Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

November 22, 2013

The Honorable Eric L. Lipman
Assistant Chief Administrative Law Judge
Office of Administrative Hearings
600 North Robert Street
St. Paul, Minnesota 55101

RE: INITIAL POST-HEARING BRIEF OF XCEL ENERGY
IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY TO INITIATE A COMPETITIVE RESOURCE ACQUISITION PROCESS
OAH DOCKET NO. 8-2500-30760
MPUC DOCKET NO. E002/CN-12-1240 AND 13-606

Dear Judge Lipman:

Northern States Power Company, doing business as Xcel Energy, submits in the above-referenced matter its Initial Post-Hearing Brief.

This document has been e-filed in Docket No. E002/CN-12-1240 and served on the attached service list. We are also serving a hard copy on your office by U.S. Mail.

Please contact me at james.r.denniston@xcelenergy.com or (612) 215-4662 if you have any questions regarding this filing.

Sincerely,

/s/ James Denniston

JAMES R. DENNISTON
ASSISTANT GENERAL COUNSEL

In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process

CERTIFICATE OF SERVICE
OAH Docket No. 8-2500-30760
MPUC Docket No. E002/CN-12-1240

Rachel Rolseth certifies that on the 22nd day of November, 2013, she filed a true and correct copy of **Xcel Energy's Initial Post-Hearing Brief,** by posting it on www.edockets.state.mn.us. Said document was also served via U.S. Mail and e-mail as designated on the Official Service List on file with the Minnesota Public Utilities Commission.

/s/ Rachel Rolseth
Rachel Rolseth

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STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY TO INITIATE A COMPETITIVE RESOURCE ACQUISITION PROCESS

MPUC DOCKET NO. E002/CN-12-1240
OAH DOCKET NO. 8-2500-30760

XCEL ENERGY'S INITIAL POST-HEARING BRIEF

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits its initial post-hearing brief in support of its recommendation on the resources the Commission should select to meet the Company's identified need, and the procedures the Commission should employ in implementing its selection.

In our recent resource plan proceeding, the Commission found a need for incremental new capacity of 150 MW in 2017, increasing up to 500 MW in 2019. The record in this case confirms a need in the range of 300 MW by 2019. The Company's analysis shows that our proposed 215 MW Black Dog Unit 6 (one combustion turbine) is the most advantageous alternative in the record and it should be selected to meet part of that need. Since Black Dog Unit 6 is not sufficient to meet the entire identified need, it is necessary for the Commission to select a second resource. The record supports selecting either (i) one 178 MW combustion turbine to be added at Invenergy's existing Cannon Falls plant, or (ii) a 345 MW combined cycle unit to be added at Calpine's existing Mankato combined cycle facility, in conjunction with Black Dog Unit 6.

The economic analyses of both the Company and the Department of Commerce Division of Energy Resource show the choice between the Invenergy Cannon Falls and Calpine Mankato expansion options to be very close. As a result, the Company recommends that the Commission order us to negotiate PPAs with both parties simultaneously and present the outcome of those negotiations to allow the Commission to choose the best alternative to be deployed in conjunction with Black Dog Unit 6.

The record also shows uncertainty regarding whether the range of need identified in the record will remain given continuing soft demand and MISO's evolving capacity reserve requirements, both of which could delay, reduce, or eliminate the capacity need. As a result, the Company further recommends that the Commission require flexibility in deploying the selected resources. We request the Commission to authorize us to provide need updates in the Fall of 2014 and 2015 to provide the Commission the most recent information on load forecasts and MISO reserve margin requirements. If the Commission finds that the need has been delayed, reduced or eliminated, it could order us to delay or stop deployment of one or both of the selected resources and treat them like cancelled projects.

To ensure this flexibility, we respectfully request that the Commission direct the parties in the PPA negotiation phase of this proceeding to develop the in-service date(s) for each of the selected resources that best matches the identified need in the 2017-2019 timeframe and provides the maximum value to our customers. This is somewhat different than a typical certificate of need-type process where the Commission would specify the in-service date for the selected resource. Flexibility in this regard will allow us to optimize deployment of the resources to maximize customer benefits. We further ask that the Commission direct those negotiations to explore appropriate mechanisms to allow for delay or cancellation with reasonable compensation to reflect the costs incurred for the project prior to delay or cancellation. This will provide valuable optionality for our customers if circumstances evolve to the point of delaying, reducing or eliminating the need.

Finally, the Company recommends that the Commission adopt the Company's proposed cost-recovery mechanism for the investments at Black Dog Unit 6. We propose that the rate of return associated with Black Dog Unit 6 be adjusted up or down when placed in service to reflect any difference between the estimated capital cost presented in this filing compared to the actual capital cost of the units. A rider, with adjusted unit ROE, would be used during the first five years of rate recovery. This mechanism provides a real incentive to keep costs as low as possible, and in doing so delivers additional benefits to our customers. Alternatively, the Commission could adopt the Department's suggestion that the Company be required to absorb any capital costs in excess of our proposal estimate but that we be allowed to keep and earn a return on any cost savings below the proposal estimate. While we believe our proposed incentive mechanism provides greater certainty and ensures customer value, under the unique circumstances of this case and based on this specific record, we do not object to the Department's proposed alternative.

II. BACKGROUND

On March 5, 2013, the Commission issued its order in our Resource Plan proceeding (Docket No. E002/RP-10-815) identifying the Company's need for 150 MW of system capacity in 2017, increasing up to potentially 500 MW by 2019. Five bids were submitted in the Company's Request for Proposals to meet this need:

- Xcel Energy proposed up to three new natural gas combustion turbine (CT) units, each adding approximately 208 MW of summer-season capacity to our system: one at the existing Black Dog site (Black Dog

Unit 6), and two at a new site near Hankinson, North Dakota (Red River Valley Units 1 and 2).

- Invenergy Thermal Development LLC offered two separate proposals for new CTs: the first for one additional CT at its existing Cannon Falls site with approximately 150 MW of summer-season capacity, and the second for two CTs at a new site located near the Hampton Corners Substation totaling approximately 300 MW of summer-season capacity.

- Calpine Corporation proposed to install a second combined cycle unit at its existing Mankato Energy Center. Calpine's proposal would add approximately 278 MW of summer-season capacity to the system.

- Geronimo Wind Energy, LLC proposed 100 MW of distributed solar energy at 20 sites located across the Company's service territory, for approximately 71 W of summer-season capacity.

- Great River Energy offered a capacity energy credit purchase of 100 MW or 200 MW (no energy or generation would be included with the purchase).

Based on the evidentiary record developed in this proceeding, both the Company and the Department come to similar results. The Department recommends that the Commission select some combination of Black Dog Unit 6, Calpine's Mankato expansion project, and Invenergy's Cannon Falls expansion project to proceed forward.

The Company's analysis shows that Black Dog Unit 6 should be selected in any event. To completely fill the identified need, the Company's analysis also shows that either the Invenergy Cannon Falls or the Calpine Mankato expansion proposal are appropriate resources and that the Commission should choose between them based on the outcome of simultaneous PPA negotiations. The recommendation to proceed to the next phase of this proceeding with Black Dog Unit 6 and the Cannon Falls and Mankato expansion projects is based on three considerations.

First, the Company recognizes the benefits to the system of deploying additional incremental generation. Based on the record, it is important to get 'iron in the ground' to ensure adequate capacity under all circumstances into the next decade. The Company's identified range of need in 2019 can only be met by a combination of resources, and the Strategist resource modeling conducted by the Company and the Department shows the two lowest cost resource plans are a combination of Black Dog Unit 6 with the Invenergy Cannon Falls project, and Black Dog Unit 6 with the Calpine Mankato expansion.

Second, for the Mankato and Cannon Falls projects to be implemented, various issues must be resolved in the PPA negotiation phase. A PPA not only contains the material terms and conditions that most directly determine its price, but must also reasonably and prudently assign contract performance risks between the seller and the purchaser, which can also affect the PPA's value to our customers. Selecting both projects to advance to the PPA negotiation phase for resolution creates an incentive for the vendors to provide their very best proposals, and should allow us to determine which of the two projects provides greater customer benefits overall. Since the economic analysis between these two proposals is very close, these negotiations could result in risk-sharing differences that sway the Commission's decision.

Third, there is still significant uncertainty about what the Company's need will turn out to be for the 2017-2019 period, principally due to continued softness in our recent demand forecasts plus the uncertainty surrounding evolving MISO reserve margin requirements. As a result, we recommend the Commission require us to submit status reports in the Fall of 2014 and 2015 so the Commission can determine whether delay in the implementation or even cancellation of the selected resources is in the best interests of our customers. Depending on the size of a reduced need, the Commission may in the end choose to proceed with only one of the selected resources.

The balance of this brief is organized in the following sections:

-Standard of Review

-Application of Need Criteria

-Recommendation

-Conclusion

III. STANDARD OF REVIEW

A resource chosen through a Commission-approved competitive resource acquisition process pursuant to Minn. Stat. § 216B.2422, subd. 5(b) is exempt from the requirement to obtain a certificate of need.[1] But as the Commission explained in its order approving the Track 2 competitive bidding process that is being used in this proceeding, the "certificate of need filing requirements and decision criteria are clear, comprehensive, directly relevant . . . , and easily transferable to th[is] resource procurement process."[2] Thus, the standard of review for the selection of a resource in this proceeding is the same as for a Certificate of Need. The primary decision criteria are:

> A. Probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;

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[1] *In The Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process*, Docket No. E002/CN-12-1240, NOTICE AND ORDER FOR HEARING at 3 (June 21, 2013) ("Competitive Acquisition Hearing Order").

[2] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E002/RP-0-1752, ORDER ESTABLISHING RESOURCE ACQUISITION PROCESS, ESTABLISHING BIDDING PROCESS UNDER MINN. STAT. § 216B.2422, SUBD. 5, AND REQUIRING COMPLIANCE FILING at 6-7 (May 31, 2006).

> B. <u>A more reasonable and prudent alternative to the proposed facility has not been demonstrated</u> by a preponderance of the evidence on the record;[3]
>
> C. A preponderance of record evidence shows the proposed facility, or a suitable modification of <u>the facility, will provide benefits to society</u> in a manner compatible with protecting the natural and socioeconomic environments, including human health; and
>
> D. The <u>record does not demonstrate</u> that the design, construction, or operation of the proposed facility, or a suitable modification of <u>the facility, will fail to comply with relevant policies</u>, rules, and regulations of other state and federal agencies and local governments.[4]

These four factors serve as the primary analytical tool in assessing the record and our recommendations in this case.

In addition, there are a number of statutory and rule provisions that identify other factors for the Commission to consider when selecting a resource to meet an identified need. These include:

> (i) whether selecting a nonrenewable resource in lieu of a renewable resource is less expensive or otherwise in the public interest (Minn. Stat. §§ 216B.2422, subd. 4 and 216B.243, subd. 3a);
>
> (ii) whether the proponent of a nonrenewable resource has assessed the risk of environmental costs and regulation over the life of the resource (Minn. Stat. § 216B.243, subd. 3(12));
>
> (iii) whether the resource proponent is in compliance with Minnesota's Renewable Energy Standards, including considering purchasing energy from community-based energy development projects (Minn. Stat. §§ 216B.1612, subd. 5(a) and 216B.243, subd. 3(10));

[3] *See also* Competitive Acquisition Hearing Order at 4 (noting the Commission will be evaluating the prudence of the competitive resource proposals in this proceeding).

[4] Minn. R. 7849.0120 (emphasis added).

(iv) whether the resource proponent has considered distributed generation (Minn. Stat. § 216B.2426);

(v) whether the need can be met through increased demand side management (Minn. R. 7849.0290 F);

(vi) whether the need can be met through purchased power, increased efficiency of existing facilities, new transmission, or alternative generation resources ((Minn. R. 7849.0250 B);

(vii) the availability of innovative energy project generation to meet the need (Minn. Stat. § 216B.1694, subd. 2(4)); and

(viii) the viability of building no facility (Minn. R. 7849.0340).

Each of these criteria will also be addressed below.

IV. APPLICATION OF NEED CRITERIA

A. Resource Need

In determining whether to add resources to the system, the Commission must first find whether a need for additional generation has been established. This is the first factor of the four factors to be applied in assessing the resource proposals. It directs the Commission to determine whether denial of the resource would have an "adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states." In other words, is the resource needed to avoid adverse consequences.

1. *Need Has Been Established*

In its March 5, 2013 order in the Company's 2010 Resource Plan proceeding (Docket No. E002/RP-10-825), the Commission found the Company "will need an additional 150 MW in 2017, increasing up to 500 MW by 2019."[5] This need assessment was based on the Company's 2011 resource plan forecast and consists of three factors: (i) a forecast of peak power demand; (ii) an additional capacity reserve margin that is set by MISO to ensure adequate back up generation is available in the system; and (iii) the total existing generation capability on our system. The first two factors determine our forecast of total capacity obligation. The total obligation is then compared to our existing resources, adjusted for planned retirements, to determine our net capacity need in the future.[6]

The Commission further stated in the March 5 Resource Need Order that the identified range of need:

> does not preclude Xcel from acquiring more than 150 MW of new resources by 2017. Those choices will be made in the context of the resource acquisition docket, based on the proposals and the evidence adduced in that docket.[7]

Consistent with this direction that the ultimate amount and timing of the resource(s) to meet the Company's need will be based on the evidentiary record developed in this proceeding, Company introduced updated resource need information so that the record includes the latest available evidence on the Company's anticipated need in the 2017-2019 time period.

As part of the Company's regular business process, we update our capacity need assessment as new information becomes available. Our most current capacity assessment - September 2013 Update – is shown in comparison to the need

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[5] *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E002/RP-10-825, ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS, AND CLOSING DOCKET at 6 (Mar. 5, 2013) ("March 5 Resource Need Order").

[6] Ex. 46 (Wishart Direct) at 5.

[7] March 5 Resource Need Order at 6.

assessment used in the Resource Plan Docket in Table 1 below.[8] The September 2013 Update indicates a generating capacity deficit of 93 MW starting in 2017, which grows to 307 MW by 2019.

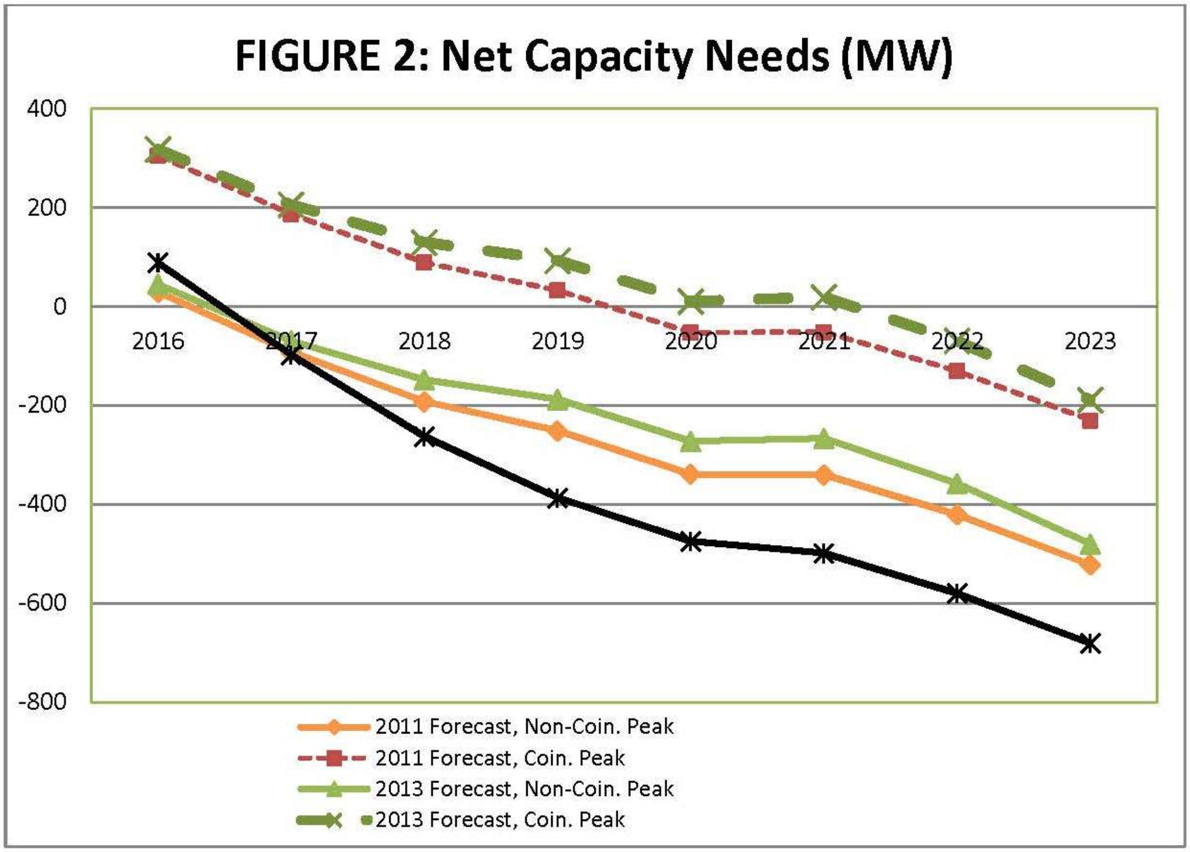
Table 1 – September 2013 - Resource Need Assessment

	Resource Plan Docket			September 2013 Update			Change		
	2017	**2018**	**2019**	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Peak	9,613	9,708	9,799	9,500	9,590	9,676	- 112MW	- 118MW	- 123MW
RM%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	0.0%	0.0%	0.0%
Total Obligation	**9,977**	**10,076**	**10,170**	**9,860**	**9,953**	**10,042**	**- 117MW**	**- 123MW**	**- 128MW**
Resources									
Coal	2,331	2,331	2,331	2,367	2,367	2,367	36	36	36
Nuclear	1,610	1,610	1,610	1,623	1,623	1,623	12	12	12
Gas	3,437	3,424	3,424	3,427	3,416	3,416	(9)	(8)	(8)
Wind, Hydro, Bio	1,280	1,229	1,202	1,238	1,189	1,162	(42)	(40)	(40)
Solar	9	10	11	49	66	83	40	56	72
Load Management	1,157	1,153	1,149	1,063	1,074	1,085	(95)	(79)	(65)
Total Resources	**9,824**	**9,758**	**9,728**	**9,768**	**9,735**	**9,735**	**(57)**	**(23)**	**8**
Long (Short)	**(153)**	**(318)**	**(443)**	**(93)**	**(218)**	**(307)**	**+60MW**	**+100MW**	**+136MW**

The Department also analyzed our capacity need based on new information. In conducting its analysis, the Department used somewhat different assumptions and inputs from the Company, but reached substantially similar conclusions. Department witness Dr. Steve Rakow considered a range of net capacity need for our system in his Strategist analysis of the proposals in this proceeding, as shown below in Figure 2 from his direct testimony.[9]

[8] Ex. 46 (Wishart Direct) at 7.

[9] Ex. 83 (Rakow Direct) at 26.



The solid line with asterisks at the bottom of Figure 2 represents the Company's need as identified in the March 5 Resource Need Order, while the solid line with triangles in the middle of the figure represents the Company's need based on updated information on load forecast and existing and planned resources.[10] Dr. Rakow concluded that his analysis of this updated information was consistent with our analysis indicating a capacity deficit of around 300 MW by 2019.[11]

2. *Uncertainty Exists Regarding the Need*

The Company's load forecasts have been reduced in recent years as a result of the aftermath of the Great Recession and changing usage patterns as a result of the overall economy. This is reflected in the September 2013 Update, which includes

[10] Ex. 83 (Rakow Direct) at 26, footnote 15; *see also id.* at 17-20.

[11] Ex. 86 (Rakow Rebuttal) at 3.

1) the Company's new load forecast; 2) updated unit capacity ratings; 3) the impact of the Minnesota Solar Mandate; and 4) an updated forecast of load management resources.[12] We recognize the potential that demand could remain soft, and while we agree it is important to construct incremental capacity to be available under all reasonable circumstances, we believe the uncertainty relating to forecasted demand is a factor that should be taken into account in the Commission's final decision.

A further consideration is the change in the reserve margin requirements established by MISO, which were not included in our September 2013 Update. MISO introduced a new reserve margin methodology in 2013. Instead of basing reserve requirements on each utility's peak demand, the new methodology is based on what each utility's load will be at the time when MISO, as a whole system, reaches its maximum peak demand. This is referred to as the "coincident peak" methodology. Our expected coincident peak is 5% lower than our non-coincident peak, significantly reducing the Company's forecasted resource need. As shown in Table 2 below, under MISO's new methodology there is no longer a capacity need in 2017, and the need in 2019 ranges from 26 MW to 128 MW.[13]

Dr. Rakow also reviewed the new MISO methodology and evaluated its impact on our system capacity need. His modeling applied the coincident peak methodology to both the 2011 need forecast and the 2013 need forecast, which in both instances resulted in there being no need for additional capacity for the entire 2017-2019 period, as represented by the two dashed lines at the top of Figure 2 above. Dr. Rakow concluded that the impact of MISO's 2013 coincident peak reserve margin methodology underscores the uncertainty of the range of need that could materialize in the 2017-2019 time period.[14]

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[12] Ex. 46 (Wishart Direct) at 7-8.

[13] Ex. 46 (Wishart Direct) at 8-10.

[14] Ex. 83 (Rakow Direct) at 27.

This analysis supports our conclusion that it is prudent to continue to monitor changes in the determination of resource adequacy in the MISO market to see if delay or even cancellation of one or more of the selected units may be warranted.[15] To that end, the Company recommends that the Commission require us to file status reports in the Fall of 2014 and 2015 so that the Commission can assess if changes in resource implementation should be made.

Table 2 – Impact of MISO's Reserve Margin On Resource Need Assessment

	September 2013 Update			**MISO 2013 Reserve Margin Adjustment**			**2014 Anticipated Reserve Margin**		
	2017	**2018**	**2019**	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Peak	9,500	9,590	9,676	9,500	9,590	9,676	9,500	9,590	9,676
Coincidence Factor	100%	100%	100%	95%	95%	95%	95%	95%	95%
Coincident Peak	9,500	9,590	9,676	9,025	9,110	9,192	9,025	9,110	9,192
RM%	3.8%	3.8%	3.8%	6.2%	6.2%	6.2%	7.3%	7.3%	7.3%
Total Obligation	**9,860**	**9,953**	**10,042**	**9,585**	**9,675**	**9,762**	**9,684**	**9,775**	**9,863**
Resources									
Coal	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367
Nuclear	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623
Gas	3,427	3,416	3,416	3,427	3,416	3,416	3,427	3,416	3,416
Wind, Hydro, Bio	1,238	1,189	1,162	1,238	1,189	1,162	1,238	1,189	1,162
Solar	49	66	83	49	66	83	49	66	83
Load Management	1,063	1,074	1,085	1,063	1,074	1,085	1,063	1,074	1,085
Total Resources	**9,768**	**9,735**	**9,735**	**9,768**	**9,735**	**9,735**	**9,768**	**9,735**	**9,735**
Long (Short)	**(93)**	**(218)**	**(307)**	**183**	**60**	**(26)**	**84**	**(40)**	**(128)**

3. *Timing of the Need*

The September 2013 Update represents an additional data point for the Commission to consider to ensure that its resource selection in this contested case proceeding takes into account the latest evidence available regarding the potential

[15] Ex. 49 (Alders Direct) at 8-9.

range and timing of our need in the 2017-2019 timeframe.[16] We therefore modeled the proposals so that we could assess the optimal resource(s) for meeting a potential need in 2019 that ranges from 307 MW up to 500 MW. This resulted in a range of resource portfolios consisting of 358 MW to 636 MW of new resources, allowing the Commission to assess which resource(s) best meet this range of need.[17]

Based on the uncertainty of the timing of our need, we recommend that the Commission allow us the flexibility to optimize the deployment of the selected resources through the 2017-2019 timeframe. The Company's proposal includes the flexibility to place Black Dog Unit 6 into service in 2017, 2018, or 2019.[18] Both Invenergy and Calpine have indicated some flexibility in the timing of their proposed resource, although that flexibility was not part of their initial proposals. We believe it is in our customers' best interest for the Commission to direct that the PPA negotiations include consideration of which in-service date(s) for each resource will best match the Company's need.

In addition to the Commission being able to determine the initial in-service date of Black Dog Unit 6 at the time of its selection, our proposal also specifically includes the flexibility to delay or cancel the unit after it has been selected in response to evolving circumstances.[19] This gives the Commission the flexibility to ensure that only those resources that are needed get deployed. The cost of delaying or cancelling Black Dog Unit 6, which the Company would seek to recover, would be small compared to the potential cost of going forward with the project if the need forecasts no longer support that outcome. As noted above, Invenergy and Calpine have both

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[16] Ex. 49 (Alders Direct) at 7. We therefore agree with Department witness Sachin Shah that the goal of these contested case proceedings is to identify the least cost resource(s) with respect to the range of need forecasts, not a single need forecast. Ex. 78 (Sachin Rebuttal) at 4.

[17] Ex. 46 (Wishart Direct) at 10-11.

[18] Ex. 49 (Alders Direct) at 2.

[19] Ex. 49 (Alders Direct) at 8.

signaled flexibility with respect to the initial in-service date of their proposals. The Company recommends the Commission also direct that the PPA negotiations address the viability of delay and cancellation options for the Cannon Falls and Mankato expansions as well. Such options may impact the projects' pricing, helping the Commission judge the value of such flexibility.[20]

B. <u>Alternatives Analysis</u>

The next criterion calls for the Commission to consider the record evidence developed with respect to each resource that has been proposed. This is the second factor of the standard in Minnesota Rule 7849.0120. It provides for the Commission to determine whether a "more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record." This calls for consideration of the alternatives proposed in the record and a determination whether any of them have been proved to be superior to the Company's proposal.

As described below, none of the proposed alternatives have been demonstrated to be superior to Black Dog Unit 6. Thus in all circumstances, the Commission should select Black Dog Unit 6 as one of the resources to fill the identified need.

However, we recognize that Black Dog Unit 6 is not large enough to satisfy the entire need identified in the record, meaning that the Commission will need to select one of the alternative proposals in addition to Black Dog Unit 6. Since the identified need requires deployment of a combination of resources, we acknowledge that both the Cannon Falls and Mankato projects are viable alternatives for selection, provided that we are able to come to satisfactory PPA terms. As described above, we recommend flexibility in deploying the selected projects be required to optimize benefits to our customers.

[20] *Id.*

1. *Xcel Energy's Proposal*

In order to meet the identified need, the Company's original proposal was to add a single CT unit at its Black Dog plant in 2017, and two CT units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019. The Company also proposed recovery of the capital cost for this new generation utilizing elements of the cost recovery mechanism developed for the Metropolitan Emissions Reduction Project (E002/M-02-633).

Because of the economic analyses conducted by the Department and the Company in this case, we recognize that our greenfield Red River Valley units are not as cost-effective as the expansion of Black Dog Unit 6. Further, unless an impediment arises during PPA negotiations, we recognize that the Cannon Falls and Mankato proposals are more cost-effective at this time than the Red River Valley greenfield units. While focusing our discussion on Black Dog Unit 6, we continue to support the Red River Valley units as viable alternatives in the event that we are unable to obtain satisfactory PPAs with Invenergy or Calpine.

a. *Black Dog Unit 6*

Black Dog Unit 6 will be located at the Black Dog plant in Burnsville, Minnesota, approximately 15 miles south of Minneapolis and east of the City of Eagan. The Black Dog plant is currently a coal- and gas-fired generating station. [21]

The original Unit 1 boiler/turbine and the Unit 2 boiler, installed at the site in the 1950s and fired on coal, were repowered in 2002 with a natural gas combined-cycle unit (Unit 5). This configuration includes a natural gas combustion turbine-

[21] Ex. 1 (Company Proposal) at 4-3.

generator combined with a heat recovery steam generator that delivers steam to the Unit 2 steam turbine and generator.[22]

Black Dog Units 3 and 4, which utilize coal as the primary fuel, were put into service in 1955 and 1960 and will be retired in 2015. Black Dog Unit 6 will be located in the existing powerhouse, in the area where Unit 4 currently is located.[23]

The new combustion turbine unit will be sized at 215 MW connected to the existing 115 kV substation. Minor modifications to the existing 115 kV switchyard will be required to connect it to the transmission system. No upgrades of the 115 kV transmission system are required since Unit 6 will utilize some of the outlet capacity from retired Units 3 and 4, and a new interconnection request with MISO is not required.[24]

Unit 6 will be fueled entirely by natural gas. CenterPoint Energy currently serves the plant site. We will be securing additional natural gas supply through a competitive process beginning in early 2014. We anticipate that the successful bidder may need to file for a route permit and other necessary permits to replace the existing pipeline serving the plant with a new higher pressure natural gas line running from the Cedar Town Border station to the plant.[25] The capital cost estimate for Black Dog Unit 6 is included in trade secret Appendix C of our April 15 proposal filing.[26]

b. *Red River Valley Units 1 and 2*

While not included in our initial resource recommendation to the Commission, the Company supports the development of Red River Valley Units 1 and 2 at some

[22] Ex. 1 (Company Proposal) at 4-4.

[23] Ex. 1 (Company Proposal) at 4-5.

[24] Ex. 1 (Company Proposal) at 4-5 to 4-6.

[25] Ex. 1 (Company Proposal) at 4-6

[26] *Id.*

point in the future. They could be available as alternatives if PPA negotiations fail with Calpine and Invenergy. And this greenfield proposal could be a viable future project adding geographic diversity and long-term value to our system. To complete the record, we provide the following brief summary of these proposed units.

We anticipate the site for the Red River Valley plant to be approximately 160 acres located in the vicinity of Hankinson in southeastern North Dakota because of ready access to both the transmission system and a major natural gas pipeline nearby.[27] The proposed facility consists of two, 215 MW natural-gas, combustion turbines with the necessary infrastructure to accommodate a full time operating and maintenance staff. The layout of the facility allows for two combustion turbines to be installed, and can accommodate conversion to combined cycle configuration in the future.[28]

The capital cost of Red River Valley Units 1 and 2, along with performance and operations and maintenance information, are presented in trade secret Appendix C. Generally, those costs are somewhat higher than Black Dog Unit 6, and Invenergy's and Calpine's proposals. We have also provided conservative indicative cost estimates for the anticipated gas pipeline interconnection, the transmission facilities to connect the plant to the transmission system, and the 230 kV network upgrade.[29]

The Staff of the North Dakota Public Service Commission provided testimony in this proceeding urging serious consideration of the Red River Valley units. Essentially the North Dakota Staff argues in favor of constructing generation near the Company's North Dakota Fargo load center.[30] That testimony notes that having local

[27] Ex. 1 (Company Proposal) at 4-7.

[28] Ex. 1 (Company Proposal) at 4-8 to 4-9.

[29] Ex. 1 (Company Proposal) at 4-12.

[30] Ex. 75 (Diller Direct) at 5-7.

generation near that load center will enhance service reliability.[31] The Company appreciates North Dakota Staff's perspective, and we agree that the Red River Valley units are potentially valuable to our system and could be cost-effective alternatives at some point in the future. The Company is willing to work with North Dakota to explore ways to maximize the viability of the units and increase their cost-effectiveness for future resource acquisitions.

2. *Cost Recovery*

In our Application, the Company proposed a specific cost-recovery mechanism that is designed to provide incentives to keep costs as low as possible and share benefits with customers. This cost-recovery proposal utilizes elements of the mechanism developed for the Metropolitan Emissions Reduction Project (MERP) (Docket No. E002/M-02-633), which is an example of a successful method of containing capital costs for new generation. We propose that a rate rider be established for Black Dog Unit 6 (as well as the Red River Valley units if they are selected). As with MERP, we propose the return on equity (ROE) associated with the capital costs of the specific unit be adjusted up or down when that unit is placed in service to reflect any difference between the estimated capital cost compared to the actual capital cost of the units. The rider, with adjusted unit ROE, would be used during the first five years of rate recovery. Similar to MERP, this mechanism provides a real incentive to keep costs as low as possible, and in doing so delivers additional benefits to our customers.[32]

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[31] The North Dakota Public Service Commission is conducting hearings relating to the Company's proposed resource acquisition on November 26, 2013 (Case Nos. PU-13-194 and PU-13-195). Mr. Diller sponsored testimony in that proceeding that argues Xcel Energy should be required to construct the Red River Valley units at some point in the future. The Company will provide an update on the North Dakota proceeding in our Reply Brief in this matter.

[32] Ex. 1 (Company Proposal) at 4-14.

The proposed ROE adjustment would be applied to the Company's last authorized ROE at the time the unit is placed in service, as shown in Table 3 below:[33]

Table 3 - Proposed ROE Adjustments Based on Unit Costs

Actual Project Cost Compared to Estimate	Project ROE Adjustment Compared to Authorized ROE
Exceeds estimate by more than 10%	100 basis point reduction in ROE
Exceeds estimate by up to 10%	50 basis point reduction in ROE
At or below estimate by up to 5%	Authorized ROE
Below estimate by more than 5% but less than 10%	50 basis point increase in ROE
Below estimate by 10% or more	100 basis point increase in ROE

We do not propose any mechanism to adjust the capital costs presented in our proposal for Black Dog Unit 6. The unit's cost estimate does not include any as yet unknown expenses; there are no anticipated transmission costs other than those included in our estimate, and new pipeline infrastructure, if any, will be the responsibility of the fuel supplier.[34]

For a regulated utility subject to ratemaking authority, the mechanism we propose effectively meets the twin objectives of establishing cost estimates that are as accurate as possible and imposing discipline to meet those estimates. Unlike a price cap, which simply disallows costs above a pre-determined amount, the Company's proposed recovery mechanism incentivizes the Company to deliver its proposal at the

[33] Ex. 1 (Company Proposal) at 4-15.

[34] Ex. 49 (Alders Direct) at 4. The transmission and pipeline capital cost estimates presented in for the Red River Valley Plant site are, however, indicative by necessity. We have not yet identified a specific site, and routes for the transmission and gas support infrastructure have not been established or permitted. In the event the Red River Valley units are selected, we propose to update transmission and gas pipeline estimates after a site and routes have been permitted and interconnection agreements achieved, and submit those updated support infrastructure estimates for Commission review to establish the baseline against which to compare actual cost. Ex. 1 (Company Proposal) at 4-14 to 4-15.

lowest possible cost below its estimate. The greater the cost reduction, the greater the savings to customers. At the same time, the mechanism includes an ROE penalty should the actual costs exceed the estimated costs. The carrot and stick structure of the mechanism provides a balanced approach to protect ratepayer value.[35]

The Department proposed an alternative to our cost recovery mechanism that requires the Company to absorb any cost increases while allowing the Company to keep any cost savings below its proposal estimates.[36] The Company recognizes that the Department's proposal offers an incentive to keep costs low but does not include a sharing mechanism for increased or decreased costs. In contrast, our proposal gives the Company a strong incentive to reduce costs as much as possible and also shares savings with customers. For this reason, the Company continues to support our cost recovery mechanism as the most balanced approach. Nevertheless, based on the unique circumstances in this case and the record developed here, the Company does not object in principle to the Department's proposed alternative.

3. Alternatives

There were five proposals to add natural gas generation to our system: two from the Company, two from Invenergy, and one from Calpine. GRE proposed a short term capacity credit purchase, while Geronimo submitted a solar proposal. Based on both the Company's and the Department's analyses, both the Calpine Mankato combined-cycle expansion and the Invenergy Cannon Falls expansion CT are viable alternatives that can be considered for selection along with Black Dog Unit 6.

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[35] Ex. 49 (Alders Direct) at 5-6.

[36] Ex. 82 (Shaw Rebuttal) at 3.

The Company used the Strategist resource expansion model to analyze the impacts of these proposed resources on our system, as did the Department. Strategist is an important analytical tool that allows consideration of both the costs and the benefits of various proposals, and provides a basis to compare the relative value of disparate proposals. Calpine, on the other hand, used a levelized cost of energy (LCOE) analysis to evaluate all the natural gas proposals, while Invenergy, Geronimo, and GRE analyses focused for the most part on their own proposals. Unfortunately, the LCOE method only analyzes the cost side of the equation and makes no attempt to analyze the relative benefits of the disparate proposals against their costs.[37] A brief description of the Strategist modeling and LCOE methodology is provided below, followed by a summary of the results showing that Black Dog Unit 6, Cannon Falls, and Mankato are the most reasonable and prudent alternatives to meet the Company's need.

The Strategist resource planning model is a computer simulation model that is used to identify the lowest cost resources to meet established reserve margin requirements. Both the Company and the Department have utilized the Strategist model in several other resource planning related dockets, and the software is used extensively throughout the country.[38]

The model begins with a forecast of the utility's peak customer demand, to which a minimum reserve margin percentage is added to arrive at a minimum total capacity value that the utility must have to ensure reliable service to its customers. The model then accounts for all of the utility's existing generation resources and how much those contribute to meeting the required reserve margin. If the model identifies a short fall in the required capacity ("capacity need"), it will simulate the addition of a resource or combination of resources to meet the reserve margin target. One of the

[37] Ex. 48 (Wishart Rebuttal) at 2-3.

[38] Ex. 46 (Wishart Direct) at 20.

unique advantages of the Strategist model is that not only will it identify the lowest cost resource to fill a capacity need, it will also identify all of the sub-optimal resource combinations and their costs. Inspection of these sub-optimal plans provides valuable insight into the cost differences between resources.[39]

The model includes a detailed hourly generation dispatch simulation where generators are ranked from lowest to highest based on generation costs and then dispatched in order to meet customers' hourly demand. Though this simulation, Strategist tracks total fuel costs, total generating hours, and associated air emissions.[40]

While Strategist provides a complete cost-benefit analysis of all the proposals, the levelized approach does not. LCOE is only appropriately used when comparing very similar resources of the same type where cost is the principal, if not only, distinguishing factor between the resources. In this proceeding there is a variety of resources: peaking and intermediate resources, dispatchable and nondispatchable resources, and natural gas, solar, and short-term "paper" capacity resources. In this situation, a proper analysis must examine both the costs of the proposed resources and their widely varying benefits, which is what Strategist does.[41] Since the LCOE approach is only a partial analysis of the alternatives, it should not be relied upon in the selection of resources in this proceeding.[42]

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[39] Ex. 46 (Wishart Direct) at 20-21.

[40] Ex. 46 (Wishart Direct) at 21.

[41] Ex. 48 (Wishart Rebuttal) at 15-16. *See also id.* at 16-17 (a recent Energy Information Administration cautionary note explaining that "the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives").

[42] Ex. 48 (Wishart Rebuttal) at 3.

4. Black Dog Unit 6, Cannon Falls, and Mankato Preferred

Based on the record developed in this case, Black Dog Unit 6 is the most appropriate resource among all the proposals.[43] Black Dog Unit 6 also provides significant in-service flexibility, being deployable in 2018 or 2019 depending how the resource need evolves. As a result, Black Dog Unit 6 is the preferred alternative that should be selected by the Commission. Since more than one unit needs to be selected in order to satisfy the entire identified need, the Commission should consider the proposed alternatives to determine which resource in combination with Black Dog Unit 6 provides our customers with maximum value.

a. *Economic Analysis Confirms Preferred Portfolio*

We provide a listing of the top 20 resource combinations in the Company's Strategist analysis in Table 4 below. Notably, all of those combinations include some combination of Black Dog Unit 6, the Invenergy Cannon Falls unit, and/or the Calpine Mankato expansion. Table 4 includes the present value of societal costs (PVSC) or net present value of the top 20 combinations of bids .[44] Great River Energy's capacity credit proposal is not one of the top two plans and Geronimo's solar proposal is not in the top 20 plans at all.

[43] Ex. 46 (Wishart Direct) at 19.

[44] Ex. 46 (Wishart Direct) at 26.

Table 4 - Strategist Top 20 Proposal Combinations (PVSC)

	Selected Bids	Total Long Term Capacity	2013-2050 PVSC $millions	Difference From Plan 1
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	358 MW	$45,366	
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,368	+ $1.8
Plan 3	GRE Short Term - 2016 - 100MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,368	+ $2.2
Plan 4	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2019 - 208MW	358 MW	$45,371	+ $5.1
Plan 5	Black Dog 6 - 2017 - 208MW Red River Valley 1 - 2018 - 208MW	416 MW	$45,375	+ $9.0
Plan 6	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,375	+ $9.1
Plan 7	GRE Short Term - 2016 - 100MW Black Dog 6 - 2018 - 208MW Red River Valley 1 - 2018 - 208MW	416 MW	$45,376	+ $9.8
Plan 8	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2017 - 208MW	358 MW	$45,377	+ $10.9
Plan 9	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2018 - 208MW	358 MW	$45,379	+ $12.6
Plan 10	GRE Short Term - 2016 - 100MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,381	+ $14.2
Plan 11	GRE Short Term - 2016 - 200MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,383	+ $16.8
Plan 12	Invenergy Cannon Falls - 2016 - 150MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	566 MW	$45,384	+ $17.8
Plan 13	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 200MW Black Dog 6 - 2019 - 208MW	358 MW	$45,386	+ $19.6
Plan 14	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2017 - 208MW	486 MW	$45,386	+ $20.0
Plan 15	Invenergy Hampton Corners - 2016 - 300MW Black Dog 6 - 2019 - 208MW	508 MW	$45,387	+ $20.6
Plan 16	GRE Short Term - 2016 - 100MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,388	+ $21.5
Plan 17	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2017 - 208MW	358 MW	$45,389	+ $23.0
Plan 18	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 200MW Black Dog 6 - 2018 - 208MW	358 MW	$45,393	+ $27.0
Plan 19	GRE Short Term - 2016 - 200MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,395	+ $28.7
Plan 20	Invenergy Cannon Falls - 2016 - 150MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	636 MW	$45,396	+ $29.4

The least cost plan identified by Strategist is a combination of Cannon Falls in 2016 followed by Black Dog Unit 6 in 2018. This combination has a total of 358 MW of summer accredited capacity. The second least cost plan, consisting of a combination of the Mankato expansion in 2017 with Black Dog Unit 6 in 2019, delivers 486 MW of capacity and is only $1.8 million more expensive on a PVSC basis than the top plan.[45] Because Black Dog Unit 6 is in both plans, the $1.8 million difference reflects the difference in the net present value costs of the Cannon Falls and Mankato projects. This difference is so small that these two resources – and the top two plans - can be considered to be essentially equivalent.[46]

As we typically do when comparing resources, we conducted a sensitivity analysis that considered high and low natural gas prices, cost sensitivities for capacity credit, a no new wind scenario, high and low carbon pricing and the value of a PPA extension. The outcome of this sensitivity analysis is shown in Table 9 of Mr. Wishart's testimony.[47] As expected, the sensitivities can have a significant effect on each of the proposals, but the effects were predictable. For example, Mankato's net present value was significantly reduced in the high-cost gas and carbon sensitivity plans, as would be expected given its higher efficiency.[48] But ultimately, the Company believes that the base case assumptions are sound and demonstrate that Black Dog Unit 6, and the Invenergy Cannon Falls or Calpine Mankato expansions are the

[45] The in-service dates of the selected portfolio should be left flexible to allow us to maximize customer benefits by finalizing the initial in-service dates to match need in the course of the PPA negotiations.

[46] Ex. 46 (Wishart Direct) at 23.

[47] Ex. 46 (Wishart Direct) at 39. The sensitivity tests included an analysis of the impacts of future environmental regulation costs, as required by Minn. Stat. § 216B.243, subd. 3(12). Potential future environmental costs of all the Company's resources are regularly reviewed by the Commission, with these costs being currently reviewed in Docket No. E002/CI-13-796.

[48] Ex. 46 (Wishart Direct) at 38.

appropriate resources for consideration in developing a portfolio to meet the capacity need.

b. *Differences Between Invenergy and Calpine*

There are a number of differences in the costs of the Cannon Falls and Mankato projects that happen to result in the two being very competitively priced in relation to one another. The Cannon Falls project was modeled with interruptible fuel supply contracts that substantially lowered their total costs. And while the Mankato project has significantly higher capacity payments than Cannon Falls, it is an intermediate combined cycle unit with cheaper energy than Cannon Falls. This creates substantial annual fuel cost savings that equalizes the net cost of the two projects. If the Cannon Falls project were modeled with firm gas supply as Calpine's Mankato project and Black Dog Unit 6 were, the cost comparison would favor Calpine.[49]

There is also a one year timing difference between the projects. Invenergy proposes an in-service year for Cannon Falls of 2016. This is one year before capacity is projected to be needed, in 2017. This results in an additional net cost for Cannon Falls over Mankato. Invenergy has signaled a willingness to be flexible with the in-service date so this cost difference could be mitigated. Moving the Cannon Falls project to 2017 result in a significant improvement in its overall performance.[50]

Finally, because of Mankato's greater capacity – 278 MW versus 150 MW for Cannon Falls - Black Dog Unit 6 can be delayed until 2019. This creates additional cost savings for the Mankato project over Cannon Falls.[51]

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[49] Ex. 46 (Wishart Direct) at 30-31; Ex. 86 (Rakow Rebuttal) at 10. We note that the issue of interruptible gas would benefit from negotiation to assess the implications of non-firm gas on our system while also determining options that may be available to mitigate the use of non-firm gas.

[50] Ex. 46 (Wishart Direct) at 31; Ex. 86 (Rakow Rebuttal) at 11.

[51] Ex. 46 (Wishart Direct) at 31.

Cannon Falls and Mankato have substantially equivalent overall costs and value based on the information in their bids. This supports selecting both to proceed to the negotiation phase for resolution of all issues that need to be addressed in a PPA, including schedule, risks, operations, fuel and the like. Because of the uncertainties described previously, we believe the viability of alternative initial in-service dates as well as delay/cancellation options should be explored in the negotiations to allow us to optimize value for our customers.

In addition to the material terms and conditions affecting price and schedule, there are performance risks that must be addressed, including among other things those related to project development, construction, capitalization, transmission interconnection, fuel supply, operations, and environmental compliance. In the end, every PPA negotiation must allocate some risks that have not been addressed in the information that the parties relied upon to commence the negotiations, and each party to the PPA has different performance, financial, and credit characteristics that bear on how that allocation should be made.[52]

c. *Department's Analysis Confirms Preferred Alternatives*

The Department's Strategist analysis used different modeling assumptions than the Company over several rounds of analysis.[53] Despite using somewhat different assumptions, the Department's analysis reaches essentially the same results. After the first two rounds of analysis, Dr. Rakow recommended the Commission select the combination of Black Dog Unit 6 and Calpine Mankato expansion.[54]

Dr. Rakow's third round of analysis confirmed that deferring the Invenergy Cannon Falls in-service date significantly reduced its costs, as did running the unit

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[52] Ex. 46 (Wishart Direct) at 46-47.

[53] *See* Ex. 46 (Wishart Direct) at 21-22; Ex. 83 (Rakow Direct) at 17-20.

[54] Ex. 83 (Rakow Direct) at 40.

with an interruptible gas supply.[55] Based on this, Dr. Rakow also recommends that both Cannon Falls and Mankato proceed to the PPA negotiation phase to determine which two of Black Dog Unit 6, Cannon Falls, and Mankato should be implemented to meet the Company's identified need.[56]

5. Summary of Results for Red River Valley, GRE, and Geronimo

While not as cost-effective, the Red River Valley units have the same type of long-term benefits as Black Dog Unit 6, and thus compare favorably to the Calpine Mankato expansion and Invenergy Cannon Falls proposals. Strategist identified Red River Valley Unit 1 in the third ranked plan, with only a $2.2 million PVSC difference between that portfolio and the least cost plan.[57] However as shown in Mr. Wishart's trade secret direct testimony,[58] the expense of building at a greenfield site results in Red River Valley Unit 1 having significantly greater cost than Black Dog Unit 6, Cannon Falls, and Mankato for the first 15-20 years of the unit's life, with significant cost savings occurring later.[59]

For this reason, the Company does not currently recommend the Commission consider Red River Valley Unit 1 in addition to Black Dog Unit 6, Cannon Falls, and Mankato. However, the Company does recommend that the Commission hold Red River Valley Unit 1 in reserve in the event neither the Cannon Falls nor Mankato PPA is acceptable upon completion of the negotiation phase. Red River Valley Unit 1 provides an attractive option to ensure that we can successfully fill the identified capacity need. It offers flexibility with its in-service dates, and an additional

[55] Ex. 86 (Rakow Rebuttal) at 10-11.

[56] Ex. 86 (Rakow Rebuttal) at 15.

[57] Ex. 46 (Wishart Direct) at 32.

[58] Ex. 44 (Wishart Trade Secret Direct) at 28, Figure 1.

[59] Ex. 46 (Wishart Direct) at 28.

consideration is that the Company currently does not have generation resources located near its load centers in North Dakota. Construction of new generation in the Fargo area would enhance the local reliability of the power grid.[60]

GRE's short-term system capacity proposal of 100 or 200 MW was always selected in combination with two other proposals (Table 4, Plans 3, 4, etc.), thus enabling the in-service date of the other resources to be delayed. However, the GRE proposal was not included in the two highest ranked plans. This was because the value of delaying either project was not sufficient to justify the cost of the GRE contract.[61]

The value of the delay is determined by comparing the cost of the GRE proposal during the period of delay to the savings incurred by delaying construction of new generation during that same period. The total cost of the GRE contract is larger than the savings derived from shifting the in-service year of Black Dog Unit 6 from 2018 to 2019.[62] Further, the purchase of short-term capacity credits does not result in the creation of new generating capacity for Xcel Energy's system. At this time, the Company supports deployment of additional capacity to ensure that we have enough generation to meet our customers' needs in the mid-to long-term. In short, it is neither reasonable nor prudent to select a short term resource to delay the need to add a long-term resource when doing so costs more than the savings realized by the delay.

Lastly, Geronimo's proposal was not included in any of Strategist's top 20 plans. The highest ranked plan that included Geronimo was number 25.[63] A significant portion of the benefits of Geronimo's solar proposal come from the

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[60] Ex. 46 (Wishart Direct) at 32-33.

[61] Ex. 46 (Wishart Direct) at 24.

[62] Ex. 46 (Wishart Direct) at 33.

[63] *Id.*

capacity credit given to the project, and from the \$21.50/ton CO_2 price assumption used in the Strategist modeling. The capacity credit is based on the accreditation estimated by Geronimo. Recent analysis performed by the Company indicates that this estimate is likely higher than the actual credit that solar projects will receive in the future. Consequently the estimated net benefits of the project are likely overstated. And the avoided cost benefit that results from CO_2 and other externality costs used in modeling the project are not actual savings that will accrue to rate payers. Rather these are planning values that are used to guide resource selection decisions, and so the rate impacts associated with the Geronimo project would be higher than the impact represented by the PVSC result.[64]

The recent amendment of Minn. Stat. § 216B.2422 does not override or contradict the Company's analysis. The amendment requires the Commission to consider whether a particular resource addition helps the utility achieve specified environmental requirements, including the solar energy standard. Minn. Stat. § 216B.2422, subd. 4. In this case, the record establishes that the natural gas proposals are in our customers' best interest and that it would not be cost effective to purchase a renewable energy option, such as solar. This does not mean that the Company will not satisfy its renewable energy commitments and obligations. To the contrary, the Company is fully committed to comply with all of its obligations to purchase solar and other types of renewable energy. However, based on the record, this is not the proceeding in which to determine how it will do so.

It is the Company's position, as well as the Department's, that the Commission cannot assess in this proceeding the reasonableness of Geronimo's project pricing relative to other solar projects that could also help the Company meet its solar energy goals under Minnesota's new solar mandate.[65] We estimate that the Company will

[64] Ex. 46 (Wishart Direct) at 34-35.

[65] Ex. 46 (Wishart Direct) at 36; Ex. 83 (Rakow Direct) at 11-12.

need to acquire approximately 290 MW of solar energy by 2020 to comply with the mandate.[66] It is not reasonable and prudent to fill approximately one third of our solar resource need without any evaluation of other potential solar resources.[67]

C. <u>Natural and Socioeconomic Impacts</u>

The third factor in Minnesota Rule 7849.0120 calls for the Commission to consider external factors to determine whether the record shows that the "proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health."

Review of the Environmental Report prepared on all the proposals in this proceeding does not reveal any land use or environmental factor that would prevent the recommended facilities from being constructed and operated in a manner consistent with Minnesota's strong environmental, natural resource, and human health laws. The Environmental Report also demonstrates that the socioeconomic impacts of the recommended resources are positive.

The cost-effective proposals in this Docket are all natural gas generation with similar impacts. As a result, this factor does not create a material difference among them. While Minnesota law creates some preference for renewable resources (as described in more detail in Section E below), those preferences do not override the Commission's certificate of need decision criteria, nor require selecting a renewable resource if it is not cost-effective or is otherwise an inappropriate resource choice.

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[66] Ex. 46 (Wishart Direct) at 22.

[67] Ex. 46 (Wishart Direct) at 36.

D. Compliance with Laws and Regulations

Finally, Minnesota Rule 7849.0120 calls for the Commission to consider whether the proposed facility or selected alternatives "will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments." Nothing in the record indicates that the design, construction or operation of Black Dog Unit 6 and the Cannon Falls and Mankato expansion projects will fail to comply with relevant state, state and federal agency and local governmental policies, rules, and regulations.

E. Other Criteria

In addition to the four primary factors to be considered under the certificate of need standard, the Commission also should consider the other statutory and rule criteria that have been established for consideration when selecting among resource alternatives. We describe those criteria and our recommended outcome on each of them below.

1. Renewable Resource is More Expensive and Not Appropriate

Minn. Stat. § 216B.243, subd. 3a calls for the Commission in a certificate of need proceeding to consider whether the Company has "explored the possibility of generating power by means of renewable energy resources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source." Likewise, Minn. Stat. § 216B.2424, subd. 4 calls for the Commission to consider whether renewable energy options are in the public interest.

The Company's April 15 filing investigated the potential to meet the anticipated resource need with renewable based generation.[68] Biomass and hydro power are the only renewable based resources that can provide reliable dispatchable generating capacity. The opportunities for additional hydro power on our system are minimal. Even if new biomass generation could be added to our system in the available timeframe it is much more expensive than our proposal, and the reliability of fuel supplies have been questioned. Wind and solar generation are not peaking or intermediate resources since production is intermittent or varies substantially and cannot be effectively dispatched.

In addition, only one renewable energy resource was bid into the process, Geronimo's solar energy bid. To be favored over a nonrenewable resource pursuant to Minn. Stat. § 216B.243, subd. 3a , Geronimo's solar energy proposal had to be a least-cost alternative. However, Geronimo's solar proposal was not included in any of the top 20 least-cost portfolios selected by Strategist to meet our range of need, as shown in Table 4 above.[69]

Moreover, the current Docket is designed to select capacity resources to ensure adequate capacity is available to meet our peak demand, regardless of weather conditions. Natural gas resources will be available during the peak regardless of whether wind is blowing or the sun is shining, and thus are a better choice for our system at this time.

We do not, however, mean to suggest that we have lessened our commitment to renewable resources. To the contrary, the Company has a long-standing commitment to and record of successful deployment of significant amounts of renewable generation. Further, we are committed to developing solar generation consistent with the new statutory requirements, and we propose a solicitation to

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[68] Ex. 1 (Company Proposal) at 5-5 to 5-7.

[69] *See also* Ex. 46 (Wishart Direct) at 33-36; Ex. 83 (Rakow Direct) at 11-13.

determine the interest in and availability of purchasing solar generation to meet those new requirements.

We believe that Geronimo's solar proposal is more appropriately considered in our upcoming solar solicitation where its proposal can be compared against other, similar generation sources, and we can adequately confirm that we are obtaining solar generation at the lowest possible price. As a result, it is not in the public interest to select Geronimo's solar proposal in this Docket to meet the new solar mandate as there is no way to determine in this proceeding whether the proposal is cost-effective in comparison to other solar options that could meet the requirements of the mandate but were not bid into this peaking/intermediate resource selection proceeding.[70]

2. RES, C-BED, Solar Standard

Pursuant to Minn. Stat. § 216B.243, subd. 3(10), the Commission should evaluate whether the applicant is in compliance with the applicable provisions of Minn. Stat. §§ 216B.1691 (the RES statute). The RES statute requires the Company to obtain renewable generation resources sufficient to produce 30 percent of retail electric sales by eligible renewable energy resources by 2020. The Department issued a letter on July 8, 2010, in Docket No. E999-PR-10-267, verifying that the Company was in compliance with the RES for 2009. Since then we have made annual compliance reports to the Commission demonstrating that we continue to comply with the statute.[71] With the renewable based generation on our system, the renewable energy credits we have banked, and our recently approved wind acquisitions in Docket Nos. 13-63 and 13-716, we can continue to comply well into 2023.[72]

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[70] Ex. 46 (Wishart Direct) at 36; Ex. 83 (Rakow Direct) at 12.

[71] Ex. 1 (Company Proposal) at 5-7.

[72] *In the Matter of the Petition of Northern State Power Company for Approval of the Acquisition of the 150 MW Border Winds Project*, Docket No. E002/M-13-716, Petition at 8 (Aug. 9, 2013).

The Company also considered C-BED energy pursuant to Minn. Stat. § 216B.1612, subd. 5(a). In our recent Wind Acquisition dockets (Docket Nos. E002/M-13-603 and 13-716) we reported that it appeared none of the projects we were proposing to acquire in late 2013/early 2014 would have any accredited capacity in the 2017 to 2019 time period, and as a result no C-BED wind project would be available to address our capacity need in that time period even if it could meet our cost and reliability requirements.[73]

The Company also considered the new Solar Energy Standard found in Minn. Stat. § 216B.1691, subd. 2f, requiring the Company to procure sufficient solar generation to provide 1.5 percent of total retail electric sales from solar by the end of 2020. First, the standard does not preclude the purchase of other resources for other purposes. And as discussed in Section E.1 above, the Company fully intends to comply with the solar energy standard, and proposes preparing a solicitation to seek solar resources for that purpose, as does the Department. A targeted solar RFP is preferable to considering a single solar energy proposal in isolation against capacity-based natural-gas proposals, as is the case in this Docket.[74]

3. Distributed Generation

Distributed solar generation was considered as required by Minn. Stat. § 216B.2426, and found to be more expensive than the natural gas proposals and not in the public interest as described in Section E.1 above. Thermal distributed generation such as micro turbines and reciprocating engines is cost prohibitive. The U.S. Energy Information Administration estimates the cost of distributed generation

[73] *See In the Matter of the Petition of Northern States Power Company for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. 002/M-13-603, Petition at 10 (July 16, 2013).

[74] Ex. 46 (Wishart Direct) at 36; Ex. 83 (Rakow Direct) at 12.

resources to be two to two-and-a-half times more expensive to construct than conventional peaking resources such as those proposed by the Company.[75]

4. Demand Side Management

The Commission recently approved the Company's 2013-2015 Conservation Improvement Program (CIP), which sets goals to reach 1.5 percent savings. The Company proposes to attain these goals by launching new programs and expanding our existing programs. However, these aggressive goals suggest that additional gains may be difficult to achieve and sustain.[76]

The Company's 2013-2015 overall electric CIP filing included incremental additions to our demand response portfolio. The projected incremental growth to our programs includes the anticipated impact of new EPA rules affecting our C&I customers, and the most recent load research which shows a decrease in available load relief (a decline in kW relief potential on a per switch basis). Given the considerable existing portfolio, combined with limited potential for traditional demand response, we project small, deliberate growth for the next three years.[77]

We undertook a benchmarking study that projected the potential of 304 MW of additional load reduction. However, it is not clear that this potential can be realized in a cost-effective manner, and the potential has not yet been adequately defined for the Company to make definitive judgments about its potential. We will be commissioning further work to help refine this analysis and incorporate the results in our next Resource Plan filing, as directed by the Commission. However, at this time,

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[75] Ex. 1(Company Proposal) at 5-10.

[76] Ex. 1 (Company Proposal) at 5-8.

[77] *Id.*

it does not appear that conservation measures can be relied on to reduce the current identified need, and there is no contrary evidence in the record.[78]

It is important to determine first whether additional demand response can be achieved and sustained before treating DSM as a generation alternative that can be depended upon to maintain reliable service to our customers. Our conservation initiatives are being actively debated in Docket E-999/CI-09-1449.[79]

5. *Purchased Energy*

Without additional generation on our system, the Company would have to rely on MISO's wholesale market for the capacity credits necessary to meet our resource adequacy obligations. MISO has indicated there are several large power plants that may be retired in the 2015/2016 timeframe. Depending on how quickly retired generation is replaced, the supply of capacity credits could be substantially decreased and, in the extreme, inadequate. Inadequate capacity credits means the region could not meet the reserve margins necessary to meet electrical reliability standards, increasing the risk of power interruptions to customers. If the market for capacity credits is adequate but supply is low, our customers are exposed to higher cost.[80]

Without new generation the Company would also have to rely on the MISO market for the energy needed to meet demand greater than we can meet with existing generation. During peak demand periods the cost of energy can be very high, especially if supply declines due to retirements. In recent years the Company has been able to sell excess electricity in the MISO market during peak demand periods and, in doing so, reduce our customers' bills.[81]

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[78] *Id.*

[79] *Id.*

[80] Ex. 1 (Company Proposal) at 5-10.

[81] *Id.*

6. Efficiency Improvements at Existing Facilities

We also considered increasing efficiency at existing facilities as an alternative. The type of efficiency project that would be appropriate to fill the identified 500 MW capacity need must increase the maximum output from a facility without substantially increasing the fuel inputs. The Company has completed such a project at the Monticello nuclear facility that added 77 MW of capacity in 2013. And another 10 MW of generation capacity is now on the system also with Sherburne County Unit 3's return to service this year. The Company will continue to pursue projects like these to the extent that they are identified as cost-effective for our customers. However, at this time the Company has not identified any additional cost-effective efficiency opportunities within our generation fleet.[82]

7. New Transmission

New transmission is not a viable alternative. The underlying assumption with this alternative is that additional transmission infrastructure would provide access to new or existing capacity resources. We are currently unaware of additional generation resources that, with the construction of new transmission, could cost-effectively provide our customers with the needed energy and capacity. Timing is also an issue when considering transmission as a viable alternative. Transmission capacity of any size can take several years to plan, permit, site, and construct, and would likely not be available in time to meet the customer need.[83]

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[82] Ex. 1 (Company Proposal) at 5-8 to 5-9.

[83] Ex. 1 (Company Proposal) at 5-9.

8. Innovative Energy Project

Minn. Stat. § 216B.1694 requires consideration of an innovative energy alternative as a supply option. At this time, the Company is not aware of an innovative energy project available to meet the need.[84]

9. No Build Alternative

Building no facility is also not a viable alternative. The Commission's March 5 Resource Need Order states there is a need for approximately 150 MW of additional generation on our system by 2017, which may grow to up to up to 500 MW by 2019. Further the record developed in this case shows a need of about 300 MW by 2019, and that DSM and other "no-build" options could not meet that need. While there is uncertainty surrounding our resource need at this time, the no build alternative would increase risks affecting our ability to reliably serve customers, and increase the risk of higher cost electricity.[85]

In reality the no build alternative (a decision by the Commission not to authorize new generation) does not avoid the construction of new generation, it only delays its installation or moves the addition to another utility's system, with the risk of increased reliance on the MISO market to meet our customers' energy requirements.[86] As described elsewhere in this filing, the Company is recommending that we provide updates to the Commission in 2014 and 2015 to assess any changes in our resource need that we may encounter.

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[84] Ex. 1 (Company Proposal) at 5-10.

[85] *Id.*

[86] *Id.*

V. RECOMMENDATIONS

A. Resource Selection

The top portfolios have very similar overall cost results. Common between these portfolios is Black Dog Unit 6. This shows that our proposed project will provide low cost capacity to our customers and long term benefits under all reasonable circumstances. Also Black Dog Unit 6 offers flexibility regarding its exact in service date. In the interest of minimizing costs for our customers, we are also willing to delay or cancel Black Dog Unit 6 to match the identified need as new information becomes available.

Next, Invenergy's Cannon Falls project and Calpine's Mankato project are substantially equivalent based on the Strategist analyses that have been introduced into the record. Either of these projects could be cost-effective resources for our customers. To enhance customer value, the Company recommends proceeding to the contract negotiation stage with both of these proposals.

During negotiations we hope to resolve issues regarding specific contract terms and conditions. Having two PPA proposals move forward ensures that, in the event that mutually agreeable terms cannot be reached with one party, there is an alternative project that can also be used to meet the forecasted capacity need. Maintaining competition though the negotiation phase ensures that parties continue to negotiate in good faith towards a contract that provides adequate protection for our rate payers. Because the cost of the Invenergy Cannon Falls and Calpine Mankato projects are so similar, the Company recommends that the contract that offers the most security and flexibility be selected as the second resource to meet our capacity need. At the end of negotiations, the Commission would select either Invenergy's or Calpine's proposal to proceed along with Black Dog Unit 6.[87]

Given the uncertainty surrounding future resource needs, we recommend status reports in the Fall of 2014 and 2015 so that the Commission can determine if customer benefits associated with delay warrants changing the expected in-service date of selected projects. It is prudent to closely monitor resource need forecasts and to adjust plans if customer benefits can be realized. Consistent with this, the Company recommends the Commission direct that the PPA negotiations also address the viability of delay and cancellation options for the Calpine Mankato and Invenergy Cannon Falls projects.

Finally, we recommend that the Commission adopt the Company's cost-recovery proposal. Similar to the MERP proceeding, this proposal provides the Company with maximum incentive to keep costs down. Alternatively, the Company does not object to the Department's suggestion that the Company be allowed to recover based upon its proposed costs even if our actual expenditures are less.

B. <u>PPA Negotiation Issues</u>

The Company believes it is helpful to recognize specific issues that need to be addressed in the PPA negotiation process. While many issues can come up during negotiations, the following material terms need to be addressed because they could impact PPA costs and hence pricing:

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[87] In the event that the two PPAs do not proceed forward for some reason, construction of our Red River Valley Unit 1 provides an appropriate back-stop option to ensure that we can successfully fill the identified capacity need. Both identified PPAs have the potential to trigger capital lease treatment and having an Xcel Energy owned unit as a competitive alternative ensures that if the capital lease issue cannot be resolved that our capacity needs can still be met. Although the near-term rate impacts of the project would be higher than for the PPAs, the long-term benefits of owned generation will approximately equalize the PVSC of the project over its 35 year operating life.

- Schedule: We believe it is in our customers' interest to negotiate the initial in-service date of the selected projects. This will allow us to optimize deployment of selected resources, and thus maximize the overall value of the selected resource portfolio for our customers. The potential for delay or cancellation of the projects should also be negotiated.
- Security Fund: We require counter parties to mitigate the exposure of our customers to the possibility of default through a pre-COD and post-COD security fund. The Company may draw from the security fund such amounts as are necessary to recover amounts owing to Xcel Energy pursuant to the PPA, including any damages due to the Company and any amounts for which the Company is entitled to indemnification under the PPA. [88]
- Carbon Dioxide ("CO2") Emission Costs and Allowances: Company will reimburse the seller for CO2 emission costs as specifically set forth in the PPA. In the event that seller receives any CO2 emission credits, allowances, allocations, offsets, tradable instruments or the like due to the operation of the particular generating facility, such credits shall be applied to mitigate or offset such emission costs. The Company will not accept responsibility for costs associated with other plant emissions. [89]
- Capital Lease: The Company must determine if the terms and payment structure of the PPA result in the agreement being treated as a capital lease for accounting purposes. If the Company enters a PPA that qualifies as a capital lease, it could adversely affect the Company by increasing its debt to total capitalization ratio, which in turn would

[88] Ex. 46 (Wishart Direct) at 48.

[89] Ex. 46 (Wishart Direct) at 48-49.

require infusion of higher cost equity to reduce the capitalization imbalance. As a result, PPA terms and payment structures are closely scrutinized during the bidding and negotiation processes.[90]

- Project-Specific Issues: The PPA negotiations with Invenergy must resolve (i) the possible need of expanded fuel oil storage at the plant site, and (ii) the lowest cost approach to solution to the transmission needed for the project. The Calpine negotiations must also resolve the impact of its current below investment grade credit rating on its ability to meet our security fund requirements.[91]

[90] Ex. 46 (Wishart Direct) at 49; Ex. 50 (Savage Direct) at 4.

[91] Ex. 46 (Wishart Direct) at 49-50.

VI. CONCLUSION

Subject to need updates the Company will provide to the Commission in the Fall of 2014 and 2015, the Commission should select Black Dog Unit 6 to meet the Company's identified need, in combination with the Invenergy Cannon Falls project or Calpine Mankato project. Both Calpine and Invenergy should be directed to proceed to the PPA negotiation phase to determine which of two provides the PPA with the best value for our customers. If neither proceed past the negotiation phase, the Commission should select our Red River Valley Unit 1 to meet our need in combination with Black Dog Unit 6.

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Respectfully submitted,

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