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DIRECT TESTIMONY AND SCHEDULES
PHILIP JOSEPH "P.J." MARTIN

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – BIOMASS PPAs APPLICATION	CASE NO. PU-17-____
NORTHERN STATES POWER COMPANY DEFERRED ACCOUNTING – BIOMASS PPAs APPLICATION	CASE NO. PU-17-____

Economic Analysis Testimony

Exhibit___ (PJM-1)

June 30, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC (PJM), Southeast Electric Reliability Council (SERC), and other markets across the U.S. My statement of qualifications is provided as Exhibit ___(PJM-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions and acquisitions, power purchase agreements (PPAs), facility retirements, and restructurings.

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

A. The purpose of my testimony is to discuss, in detail, the economic impacts of the three biomass-related transactions that are the subject of this Application. The three transactions that I analyze are: (1) Benson Power (Fibrominn) PPA Termination and Facility Acquisition for Subsequent Shutdown; (2) Pine Bend Biogas PPA Early Termination; and (3) Hennepin Energy Recovery Center (HERC) PPA Extension and Restructuring (collectively, the Proposed Transactions). My testimony details the economic impacts of these three transactions and supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the Proposed Transactions, in its entirety. My testimony provides an economic analysis of the Proposed Transactions and the overall ratepayer benefits it generates.

II. ECONOMIC ANALYSIS

Q. HOW DID THE COMPANY EVALUATE THE PROPOSED TRANSACTIONS?

A. We performed mark-to-market modeling in Microsoft Excel to calculate the cost savings to customers. The details of the calculations for each project are included in greater detail below. At a high level, we compared the costs of the Proposed Transactions, including the costs of market replacement energy with the projected costs of the existing contracts through expiration.

Q. DID YOU PERFORM AN ANALYSIS USING STRATEGIST?

A. No. We used a mark-to-market analysis instead of using Strategist for five reasons.

First, the total nameplate capacity of all the resources in question total 100.7 MW, which is small relative to the total nameplate capacity on our system which is over 10,000 MW.

Second, the contracts at issue all are "must take" contracts and the volumes are generally predictable on an annual basis. Accordingly, because production levels stay relatively flat, the analysis did not require a full system model to simulate the dispatch of these resources relative to others.

Third, 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.

Fourth, because the proposed transactions only impact energy/fuel—as opposed to capacity—a simple comparison to the Minnesota Hub forward curve provides a good proxy alternative to a full Strategist run.

Fifth and finally, for contracts that we are ending prematurely, our analysis assumes all avoided contract MWh are replaced with market energy purchases. This is likely a conservative assumption as there are many hours in which the system is long on energy and eliminating the contracts is not only avoiding the purchase costs associated with the existing PPA contracts but also potentially reducing the amount of energy that we are selling at low Locational Marginal Prices (LMP) market prices into the MISO market. In other words, eliminating the energy from these contracts potentially reduces the amount of excess energy we have to sell off of other NSP resources in low load hours and thereby reduces our exposure to market prices. Strategist could have provided some insight into the impacts on market sales; however, we felt the benefits of the proposed transactions are compelling without including any additional savings.

Q. WHAT IS THE OVERALL IMPACT OF THE PROPOSED TRANSACTIONS?

A. If approved by the Commission, the proposed transactions will achieve more than $519.1 million in total nominal cost savings for our customers or $377.4 million net present value (NPV) over the next 11 years. This total is on a system-wide basis.

Q. WHAT ARE THE NORTH DAKOTA-SPECIFIC IMPACTS OF THE PROPOSED TRANSACTIONS?

A. The North Dakota jurisdiction represents about 5.49 percent of the overall NSP System, net of Interchange Agreement billings to NSPW. As a result, North Dakota customers should see overall benefits from the Proposed Transactions commensurate with that level.

The results of the analysis show that terminating the Benson PPA (with the purchase and subsequent shutdown of the Benson facility) and the Pine

Bend PPA as proposed in the Application as well as the renegotiation of the HERC PPA results in net ratepayer savings to our North Dakota customers in the neighborhood of $20.7 million NPV ($28.5 million nominal). The total estimated savings associated with the Proposed Transactions is summarized in Table 1 below.

Table 1: Nominal and NPV Savings of Proposed Transactions

	Nominal Dollars in Millions				NPV Dollars in Millions			
	System			ND	System			ND
Transaction	Current	Proposed	Savings	Savings	Current	Proposed	Savings	Savings
Pine Bend	15.4	8.8	6.6	0.4	12.3	7.1	5.2	0.3
HERC	89.1	56.2	32.9	1.8	71.5	44.9	26.6	1.5
Fibrominn	771.6	292.0	479.6	26.3	561.2	215.6	345.6	19.0
Total	876.1	357.0	519.1	28.5	645.0	267.6	377.4	20.7

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the Proposed Transactions will provide material cost savings to our North Dakota customers.

Q. DID THE COMPANY ANALYZE THE COST IMPACT OF EACH OF THE ELEMENTS OF THE PROPOSED TRANSACTIONS?

A. Yes, I address each, in turn, below.

A. Benson PPA Termination and Buyout for Subsequent Shutdown

Q. PLEASE DESCRIBE THE BASIC PARAMETERS ANALYZED IN YOUR REVIEW OF THE BENSON PPA.

A. I compared the cost of the Benson PPA for the remainder of its term (through 2028) with the sum of (i) the cost of the purchase of the asset and subsequent shutdown of the Benson facility, plus (ii) the cost of replacement market energy during that same period.

Q. HOW DID YOU DETERMINE THE COST OF THE BENSON PPA FOR THE REMAINDER OF ITS TERM?

A. I took the assumed production from the Benson facility based on historical actual production and calculated the annual obligations under the PPA. I assumed that the Benson facility would produce ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** per year with the exception of a few years that were adjusted slightly lower to account for maintenance. This results in an estimated levelized cost to customers including all energy, fuel transportation, ash revenue shortfall, and property tax costs of ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** over the remainder of the Term.

Table 2 below provides a summary of the assumptions used in our Benson PPA cost analysis.

Table 2: Assumptions for Continuing PPA

Assumption	Support
Energy price escalation	1.1% based on 50% of the Company's most recent internal non-labor escalation factor, in line with escalation terms under the PPA and historical actuals. Energy price escalates through mid-2023, then remains flat until cumulative generation reaches 7.9 million MWhs (anticipated in 2027) at which point the energy price is based on market through the remainder of the PPA

Assumption	Support
Pass through escalation	2.2% based on the Company's most recent internal non-labor escalation factor, in line with escalation terms under the PPA. Escalation is applied to pass through costs through the remainder of the PPA
Heat content and heat rate	Heat content of 8.55 MMBtu/Ton and plant heat rate of 14,250 Btu/kWh per Benson Power's 2016 budget
86% capacity factor	Based on Benson Power's last 5 months of historical performance in 2016, first 5 months in 2017 and 2 months for Benson Power's 2017 forecast
$62.9M 2018 energy and fuel transportation charge	PPA component; based on recent Benson Power invoices escalated for inflation per the PPA (incorporates 35%/65% poultry litter/wood biomass fuel mix, consistent with April 2017 actuals and Benson Power expectations)
[TRADE SECRET BEGINS TRADE SECRET ENDS] 2018 ash revenue shortfall	PPA component; based on recent Benson Power invoices escalated for inflation per the PPA
$949K 2018 property taxes	PPA component; based on Swift County 2017 property tax statement escalated for inflation per the PPA

The present value of revenue requirements of that stream of payments equals $561.2 million through 2028 ($771.6 million in nominal dollars).

Q. HOW DID YOU DETERMINE THE COST OF REPLACEMENT POWER IN THE EVENT THAT THE BENSON FACILITY IS SHUT DOWN?

A. I conducted a mark-to-market analysis of projected energy prices through 2028. This allowed me to compare the cost of power under the existing PPA with Benson Power against current market estimates. I note that the estimates of market energy range from about $23/MWh to $34/MWh during the same timeframe as the PPA levelized cost is estimated to be ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***.

The analysis did not include any costs for replacing capacity due primarily to the small size of the plant and the fact that the NSP System has sufficient capacity through most of the remainder of the contract. This resource provides 55 MW of contracted capacity to the NSP System so it is not expected to have material impact on capacity needs through the mid-2020s.

The cost of replacement energy is a conservative assumption as there will be many hours during the year that market replacement energy is not needed because NSP System generation production is sufficient to meet load needs. The NSP System is generally long energy today and in many cases this increment of energy would not need to be replaced, at least not before major baseload retirements.

Replacement costs for the energy provided by the Benson facility over the life of the PPA are expected to total $127.7 million nominal ($90.2 million NPV). To the extent the Company does not need to buy replacement power, our customers will realize additional savings.

Q. WHAT OTHER COSTS DID YOU ASSUME IN CREATING A COMPARISON?

A. I included the costs of ownership that NSP will incur. This includes the cost of terminating the PPA and purchasing the Benson facility as well as the costs to shut it down. These costs contain several components.

First, the Company will incur $106.8 million in contractual costs to terminate the PPA and acquire and close the Benson facility. These costs include the PPA termination and asset purchase price, contract termination fees, stranded investment costs for the City of Benson, and payment to the fertilizer plant. The $106.8 million also includes demolition and remediation costs. The Company used a third party consultant to estimate the demolition costs. To be conservative, our cost estimate includes assumptions for complete foundation removal. Our estimate also includes $400,000 in salvage credit that we expect to receive from the sale of equipment. This salvage credit assumes the sale of some motors, transformers, air compressors, the generator, and recycling of copper and steel. The Company will work to maximize the value of the materials and salvage value and to the extent we recognize more value than currently estimated, the recovery amounts would be reduced accordingly and the expected customer benefits from the transaction would increase.

Next, there are $14.5 million (nominal) in expenses necessary to wind down operations and shut down the facility including operation and maintenance (O&M)costs, property taxes, fuel, and fuel transportation. This estimate includes the expected cost to operate the Benson facility at full capacity for two months after the transaction closes—as well as a small amount of expenses to operate the plant during the subsequent four-month shutdown phase in the event the plant is called on to run, plus one more month to remove all hazardous material from the site prior to turning to demolition efforts. The seven-month timing estimate is based on the six-month Attachment Y filing process, which I describe further below, plus one additional month to shut down the facility.

Table 3 below provides the underlying assumptions for the plant purchase and closure.

Table 3: Assumptions for Plant Purchase and Closure

Assumption	Support
$95M PPA termination and asset purchase price	Arms-length negotiation for termination of the PPA and purchase of the power plant (to the extent there are costs payable to North American Fertilizer (NAF) to be approximately $2M, such costs will be deducted from the purchase price and paid to NAF)
$1.5M contract termination fees	Jennie-O litter contract termination
$1.5M legal, miscellaneous fees and insurance	Title insurance, escrow agent fee, antitrust filing fee, and legal.
$8.8M demolition, remediation and certain other costs per the May 1, 2017 Letter Agreement with the City of Benson	We consulted with a third party to provide an initial estimate of the demolition scope and costs. For purposes of this estimate, we assumed a salvage value of $400,000 with the expectation that we will offset demolition costs to the extent practical by actively managing the salvage process. While our plan includes removal of all underground foundations, wire, and piping to the maximum feasible depth, we will work with the MPCA to determine specific site requirements during the permitting process. In no case will removals be less than the minimum of four feet below grade per agreement letter with the City of Benson. Per agreement with the City of Benson the transaction would reimburse approximately $600K of stranded investment by the city, and$200K for a new water line and relocation of controls for NAF.

Assumption	Support
$1M fuel and $5M transportation	Assumes plant runs two months at 86% capacity factor and 35%/65% litter/wood mix with no inventory on hand at closing; assumes two 16 hour burns thereafter for emergency run only, using 100% wood, until plant is shut down
$3K ash disposal to landfill	Assumes ash disposal to landfill will only be needed for the two 16-hour burns using 100% wood biomass fuel. Cost is based on approximately 59 tons of ash at $55/ton
$4.9M operating contracts, materials, & supplies	This includes the costs necessary to run the plan for seven months. Includes labor, supplies, parts, services, utilities, and professional fees. Assumes plant runs at full capacity for up to two months to use the existing fuel inventory and honor fuel contracts during cancelation process, then changes to "emergency run only" for months three through six which reduces labor and employees by 50% and supplies, parts and services by 75%, and in month seven, reduces labor and employee related O&M by 86% (includes two maintenance mechanics, two instrumentation and electrical techs, one instrumentation and control tech, and one operations person for isolations, equipment layup, hazardous material removal, etc.). These costs do not include labor for Xcel Energy on site Manager or Xcel Energy support organization assistance. Also includes costs to honor the Backup Station Power Agreement per the May 1, 2017 Letter Agreement with the City of Benson (1MW @ $8.25/kW-mo through April 2027)

Assumption	Support
$3.5M property taxes	Property taxes continue until the facility has been removed. For a period of two years following removal, the Company will make two annual final payments consisting only of local county, city, and school property taxes per the May 1, 2017 Letter Agreement with the City of Benson. Forecasted amounts are based on the Swift County 2017 property tax statement escalated for inflation with the two additional annual payments each reduced $200k to reflect our obligation under the Letter Agreement with the City of Benson.

The NPV cost to terminate the PPA, buy and shut down the facility, and replace any necessary energy is approximately $215.6 million ($292.0 million in nominal dollars).

Q. IS THE COMPANY'S DEFERRED ACCOUNTING REQUEST TAKEN INTO ACCOUNT IN THE ECONOMIC ANALYSIS FOR THE BENSON TRANSACTION?

A. Costs are recovered and accounted for differently across the states of the NSP System. In order to estimate the economic effects of the Benson PPA for customers across all states, NSP assumed that the $106.8 million of costs in the first four lines of Table 3 above will be treated as a regulatory asset subject to deferred accounting, and the remaining $14.5 million in expenses would be recovered from customers as they are incurred. In the Company's current Application, however, we are requesting that all costs of North Dakota's traditionally allocated share of the Benson transaction, including the $14.5 million of O&M costs, be deferred. This may result in a slight impact to our economic analysis, though it should not be material when compared against the millions of dollars in estimated savings for North Dakota customers.

Q. IS MISO AUTHORIZATION IS REQUIRED TO SHUT DOWN THE BENSON FACILITY?

A. Yes. The Company will file Attachment Y (Notification of Generation Resource/SCU/Pseudo-tied Out Generator Change of Status) with MISO regarding the proposed closure of the Benson facility once we have Commission approval. MISO's process requires the owner of a Generation Resource to submit an Attachment Y Notice at least twenty-six (26) weeks prior to retiring the plant, so our costs and assumptions (discussed in greater detail below) assume a seven month period where the plant would need to continue to run before we could begin the shutdown process.

As part of its review process, MISO will consider whether the Benson facility is a System Support Resource (SSR), a unit that is required to maintain the reliability of the transmission system. While possible, we understand the likelihood of the Benson facility being categorized as an SSR is remote.

MISO will also consider how the closure of the Benson facility may impact its planning year—which runs from June 1 through May 31. If we submit the Attachment Y notification after December 1, we may be obligated to utilize the facility to meet our planning reserve requirements or offer the facility into the planning resource auction for the next planning year. Again, we understand that this scenario is unlikely due to the excess of capacity in MISO's Zone 1.

Q. WHAT IS THE TOTAL COST OF THE SHUTDOWN AND REPLACEMENT POWER SCENARIO?

A. The NPV cost of continuing the existing Benson PPA is approximately $561.2 million and the NPV cost to terminate the PPA, buy and shut down the Benson facility, and replace any necessary energy is approximately $215.6 million. Accordingly, our analysis shows that the Benson transaction delivers a customer savings of approximately $345.6 million NPV. The nominal cost of continuing the existing Benson PPA is $771.6 million and the nominal cost of the Benson transaction is $292.0 million, so the nominal savings of buying the Benson facility and terminating the PPA is approximately $479.6 million.

Q. WHAT IS THE NORTH DAKOTA ALLOCATION OF THIS SYSTEM SAVINGS?

A. The North Dakota share of this savings is approximately $19.0 million NPV and $26.3 million nominal over the same period based on an approximately 5.49 percent share of the overall NSP system. As noted above, this projected savings is a very conservative estimate. If the energy associated with the Benson Power contract does not need to be replaced, the savings to ratepayers would increase.

Q. DO YOU HAVE A TABLE THAT SUMMARIZES THIS ANALYSIS AND ARE THERE SAVINGS IN EACH YEAR AFTER THE BUYOUT AND SHUTDOWN IS COMPLETED?

A. Yes. Table 4 below provides a summary of this analysis.

Table 4: Benson Power Transaction Economic Analysis

Buy & Shut Down

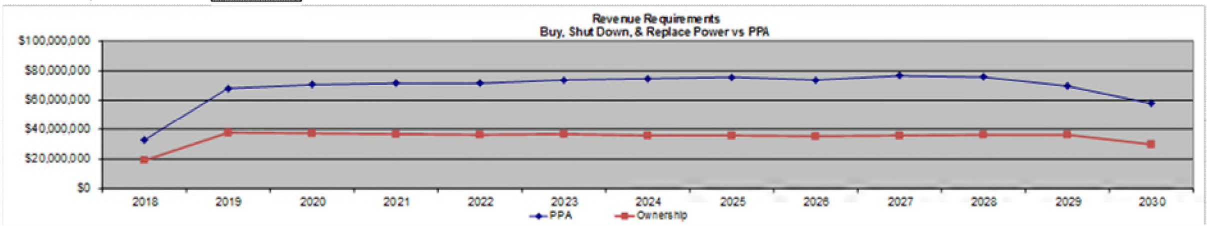
# of Months	12	12	12	12	12	12	12	12	12	12	8.3	0
Year	1	2	3	4	5	6	7	8	9	10	11	12
Ownership	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Revenue Req - Buy & Shut Down	$24,651,003	$19,568,728	$18,542,832	$17,332,838	$15,329,374	$14,178,836	$13,066,852	$12,129,590	$11,447,382	$10,798,456	$7,194,893	
Revenue Req - Replacement Energy	$8,523,857	$9,983,562	$9,698,396	$10,530,424	$11,053,696	$11,970,939	$11,879,538	$12,988,077	$13,371,550	$13,879,765	$13,831,460	
Total Revenue Requirements	$33,174,860	$29,552,290	$28,241,228	$27,863,262	$26,383,070	$26,149,774	$24,946,390	$25,117,667	$24,818,932	$24,678,221	$21,026,353	
MWh *[TRADE SECRET BEGINS*												
$/MWh												*TRADE*
PVRR	$215,604,983											*SECRET ENDS]*

PPA

# of Months	12	12	12	12	12	12	12	12	12	12	8.3	0
Year	1	2	3	4	5	6	7	8	9	10	11	12
PPA	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Revenue Requirements	$68,731,333	$69,769,029	$69,371,834	$72,006,908	$73,155,782	$74,107,569	$71,688,074	$75,629,482	$76,415,526	$66,758,539	$53,949,131	$0
PVRR	$561,164,581											
MWh *[TRADE SECRET BEGINS*												
PPA $/MWh												
PPA $/MWh Levelized												*TRADE SECRET ENDS]*

Buy & Shut Down vs. PPA Comparison

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Delta Ownership vs. PPA Cost	($35,556,473)	($40,216,739)	($41,130,606)	($44,143,645)	($46,772,712)	($47,957,795)	($46,741,684)	($50,511,815)	($51,596,594)	($42,080,319)	($32,922,778)	$0
Delta Ownership vs PPA PVRR	($345,559,598)											



Q. ARE THERE OTHER INDIRECT COSTS OF THE TRANSACTION?

A. Yes. The Minnesota legislature required NSP to pay $20 million ($4 million in 2018, $6.5 million in 2019 and 2020, and $3 million in 2021) from the Renewable Development Fund (RDF) to the City of Benson, Minnesota to assist it with economic development efforts necessitated by the loss to the local economy of the Benson facility.

Q. DOES THE COMPANY INCLUDE THESE INDIRECT COSTS FOR PURPOSES OF ASSESSING RATEPAYER SAVINGS FROM THE TRANSACTION?

A. No. My economic analysis does not include the additional $20 million of indirect costs paid from the RDF to the City of Benson. I note that this payment is small compared to the $345.6 million of projected NPV savings from the PPA termination and subsequent shutdown of the Benson facility.

Q. DOES NORTH DAKOTA SHARE IN THE COSTS PAID FROM THE RDF?

A. No. It is my understanding that North Dakota customers do not contribute to the RDF so these additional indirect costs are not funded by North Dakota customers. As a result, North Dakota customers receive their full allocated share of the savings of the PPA termination and early shutdown of the Benson facility without reduction associated with the payments from the RDF.

B. Pine Bend Biogas PPA Early Termination

Q. WHAT IS THE PINE BEND PPA?

A. Gas Recovery Systems (GRS) owns and operates the 12 MW Pine Bend landfill gas facility in Dakota County, Minnesota. In 1994, NSP entered into a PPA to purchase the output from that facility based on the Company's obligations under the Public Utilities Regulatory Policy Act (PURPA) and Minn. Stat. § 216B.264.

Q. WHEN IS THE PINE BEND PPA SCHEDULED TO TERMINATE?

A. According to its terms, this PPA is scheduled to terminate on December 31, 2025.

Q. HOW HAVE THE PARTIES TO THE PINE BEND PPA ADDRESSED AN EARLY TERMINATION?

A. The parties have agreed to terminate the Pine Bend PPA in exchange for the Company making net monthly payments to the project owners up to a total of $1,050,000 over a two- to three-year period. Mr. Chamberlain's Direct

Testimony provides more discussion of the economic terms of the agreement to terminate the PPA.

Q. DOES THE EARLY TERMINATION OF THE PINE BEND PPA AND THE PAYMENT OF $1,050,000 OVER TWO TO THREE YEARS RESULT IN NET CUSTOMER BENEFITS?

A. Yes. We have prepared an NPV analysis of the Pine Bend contract modifications. We compared the current contract prices through the term ending December 31, 2025, to the net payments arising out of the termination agreement.

Q. PLEASE DESCRIBE HOW YOU UNDERTOOK THIS ANALYSIS.

A. First, based on past history under this PPA, we assumed that the plant would produce 36,000 MWhs per year. The netting process assumes NSP will pay current contract prices for that volume less monthly published average hourly MISO energy prices at the NSP.NSP node (on a day-ahead basis) with a $10/MWh adder. Payments continue for 36 months unless cumulative payments reach $1,050,000. We assumed market replacement energy purchases at Minnesota Hub prices, which serves as a close proxy for NSP.NSP, through December 31, 2025, so that the study period is the same as the current contract.

Based on an execution date of December 1, 2017, the $1,050,000 cap is forecasted to be reached in approximately two years.

Q. DID YOU INCLUDE A CAPACITY ASSUMPTION FOR THIS PPA TERMINATION?

A. No. The Pine Bend PPA is scheduled to terminate at the end of 2025, at a time when we do not foresee the need for capacity. As a result, we did not include any assumption for the cost of replacement capacity for this facility.

Q. WHAT ARE THE OVERALL SAVINGS ARISING OUT OF THIS ARRANGEMENT ON AN NPV BASIS?

A. The values we determined are shown below:

- NPV current contract obligations $12.3 million
- NPV market energy purchases plus net payment $7.1 million
- NPV savings $5.2 million on a system-wide basis

Q. WHAT IS THE NORTH DAKOTA SHARE OF THIS SAVINGS?

A. The North Dakota allocated share of these NPV savings will be about $285,000.

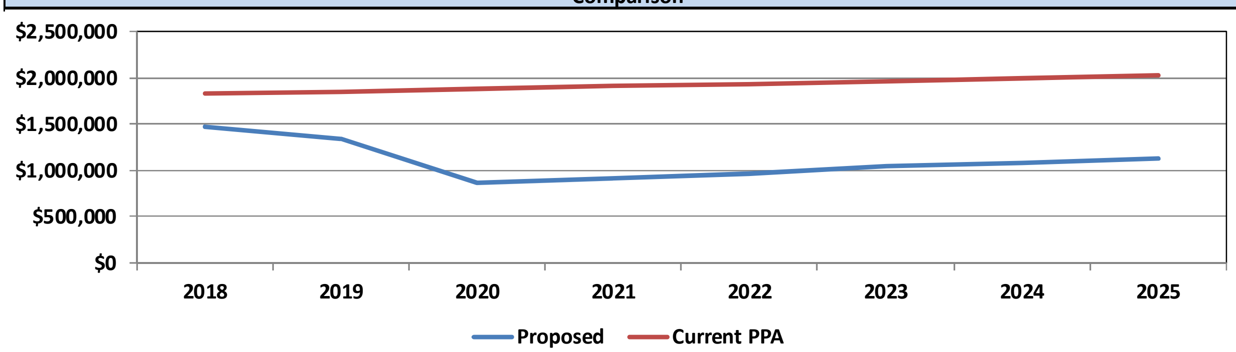
Q. DO YOU HAVE A TABLE THAT SUMMARIZES THIS ANALYSIS AND ARE THERE SAVINGS IN EACH YEAR?

A. Yes. Table 5 below provides a summary of this analysis.

Table 5: Pine Bend Transaction Economic Analysis

	2018	2019	2020	2021	2022	2023	2024	2025
Proposed								
Revenue Req - Payments	577,951	472,049	0	0	0	0	0	0
Revenue Req - Replacement Energy	886,529	866,100	861,363	913,542	958,937	1,038,510	1,080,774	1,126,750
Total Revenue Requirements	1,464,480	1,338,149	861,363	913,542	958,937	1,038,510	1,080,774	1,126,750
MWh ***[TRADE SECRET BEGINS***								
$/MWh								
Levelized $/MWH		***TRADE SECRET ENDS]***						
PVRR	5,169,174							
Current PPA								
Revenue Requirements	1,824,480	1,851,930	1,879,740	1,907,910	1,936,440	1,965,420	1,995,030	2,025,000
MWh ***[TRADE SECRET BEGINS***								
$/MWH								
Levelized $/MWH		***TRADE SECRET ENDS]***						
PVRR	12,304,086							

Comparison



C. HERC PPA Extension and Restructuring

Q. PLEASE DESCRIBE THE FINANCIAL PARAMETERS OF THE HERC PPA.

A. The HERC PPA currently includes both energy and capacity payments. The energy charge is based on actual production costs at Sherco 3 subject to a formula adjustment which assigns more value for volumes delivered during the on-peak versus the off-peak. The capacity charge is currently ***[TRADE***

SECRET BEGINS ***TRADE SECRET ENDS]*** and is adjusted annually in May. The capacity payment allows HERC to get paid a significant amount of money ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** regardless of actual MWh output at the facility. Annual production at the facility has averaged ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** over the past five years.

Under the amended PPA, we will pay an all-in $/MWh of ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** for the output of the HERC facility in 2017, which would have been the last year under the existing PPA. The ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** energy only price is based on current expectations of what the average $/MWh price will amount to at the end of the year per the current price structure, but it removes the guaranteed compensation associated with the capacity payment and enhances the performance incentive for HERC. The negotiated going-forward energy prices drop significantly starting in 2018 and continuing through 2024, as shown in Table 6 below:

Table 6: HERC PPA Pricing

Year	Existing PPA Price	Proposed 7 Year Extension Pricing
	[TRADE SECRET BEGINS	
2018		
2019		
2020		
2021		
2022		
2023		
2024		
	TRADE SECRET ENDS]	

Q. DOES THE RESTRUCTURING OF THE HERC PPA RESULT IN RATEPAYER SAVINGS?

A. Yes. Assuming the 5-year historical production average of about ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** per year, the proposed extension pricing is expected to provide NPV savings of $26.6 million from 2018 through 2024 compared to the existing pricing methodology (capacity charge and energy charge based on Sherco 3 production costs as explained above). Prices under the existing methodology were estimated to amount to ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** whereas the proposed extension pricing is in the ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** range. Stated differently, if we continued the current contract, we estimate the costs would have totaled $71.5 million

(NPV) over the remainder of the PPA, however, with the newly structured PPA, we estimate costs will total $44.9 million (NPV).

Q. WHAT IS THE NORTH DAKOTA SHARE OF THIS SAVINGS?

A. The North Dakota allocated share of the extension savings is about $1.5 million on an NPV basis.

Q. WAS THE OUTCOME THE COMPANY ACHIEVED REASONABLE UNDER THE CIRCUMSTANCES?

A. From a ratepayer perspective, I believe it was. This was an outcome negotiated within the context of a contract that provided HERC an option to extend the contract at "fair market value." Given this, we believe the outcome is reasonable in that the agreed-upon price is a sensible approximation of the energy and capacity value that HERC can provide over a 7-year term. Additionally, as shown in the table above, the PPA extension pricing is significantly lower than the pricing under the terms of the existing PPA.

Q. ARE THERE OTHER BENEFITS OR IMPACTS THAT NEED TO BE TAKEN INTO ACCOUNT IN ASSESSING THE COST AND VALUE OF THE RESTRUCTURED HERC PPA?

A. Yes. The all-in $/MWh contract structure as opposed to a pricing structure with a very high capacity payment and accompanying energy payment shifts all operational risk to HERC and ensures our customers are only paying for energy that is actually delivered. Previously, with the capacity component, HERC would receive significant payment regardless of performance. In the event of a major outage, HERC was still entitled to the capacity payment even though they were not producing any actual energy. The new contract structure only allows them to get paid when they are actually providing energy which makes it a much more attractive pricing structure for customers.

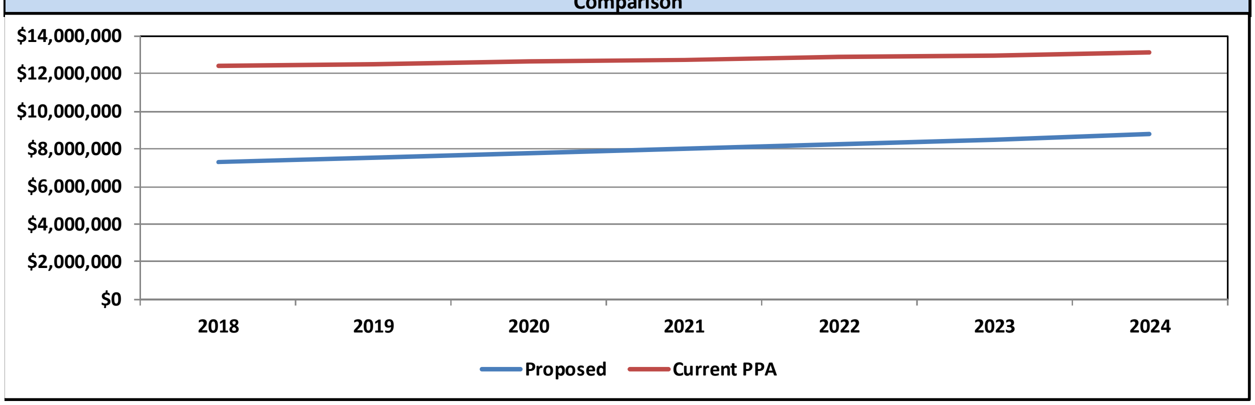
Q. DO YOU HAVE A TABLE THAT SUMMARIZES THIS ANALYSIS?

A. Yes. Table 7 below provides a summary of this analysis.

Table 7: HERC Transaction Economic Analysis

	2018	2019	2020	2021	2022	2023	2024
Proposed							
Revenue Requirements	7,335,932	7,556,010	7,782,690	8,016,171	8,256,656	8,504,356	8,759,486
MWh ***[TRADE SECRET BEGINS***							
$/MWh							
Levelized $/MWH		***TRADE SECRET ENDS]***					
PVRR	44,864,912						
Current PPA							
Revenue Requirements	12,388,315	12,499,113	12,611,856	12,726,585	12,843,341	12,962,170	13,083,113
MWH ***[TRADE SECRET BEGINS***							
$/MWH							
Levelized $/MWH		***TRADE SECRET ENDS]***					
PVRR	71,454,701						

Comparison



D. Negotiated Agreement Refund Analysis

Q. HAVE YOU PERFORMED ANY ADDITIONAL ECONOMIC ANALYSES OF THE PROPOSED TRANSACTIONS?

A. Yes. I performed an analysis of the impact of the Proposed Transactions on the potential refund liability that the Company has agreed to in the Negotiated Agreement approved by the Commission in Case No. PU-12-813. Mr. Chandarana discusses the relevant terms of the Negotiated Agreement in his Direct Testimony.

Q. HAS THE COMPANY QUANTIFIED THE POTENTIAL REFUND LIABILITY PROVIDED FOR IN THE NEGOTIATED AGREEMENT?

A. Yes. In testimony supporting the Negotiated Agreement, Company witness Mr. Kurtis Haeger quantified the potential collections and refund obligation in his Direct Testimony. Table 8, below, provides this quantification.

Table 8: Refund Obligation in Kurt Haeger Testimony

Biomass ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Laurentian ***[TRADE SECRET BEGINS***											
FibroMinn											
St Paul Cogen											
KODA Energy LLC											***TRADE***
WM Renewable Energy (MN Methane)											***SECRET***
Pine Bend											***ENDS]***
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

As shown in Table 8, we originally calculated that between 2016 and 2025, the Company will likely recover approximately $50 million from the biomass contracts at issue in the Negotiated Agreement over an adjusted system average cost. Based on this, we calculated the potential refund to be approximately $25 million.

Q. HAVE YOU UPDATED THE ANALYSIS ABOVE TO REFLECT THE PROPOSED TRANSACTIONS?

A. Yes. Table 9, below provides this updated analysis. The calculations below are slightly different from what was presented in Mr. Haeger's original testimony as we have made a number of changes to assumptions in our Strategist model. These values are based on the model that was used for our recent proposed wind additions in Case No. PU-17-120.

Table 9: Refund Obligation with Updated Strategist Assumptions

Biomass ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Laurentian *[TRADE SECRET BEGINS*											
FibroMinn											
St Paul Cogen											
KODA Energy LLC											*TRADE*
WM Renewable Energy (MN Methane)											*SECRET*
Pine Bend											*ENDS]*
Total	($5,806)	($5,800)	($5,883)	($5,721)	($5,727)	($5,762)	($5,700)	($4,594)	($4,150)	($4,210)	($53,354)

As shown in Table 9, above, our updated analysis indicates that between 2016 and 2025 the Company will likely recover approximately $53 million from the biomass contracts at issue in the Negotiated Agreement over an adjusted system average cost. As a result, the 50 percent refund would be approximately $27million.

Q. WHAT IS THE IMPACT OF THE PROPOSED TRANSACTIONS ON THESE CALCULATIONS?

A. Table 10, below, updates our calculations taking into account the Proposed Transactions. Specifically, the analysis in Table 10 replaces the costs of the Pine Bend and Benson PPAs with the costs of replacement fuel and the transaction costs. As shown in Table 10, North Dakota customers will pay less and our refund obligation is lowered.

Table 10: Refund Obligation with Impact of Proposed Transactions

Biomass ($000)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Laurentian ***[TRADE SECRET BEGINS***											
FibroMinn											
St Paul Cogen											
KODA Energy LLC											***TRADE***
WM Renewable Energy (MN Methane)											***SECRET***
Pine Bend											***ENDS]***
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

As shown in Table 10, above, if the Proposed Transactions are approved and take place, the Company will likely recover approximately $38 million over an adjusted system average cost from the biomass contracts at issue in the Negotiated Agreement. In that case, the Company's refund obligation would be approximately $19 million.

Q. WHAT DO YOU CONCLUDE FROM TABLES 9 AND 10 ABOVE?

A. I conclude that regardless of whether the Company's refund obligation is triggered, our North Dakota customers will be better off with the Proposed Transactions than they would be without it.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Philip Joseph "P.J." Martin
Director, Resource Planning and Bidding
NSP

Philip Joseph "P.J." Martin is the Director, Resource Planning and Bidding for Northern States Power Company – Minnesota. He is responsible for the direction of electric resource planning for the NSP System, which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

Martin joined Xcel Energy in August 2015 as Director, Strategic Asset Planning where he focused primarily on business planning for the four operating companies at Xcel Energy Inc. In October 2016, he was promoted to his current role.

Prior to joining Xcel Energy, Martin was a Portfolio Direct and Energy Trader at ACES Power Marketing. In these roles, he engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. He also supported long-term planning and risk management efforts for these customers in MISO, PJM, SERC, and other markets across the United States.

Martin received his B.A. in international relations from Dartmouth College and his Master of Business Administration degree with an emphasis in finance from East Carolina University.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – BIOMASS PPAS APPLICATION	CASE NO. PU-17-____
NORTHERN STATES POWER COMPANY DEFERRED ACCOUNTING – BIOMASS PPAS APPLICATION	CASE NO. PU-17-____

VERIFICATION

STATE OF MINNESOTA)
)ss.
COUNTY OF HENNEPIN)

Philip Joseph Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Philip Joseph Martin

Subscribed and sworn to before me on this 28th day of June, 2017.

JOHN S. LIVINGSTON
NOTARY PUBLIC - MINNESOTA
My Commission Expires
January 31, 2020

Notary Public
My Commission Expires: 1/31/2020