this 33.7 MW waste-to-energy plant. The facility is located in downtown Minneapolis in Hennepin County in Minnesota. In 1985, NSP entered into a twenty eight year energy and capacity contract to buy the output of this project under PURPA. The pricing structure of the contract was amended in 2010. The current pricing terms end on December 31, 2017; however, the HERC agreement has an option for a seven year extension at fair market value.

**Q. What is the structure of the existing HERC contract?**

A. Under the 2010 contract amendment, NSP is obligated to purchase all energy from the facility at a cost based upon an estimate of Sherco's avoided costs, with adjustment factors for both on- and off-peak energy.[5] In addition the contract includes a separate capacity payment. Over the 2012 to 2016 period the capacity payments accounted for 63% of the annual payments.[6] The contract contains a clause that gives Hennepin County the option to extend the contract for seven years at "Fair Market Value", a term that is not defined within the contract. NSP indicates that formal negotiations over the extension price commenced in January 2017.[7]

**Q. What pricing is NSP proposing for the HERC contract extension?**

A. NSP is proposing an all-hours energy only payment with no adjustment for on- and off-peak prices. The proposed contract price for energy escalates at 3% per year. The new formula would be applied retroactively back to January 1, 2017.

**Q. Would you please provide a brief description of the Benson biomass facility?**

A. Benson Power (Benson) owns a 55 MW biomass-fueled steam-fired generator located in Benson, Minnesota. The primary fuels for these projects are poultry litter (35%) and wood (65%).

**Q. Would you please summarize the existing Benson contract?**

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[5] The on-peak energy charge is equal to 1.3 times the average Sherco production cost; the off-peak energy charge is equal to 0.78 times the average Sherco production cost. (NSP Response to NDPSC 5-003).

[6] See NSP's corrected response to NDPSC 3-004.

[7] Application p 17.

A. In 2000, NSP signed a twenty year PPA with Benson for the period starting September 2007 and ending in September 2028. The contract obligates NSP to purchase the energy based upon a contracted energy cost plus potential adders for fuel transportation costs, property taxes, and shortfall payments related to ash sales.

**Q. How is NSP proposing to restructure the Benson Contract?**

A. NSP is proposing to purchase the facility, operate it for six months at close to full load, and then shut it down upon obtaining MISO approval. The purchase price of $106.8M is described in detail below in Table 5, with the operating costs projected to be $14.5M. NSP proposes purchase and then continuing to operate the facility for an additional six months to honor existing fuel contracts and remove fuel inventory. NSP has estimated that the facility demolition and site remediation will take approximately 18 months.[8]

**Table 5. Components of Benson Purchase Price[9]**

| Component | Cost | Type |
|---|---|---|
| Asset Purchase | $95,000,000 | Purchase Cost |
| Jennie-O Contract Termination | $1,500,000 | Purchase Cost |
| Legal & Other | $1,394,000 | Purchase Cost |
| Other Transaction Costs | $306,000 | Purchase Cost |
| Demolition & Remediation | $8,000,000 | Purchase Cost |
| City of Benson Stranded Assets | $606,823 | Purchase Cost |
| Fuel Cost | $1,073,302 | Operating Cost |
| Fuel Transportation | $5,035,189 | Operating Cost |
| Property Tax Payments | $3,523,727 | Operating Cost |
| O&M Costs | $3,972,877 | Operating Cost |
| Other Operating Costs | $927,227 | Operating Cost |

[8] Application p 12
[9] MPUC Staff Briefing Papers, Docket 17-530 Benson, November 30, 2017

**Q. Would you please provide a brief description of the Laurentian biomass facilities?**

A. Laurentian Energy Authority, LLC (LEA) is a company owned by two Minnesota public utilities: Hibbing Public Utilities Commission and Virginia Public Utilities Commission. LEA owns two biomass-fueled steam fired generators: a 20 MW facility in Hibbing, Minnesota, and a 15 MW facility in Virginia, Minnesota. The primary fuel for these projects is wood.

**Q. Would you please summarize the existing Laurentian contract?**

A. In 1998 NSP signed a thirty year PPA with LEA. The contract expires in December 2026. The contract pricing has been modified multiple times per the Minnesota Legislature's requirements. The current pricing incorporates an energy rate and a fuel adjustment clause. NSP is obligated to purchase the entire output of both of the two LEA facilities.

**Q. How is NSP proposing to restructure the Laurentian PPA?**

A. NSP is proposing to terminate the PPA in return for paying LEA $108.5 million. The payments would be made annually, and in equal amounts, over a six year period.[10] The existing contract remains in effect until the PPA is terminated.

## IV. Current and Proposed NDPSC Treatment of the Biomass Projects

**Q. Is NSP currently recovering the cost of the biomass projects in North Dakota rates?**

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[10] LEA will also be paid $34M from the Minnesota Renewable Development Fund, but those payments are not funded in any part by North Dakota rate payers.

A. Yes. Under the negotiated settlement in Case No. PU-12-813, NSP is recovering the full costs of the Pine Bend, Benson, and Laurentian PPAs, subject to a fifty percent refund. The refund requirement would be triggered by NSP failing to construct a gas-fired power plant in North Dakota by the end of 2025. NSP is recovering the full cost of the HERC facility in current rates, and recovery of HERC costs is not subject to refund.

**Q. What is the current mechanism for recovery of these Project costs?**

A. The energy charges are recovered in the fuel adjustment clause. Capacity costs for HERC are recovered in base rates.

**Q. What is NSP's proposal for recovery of costs associated with the termination of the biomass projects?**

A. The Company is proposing to create regulatory assets to capture the costs of terminating the Laurentian and Pine Bend PPAs and to purchase and shut down the Benson facilities. The Company is also asking for a return on the regulatory assets. The proposed treatment of the regulatory assets is evaluated by Advocacy Staff witness Mr. Jeanson.

## V. Review of NSP's Approach to the Savings Analysis

**Q. Would you please summarize how NSP developed the savings analysis associated with terminating the Pine Bend, Benson, and Laurentian PPAs?**

A. NSP developed a spreadsheet analysis that broadly contained four elements:

1) A calculation of projected payments under the current contract;
2) Expected payments associated with the termination of the PPAs and the purchase and subsequent retirement of the Benson facility;
3) A calculation of the cost of replacement energy based upon a forecast of power prices at Minnesota Hub; and
4) A calculation of savings based upon the first three elements.

**Q. Did NSP use the same process to calculate the savings associated with the proposed HERC contract extension?**

A. No, NSP used a different calculation and modified the third step. The Company did not calculate the cost of replacement power based upon market purchases. Instead, it calculated what costs would have been if the contract was extended using the same pricing formula as the expiring contract even though NSP is under no obligation to extend the contract at the existing pricing formula.

**Q. Are the anticipated costs associated with continuing the three PPAs that NSP has asked to terminate known with certainty?**

A. No, the costs are not known with certainty and therefore the savings are estimates and are not known with certainty. There is some uncertainty regarding the electricity generation from each of the projects. In addition, under the Laurentian PPA there is some uncertainty relative to the fuel cost adjustment and hence the total fuel costs. I discuss the basis for the assumptions used by NSP later in this section of my testimony.

**Q. Are the anticipated costs associated with terminating the three PPAs known with certainty?**

A. The costs associated with terminating the Laurentian PPA are contractually determined so those are known with certainty. The costs associated with terminating the Pine Bend PPA are based upon a formula incorporating market energy prices, so the magnitude of the monthly payments is not known with certainty. However, the maximum period of the monthly payments (three years) and the total payments ($108.5M) are known with certainty. Finally, the purchase costs for the Benson facility are known with certainty. However, the cost of continuing to operate the plant and then shutting it down and performing site remediation are not known with certainty.

**Q. Are the costs associated with purchasing replacement electricity known with certainty?**

A. No, the market cost of replacement electricity is not known with certainty. In its analysis, NSP based the cost of replacement power on an August 2016 monthly on- and off-peak price forecast for Minnesota Hub. NSP's analysis of replacement power costs is based upon a single market price forecast. The reasonableness of the NSP forecast as well as alternative price forecasts is discussed in the next section of my testimony.

**Q. Did NSP incorporate the cost of replacement capacity in its analysis?**

A. No, the Company indicates that the capacity is not needed.

> "The NSP System is currently projected to be long on capacity until the mid-2020s. As a result, eliminating these contracts has a limited impact on our capacity position and does not change our expansion plan."[11]

**Q. Is it appropriate to consider the cost of replacement capacity if NSP is long on resources?**

A. Yes. As a member of MISO, NSP does not dispatch its resources to directly meet its load obligations. NSP dispatches its resources according to MISO instructions and MISO determines which resources should be dispatched to meet load based upon the price of the resources bid into the market, subject to the operational constraints of each generator and MISO grid requirements. Because NSP has a take-or-pay obligation with each of the contracts, NSP should bid the resources in at a low cost and accept the market clearing price. Consequentially, if the PPAs were not terminated, the value of the electricity

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[11] Martin Direct p 3 l 18 – 20.

generated is based upon the MISO market clearing price regardless of whether those resources are needed to serve NSP's load obligations.

**Q. Do you agree with NSP's assertion that the PPA savings estimates are conservative because the Company would not necessarily have to purchase the electricity at market prices if the contracts are cancelled?**

A. No, Mr. Martin makes this assertion given that reducing the need to sell the energy from the contract reduces the amount of excess energy the Company needs to sell in low load hours.[12] However, the value of the energy is tied to the MISO market price regardless of whether NSP needs that generation to meet its load requirements. In addition, elimination of this small amount of generation appears unlikely to move prices in the large MISO system.

**Q. Should NSP have used Strategist to forecast the market value of the electricity produced by the PPAs?**

A. No, the use of Strategist would have made the calculation unnecessarily complex without adding new information. My understanding is that NSP uses Strategist to identify the cost of different resource portfolios. However, Strategist would not add value in this instance for two reasons. First, NSP is under a take or pay obligation and these types of resources will always be dispatched unless there is an outage or the marginal cost of dispatch is greater than the payment by NSP. As such, the resources would have been modelled to always dispatch in Strategist subject to unit availability, and so Strategist would provide no insight into the dispatch of these PPAs. Second, NSP enters wholesale market on- and off-peak electricity prices as an input into Strategist. Because the market prices are not calculated by Strategist, there is no value in running Strategist to project the revenues from the Projects, as the Projects will receive the market value of electricity.

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[12] Martin Direct p 4 l 1 – 8,

**Q. Should NSP have considered alternative market price forecasts in evaluating the savings estimates from terminating the PPAs?**

A. Yes, while it is reasonable and appropriate to present the expected savings, NSP should also have considered the level of savings should power prices be higher than forecast. The fixed price for power in the PPAs represents an effective hedge against higher natural gas prices and the associated market prices. Given the relatively high contract prices, it does not appear to be a cost effective hedge based upon the total prices of the contracts. However, market prices change and forecasts are often wrong, so resource decisions have traditionally incorporated a range of power prices. It is recommended that the level of savings should be evaluated against alternative scenarios to demonstrate that the proposed PPA terminations make sense even if market prices increase.

**Q. Should NSP include the value of the capacity associated with the PPAs?**

A. Yes, the lost market value of the capacity should be considered even if NSP does not need the capacity. However, as I discuss in the next section of my testimony, the market value of the capacity is an insignificant driver of the savings estimate.

**Q. Did NSP calculate the NPV of the savings projections for each PPA?**

A. Yes, the Company calculated the NPV using a 5.79% discount rate to reflect an after-tax weighted average cost of capital (WACC). The corresponding pre-tax WACC is 6.47%

**Q. Is the Company's use of a 5.79% discount rate reasonable?**

A. Yes it is a reasonable proxy to use for the purpose of calculating the NPV of the savings based upon what was known at the time of the filing. However, it may not the appropriate to use should deferred accounting with a return be authorized. The basis for the pre-tax WACC is summarized in Table 6. The ROE is consistent with MNPUC 2017 order.[13] I note that the Company uses its current combined federal / state tax rate to calculate the after tax rate. That may need to be recomputed based upon tax law changes under consideration and the proposed decrease in the corporate federal income tax rate to 21%.

**Table 6. Cost of Capital Assumptions**

| Component | Structure | Return | Before Tax WACC |
|---|---|---|---|
| L-T Debt | 46.24% | 3.50% | 1.62% |
| Common Equity | 52.50% | 9.20% | 4.83% |
| S-T Debt | 1.26% | 1.40% | 0.02% |
| **Total** | | | **6.47%** |

**Q. Do the savings estimates in Tables 1 and 2 include NSP's requested return on regulatory assets?**

A. The Benson estimate of savings includes the cost based upon depreciating the asset until 2028. That is a reasonable proxy for the cost of holding it as a regulatory asset. However, the savings for Pine Bend and Laurentian include neither a return component on the regulatory asset nor a proxy calculation.

**Q. Did NSP negotiate sufficient savings in the termination of the Pine Bend, Benson, and Laurentian PPAs?**

A. I do not have a basis to make that determination as I was not part of the negotiations and I do not know what the operating costs of the projects are. However, I have considered not only the total savings, but the percent savings that NSP negotiated as well. Table 7

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[13] Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order, Minnesota Public Utilities Commission.

shows the percentage savings. Because the termination of the PPAs involves payments in the near future versus long-term payments the discount rate assumption is a critical part of the savings estimates. It is also possible that NSP and the generation owners have different discount rates and if the generation owners have higher discount rates than NSP then they might calculate lower savings from the negotiated contract termination. However, I do not know what discount rate the generation owners assumed.

**Table 7. Percent Savings Associated With Contract Terminations**

| Project | NPV Savings – NSP[14] | Percent Savings |
|---|---|---|
| Pine Bend | $0.3M | 42% |
| Laurentian | $4.8M | 39% |
| Benson / Fibrominn | $19.0M | 62% |
| HERC | $1.5M | NA[1] |

1. NA inserted since NSP calculation is not appropriate

**Q. Do you have additional comments regarding the specifics of the savings calculations for each of the PPAs?**

A. I address specific comments associated with HERC and Benson in the following two sections.

## VI. NSP's Economic Analysis of HERC

**Q. Is NSP obligated to extend the HERC contract that expires at the end of 2017?**

A. Yes, my non-legal interpretation of the contract provision in Section 7.13 is that NSP is obligated to extend the contract for seven years if the seller makes the request. The text of Section 7.13 follows.

[14] Table 1, NSP Biomass Application

> "Term of Agreement. This agreement shall be effective upon execution and shall continue in effect until 28 years after the Commercial Operation Date. If Seller decides to continue to operate the plant after the first 28 years, NSP will purchase the electrical output offered to NSP by Seller at its fair market value to NSP at the time it is offered, for up to an additional 7 years of plant operation."

**Q. Is the term "fair market value" defined in the HERC contract?**

A. No, it is not. NSP in response to NDPSC data request 1-7 refers to the IRS definition and states that it "is the price at which a willing buyer and willing seller can agree".[15] However, that is not the full definition. The full definition follows.

> "Fair market value (FMV) is the price that property would sell for on the open market. It is the price that would be agreed on between a willing buyer and a willing seller, with neither being required to act, and both having reasonable knowledge of the relevant facts."[16]

The American Society of Appraisers defines fair market value in a similar manner.

> "An opinion expressed in terms of money, at which the property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or to sell and both having reasonable knowledge of relevant facts, as of a specific date."[17]

**Q. Is there an "open market" for energy and capacity in MISO?**

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[15] NSP response to NDPSC 1-7.

[16] IRS Publication 561 p 2.

[17] http://www.appraisers.org/Disciplines/Machinery-Technical-Specialties/mts-appraiser-resources/DefinitionsOfValue

A. Yes, MISO operates an energy and capacity market. In May 2011, NSP requested that the FERC determine that there is a competitive and open market in order to relieve NSP of the burden to buy power from QF facilities. In August 2011, FERC determined that QFs over 20 MW had nondiscriminatory access to the MISO markets and that NSP did not have to purchase power from QFs over 20 MW located in NSP's service territory and MISO.[18]

**Q. What is your opinion regarding what is fair market value for purchasing power from HERC?**

A. Based upon the IRS definition of fair market value and the FERC determination that QFs greater than 20 MW have nondiscriminatory access to the MISO market, my conclusion is that fair market value is the expected price of energy in the MISO market.

**Q. Is the NSP obligated to contract with HERC under PURPA?**

A. No. Even though the original contract was signed under PURPA, as previously discussed, NSP is not obligated to purchase power from HERC under PURPA.

**Q. Has NSP signed any PURPA contracts in the past five years?**

A. Yes, NSP has signed two purchase power agreements under PURPA for projects under 20 MW.[19]

**Q. What is the basis for pricing in those two new QF contracts?**

A. The basis of the pricing is **[Confidential Data Begins]** [redacted] **[Confidential Data Ends]**.

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[18] Federal Energy Regulatory Commission, Docket No. QM15-2-000, May 14, 2015.
[19] NSP response to NDPSC 5-1 and Case No. PU-17-245.

**Q. Is the pricing in the NSP contract extension with HERC based upon NSP's forecast of Minnesota Hub prices?**

A. No, the proposed contract pricing is substantially above the NSP forecast of Minnesota Hub prices as represented by the forecast of electricity prices at the NSPNSP node. Furthermore, the proposed contract prices are significantly above market even if the market value of the capacity is factored into the contract price.

**Q. How did NSP calculate the savings associated with the HERC contract extension?**

A. NSP calculated that the contract extension would save $26.6 M based upon a forecast of what the existing contract rate would have been if it were extended for seven years. However, that is a false comparison since NSP has no obligation to extend the contract at the old contract rate. Furthermore, the proposed contract extension is above market prices so that there are not rate payer savings, but in fact a cost to rate payers.

**Q. Is the term "at the time it is offered" defined in the HERC contract?**

A. No it is not. In the MNPUC hearing NSP suggested that the term is relevant since it could be interpreted as meaning that NSP would have to pay the avoided cost at the time HERC offered to extend the contract. That date may be as early as 2014 although NSP indicated that it did not begin negotiations until January 2016. However the Company states that formal negotiations began in January 2017.

> "Formal negotiations began in January 2017 when HERC provided an initial extension offer to NSP."[20]

**Q. Has NSP's forecast of market prices changed substantially since January 2014?**

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[20] NSP Application p 17

A. Yes. In order to identify NSP's expectations contemporaneous with the January 2014 date, I looked at the Company's IRP issued on January 5, 2015, because that would include a 2014 perspective on the wholesale market.

**Q. Has the forecast of the Minnesota Hub prices changed significantly in the past three years?**

A. Yes, I compared the graph of the forecasts of Minnesota Hub on- and off-peak prices from the January 2015 IRP with the current forecasts used in NSP's models. On average, over the seven year forecast period 2017-2024, the projected electricity prices have decreased 37%.

**Q. Is the NDPSC obligated to approve the contract pricing proposed by NSP if the utility is obligated to extend the contract?**

A. No, it is not. It is my understanding that it is in the Commission's discretion to determine if the contract price is reasonable from the standpoint of North Dakota rate payers.

**Q. Do you consider the contract extension term as prudent?**

A. I do not know the history of the original contract negotiation. However, I do not see any reason why NSP would have included the contract extension term. At the time I doubt the parties to the contract had a vision of what would be the long term status of PURPA or that there would be a competitive market that would make it unnecessary to sign PURPA contracts for generators over 20 MW. The Company already was offering a 28 year contract and that should have been sufficient.

## VII. NSP's Economic Analysis of Benson

**Q. Would you please summarize how NSP developed its economic analysis of Benson?**

A. Yes. First I want to point out that unlike the two contracts that involve payments for early termination; this transaction involves: 1) purchasing the facility, 2) addressing existing fuel contracts, 3) operating the plant for a short period before retiring the facility, and 4) site remediation. In order to capture the complexity of this transaction NSP constructed a more complex financial model. The annual financial model includes estimates for depreciation expense, non-fuel operating costs, fuel costs, fuel transportation costs, property taxes, and insurance. The model is used to calculate the annual costs associated with the purchase, operation, and shutdown of the plant. Other parts of the model include replacement power costs as well as estimates of costs to customers if the facility were not purchased.

**Q. Do you agree Benson should be shut down after NSP takes ownership?**

A. Yes, I developed an estimate of operating costs based upon the NSP estimates of fuel and transportation costs as well as labor and property taxes. The operating costs would be over $112M. Note, this excludes the return on the asset as that is already part of the asset purchase.

**Q. Does the NSP model have any valuations of the Benson project as an on-going enterprise?**

A. Yes, the model has two valuations assuming the contract continues. These valuations range from $65M to $75M.

**Q. How do the valuation estimates compare with price proposed for Benson?**

A. The valuation estimates are substantially below the $95M that the Company is proposing to pay. As I have no insight into negotiations with Benson, I have no understanding as to how the parties arrived at the final purchase price. However, from a seller's perspective I would point out the seller would try to capture some share of the potential savings to rate payers.

**Q. Do you have any concerns with other parts of the transaction costs?**

A. Yes, I am concerned about the payment of $606,823 to the City of Benson for Stranded Assets. NSP is compensating the City of Benton for stranded water, wastewater, and electric distribution assets. My perspective is that those investments made by the city are a business risk that they should bear. When the City of Benson made the investment, it should have recognized that not only would the plant eventually shut down, but also that the operating life of any power project is unknown. While the North Dakota share of this cost is less than $35,000, it should not be the responsibility of North Dakota rate payers.

## VIII. PA's Analysis of Benchmark Mark-to-Market Prices

**Q. What are the revenues associated with the existing PPAs?**

A. The Projects earn revenues based upon dispatching against the clearing price in the MISO market. The market clearing price reflects congestion and losses allocated to each generator's interconnection node. Because NSP has a take-or-pay obligation associated with these projects, NSP presumably bids them at a price that will clear the market regardless of the cost to NSP.

**Q. What are the implications of dispatching into the MISO market with respect to evaluating the savings from the Projects?**

A. Because the Projects are bid into the MISO market at a price sufficient to ensure they clear the market, there is little uncertainty regarding their projected revenues. The savings to customers can be estimated by projecting the revenues from market sales less the projected costs of the Projects.

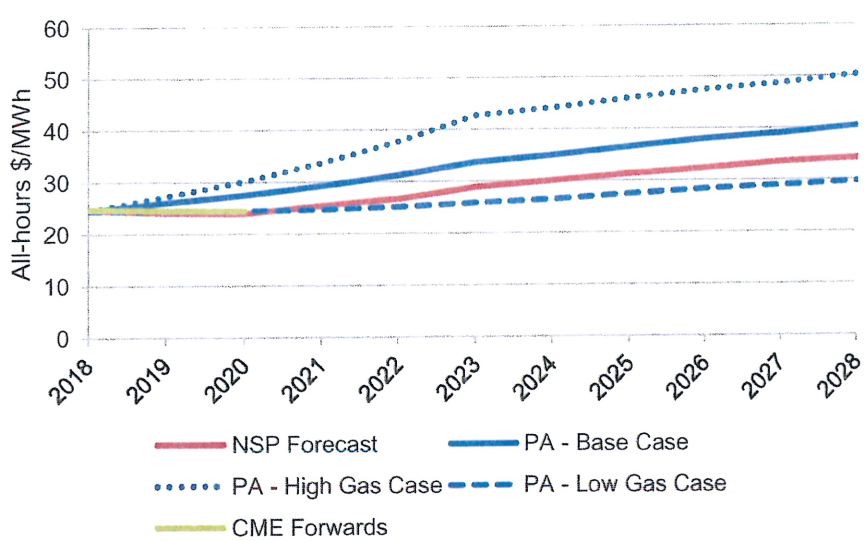
**Q. Have you performed an independent calculation of the savings based upon a forecast of market prices?**

A. Yes. I calculated the market revenues based upon the production estimates developed by NSP as well as alternative production estimates and I calculated the revenues based upon PA's independent forecast of MISO market electricity and capacity prices under a base case and high gas case scenario.

**Q. Have you prepared a comparison of the NSP and PA Minnesota Hub forecasts?**

A. Yes, the PA base case follows a similar trajectory but the PA forecast starts lower in the first year and then increases above the NSP forecast. Figure 1 illustrates the NSP and PA price forecasts.

**Figure 1. Comparison of Market Price Forecasts**



**Q. Are the estimated savings impacted by natural gas prices?**

A. Yes. Because natural gas-fired generation units are frequently the marginal units setting MISO market prices, there is a strong relationship between gas prices and power prices. The MISO Market Monitor reports that over the last 13 months, the correlation coefficient between the Henry Hub natural gas price and the MISO RT LMP was almost 0.77.[21]

**Q. How does the forecast of natural gas prices compare to historical prices and other forecasts?**

A. The NSP natural gas price forecast appears reasonable. Figure 2 shows the Company's forecast associated with its market price forecast, as well as the PA forecast for comparison.[22] The PA base case forecast is \$0.31 to \$0.77/MMBtu higher than the Company's forecast between 2018 and 2028; however, in most years the two forecasts increase at similar rates. In general, lower gas prices will tend to increase the value of terminating the Projects, and given that the Company's forecast is on average \$0.50 /MMBtu lower than the PA forecast, I believe both forecasts are in the range of reasonableness.

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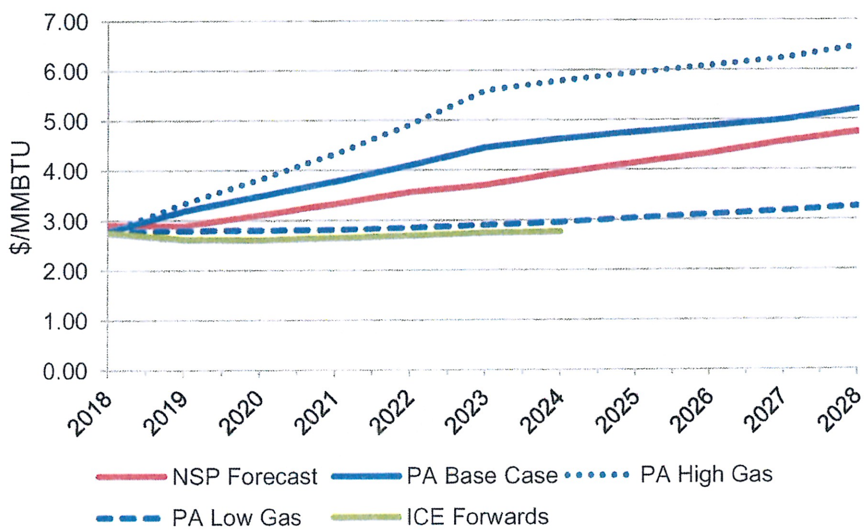
[21] MISO May 2017 Monthly Market Assessment Report, Market Evaluation and Design, July 13, 2017, p 17.

[22] The EIA forecast was created using EIA's Reference Case Henry Hub forecast, to which PA Consulting's estimate of basis differential and transport costs were added to project the Ventura Hub forecast.

**Figure 2. PA Natural Gas Price Forecast vs. NSP Forecast ($/MMBtu)**




**Q. How does the forecast of market power prices compare to historical prices?**

A. Because market power prices are highly correlated to natural gas pricing, the 2012 to 2016 power prices followed a similar pattern to natural gas prices, with power prices having risen in the 2013 to 14 timeframe, followed by a sharp decline in 2015 and a small increase since then. For the purposes of this evaluation, I noted that the 2015 to 16 prices were the lowest of the five year period.

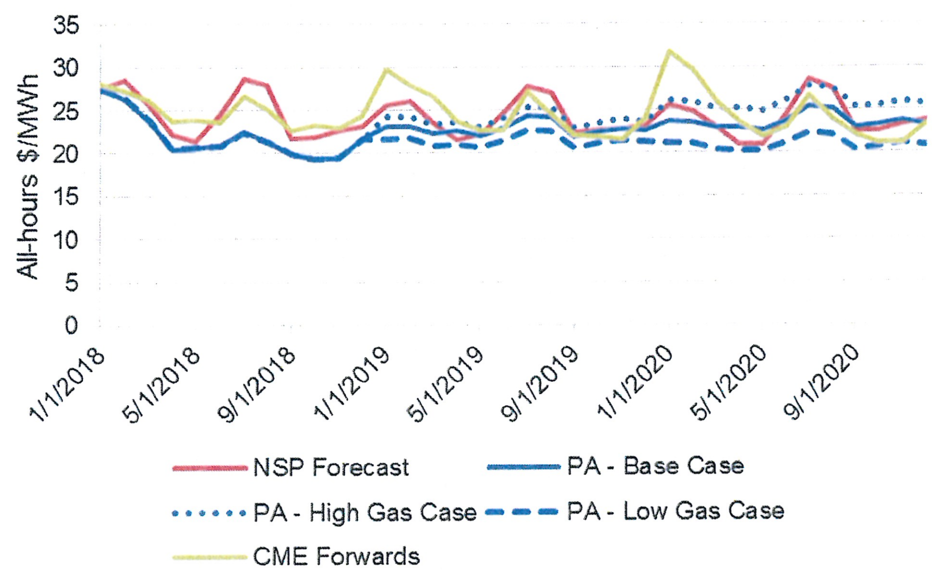
**Q. How does the Company's forecast of market power prices compare to current forward prices?**

A. The forecast is reasonably consistent with the forward market, recognizing that the forward market has some volatility while the NSP forecast is a single point in time forecast. Figure 3 provides a comparison of the forecasts.[23] All else being equal, a

[23] Forwards as of November 19, 2017 for the Minnesota Hub as reported by CME http://www.cmegroup.com/trading/energy/electricity/minnesota-hub-off-peak-calendar-month-lmp-swap-futures.html

higher market price forecast will result in a lower estimate of savings from terminating the contracts.

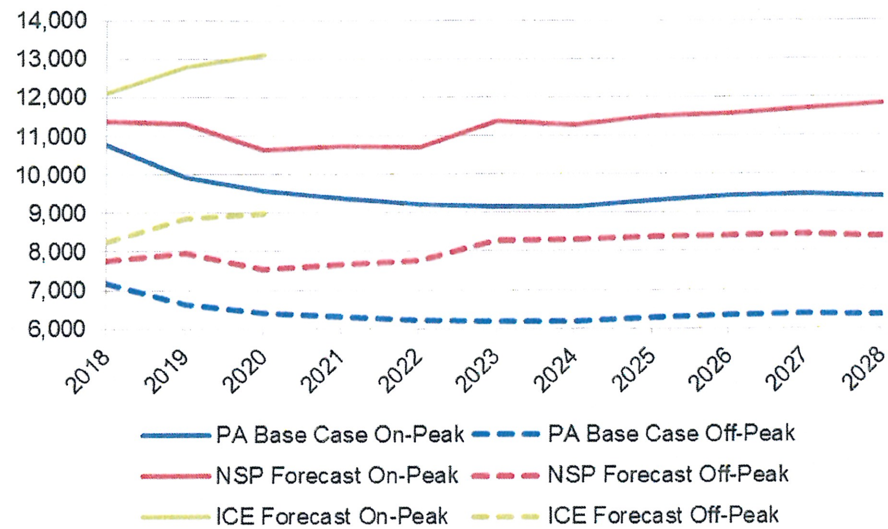
**Figure 3. Current MIN HUB Forwards versus NSP Forecast ($/MWh)**




**Q. Does the Company's market power price forecast appear reasonable based upon the calculated market heat rate?**

A. I calculated monthly on- and off-peak market heat rates using the monthly market price and gas price forecasts used by NSP as inputs to Strategist, and did the same using the forward market power price and natural gas price forecasts. The analysis revealed that through 2027, the Company's implied on-peak heat rates were either lower than or generally equal to the forward market implied heat rates, suggesting the Company's forecast aligned with the market. The Company's off-peak implied heat rates are consistently higher than the forward market off-peak heat rates, which will tend to overstate the Projects' energy cost savings. This comparison is shown in Figure 4.

**Figure 4. Market Heat Rate Forwards versus NSP Forecast (Btu/kWh)**




## IX. PA's Contract Analysis

**Q. Did you review the Company's economic analysis of the estimated electricity cost savings to ratepayers associated with the four projects?**

A. Yes, I reviewed the individual spreadsheet models provided by the Company. My conclusion is that the spreadsheet models were structurally developed correctly and that the reported levelized costs are consistent with the models. Of course, these results are based upon a number of critical assumptions. I previously discussed the assumptions related to Minnesota Hub wholesale market power prices, cost of capital, and the incorrect reference prices used to calculate savings for HERC. In this section of my testimony, I summarize the results of my analysis using PA's market price forecasts as well as inclusion of the market value of the capacity that will be lost associated with terminating the three contracts. In addition, I reviewed the volume estimates used by NSP to estimate the restructured contract savings.

**Q. Does the economic analyses include any valuation of environmental or economic development benefits?**

A. No, neither environmental nor economic development benefits are incorporated into the estimated savings to ratepayers or levelized cost analysis. My understanding is that exclusion of these two items is consistent with North Dakota statute.[24]

**Q. How did you value the capacity of the Projects in the economic analysis?**

A. I started with the clearing price of $1.50 / MW-day from the MISO 2017/2018 Planning Resource Auction results for MISO Zone 1. While this is not enough money to support the construction of new capacity it is a reflection of both the need for capacity in the region as well as the dynamics of a market dominated by vertically integrated utilities that conduct advanced planning and procure resources sufficient to meet their needs.

**Q. Did you estimate how the savings from terminating the PPAs would change under different market power price scenarios?**

A. Yes. I evaluated the savings under two market power price scenarios; the PA base case market price forecast and high gas forecast for Minnesota Hub.

**Q. What are the estimated savings based upon the different market power price scenarios that you developed?**

A. As shown in Table 8 below, the base case savings are approximately 3% to 17% lower than the NSP estimates for Pine Bend, Laurentian, and Benson. This is expected due to PA's higher price forecast discussed in the prior section. The savings estimate for HERC are negative since NSP based their savings estimate compared to continuing the expired contract pricing. The high gas case savings are lower than the base case due to the higher resulting market prices.

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[24] *See* N.D.C.C. § 49-02-23.

**Table 8. Market Price Sensitivity Analyses**

| Project | NPV Savings – NSP | NPV Savings – PA Base | NPV Savings – PA High Gas Case | NPV Savings – PA Low Gas Case |
|---|---|---|---|---|
| Pine Bend | $5.2M | $4.3M | $3.2M | $5.3M |
| Laurentian | $87M | $80.1M | $70.5M | $89.5M |
| Benson / Fibrominn | $345.6M | $332.3M | $312.9M | $351.5M |
| HERC | $26.6M | $(15.8)M | $(11.4)M | $(19.9)M |

**Q. Is it likely that market power prices will increase to the point that the negotiated payments to terminate the projects are not economic?**

**A.** I do not think it is likely, because the market power prices would have to increase significantly above the PA higher priced high gas case.

**Q. Did you review the volume estimates that NSP used to calculate the NPV of savings?**

**A.** Yes, I evaluated the basis for their selection of volumes and also reviewed historical production volumes. While not a large factor, my conclusion is that the Company's choice of using the most recent year production for a number of projects rather than using an average of historical years tended to result in higher volumes and therefore higher estimates of savings. A summary of my analysis is shown in Table 9.

**Table 9. Contract Analysis Volumes[25]**

**[Confidential Data Begins]**

| Project | Company Criteria | Company Volume Estimate (MWH) | Five Year Average (2012 – 2016) MWH |
|---|---|---|---|
| Pine Bend | [redacted] | [redacted] | [redacted] |
| Laurentian | [redacted] | [redacted] | [redacted] |
| Benson / Fibrominn | [redacted] | [redacted] | [redacted] |
| HERC | [redacted] | [redacted] | [redacted] |

**[Confidential Data Ends]**

**Q. What are your conclusions with regards to the Company's estimate of $464 million of savings from terminating the PPAs?**

A. My conclusion is that the Company's proposed treatment of the Projects, with the exception of HERC, will result in electricity cost savings to North Dakota customers.

## X. Recommendations

**Q. Is the Pine Bend PPA termination and associated payments in the interest of North Dakota rate payers?**

A. Yes, my analysis is consistent with the Company's analysis and it will result in lower costs.

**Q. Does the Pine Bend transaction qualify for treatment as an ADP?**

[25] Five year historical production in last column is based upon NSP response to NDPSC 3-004. Company Criteria in column 2 based upon NSP response to NDPSC 7-001.

A. This question asks for a legal conclusion... The advance determination of prudence statute states:

> "In this section, unless the context otherwise requires, resource addition means construction, modification, purchase, or lease of an energy conversion facility, renewable energy facility, demand response system, transmission facility, or a contract to acquire energy, capacity, or demand response for the purpose of providing electric service." 49-05-15

The contract with Gas Recovery Systems Energy is clearly to terminate the existing power purchase agreement and not to acquire a facility, acquire energy or capacity. However the language "unless the context otherwise requires" may give the Commission discretion. If the transaction qualifies under the statute, my conclusion is that the transaction is in the public interest and NSP should be encouraged to pursue transactions such as this, and PPAs that are not cost effective should be terminated if economic to do so.

**Q. If the Commission determines that an ADP for Pine Bend is appropriate, should there be any qualifications on the ADP?**

A. Yes, the ADP should be clear that if NSP does not hold to a prior settlement commitment to build a gas turbine in eastern North Dakota before the end of 2025, the ADP will be adjusted downward by 50% to match the refund commitment in the Case No. PU-12-813 settlement.

**Q. Should the Commission grant an ADP for the Benson project?**

A. Yes, the transaction will result in savings to North Dakota rate payers. However, the ADP should be qualified such that if NSP does not hold to a prior settlement commitment to build a gas turbine in North Dakota before the end of 2025, the ADP will be adjusted downward by 50% to match the refund commitment in the Case No. PU-12-813 settlement. In addition, I recommend the removal of the $607K from the capital costs associated with the payment to the City of Benson for stranded investments related to water, waste water, and electric distribution assets.

**Q. Should the Commission grant an ADP for the HERC PPA extension?**

A. No, the negotiated contract price is significantly above market prices resulting in an increased burden on North Dakota rate payers.

**Q. Should the Commission order any other adjustments associated with the termination of the HERC contract at the end of 2017?**

A. Yes, a mechanism is needed to compensate rate payers for the cost of capacity that is included in base rates since NSP will no longer incur those costs.

**Q. Do you have any recommendations with regards to how NSP should conduct a similar analysis in the future?**

A. Yes, for a similar contract, the Company should test the savings against alternative price forecasts. In this instance the contracts are so far above current market pricing that typical sensitivities do not change the conclusions. However, market prices and forecasts inevitable vary from a single point forecast so different scenarios should always be evaluated.

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

A. Yes.

## Jim Heidell

Jim Heidell specializes in electric and gas utility regulation, utility finance, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. Mr Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. Mr Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. .

### Primary expertise

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation

### Related experience

- Strategic planning
- Financial modelling of complex investments
- Financial planning

### Qualifications

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

## Primary expertise

Utility Regulatory Support - Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.

Renewable Energy Technologies - Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.

Analysis of Electric Markets - Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

Asset Valuation / M&A Advisor - Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.

Damages Estimation for Civil Litigation Testimony - Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

Financial Analysis - Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.

## Key client achievements

### *UTILITY REGULATORY SUPPORT*

Analysis and testimony on behalf of Constellation Energy Group related to typical merger and acquisition conditions required by regulators in utility and non-utility transactions. Testimony related to the EDF / Constellation joint venture.

Testimony related the use and design of ratchet rates on behalf of Northern Indiana Public Service Company. Testimony related to the application of ratchets to the client's unique position and appropriate recovery of costs.

Analysis of the economics of an electric utility's interruptible rates including the value of interruptions versus the payments received by customers. Developed recommendations for pricing interruptible rate programs that were consistent with the utility's avoided costs and ISO markets.

Developed electric cost-of-service studies, rate design, and testimony to support Puget Sound Energy in multiple general rate cases in Washington. The engagements included addressing issues such as special rates for strategic customers with competitive options, line extension policies, and rates to address revenue attrition.

Developed natural gas cost-of-service studies, rate design, and testimony to support Puget Sound Energy in a general rate case in Washington.

Prepared marginal cost of service studies and testimony to support Montana-Dakota utilities in multiple Montana rate cases.

Assist Montana-Dakota Utilities in development of its integrated resource plan through analysis of options using the Strategist planning model.

Supported Montana-Dakota Utilities in answering a complaint in front of the South Dakota Public Utilities Commission regarding a wind generator requesting a contract under the provisions of PURPA.

Provided expert testimony related to Montana Dakota's proposed participation in the Big Stone II power plant. Prepared and delivered testimony provided in multiple hearings in North Dakota and Minnesota.

Prepared testimony on behalf of Hydro One Networks regarding rate shock and how to address necessary rate changes associated with the restructuring of the electric utility business in Ontario.

Developed an analysis or weather risk associated with the retail power sales of IPALCO. Effort was conducted as part of a comprehensive risk assessment conducted by AES. Models of the weather / load relationship were developed and then integrated with the rate structures and cost adjustment mechanisms to assess the utility's overall exposure to weather risk.

Advised Old Dominion Electric Cooperative on options for acquiring new generation in a depressed power market and incorporation of the analysis in their long-term resource planning.

### MEXICO ENERGY MARKET REFORM

Developed rate proposals for PEMEX SDC tariffs for transportation, conditioning and storage of oil and natural gas. The rate proposals were the final stage of a project that started with benchmarking tariff structures in key markets worldwide, development of business considerations, development of appropriate cost of service and rate design principles, preparation of a revenue requirement, development of a cost of service model and study, and development of proposed rates for the PEMEX services.

Developed long-run electricity price forecasts multi-national energy companies reflecting the rules of the reformed market. Price forecast based upon an hourly chronological dispatch model.

Delivery of a workshop for rate design for CFE transmission. Review of distribution and transmission revenue requirements for CFE and analysis of financial implications of energy reform on CFE.

### ELECTRIC MARKETS RISK MODELING

Advised major European trading company on entering the U.S. electricity trading business. Project included selection of target markets, characterization of types of trading opportunities, characterization of market volumes, identification of target customers, review of key licensing requirements, and development of a high level business strategy.

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

### M&A and BANKRUPTCY ADVISOR

Advised creditors of the Puerto Rico Power Authority (PREPA) with regards to restructuring over eight billion dollars of debt. Multiple analyses were developed to support the restructuring negotiations including the development of a financial model to forecast the revenue requirement under different scenarios of fuel costs, types of generation resources, and cost savings initiatives.

Prepared an analysis of New Mexico Gas Company to support a prospective buyer. We assisted multiple clients with due diligence related to the acquisition of gas LDCs. Assisted the client with a review of the deal model including: assumptions about rate cases, assumptions regarding ROE, sales growth by rate class, and revenue by rate class. The engagement also included an assessment of the regulatory climate and potential conditions and costs associated with obtaining regulatory approval of the transaction.

Prepared a valuation of the Mountaineer Gas Company including the analysis of regulatory issues to support the debt financing associated with the purchase of the energy company.

Assisted an infrastructure fund in valuing power contracts and reviewed the regulatory model used in conjunction with establishing the price to bid for the acquisition of Northwestern Utility.

Prepared an analysis of Duquense Light to support an infrastructure fund's bid for the utility. The analysis included projections of growth opportunities through distribution & transmission investment, analysis of the POLR load obligation, and a review of key regulatory issues.

Developed a valuation model of Mirant including analysis of debt carrying capacity to assist a strategic player in the U.S. Power Industry determine whether to make an unsolicited offer to purchase Mirant.

Assisted an international oil company in development of modelling processes and assumptions to support a corporate effort to acquire a fleet of U.S. merchant generating assets.

Support a strategic player in valuing the Lake Road Generation Plant as part of their bid to acquire the asset in a competitive auction. Effort involved projection of future gross margins of the plant, analysis of the ISO-NE Forward Capacity Market, and analysis of transmission constraints.

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG.

Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

Member of team that advised Calpine as part of the company's restructuring and plan of reorganization. Assignment included analysis of the Canadian portfolio, advising on the sale of generation assets, modelling of long-term turbine maintenance costs, and the valuation of complex power contract.

Assisted the lenders on valuation and strategy related to AES' turn-back of the Granite Ridge Power Plant to the lender group.

Advised the bank and lender group on valuation and strategy related to the bankruptcy of the Kendall Power Plant.

***ELECTRIC GENERATION FINANCE SUPPORT:***

Market expert report for the Landfill Energy Systems, a national 66 MW portfolio of fourteen landfill gas power plants. The market expert report included a discussion of the key attributes of each of the power markets that the portfolio encompasses, long-term forecasts of wholesale electricity prices, and forecasts of gross margins.

Independent Market Expert Report to support the financing of the repowering and development of a fleet of combined cycle and simple cycle power plants in the ERCOT market. The independent market expert report was used to support the syndication of loans and obtaining debt ratings associated with investing over $1 billion in the Barney Davis, Nueces Bay, and Laredo Energy Center facilities.

Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the syndication and rating of over $400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over $100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

## Additional Expertise - Expert Testimony

Before the Hawaii Public Service Commission, Direct Testimony Of James A. Heidell, Docket No. 2017-0105 In The Matter Of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

# Historical and Forecast Electricity Production

*MWh*

| Year | (A)ctual / (F)orecast | Pine Bend | Laurentian Energy Authority, L.L.C. | Benson Power, LLC/Fibrominn | Covanta Hennepin Energy Resource Co LP |
|---|---|---|---|---|---|
| 2003 | A | 93,666 | N/A | N/A | 205,378 |
| 2004 | A | 70,378 | N/A | N/A | 222,086 |
| 2005 | A | 43,945 | N/A | N/A | 218,623 |
| 2006 | A | 60,753 | N/A | N/A | 218,587 |
| 2007 | A | 66,124 | 244,527 | 171,813 | 224,116 |
| 2008 | A | 56,581 | 270,140 | 338,776 | 215,402 |
| 2009 | A | 49,829 | 286,768 | 394,447 | 187,055 |
| 2010 | A | 44,286 | 266,540 | 409,574 | 194,352 |
| 2011 | A | 43,080 | 255,559 | 430,080 | 217,708 |
| 2012 | A | 34,544 | 265,664 | 442,523 | 197,472 |
| 2013 | A | 36,750 | 270,631 | 336,476 | 124,097 |
| 2014 | A | 36,046 | 242,970 | 392,576 | 189,628 |
| 2015 | A | 31,600 | 262,966 | 378,491 | 178,892 |
| 2016 | A | 36,538 | 264,543 | 344,054 | 193,000 |
| | | [ Confidential Data Begins] | | | |
| 2017 | A/F[1] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2018 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2019 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2020 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2021 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2022 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2023 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2024 | F | [redacted] | [redacted] | [redacted] | [redacted] |
| 2025 | F | [redacted] | [redacted] | [redacted] | |
| 2026 | F | | [redacted] | [redacted] | |
| 2027 | F | | | [redacted] | |
| 2028 | F | | | [redacted] | |
| | | [ Confidential Data Ends] | | | |

*Summary*

| | | | | |
|---|---|---|---|---|
| *Avg 2012 - 2016* | 35,096 | 261,355 | 378,824 | 176,618 |
| *Avg 2013 - 2017* | 33,804 | 259,962 | 374,013 | 179,170 |
| | [ Confidential Data Begins] | | | |
| *Avg Used by NSP in Models* | [redacted] | | | |
| | [ Confidential Data Ends] | | | |

**Notes**

1. 10 months actuals / two months forecast

## Power Pricing Forecasts

### Annual

| | *nominal$* | | | | | | | | | *nominal$* | | | *nominal$* | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PA - Base Case** | | | **PA - High Gas Case** | | | **PA - Low Gas Case** | | | **NSP Forecast** | | | **CME Forwards** | | |
| *year* | *On Peak* | *Off Peak* | *All-hours* | *On Peak* | *Off Peak* | *All-hours* | *On Peak* | *Off Peak* | *All-hours* | *On Peak* | *Off Peak* | *All-hours* | *On Peak* | *Off Peak* | *All-hours* |
| | **[ Confidential Data Begins ]** | | | | | | | | | **[ Confidential Data Begins ]** | | | | | |
| 2018 | [redacted] | | | | | | | | | [redacted] | | | 33.30 | 22.66 | 24.78 |
| 2019 | [redacted] | | | | | | | | | [redacted] | | | 33.40 | 23.11 | 24.49 |
| 2020 | [redacted] | | | | | | | | | [redacted] | | | 34.12 | 23.40 | 24.41 |
| 2021 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2022 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2023 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2024 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2025 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2026 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2027 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2028 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2029 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2030 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2031 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2032 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2033 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2034 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2035 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2036 | [redacted] | | | | | | | | | [redacted] | | | | | |
| | **[ Confidential Data Ends ]** | | | | | | | | | **[ Confidential Data Ends ]** | | | | | |

On-peak hours: 47%
Off-peak hours: 53%

## Natural Gas Pricing Forecasts

**Annual**

| year | PA Base Case (nominal$) | PA High Gas (nominal$) | PA Low Gas (nominal$) | NSP Forecast (nominal$) | ICE Forwards (nominal$) |
|---|---|---|---|---|---|
| | [ Confidential Data Begins ] | | | | |
| 2018 | [redacted] | [redacted] | [redacted] | [redacted] | 2.75 |
| 2019 | [redacted] | [redacted] | [redacted] | [redacted] | 2.61 |
| 2020 | [redacted] | [redacted] | [redacted] | [redacted] | 2.60 |
| 2021 | [redacted] | [redacted] | [redacted] | [redacted] | 2.65 |
| 2022 | [redacted] | [redacted] | [redacted] | [redacted] | 2.69 |
| 2023 | [redacted] | [redacted] | [redacted] | [redacted] | 2.74 |
| 2024 | [redacted] | [redacted] | [redacted] | [redacted] | 2.76 |
| 2025 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2026 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2027 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2028 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2029 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2030 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2031 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2032 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2033 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2034 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2035 | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2036 | [redacted] | [redacted] | [redacted] | [redacted] | |
| | [ Confidential Data Ends ] | | | | |

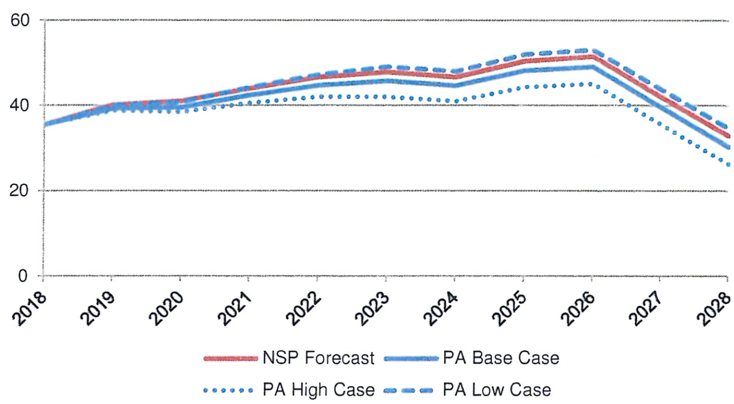
**Market Heat Rates**

| | nominal$ | | | | | | | | | nominal$ | | | nominal$ | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | PA Base Case | | | PA High Gas Case | | | PA Low Gas Case | | | NSP Forecast | | | ICE Forecast | | |
| *year* | *On-Peak* | *Off-Peak* | *All-hours* | *On-Peak* | *Off-Peak* | *All-hours* | *On-Peak* | *Off-Peak* | *All-hours* | *On-Peak* | *Off-Peak* | *All-hours* | *On-Peak* | *Off-Peak* | *All-hours* |
| | **[ Confidential Data Begins ]** | | | | | | | | | **[ Confidential Data Begins ]** | | | | | |
| 2018 | [redacted] | | | | | | | | | [redacted] | | | 12,127 | 8,251 | 9,025 |
| 2019 | [redacted] | | | | | | | | | [redacted] | | | 12,786 | 8,847 | 9,376 |
| 2020 | [redacted] | | | | | | | | | [redacted] | | | 13,104 | 8,987 | 9,375 |
| 2021 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2022 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2023 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2024 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2025 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2026 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2027 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2028 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2029 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2030 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2031 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2032 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2033 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2034 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2035 | [redacted] | | | | | | | | | [redacted] | | | | | |
| 2036 | [redacted] | | | | | | | | | [redacted] | | | | | |
| | **[ Confidential Data Ends ]** | | | | | | | | | **[ Confidential Data Ends ]** | | | | | |

## Savings Analysis

**Benson (buy and shut down)**
*nominal $ (chart in nominal $millions)*

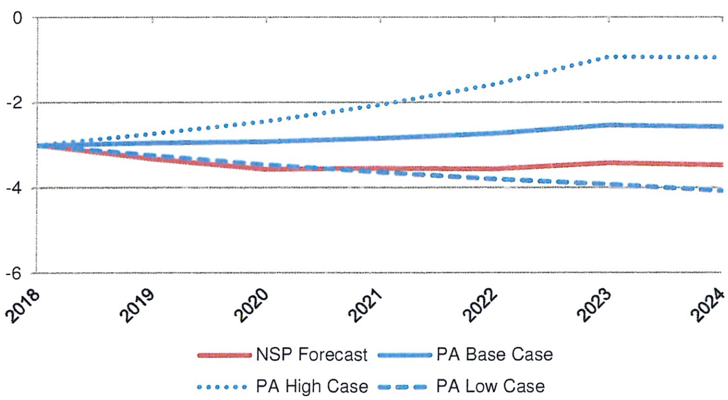
| Year | NSP Forecast | PA Base Case | PA High Case | PA Low Case |
|---|---|---|---|---|
| 2018 | 35,556,473 | 35,567,565 | 35,567,565 | 35,567,565 |
| 2019 | 40,216,739 | 39,351,035 | 38,847,097 | 40,033,144 |
| 2020 | 41,130,606 | 39,643,720 | 38,553,942 | 40,884,201 |
| 2021 | 44,143,645 | 42,492,010 | 40,649,879 | 44,360,483 |
| 2022 | 46,772,712 | 44,817,034 | 42,104,592 | 47,337,214 |
| 2023 | 47,957,795 | 45,882,657 | 42,117,070 | 49,141,984 |
| 2024 | 46,741,684 | 44,737,760 | 41,093,323 | 48,111,065 |
| 2025 | 50,511,815 | 48,282,561 | 44,370,841 | 52,072,039 |
| 2026 | 51,596,594 | 49,153,151 | 45,174,865 | 53,152,279 |
| 2027 | 42,080,319 | 39,716,671 | 35,665,549 | 43,888,389 |
| 2028 | 32,922,778 | 30,323,762 | 26,278,435 | 34,669,185 |
| **TOTAL** | **479,631,160** | **459,967,926** | **430,423,157** | **489,217,547** |
| **NPV** | **345,545,226** | **332,260,977** | **312,852,263** | **351,453,003** |
| **ND Share NPV** | **18,970,433** | **18,241,128** | **17,175,589** | **19,294,770** |



**HERC**

*nominal $ (chart in nominal $millions)*

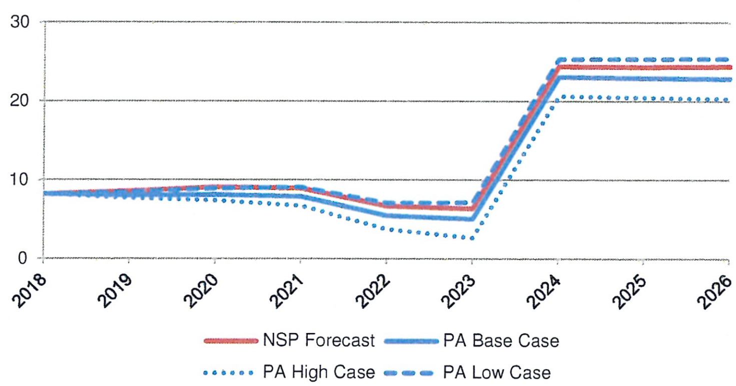
| Year | NSP Forecast | PA Base Case | PA High Case | PA Low Case |
|---|---|---|---|---|
| 2018 | -2,987,015 | -2,992,674 | -2,992,674 | -2,992,674 |
| 2019 | -3,307,307 | -2,938,889 | -2,724,429 | -3,229,175 |
| 2020 | -3,557,226 | -2,909,409 | -2,434,607 | -3,449,870 |
| 2021 | -3,534,740 | -2,831,854 | -2,047,898 | -3,627,019 |
| 2022 | -3,552,536 | -2,720,259 | -1,565,925 | -3,792,771 |
| 2023 | -3,409,885 | -2,526,769 | -924,249 | -3,913,840 |
| 2024 | -3,457,689 | -2,563,345 | -936,845 | -4,068,839 |
| **TOTAL** | **-23,806,398** | **-19,483,199** | **-13,626,626** | **-25,074,189** |
| **NPV** | **-19,050,829** | **-15,757,393** | **-11,427,569** | **-19,922,324** |
| **ND Share NPV** | **-1,045,891** | **-865,081** | **-627,374** | **-1,093,736** |



**Laurentian**

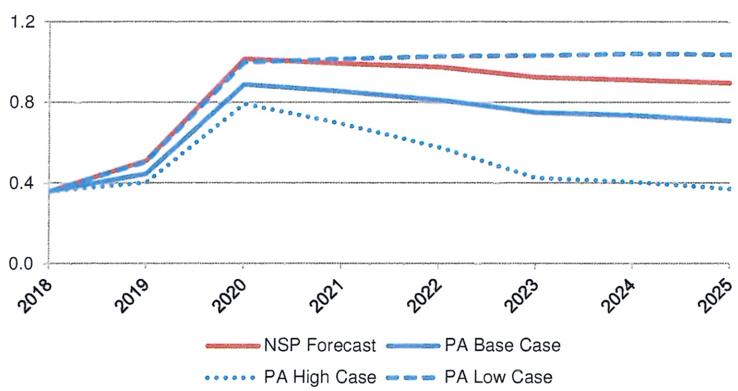
*nominal $ (chart in nominal $millions)*

| Year | NSP Forecast | PA Base Case | PA High Case | PA Low Case |
|---|---|---|---|---|
| 2018 | 8,266,779 | 8,276,923 | 8,276,923 | 8,276,923 |
| 2019 | 8,628,514 | 8,076,039 | 7,754,960 | 8,511,037 |
| 2020 | 9,144,403 | 8,174,684 | 7,463,140 | 8,984,730 |
| 2021 | 8,985,951 | 7,931,275 | 6,756,428 | 9,123,029 |
| 2022 | 6,764,135 | 5,514,612 | 3,785,003 | 7,122,270 |
| 2023 | 6,421,947 | 5,094,990 | 2,693,298 | 7,174,668 |
| 2024 | 24,473,574 | 23,131,632 | 20,693,926 | 25,388,602 |
| 2025 | 24,424,269 | 22,999,088 | 20,504,090 | 25,416,441 |
| 2026 | 24,473,078 | 22,911,143 | 20,373,945 | 25,462,193 |
| **TOTAL** | **121,582,650** | **112,110,386** | **98,301,712** | **125,459,893** |
| **NPV** | **86,927,974** | **80,138,556** | **70,530,853** | **89,459,955** |
| **ND Share NPV** | **4,772,346** | **4,399,607** | **3,872,144** | **4,911,352** |



**Pine Bend**
*nominal $ (chart in nominal $millions)*

| Year | NSP Forecast | PA Base Case | PA High Case | PA Low Case |
|---|---|---|---|---|
| 2018 | 360,000 | 360,000 | 360,000 | 360,000 |
| 2019 | 513,781 | 447,918 | 404,340 | 506,871 |
| 2020 | 1,018,377 | 890,674 | 794,171 | 1,000,446 |
| 2021 | 994,368 | 855,631 | 696,280 | 1,017,183 |
| 2022 | 977,503 | 812,670 | 577,992 | 1,030,503 |
| 2023 | 926,910 | 752,086 | 426,263 | 1,033,709 |
| 2024 | 914,256 | 737,371 | 406,691 | 1,043,030 |
| 2025 | 898,250 | 710,590 | 372,139 | 1,037,990 |
| **TOTAL** | **6,603,444** | **5,566,940** | **4,037,876** | **7,029,732** |
| **NPV** | **5,041,532** | **4,276,027** | **3,180,060** | **5,330,535** |
| **ND Share NPV** | **276,780** | **234,754** | **174,585** | **292,646** |



STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

| | |
|---|---|
| **Public Service Commission**<br>**Northern States Power Company**<br>**Advance Prudence – Biomass PPAs**<br>**Application** | **Case No. PU-17-270** |
| **Public Service Commission**<br>**Northern States Power Company**<br>**Deferred Accounting – Biomass PPAs**<br>**Application** | **Case No. PU-17-271** |
| **Public Service Commission**<br>**Northern States Power Company**<br>**Deferred Accounting – Laurentian PPA Termination**<br>**Application** | **Case No. PU-17-322** |

## VERIFICATION

STATE OF COLORADO )
) ss.
COUNTY OF DENVER )

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

James A. Heidell

Subscribed and sworn to before me this 19 day of December, 2017.

JEREMY RYAN MAST
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164043780
MY COMMISSION EXPIRES NOVEMBER 9, 2019

Notary Public
My Commission Expires: Nov. 9, 2019