414 Nicollet Mall
Minneapolis, MN 55401

March 30, 2012

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: NOTICE OF CHANGED CIRCUMSTANCES AND PETITION
PRAIRIE ISLAND EXTENDED POWER UPRATE
DOCKET NO. E002/CN-08-509

Dear Dr. Haar:

Enclosed for filing is the Petition of Northern States Power Company and A Notice of Changed Circumstance related to our 2008 Application for a Certificate of Need for Extended Power Uprate at the Prairie Island Nuclear Generating Plant.

We make this filing pursuant to Minn. R. 7849.0400, subp. 2(H), which provides that a utility shall inform the Commission of changed circumstances that may affect a change in the size, type, timing or ownership of a large generation or transmission facility previously certified by the commission. As we described in our Resource Plan update filed last December there have been changes in the timing and size of the project since it was certified. Our analysis demonstrates those changes alone would not have warranted a different decision by the Commission. However, other changes – such as our load forecasts, the costs of alternative resource options, and uncertainties now possible in the federal licensing process have reduced the potential benefits associated with the project and could combine to lead the Commission to determine the uprate program should not be further pursued. Therefore, we request the Commission review and reaffirm the project remains in the public interest before we proceed further.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists for this docket and also as a courtesy to those parties on the service list for the Company's 2010 Resource Plan (Docket No. E002/RP-10-825.)

Please contact me at Christopher.B.Clark@xcelenergy.com or 612-215-4593 or Jim Alders at James.R.Alders@xcelenergy.com or 612-330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

CHRISTOPHER B. CLARK
MANAGING DIRECTOR
REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Phyllis Reha	Vice-Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR A CERTIFICATE OF NEED FOR THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT FOR AN EXTENDED POWER UPRATE

DOCKET NO. E002/CN-08-509

NOTICE OF CHANGED CIRCUMSTANCES AND PETITION

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this Notice of Changed Circumstances and Petition seeking Minnesota Public Utilities Commission's affirmation before we continue with the extended power uprate project planned at our Prairie Island nuclear generating plant. Because we are about to embark on significant expenditures to complete the federal licensing process, we believe it is the best interest of our customers to assess this project in light of current conditions and gain Commission approval before we proceed.

As outlined in our recent Resource Plan update, [1] the timing and expected output of this project have changed since the Commission's consideration of the original Certificate of Need. While those changes alone would not have warranted a different decision by the Commission, other changes – such as our load forecasts, the costs of alternative resource options, and uncertainties now possible in the federal licensing process – could combine to lead to a determination that the uprate program is not cost-effective for our customers and should not be further pursued.

Therefore, we request the Commission review and reaffirm this project before we proceed further. This Petition facilitates this review and demonstrates that:

- *Changes in project timing and output would not have changed the Commission's original approval of the uprate*, thus the requirements of the Changed Circumstance Rule

[1] Docket No. E002/RP-10-825.

(Minn. R. 7849.0400, subp. 2(H)) have been satisfied. Our execution to date has been prudent and has facilitated better understanding of the costs, risks, and benefits of the project.

- *The project is still expected to benefit customers; however the magnitude of the benefit is substantially lower than originally anticipated.* Further, there are possible combinations of new conditions that could lead to the conclusion that the uprates are no longer cost-effective. We provide this Petition to facilitate a thorough understanding of the issues that could impact customer benefits so that the Commission and stakeholders can weigh them before significant additional costs are incurred.

The Commission has the authority to reassess the uprate program in light of both the retrospective consideration provided by the Changed Circumstance Rule and broader public interest considerations. Therefore, we respectfully request the Commission:

- Find that had the delay in implementation and change in size of the uprates been known at the time the Certificate of Need was issued, the Commission's decision would not have been different; and
- Determine the project remains in the public interest before we continue with the extended power uprate at Prairie Island.

We have structured this Notice and Petition to facilitate the Commission and stakeholders' assessment of these issues.

Commission rules provide that Parties' comments on a Notice of Changed Circumstance request be provided within 15 days. Given the significance of this Petition and substantial information provided for consideration, the Company respectfully requests the Commission provide an initial comment period of at least 60 days, with replies due 30 days thereafter.

We have organized the remainder of this Petition as follows:

- *Background,* providing an overview of information relevant to the Commission's consideration of this Petition.
- *Changes in Circumstances,* outlining key issues that have changed since approval of our Certificate of Need application.
- *Standard for Review,* summarizing the legal guidance for consideration of this request.
- *Analysis Results,* presenting the results of our Strategist modeling from both a retrospective and prospective perspective.

- *Risk Assessment,* providing our assessment of the various issues that could impact benefits to customers and the likelihood of their occurrence.
- *Conclusion and Recommendation,* summarizing our request to the Commission.

I. SUMMARY OF FILING

A one-paragraph summary of this filing accompanies this Petition pursuant to Minnesota Rule 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7849.0400, subp. 2(H), Xcel Energy has served a copy of this Petition to each intervenor in the Certificate of Need proceeding. We have also provided copies to those parties on the service lists for the Company's 2010 Resource Plan (Docket No. E002/RP-10-825).

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Matthew P. Loftus
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401
(612) 215-4501

C. Date of Filing and Proposed Effective Date of Rates

Xcel Energy submits this Petition on March 30, 2012. We do not seek any rate determination as a part of this Petition.

D. Statute Controlling Schedule for Processing the Filing

No statute controls the schedule for the processing this Petition. However, Minn. R. 7849.0400, subp. 2(H) requires this filing and allows comments within 15 days of being notified of the change. The Commission thereafter has 45 days to decide whether to recertify the Certificate of Need or to order further proceedings. As noted above, we request that the Commission provide additional time for comments and replies, given the significance of this Petition.

E. Utility Employee Responsible for Filing

Christopher B. Clark
Managing Director, Regulatory Affairs
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 215-4593

IV. BACKGROUND

We filed our Application for a Certificate of Need for an Extended Power Uprate ("EPU") at Prairie Island in May 2008, proposing a 164 MW project costing approximately $322 million to be implemented during 2014 and 2015 refueling outages. The Commission granted the Certificate of Need on December 18, 2009, finding the uprate program provided value to our customers, satisfied the Commission's rules, and was the best alternative on the record.

Since that approval, we began the engineering, analysis, and design work necessary for the Nuclear Regulatory Commission's ("NRC") licensing process. The largest component of our work to date relates to preparation of our license amendment request ("LAR"), which must adhere to the NRC's Review Standard for Extended Power Uprates. The LAR package generally takes between 12-18 months to complete and includes extensive information regarding the impact of proposed changes to the plant, detailed design information, and complex engineering and operating analyses. However, the recent addition of design detail required by the NRC has expanded the scope of work to complete the LAR package.

We also undertook the Measurement Uncertainty Recovery program ("MUR") shortly after receiving the Certificate of Need. Our proposed 164 MW uprate included 18 MW to be achieved by reducing feed water flow measurement uncertainty. After the NRC approved this portion of the project in 2010, we completed installation and necessary equipment upgrades. The 18 MW of additional capacity went into service in October 2010.

V. CHANGES IN CIRCUMSTANCES

A. Project Changes

Based on our work to date, we have identified changes in the size and timing of the Prairie Island EPU. As noted in our 2010 Resource Plan update filing, the total project size is now estimated to be 135 MW because we determined that implementation of the low pressure turbine was not cost-effective. We also now estimate project implementation during the 2016 and 2017 refueling outages, assuming receipt of timely regulatory approvals.

Delayed implementation is due to several factors. First, we anticipated filing our LAR in early 2011, assuming we would receive NRC approval to extend the operating license for Prairie Island in late 2010 or early 2011. However, we did not receive that approval until June 2011, and NRC rules do not allow us to submit a LAR while a license renewal is pending.

Second, before a LAR can be reviewed, it must be accepted by the NRC. Beginning with its review of the Point Beach Nuclear Power Plant LARs, the NRC staff began requiring additional design detail before granting acceptance. We have observed these requirements steadily increasing as a part of the subsequently-filed LARs. We understand the additional design detail is primarily required to ensure the safe operation of the plants at the EPU operating levels; however, this is a change from the historical practice of allowing design modifications in parallel with the NRC review of the LAR. Thus, the scope of work now required to complete the LAR exceeds the work we have performed to date. We will therefore be required to invest significant additional resources before receiving any feedback on the EPU application from the NRC.

Further, in March 2011 the Fukushima Daiichi nuclear plant in Japan was devastated by an earthquake and tsunami. As a result, the NRC is comprehensively reviewing the impact of external events on the safe operation of nuclear power plants to determine if additional plant modifications or safety regulations are necessary. Because of this post-Fukushima work, our understanding is the NRC may require 30-36 months to review LARs, compared to the historical 12-22 month processing period. The additional time is necessary because NRC resources may be diverted from uprate reviews to other higher-priority safety projects.

If the Commission decides by early 2013 that it is appropriate for us proceed with EPU program, we can move forward with the LAR process at the NRC while simultaneously undertaking procurement of major equipment. We believe a 30-month review for our LAR is a reasonable expectation, but recognize that it could take longer. A 30-month review would allow us to implement the EPU during refueling outages in 2016 and 2017, whereas a 36-month review would allow implementation in 2017 and 2018.

Assuming we are able to implement an EPU by 2016 and 2017, our estimate of total costs to complete the EPU is approximately $237 million.[2] Through 2011, we have incurred approximately $57 million to undertake a portion of the detailed engineering, design and development work necessary to prepare the LAR. Therefore, our current total cost estimate for the EPU is $294 million.

B. Other Changed Conditions

Other changes beyond those related to the EPU project itself have developed since the Certificate of Need was issued. The two key factors that potentially affect the benefits of the EPU are lower forecasts of customer demand and lower natural gas prices.

The pace of projected economic growth has slowed, and in some cases is reflecting short-term contraction, which significantly impacts forecasted demand for capacity and energy on our system. As noted in our Resource Plan update, we expect 0.7% annual demand growth and 0.5% annual energy growth over the planning horizon, down from 1.1% and 0.9%, respectively, in our initial Resource Plan filing. Our refreshed analyses incorporate these economic uncertainties and revised forecasts.

At the same time, natural gas prices have fallen dramatically and are forecasted to remain low. Development of shale gas has been ramping up over the past two years and now accounts for more than one-third of all U.S. natural gas production. The surge in production has pushed down U.S. natural gas prices.

One of the benefits of the EPU is it acts as a hedge by reducing our exposure to natural gas prices and future environmental regulations. However, the effect of lower gas prices and the potential for further reductions should be considered when assessing the benefits of the EPU.

[2] Of this amount, approximately $232 million can be avoided if the Commission determines it is not in the public interest for the EPU to be implemented. Approximately $5 million in contractual obligations are expected to be incurred in 2012, largely due to amounts payable to Westinghouse for services performed under our LAR contract.

V. STANDARD FOR REVIEW

The Changed Circumstance Rule provides the guidance for consideration of this Petition. The Rule states:

> If an applicant determines that a change in size, type, timing, or ownership other than specified in this subpart is necessary for a large generation or transmission facility previously certified by the commission, the applicant must inform the commission of the desired change and detail the reasons for the change...The commission shall evaluate the reasons for and against the proposed change and notify the applicant whether the change is acceptable without recertification. The commission shall order further hearings if and only if it determines that the change, if known at the time of the need decision on the facility, could reasonably have resulted in a different decision under the criteria specified in part 7849.0120.

Typically the Commission has limited its review to a retrospective focus and only required additional hearings if a different decision could have reasonably been made in light of changes.[3] We believe a retrospective review is appropriate in this Petition to confirm that a different decision would not have reasonably been made had the Commission known the current timing and size of the EPU at the time the Certificate of Need was issued.[4]

While the Commission has typically performed this retrospective review, the Rule does not prohibit the Commission from considering other factors to determine whether implementation continues to be in the public interest. Indeed, the Commission has broad authority to apply a public interest standard as a part of its review – particularly in this case, where we are seeking affirmation before expending significant funds to execute the project. For example, changes in our load forecasts affect the need for the project, as do changes in the costs of alternatives to the project. We believe it is within the Commission's authority to consider such factors and their impact on customer benefits when deciding whether the EPU should proceed.

We thus provide more detailed information and analysis than would typically be considered by the Commission under a strict reading of the Changed Circumstance

---

[3] *See* In the Matter of the Application of Northern States Power, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate - Notice of Changed Circumstances, Docket No. E002/CN-08-185, January 6, 2012, at 3.

[4] Although the reduction in size of the EPU does not technically require a notice, we believe it is appropriate to recognize it in the retrospective review.

rule. We provide analyses to consider both the retrospective view and a prospective view, which assesses the EPU in light of more general resource planning considerations and presents several risk sensitivity scenarios. We believe this information will provide the Commission the basis it needs to decide whether the EPU should proceed.

VI. ANALYSIS RESULTS

A. Retrospective Analysis

To analyze the new timing and reduction in size, we repeated the analysis of alternatives in our Certificate of Need proceeding assuming the EPU was implemented during the 2016 and 2017 refueling outages and at a size of 135 MW. This involved re-running the same Strategist modeling used in our Certificate of Need analysis without any changes to other assumptions. Our refreshed analysis under this scenario shows customer benefits of $278 million in present value revenue requirements ("PVRR") benefits above the next best alternative, approximately $155 million, or 35 percent less than the $433 million in PVRR benefits identified in the Certificate of Need process.[5] This analysis confirms that, while the expected benefits of the project have decreased under these assumptions, a different decision would not have been reached had this information been known at the time of the Certificate of Need was issued.

We note that this retrospective analysis reflects current information regarding the project size and likely the best case for implementation timing. Broader risks to both timing and project cost exist, and should be weighed before we proceed further. We discuss the risk associated with these issues in the *Risk Assessment* section below.

B. Prospective Analysis

Our prospective analysis provides a current estimate of PVRR benefit from the EPU of $50 million. This analysis results from the following core assumptions:

---

[5] Revised Table 6-5 of our March 20, 2009 Supplemental Filing in the Certificate of Need proceeding.

Assumption	Value	Explanation
Timing	2016 and 2017 refueling outages	Implementation of the EPU in 2016 and 2017 is our best case estimate.
Size	117 MW	Amount of additional capacity expected from continued implementation of the EPU.
Cost	$237 million	Incremental cost estimate to achieve the remaining 117 MW, including contingency costs based on our experience executing other projects.
Forecast	Fall 2011 median forecast: average growth rate is 0.7%	Reflects our current forecast, provided in our December 2011 Resource Plan update filing.
Natural gas prices forecasts	The midpoint of a range of forecasts	Reflects the fundamental change in the gas market due to shale gas exploration and the trend of declining natural gas price forecasts. Our analysis reflects the approximate midpoint of the range.
Future carbon dioxide regulation costs	$0	Reflects the general observation that carbon regulation remains uncertain and costs are not likely until 2020 or later.

When these core assumptions above were incorporated into Strategist, along with the other updated assumptions described in Appendix A, a range of PVRR benefits resulted. We chose roughly the midpoint of the range of possible natural gas futures to arrive at approximately $50 million in PVRR benefits. [6]

The $50 million in potential system benefits is a significant reduction from the $278 million identified in the retrospective analysis. The two primary drivers for the reduction are lower natural gas prices and decreased carbon dioxide benefits due to the current expectation that carbon dioxide regulation costs are not likely until 2020 or later. Below we show how the $50 million in customer benefits could further fluctuate under risk scenarios and combinations of risk scenarios.

[6] As set forth in Appendix A, our modeling range showed a range of PVRR benefits of $79 million to $19 million. $50 million was the approximate mid-point.

1. *Potential Project Changes*

We first considered the impact of further changes in timing, size, and cost of the project itself.

a) *Further Delay*

Moving forward with the uprate program requires federal regulatory approval. The risk of further delays related to the federal licensing process is substantive and beyond our control. Accordingly, we tested the sensitivity of the benefits to the timing of implementation. With each refueling outage delay, a decrease in the $50 million in benefits results:

Delayed Implementation

Implementation Date	2017-18	2019-19	2019-20
PVRR Impact	($5)	($15)	($30)
Net Project Benefits	$45	$35	$20

Thus, a delay in implementation to the refueling outages in 2019 and 2020 could reduce the $50 million in benefits by $30 million.

b) *Further Reduction in Size*

We have a reasonable level of confidence the remaining 117 MW of capacity will be achieved if we proceed with the EPU. However, to indicate how a further reduction in size would affect the benefit of the project, we modeled a capacity increase of 10 MW less.

Reduced Size

Implementation Date	2016-17	2017-18	2019-19	2019-20
EPU less 10MW	($50)	($55)	($65)	($95)
Net Project Benefits (Cost)	0	($5)	($15)	($45)

Thus, assuming the EPU is implemented in 2016 and 2017, a reduction in size of 10 MW decreases the benefits by approximately $50 million. If the EPU is implemented in 2019 and 2020 at the reduced size, the benefits decrease by $95 million.

c) Additional Costs

In addition to timing and size, the costs to complete the EPU increase if a delay in implementation occurs due to inflationary effects of cost components (i.e., wage increases, materials prices, etc.). Compared to our current estimate of $237 million to complete the EPU, each refueling delay would increase the remaining cost to complete the EPU at the following levels:

Remaining Cost to Complete EPU Based on Delayed Implementation

Implementation Date	2017-18	2019-19	2019-20
Remaining Cost to Complete EPU (millions)	$254	$271	$272

We also estimated the point at which EPU program costs would become high enough to off-set any customer benefits. Compared to our current estimate of $237 million to complete the EPU, our modeling shows that at a remaining cost of $316 million to complete the EPU, no customer benefits would result from the project.

2. Potential Changed Conditions

Our analysis also considers the impact of potential additional changes in the economy, natural gas prices, and carbon legislation, all of which may impact the benefits of the EPU project.

a) Customer Demand for Capacity and Energy

The $50 million in PVRR benefits of the EPU reflects our Fall 2011 demand forecast, which is significantly lower than the demand forecast used for our Certificate of Need. We also considered the impact on EPU benefits of higher and lower demand forecasts. The low load sensitivity is based on the 20th percentile of the distribution, meaning there is a 20 percent chance actual load will fall below this level. The high load sensitivity is based on the 80th percentile, meaning that there is an 80 percent chance load will fall below this level.

Assuming the EPU is implemented in 2016 and 2017 under low load conditions, the $50 million in benefits decreases by approximately $45 million. Under high load conditions, the $50 million in benefits increases by approximately $30 million.

b) Natural Gas Prices

The natural gas market has undergone a major transformation with the tremendous surge of shale gas exploration and production. With this significant increase in natural gas production, natural gas prices have dropped to near record lows.

The Energy Information Administration's 2012 Annual Energy Outlook (Early Release Version) is now predicting that natural gas prices will stay below $6/MMBtu through 2020. This is a significant change from the $10/MMBtu some forecasting agencies were predicting for 2020 in 2007 and the high natural gas prices, exceeding $13/MMBtu, that were experienced in the summer of 2008. In addition, the current market price, as represented by the NYMEX futures market, suggests the expectations for natural gas prices have continued to decline as natural gas production continues to be very strong. Thus, we believe these are indications the U.S. natural gas market is undergoing long-term fundamental changes.

We have observed that in light of the significant decrease in natural gas prices, forecasting agencies have increased the frequency of updated projections, and the projections have generally been higher than the actual natural gas prices experienced. Consequently, we believe it may be more realistic to assume lower natural gas price forecasts when assessing PVRR benefits of the EPU. The $50 million of PVRR benefits reflects these observations.

We also considered changes in benefits if natural gas prices are different than our base assumption. To perform this assessment, we examined the impact of natural gas prices as currently forecasted by industry advisers and a forecast with 20 percent lower natural gas prices compared to the industry forecast. If the EPU is implemented in 2016 and 2017, and natural gas prices are as currently forecasted by industry observers, the $50 million in benefits increases by approximately $30 million. If the natural gas forecast trends toward the lower end of the range, the $50 million in benefits decreases by approximately $30 million.

We further estimated the levelized price of natural gas at which no PVRR savings would result from the EPU program. This "break even" analysis showed that if levelized natural gas prices over 20 years are below $5.11/MMBtu, the EPU would result in no PVRR benefit. Xcel Energy does not believe that natural gas prices could be sustained at such a low level over the long term. Nevertheless, new technologies have substantially changed the natural gas industry. We include the calculation as a bounding exercise to help better understand the magnitude of a market change that, by itself, would erode the potential benefits of the EPU.

c) *Carbon Dioxide Legislation*

Our prospective analysis also considers the impact on EPU benefits of the potential costs to comply with carbon dioxide legislation. Our base assumptions used for Strategist modeling did not include this cost. Instead, we tested the sensitivity of the benefits to carbon dioxide legislation that results in costs ranging between \$9 and \$34 per ton of CO_2 emitted, which complies with the recent recommendations of the Department of Commerce and the Minnesota Pollution Control Agency in Docket No. E999/CI-07-1199.

Assuming the EPU is implemented in 2016 and 2017, the \$50 million in benefits increases by approximately \$10 million at \$9 per ton of CO_2 and by \$75 million at \$34 per ton of CO_2. However, those benefits decline with additional delay in implementation of the EPU. For example, if EPU implementation occurs in 2019 and 2020, the increase in benefits at \$9 per ton of CO_2 is reduced to \$5 million and the increase in benefits at \$34 per ton of CO_2 is reduced to \$55 million.

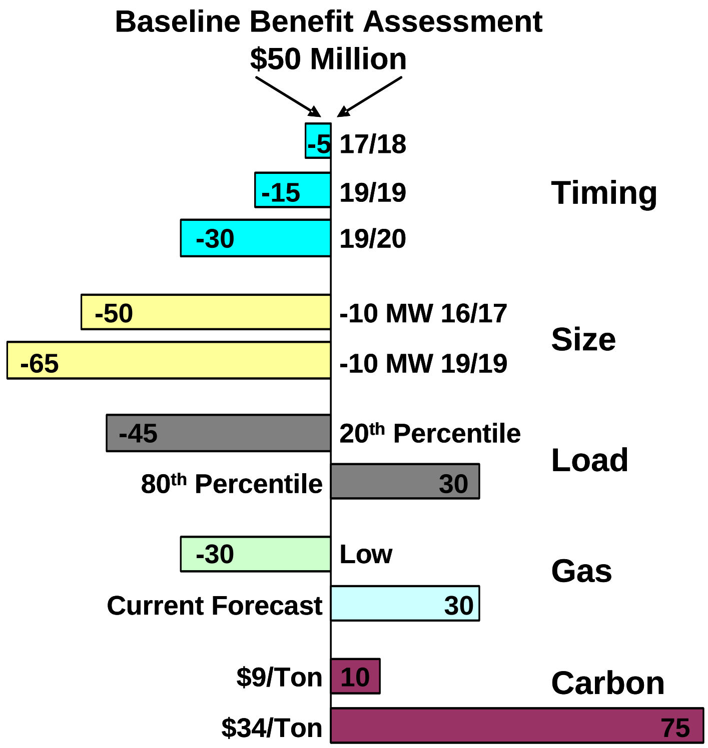
3) *Potential Changes in Combination*

While reviewing risk factors in isolation is helpful to provide an overview of the potential changes in EPU benefits, it is also important to consider the impact if combinations of these factors occur. Each risk factor has the following individual impact, and combining the risk factors will provide a larger aggregate change to the \$50 million in benefits.

Risk Factor	PVRR Impact
Timing Delay	2017 – 2018 = (\$5) million 2019 – 2019 = (\$15) million 2019 – 2020 = (\$30) million
Low Natural Gas pricing	(\$30) million
Low Load	(\$50) million
Reduction in size by 10 MW	(\$50) million
Carbon Dioxide Regulation	+\$10 million at \$9/ton of CO2 +\$75 million at \$34/ton of CO2

As an example, a combination of low natural gas pricing and a two-year delay would reduce the \$50 million in benefits to approximately \$5 million. Thus, under a number of combinations, the PVRR benefits of the EPU are reduced or become negative.

The figure below provides a summary of the prospective analysis and the potential impact on the benefits of the EPU.



VII. RISK ASSESSMENT

Given the current project specifications and what we believe is a reasonable set of circumstances, the EPU is expected to provide approximately $50 million of PVRR benefits to our customers. In this section, we provide our assessment of the likelihood that the additional risks noted above will further impact the benefits of EPU program.

A. Likelihood of Further Project Changes

1. *Further Delay*

Projected implementation of the EPU in 2016 and 2017 is dependent on three key assumptions:

- Receipt of the Commission's decision in this proceeding by the first quarter of 2013;

- Submission of an acceptable LAR to the NRC within one year of the Commission's decision; and
- NRC approval of our LAR within 30 months of receipt.

While we believe a decision from the Commission in this proceeding is likely by the first quarter of 2013, each of the NRC-related assumptions carries greater uncertainty.

As noted above, the NRC staff has steadily required additional design detail for the acceptance of LARs. Further, there are three pressurized water reactor EPU LARs currently pending before the NRC. To the extent additional issues are identified by the NRC as a part of its review of those applications, we will be obligated to address any such issues either in our LAR submittal or as a part of the review process. We will fully comply with any new requirements established by the NRC, but at this time it is difficult to predict if new LAR requirements, and resulting additional delays in LAR preparation, may be imposed.

In addition, we noted the NRC may require additional time for LAR reviews in light of the additional post-Fukushima work. This work is ongoing and comprehensive in nature, including assessments of the impact of events such as tornados, hurricanes, high winds, earthquakes, high tides, and flooding on the safe operation of nuclear power plants. As NRC resources are assigned to perform the post-Fukushima work, fewer resources may be available to undertake LAR reviews.

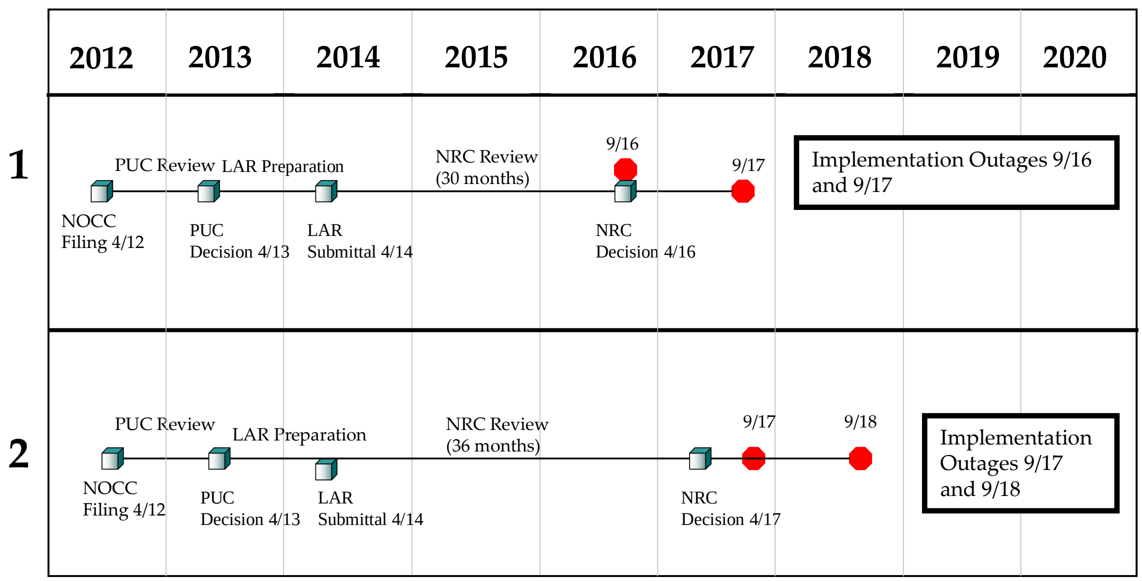
We also routinely monitor the status of other pending EPU LAR reviews. Historically, it was reasonable to expect the NRC to complete its review within 18-22 months. As shown below, review time had been increasing even before the Fukushima incident.

Approved Pressurized Water Reactor EPU Applications

Plant	Date Submitted	Date Approved	Total Duration
Point Beach 1	4/7/2009	05/03/2011	25 months
Point Beach 2	4/7/2009	05/03/2011	25 months
Beaver Valley 1	10/4/2004	07/19/2006	21.5 months
Beaver Valley 2	10/4/2004	07/19/2006	21.5 months
Ginna	07/07/05	07/11/2006	12 months
Waterford	11/13/2003	04/15/2005	17 months

Given this trend, we believe our estimate of 30 months for review of our LAR is reasonable, allowing for implementation of the EPU in 2016 and 2017. However, it is important to recognize the potential for delay in federal licensing process is a real possibility and outside of our control. The charts below show the possible EPU implementation dates if certain timing assumptions are altered.

Parallel Implementation Timelines

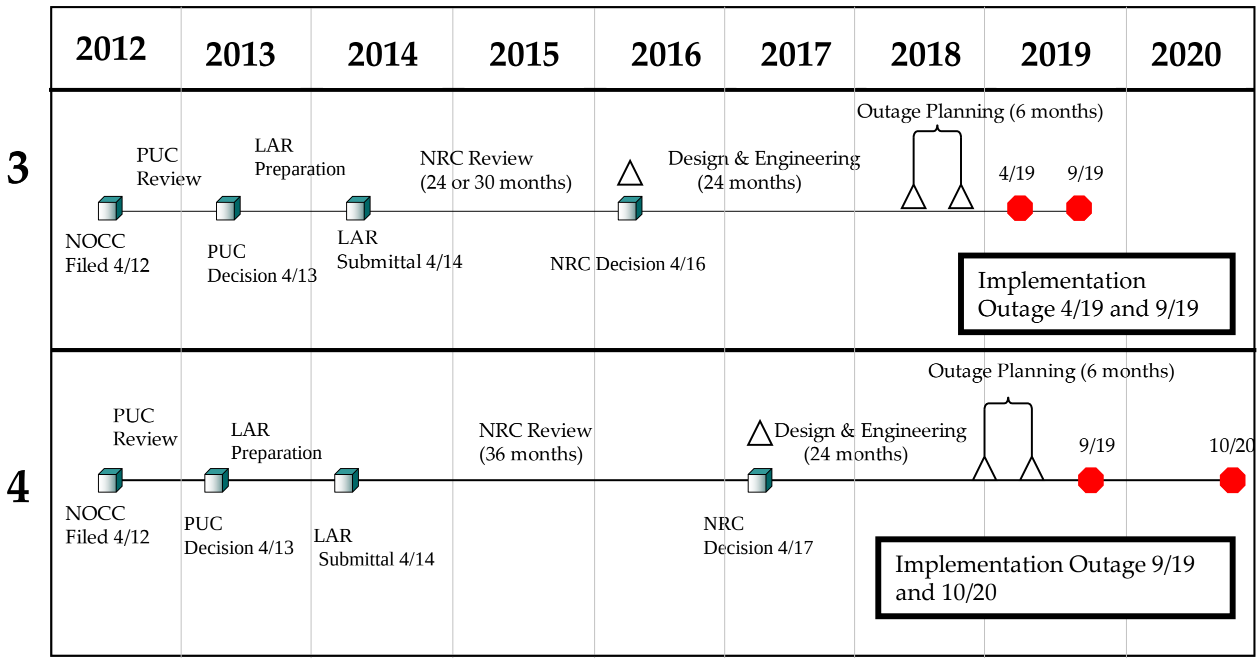


Assumptions:
* Only NRC Review time varies.
* Assumes Design, Engineering and Outage Planning are done in parallel with LAR preparation.

The timelines above reflect proceeding with the LAR preparation while simultaneously commencing detailed engineering and procurement of major equipment. Under this "parallel" scenario, once we receive the Commission's approval to move forward with the EPU, we would incur significant expenditures toward implementing the program before receiving NRC approval. The parallel approach is necessary to preserve the potential benefits of the earliest in service date possible. However, it is important to recognize the potential for delay in federal licensing process even under this approach.

We could also defer any EPU implementation activities until after the NRC has completed review of the LAR. Below are the timelines showing possible implementation dates under a sequential approach.

Sequential Implementation Timelines



Assumptions:

* Only NRC Review time varies. Scenario 4 encompasses up to a 30 month NRC review since there is a 6 month buffer between the end of outage planning and the first implementation outage in 4/19.

* Significant efficiencies (LCM v EPU, and Team) will be lost if Design, Engineering and Outage Planning are not performed in parallel.

The sequential approach would delay final implementation until 2019 or 2020. Further delay in EPU implementation would provide lower PVRR benefits because the EPU would be in-service for a shorter period of time. Thus, while a sequential approach would delay significant expenditures at the outset, it would also reduce the PVRR benefits of the project. We do not recommend a sequential approach since it adversely affects potential customer benefits, but we recognize it is a decision option for the Commission.

2. *Further Reduction in Size*

In light of the engineering, development, and design work we have performed, as well as vendor bid estimates, we have a reasonable degree of confidence the EPU will result in an additional 117 MW of capacity. However, as with any large equipment installation that interacts with other plant systems, actual results can vary due to unanticipated conditions.

3. Additional Costs

Our cost estimate for completing the EPU in 2016 and 2017 reflects:

- Detailed engineering, design, and development work performed to date;
- Estimates received from various component and equipment vendors; and
- Vetting through the Nuclear Business unit's peer group review process.

Thus, the cost estimate of $237 million to complete the EPU is consistent with industry best practices and is significantly more refined than the indicative planning estimate that was available for our Certificate of Need proceeding. Similarly, our cost estimate reflects a level of detail typical of projects that are at an intermediary stage of development. However, additional scoping work and development of work packages will be necessary to complete the EPU. Thus, it is important to acknowledge the costs of the EPU could increase after future scoping and design is completed.

In addition, our current cost estimate includes components for known and unknown contingency risks. While we have made good faith efforts to arrive at these contingency cost components, it is important to acknowledge additional costs could result under certain circumstances.

B. Likelihood of Further Changes in Circumstances

1. Customer Demand for Capacity and Energy

Based on consideration of several factors, most importantly economic growth indicators, we expect lower customer demand for the foreseeable future. We rely on various macroeconomic indicators to understand the possible directions of economic growth. The three most critical indicators are:

- *Gross Domestic Product ("GDP")*, generally considered the broadest measure of economic activity.
- *Minnesota Gross State Product ("GSP")*, measuring the economic output of Minnesota.
- *Minnesota Households*, generally indicating how many new Minnesota residential customers will be added.

Since the Commission granted our Certificate of Need in 2009, the downward trend in the economy can be seen in the growth predicted by the forecasting companies we rely on (*i.e.*, Global Insight and others) for each of the three critical macroeconomic indicators.

Indicator	**EPU CON (May 2008)**	**2010 Resource Plan (June 2010)**	**Black Dog CON Update (June 2011)**	**Update to 2010 Resource Plan (Sept. 2011)**	**Current Forecast (Mar. 2012)**
2011/2012 Average GDP Growth Rate	2.5%	3.3%	2.6%	2.2%	1.7%
2011/2012 Average GSP Growth Rate	2.7%	2.8%	2.6%	1.7%	2.0%
2011/2012 Avg. Minnesota Households Growth Rate	1.1%	1.1%	1.1%	0.9%	0.9%

Source: Global Insight

Our forecasted growth in system peak demand and median net energy has followed the downward trend in economic growth.

Forecast Used For:	**Annual Growth in System Peak Demand**	**Annual Growth in Median Net Energy**
2007 Resource Plan	1.2%	1.1%
2010 Resource Plan (June 2010)	1.1%	0.9%
Black Dog CON Update (June 2011)	0.9%	0.7%
Resource Plan Update (September 2011)	0.7%	0.5%

Because it is difficult to predict when economic growth will return to pre-recession levels, we believe it is appropriate to continue to use conservative assumptions to forecast the future capacity and energy needs of our customers until data shows the economic growth rate is expected to increase.

2. *Natural Gas Prices*

The $50 million in customer benefits for the EPU reflects our assumption that natural gas prices may fall lower than the current forecasts. This assumption stems from the fundamental change in the natural gas market as a result of the increase in natural gas production from shale gas exploration and from our observation that forecasts of natural gas pricing have generally been higher than the actual natural gas prices.

Thus, while the EPU continues to present a hedge against potential higher natural gas prices, the price of natural gas has decreased dramatically since the Commission approved the EPU in 2009. Therefore, it is important to consider the value of the natural gas hedge in light of the historically-low natural gas pricing we are currently experiencing and will likely experience going forward.

3. Carbon Dioxide Regulation

Contrary to expectations at the time of our Certificate of Need proceeding, there has been little recent activity at the federal or regional level to suggest that carbon dioxide costs will be applied to emitters over the short term. In 2009, the U.S. House of Representatives passed a nationwide cap and trade program. Although the Senate did not support this program, there was widespread interest at a federal level. At the same time, on a regional level the Midwest Greenhouse Gas Reduction Accord drafted recommendations on a cap and trade program. In 2010, due to a shift in control of the House of Representatives and a sluggish economy, the interest in a greenhouse gas cap and trade program decreased significantly.

In 2011, the EPA began regulating greenhouse gas emissions for air permits issued to new power plants or those undertaking major modifications. However, there was still little appetite for a carbon cap and trade program.

As we recently noted in our March 9, 2012 comments in the Commission's ongoing process to establish estimates of future carbon dioxide regulation costs, the majority of consulting firms we rely upon to develop a carbon dioxide proxy pricing foresee significant delays. This view is supported by a general lack of political interest by the current Congress and lack of clear support from the current administration. Thus, we do not predict carbon pricing until the 2020-2022 time frame. Other utilities expressed a similar outlook.

Thus, while the EPU acts as a hedge against potential carbon dioxide regulations and associated costs, we now believe it is unlikely that such costs will come into existence before 2020. Given the fact that Prairie Island will end operations in 2033 and 2034, the relatively short amount of time in which the EPU would provide an offset against carbon dioxide regulation costs should be considered.

C. Conclusion

Our estimate of $50 million in PVRR benefits for the Prairie Island EPU relies on a number of key assumptions. Based upon the best information today, we have provided our assessment of the likelihood of additional risks affecting the benefits of the EPU. We believe the risk factors discussed above are likely to occur in combination and magnitude. While we cannot anticipate what combination of risk factors may occur or to what degree, clearly a combination of risk factors amplifies the likelihood that the benefits of proceeding with the EPU could be lost due to circumstances beyond our control. In instances where benefits would still be realized under a combination, the value of the project may be considered insufficiently small to warrant proceeding with the EPU.

VIII. CONCLUSION

The timing and expected output of the extended power uprates at our Prairie Island nuclear generating plant have changed since the Commission issued its Certificate of Need in 2009. Our retrospective analysis demonstrates consistent with the Changed Circumstance Rule, the Commission would not have made a different decision had timing and size changes been known at the time the Certificate of Need was issued. However, those changes, along with changes in costs, load forecasts, natural gas prices and uncertainty in the federal licensing process have reduced potential benefits considerably and could combine to lead the Commission to determine it is no longer in the public interest to implement the uprates.

We have diligently undertaken detailed engineering, design, and development work necessary to prepare a portion of the license amendment request for the NRC. We are at a critical juncture in the development of the project. Our best opportunity to address the continuation of the project is now, before we start incurring the significant remaining expenditures to complete the federal licensing process and implement the uprates.

Based on the information available at this time, our analyses continue to show the power uprate could provide approximately $50 million in benefits if the Commission determines the project should continue to be implemented. However, there are many factors beyond our control that could individually, or in combination, impact the cost-effectiveness of the uprate.

We are willing to implement the EPU if the Commission determines it is in the public interest after balancing the potential risks and benefits. We look forward to working with the Commission and interested parties to facilitate review of the project and determine the best decision for our customers. We respectfully request the Commission: (1) find the delay in size and timing of the uprates program would not have changed the Commission's initial decision to grant the Certificate of Need; and (2) reaffirm the uprate program remains in the public interest before we proceed further.

Dated: March 30, 2012

Northern States Power Company

Respectfully submitted by:

/s/

CHRISTOPHER B. CLARK
MANAGING DIRECTOR
REGULATORY AFFAIRS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Phyllis Reha	Vice-Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR A CERTIFICATE OF NEED FOR THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT FOR AN EXTENDED POWER UPRATE

DOCKET NO. E002/CN-08-509

NOTICE OF CHANGED CIRCUMSTANCES AND PETITION

SUMMARY OF FILING

Please take notice that on March 30, 2012, Northern States Power Company doing business as Xcel Energy filed with the Minnesota Public Utilities Commission a Notice of Changed Circumstances and Petition related to the extended power uprate project for the Prairie Island nuclear generating plant. The Company requests the Commission find current changes in size and timing of the extended power uprate project would not have led to a different decision at the time the Certificate of Need was issued on December 18, 2009. The Company also requests the Commission review and reaffirm that the project continues to be in the public interest before the Company proceeds further.

Strategist Modeling Assumptions and Results

I. Strategist Description

This document provides details regarding the Strategist Planning Model assumptions and results for the Prairie Island Extended Power Uprate ("EPU") program.

Strategist is a resource expansion model that uses input assumptions (*i.e.,* fuel costs, O&M costs, emission rates, and capital costs) to simulate the operation of the NSP generation system and calculate total system costs. The total system costs are reported as the net present value of revenue requirements ("PVRR") to operate and expand the system over the entire term of the simulation. We calculate the PVRR by adding all operating, depreciation, return on rate base, and tax costs, less any revenues from sales discounted back to the present, using the Company's most recently authorized weighted after-tax cost of capital.

We use Strategist to compare the PVRR of various scenarios, such as adding different generation alternatives. We are also able to evaluate how changes in economic factors, load, or capacity may affect the PVRR of a particular program. By comparing PVRR values, we are able to select a robust plan that meets our current and expected requirements.

Strategist includes four modules:

1) The *Load Module* contains Xcel Energy's load forecast, load management, and conservation programs. This module produces long-range estimates of the Company's net energy requirements and peak capacity requirement.

2) The *Generation Module* stores the generation characteristics for all of the Company's thermal, hydro, and wind units, in addition to the energy profiles for all purchased power agreements ("PPAs"). The generation module simulates security-constrained dispatch to meet energy demand, and keeps track of generation, fuel burn, operating costs, and emissions for each unit.

3) The *Capital Expenditure and Recovery Module* is where all capital projects are modeled. Capital costs and escalation rates are used as inputs and the model calculates the revenue requirements for each project taking into account book depreciation, tax deprecation, insurance, property taxes, the cost of debt, and the Company's targeted return on equity.

4) The *Expansion Planning Module* uses a dynamic programming algorithm to derive the least cost expansion plan under the assumptions used. This module calculates the customer and societal costs for thousands of different resource combinations to arrive at the least cost plan.

II. Retrospective Analysis

The Retrospective Analysis involves refreshing the Certificate of Need Strategist model used in that proceeding with the current EPU program timing and size. All assumptions remained the same except (1) program implementation timing was changed to 2016 and 2017, and (2) program size was changed to 135 MW. The EPU program was compared to the same alternatives considered during the Certificate of Need proceeding; here, however, we only present a comparison of the EPU program to the next best alternative identified on the Certificate of Need record and the unconstrained scenario.[1]

The Strategist results are as follows:

Original Filing

	EPU	164 MW Coal PPA	Unconstrained
PVRR	$59,829	$60,298	$60,262
PVRR Delta		$468	$433

Changed Timing Only

	EPU	164 MW Coal PPA	Unconstrained
PVRR	$59,912	$60,248	$60,262
PVRR Delta		$336	$350

Changed Timing and Size

	EPU	136 MW Coal PPA[2]	Unconstrained
PVRR	$59,984	$60,205	$60,262
PVRR Delta		$221	$278

III. Prospective Analysis

The Prospective Analysis examines the costs effectiveness of the EPU program using the core assumptions described in our Petition, along with other updated assumptions

[1] The two identified alternatives in the Certificate of Need were 164 MW coal power purchase agreement and a 164 MW biomass facility.
[2] We adjusted the size of this alternative downward to match the expected capacity output from the EPU program.

available today. We generally used the same Strategist model as in the December 1, 2011 Update to the 2010 Resource Plan. Below, we describe several assumptions and updates to those assumptions from our Resource Plan Update.

A. Assumptions

1. Load Forecast

The base model uses the peak demand and energy forecasts that were developed in the fall of 2011. This forecast predicts a peak of 9,215 MW in 2012 and grows gradually at an average rate of 0.7%. For 2012 the total forecasted energy requirement is 45,757 GWh with an average annual growth rate of 0.5%.

2. Existing Generating Fleet

- The Sherco and King plants are modeled to continue running through the end of the study period.
- Black Dog Units 3 and 4 are modeled as switching to natural gas in 2013 and retiring year end 2015.
- All nuclear units are modeled to retire at the end of their current license period. To maintain consistency in the future energy mix, these units are replaced with generic nuclear units in the model.
- Other facilities are modeled to retire at the end of their current book depreciation life unless a life extension plan as been developed for a particular unit.
- Purchased power contracts are modeled with their specific start and end dates.

3. Renewable Energy

- Given the expected expiration of the federal production tax credit, wind additions were limited to those necessary to maintain a relatively stable proportion of wind generation throughout the study period.
- The base Strategist model includes the continued growth of the company's Solar Rewards program. This program is forecasted to have approximately 4 MW of solar PV in 2012 and then to grow by 1.7 MW annually until reaching a steady state of 34 MW in 2032.

4. Emissions

- The base model contains no additional costs for CO_2 emissions. However the analysis includes sensitivity runs for the Commission's low ($9/ton) and high

($34/ton) carbon scenarios. In addition the modeling includes a "late" carbon scenario based on external consultant forecasts with costs of about $5/ton starting in 2018 which escalates unevenly over time.

5. Expansion Plan

- As discussed in the Company's December 2011 Resource Plan Update, the forecasted need for the Black Dog natural gas combined cycle ("CC") unit has diminished. It was not included in the modeled expansion plan in this analysis.
- The near term expansion plan instead includes various additions of simple cycle natural combustion turbines ("CTs") with in-service dates from 2017 to 2025.

6. Natural Gas Price Forecast

Because natural gas and the associated price of avoided energy is a critical component in the evaluation of the Prairie Island EPU, the Strategist model was updated with a new price forecast in late January.[3] For the period relevant to evaluation of the EPU program (2016 implementation through 2034 current end of operating license), the forecasted average price of natural gas fell 7%. We also tested a scenario 20% lower than the January forecast.

B. PVRR Results

The Prairie Island EPU program was modeled with four different in-service dates and was compared to a "No EPU" scenario. The No EPU scenario assumes the EPU program will not proceed, but continues to include the costs of undertaking life cycle maintenance ("LCM") activities necessary to maintain the safety and reliability of the Prairie Island facility through 2034.

Each scenario was evaluated under base case assumptions plus twelve assumption sensitivities regarding load, fuel prices, capital expenditures, emission costs, access to the MISO market, and environmental externalities. Our Prospective Analysis in the Petition compares certain scenarios and normalizes the customer benefits for each scenario against the $50 million in benefits. As stated in our Petition, we chose roughly the midpoint of the range of possible natural gas futures to arrive at approximately $50 million in PVRR benefits.

[3] Our December 2011 Resource Plan Update used a gas forecast from September 2011.

Below we provide the PVRR results of our modeling using the assumptions discussed above. The PVRR results below do not reflect an adjustment to account for lower natural gas price forecasts.

Table A1: PVRR Matrix

Present Value of Revenue Requirements (PVRR) 2012-2050, 7.56%, $millions	No EPU LCM 2016	Case 2 EPU 2016-17	Case 3 EPU 2017-18	Case 4 EPU 2019-19	Case 5 EPU 2019-20
Base Case	$82,935	$82,856	$82,859	$82,870	$82,886
EPU less 10MW	$82,935	$82,905	$82,910	$82,921	$82,950
Low Gas -20%	$81,617	$81,599	$81,599	$81,604	$81,617
Low Load 20th Percentile	$79,698	$79,667	$79,668	$79,670	$79,678
Low Capital	$82,887	$82,783	$82,787	$82,800	$82,817
High Gas +20%	$84,182	$84,048	$84,055	$84,070	$84,089
High Load 80th Percentile	$85,842	$85,734	$85,738	$85,750	$85,780
Late CO2 - 3 Source	$88,262	$88,110	$88,113	$88,127	$88,145
High CO2 - $34/ton	$94,540	$94,388	$94,396	$94,415	$94,436
Low CO2 - $9/ton	$86,355	$86,266	$86,270	$86,282	$86,299
No Markets	$83,033	$82,935	$82,939	$82,952	$82,969
High Externalities	$84,833	$84,740	$84,745	$84,757	$84,774
Low Externalities	$83,229	$83,148	$83,152	$83,163	$83,179

Using the above data, we were able to calculate the differences between PVRR results for the various scenarios:

Table A2: PVRR DELTA Matrix

PVRR DELTA 2012-2050, 7.56%, $millions	No EPU LCM 2016	Case 2 EPU 2016-17	Case 3 EPU 2017-18	Case 4 EPU 2019-19	Case 5 EPU 2019-20
Base Case	BASE	($79)	($75)	($65)	($49)
EPU less 10MW	BASE	($29)	($24)	($14)	$15
Low Gas -20%	BASE	($19)	($18)	($14)	($1)
Low Load 20th Percentile	BASE	($32)	($30)	($28)	($20)
Low Capital	BASE	($104)	($99)	($87)	($70)
High Gas +20%	BASE	($134)	($128)	($112)	($93)
High Load 80th Percentile	BASE	($108)	($104)	($92)	($62)
Late CO2 - 3 Source	BASE	($152)	($148)	($135)	($117)
High CO2 - $34/ton	BASE	($152)	($144)	($125)	($104)
Low CO2 - $9/ton	BASE	($90)	($85)	($73)	($56)
No Markets	BASE	($98)	($94)	($81)	($64)
High Externalities	BASE	($92)	($88)	($76)	($59)
Low Externalities	BASE	($81)	($77)	($66)	($50)

1. *EPU – Incremental Costs*

In the Strategist model, the EPU program consists of three primary elements:

- The project capital and associated revenue requirements;
- The capacity increase and associated increased annual energy generation; and
- The additional fuel burn that will accompany the additional generation.

Table A3 lists the capital assumptions that were used in Strategist for the EPU and the associated life cycle management projects.

Table A3: EPU & LCM Capital Cost Assumptions[4]

	Spent Capital ($millions)	Base Capital Assumptions ($millions)		Low Capital Assumptions ($millions)	
	LCM/EPU 2006-2011	**LCM**	**EPU 2012 +**	**LCM**	**EPU 2012 +**
Base Case No EPU LCM 2016	$64.9 + $6 AFUDC	$300	$7	$260	$6
Case 2 EPU 2016-17	$64.9 + $6 AFUDC	$300	$237	$260	$212
Case 3 EPU 2017-18	$64.9 + $6 AFUDC	$312	$254	$272	$227
Case 4 EPU 2019-19	$64.9 + $6 AFUDC	$312	$271	$272	$242
Case 5 EPU 2019-20	$64.9 + $6 AFUDC	$312	$272	$272	$244

The Strategist model estimates future revenue requirements for these capital projects using standard rate making calculations. Assumptions include:

- The program will be depreciated over the remaining life of the plant;
- The assumed return on equity was 10.81%; and
- The associated before-tax weighted average cost of capital was 8.75%.

[4] In the model, the projects are assumed to accrue AFUDC until their in-service date.

Figure A1: EPU Capital Revenue Requirements

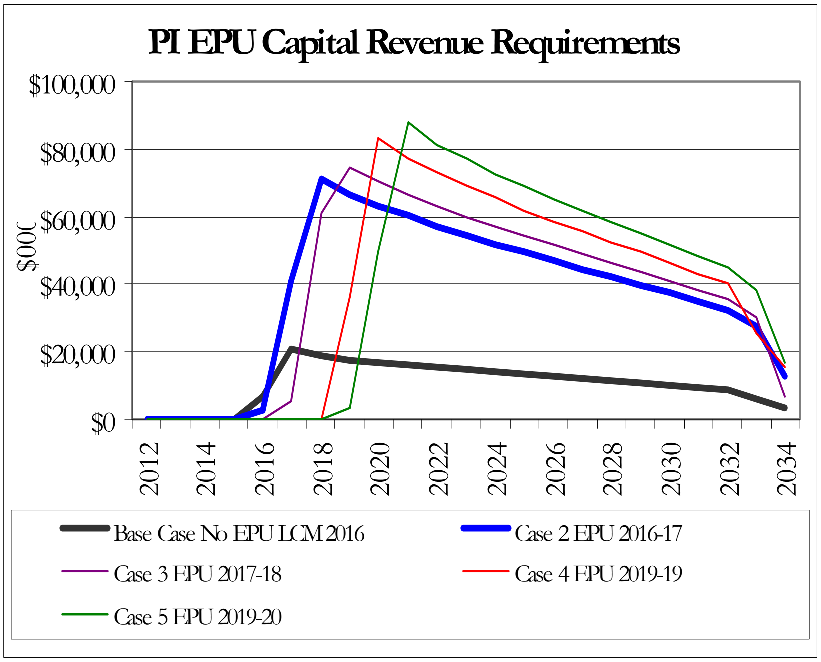


Table A4: PI EPU Capital NPV Rev. Req. (PVRR)

	Capital Rev Reqs 2012-2034 (NPV 7.56%) ($millions)	**Change From Base Case** (NPV 7.56%) ($millions)
Base Case No EPU LCM 2016	$109	
Case 2 EPU 2016-17	$367	+ $259
Case 3 EPU 2017-18	$362	+ $254
Case 4 EPU 2019-19	$338	+ $229
Case 5 EPU 2019-20	$332	+ $223

In Strategist, the EPU program is modeled to coincide with scheduled outages. We anticipate the gain of an additional 117 MW if the EPU program goes forward.[5] The 117 MW of additional capacity is expected to have an average capacity factor of approximately 90%, resulting in average generation of 919 GWh which is approximately 2% of our forecasted total energy requirements. In Strategist, each unit's net heat rate is modeled to fall about 3% from 10.45mmBtu/MWh to 10.16mmBtu/MWh

[5] This is in addition to the 18 MW already achieved through the Measurement Uncertainty Recovery program.

Table A5: PI EPU Operational Impacts

Prairie Island EPU Opperational Impacts

	Winter	Summer	Average Generation	Average C.F.%	Average Heat Rate
Baseline					
Unit 1	560 MW	535 MW	4,366 GWh	89%	10.45 mmBtu/MWh
Unit 2	560 MW	535 MW	4,366 GWh	89%	10.45 mmBtu/MWh
Total	1,120 MW	1,070 MW	8,732 GWh	89%	10.45 mmBtu/MWh
With EPU					
Unit 1	619 MW	594 MW	4,837 GWh	89%	10.16 mmBtu/MWh
Unit 2	619 MW	594 MW	4,814 GWh	89%	10.16 mmBtu/MWh
Total	1,237 MW	1,187 MW	9,651 GWh	89%	10.16 mmBtu/MWh
Change	+ 117 MW	+ 117 MW	+ 919 GWh		-0.29 mmBtu/MWh

Despite the improved heat rate, the EPU program will result in more fuel being used at Prairie Island and an increase in variable O&M expense. Over the life of the EPU program, the average cost of fuel is expected to be $1.15/mmBtu and the average annual increased fuel & variable O&M costs are forecasted to be $8.3 million. The net present value of the fuel cost increase is forecasted to be $57 million for Case 2 (EPU implementation in 2016-17).

Figure A2: PI EPU Incremental Fuel Costs

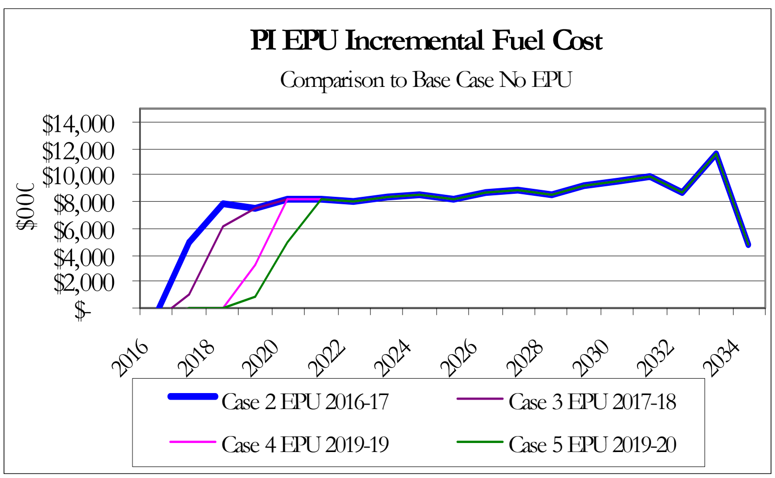


Table A6: PI EPU Incremental Fuel Costs

	Total Fuel Cost 2012-2034 (NPV 7.56%) ($millions)	Change from Base Case (NPV 7.56%) ($millions)
Base Case No EPU LCM 2016	$1,157	-
Case 2 EPU 2016-17	$1,215	+ $57
Case 3 EPU 2017-18	$1,210	+ $53
Case 4 EPU 2019-19	$1,203	+ $46
Case 5 EPU 2019-20	$1,200	+ $43

The capital revenue requirements plus the incremental fuel costs combine for an average incremental cost of $44.7 million for Case 2 (EPU implementation 2016-2017). Delays for placing the EPU program in-service increase the average incremental cost of the project. For Case 5 (EPU implementation during 2019 and 2020 fuel outages), the average incremental cost is $59.4 million.

Figure A3: PI EPU Total Incremental Cost

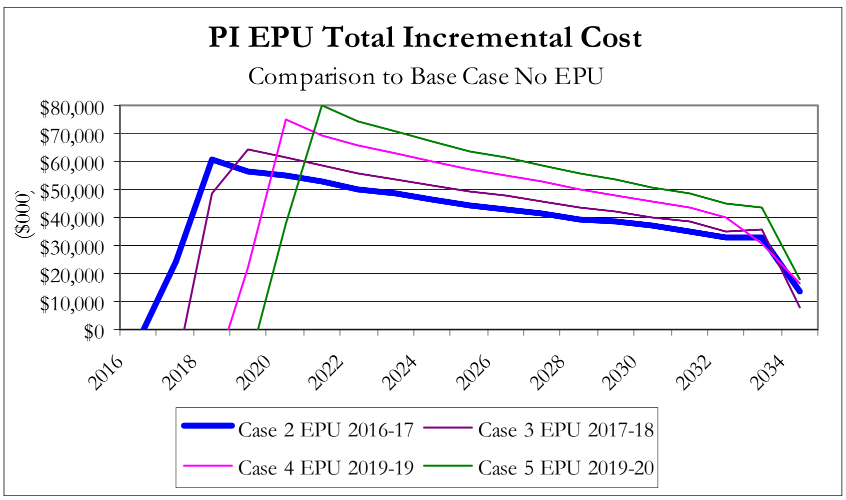


Table A7: PI EPU Total Incremental Cost

	Total Incr Cost 2012-2034 (NPV 7.56%) ($millions)	Average Annual Incr Cost ($millions)	Average Annual Energy	Average Cost
Case 2 EPU 2016-17	$316 M	$44.7 M	923 GWh	$48.40/MWh
Case 3 EPU 2017-18	$307 M	$48.3 M	922 GWh	$52.34/MWh
Case 4 EPU 2019-19	$275 M	$54.0 M	924 GWh	$58.45/MWh
Case 5 EPU 2019-20	$266 M	$59.4 M	923 GWh	$64.34/MWh

2. *EPU – Avoided Cost*

The implementation of the EPU program will eliminate the need to add new resources to the NSP system as well as displace generation from existing fossil fuel-based resources. Strategist simulations suggest that the EPU program will displace or delay natural gas combustion turbines from 2018 through 2034, and that 80% of the displaced generation will be from natural gas units or market energy.

The Strategist model builds a least cost expansion plan to meet the required reserve margin for each scenario. Consequently, adding the EPU program to the expansion plan will cause some resources to be displaced or delayed. If in any given year the total capacity in the model exceeds the reserve margin, a capacity credit is given to the portfolio. This analysis used a capacity credit of $13.50/kW-yr. Figure A4 illustrates how the EPU program delays the addition of CT units in the expansion plan.

Figure A4: PI EPU Displaced Capacity

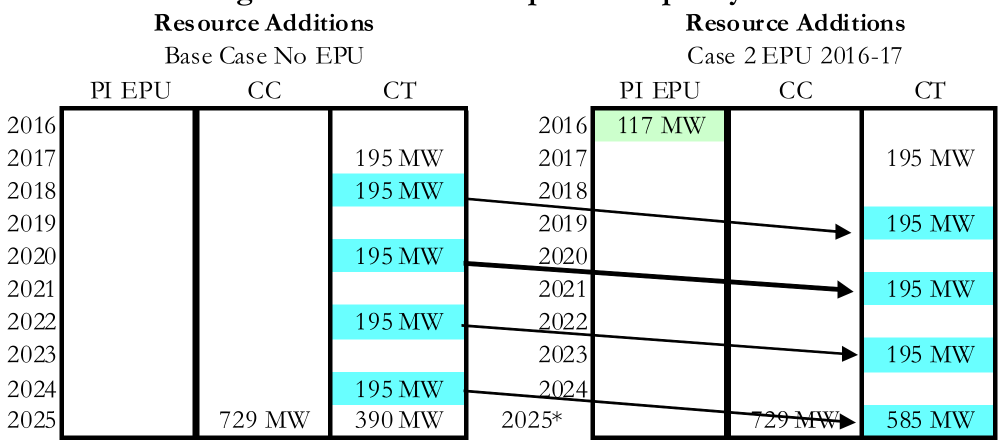


Figure A5: PI EPU Avoided Capacity Benefit

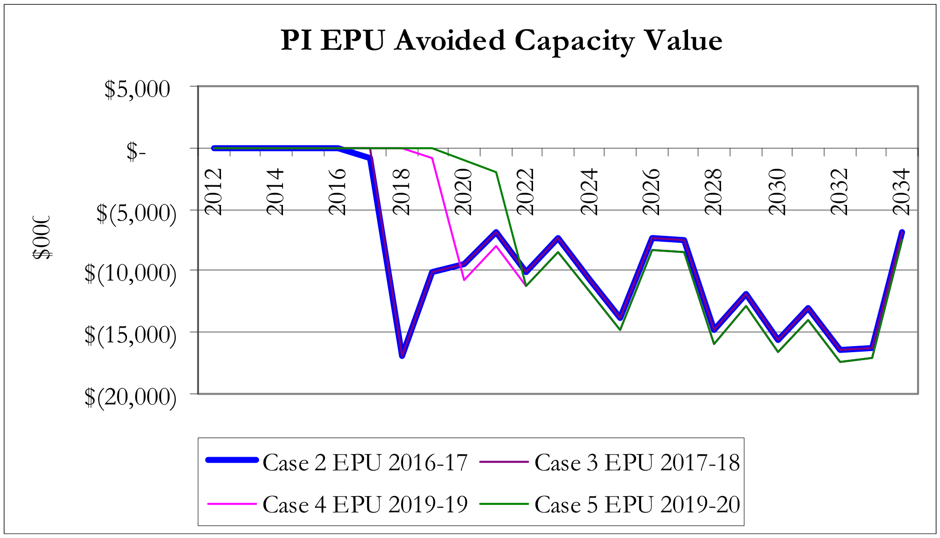


Table A8: PI EPU NPV Avoided Capacity Benefit

	Total Avoided Capacity (NPV 7.56%) ($millions)	Annual Average ($millions)	PI EPU Capacity	Average Price of Avoided Capacity
Case 2 EPU 2016-17	-$73 M	-$11.8 M	117 MW	$8.37/kW-mo
Case 3 EPU 2017-18	-$72 M	-$11.8 M	117 MW	$8.37/kW-mo
Case 4 EPU 2019-19	-$63 M	-$12.6 M	117 MW	$8.95/kW-mo
Case 5 EPU 2019-20	-$53 M	-$13.1 M	117 MW	$9.32/kW-mo

In addition to avoided capacity additions, the EPU program will also avoid generation from existing fossil fuel units. In Strategist nuclear units are modeled as must-run units that always produce energy unless the units are on a planned or unplanned outage. When the EPU program capacity is added to our system, the additional energy from the uprate causes other units in the Strategist simulation to be backed down. Because Strategist dispatches units according to price, the most expensive units are backed down first. Strategist simulations estimate that the EPU energy will displace 46% market energy, 34% natural gas energy, 16% coal energy, and 4% will be excess energy that may result in curtailment of wind generation or other variable output resources. The displaced market energy has an average implied heat rate of 7.3mmBtu/MWh, meaning that the value of this energy is very similar to energy from a natural gas combined cycle unit.

Figure A6: PI EPU Displaced Energy

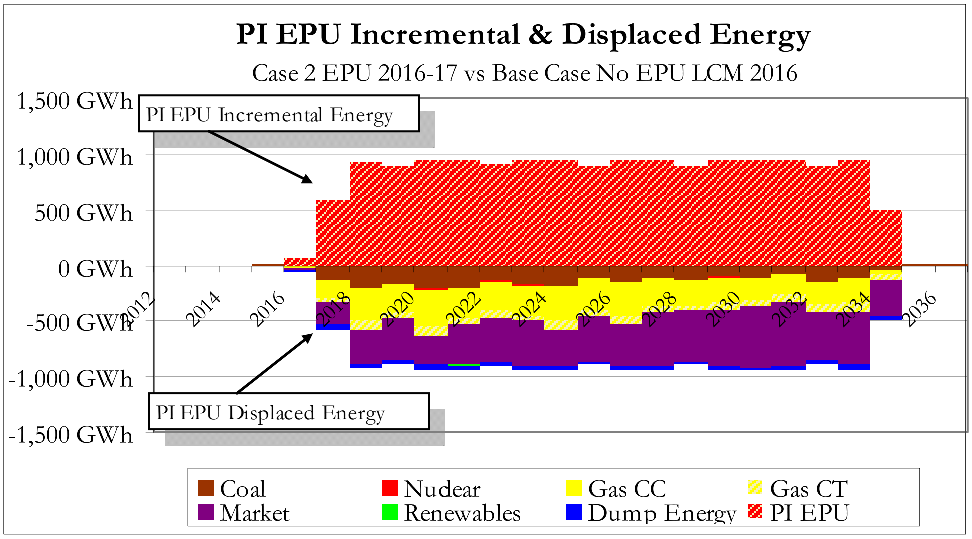


Table A9: PI EPU Percentage Displaced Energy

	Displaced Energy* Case 2 EPU 2016-17
Coal	16%
Gas CC	27%
Gas CT	7%
Market	46%
Dump Enegy	4%
Other	1%

*Rounded to whole percentage

The value of displaced energy is the largest benefit identified in this analysis. The value of the displaced energy is forecasted to be about $50 million per year. However, these savings could be lower if natural gas prices continue to fall or if our load is lower than forecasted.

Figure A7: PI EPU Value of Displaced Energy

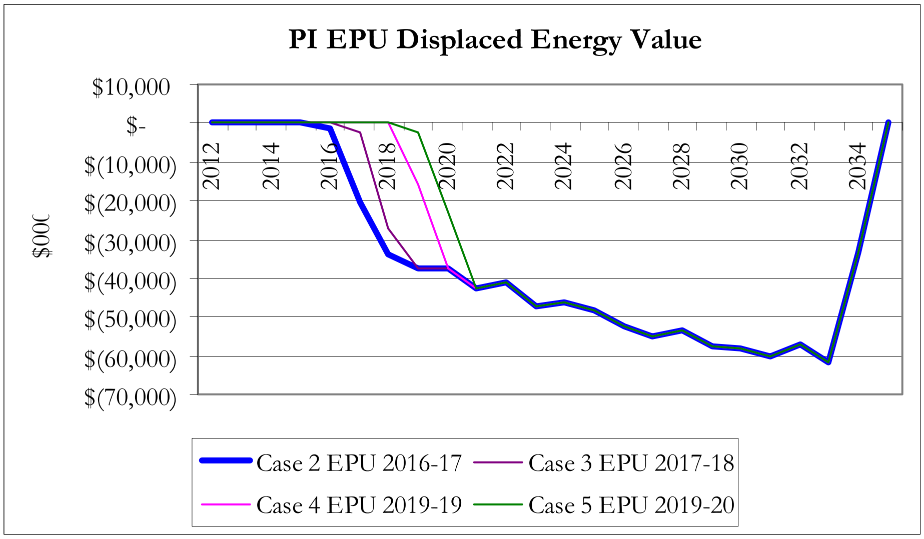


Table A10: PI EPU NPV Displaced Energy

	Total Displaced Energy (NPV 7.56%) ($millions)	**Annual Average** ($millions)	**PI EPU Average Energy**	**Average Price of Displaced Energy**
Case 2 EPU 2016-17	-$316 M	-$49.4 M	923 GWh	$53.50/MWh
Case 3 EPU 2017-18	-$299 M	-$49.0 M	922 GWh	$53.12/MWh
Case 4 EPU 2019-19	-$266 M	-$51.3 M	924 GWh	$55.54/MWh
Case 5 EPU 2019-20	-$250 M	-$53.2 M	923 GWh	$57.60/MWh

Total net cost for the EPU program scenarios is the sum of the revenue requirements for the incremental EPU program capital expenditures and the incremental fuel costs, less the avoided capacity and energy benefits, plus a small adjustment for timing differences for the LCM projects. Table A11 illustrates each of the net cost components and the resulting total. These net costs correspond to the values shown in Table A2 PVRR DELTA Matrix.

Table A11: PI EPU Net Cost Calculation

	EPU Capital Rev Req (NPV 7.56%) ($millions)	**LCM Capital Incr. Rev Req** (NPV 7.56%) ($millions)	**EPU Incr. Fuel** (NPV 7.56%) ($millions)	**Total EPU Costs** (NPV 7.56%) ($millions)	**Total Avoided Capacity** (NPV 7.56%) ($millions)	**Total Displaced Energy** (NPV 7.56%) ($millions)	**Total PI EPU Benefits** (NPV 7.56%) ($millions)	**Total PI EPU Net Costs** (NPV 7.56%) ($millions)
Case 2 EPU 2016-17	$259 M	-$5 M	$57 M	$311 M	-$73 M	-$316 M	-$389 M	-$79 M
Case 3 EPU 2017-18	$254 M	-$11 M	$53 M	$296 M	-$72 M	-$299 M	-$371 M	-$75 M
Case 4 EPU 2019-19	$229 M	-$11 M	$46 M	$264 M	-$63 M	-$266 M	-$329 M	-$65 M
Case 5 EPU 2019-20	$223 M	-$11 M	$43 M	$255 M	-$53 M	-$250 M	-$304 M	-$49 M