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November 14, 2013

- Via Email and Federal Express -

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

RE: NORTHERN STATES POWER COMPANY
ADVANCE DETERMINATION OF PRUDENCE – NG GENERATOR APPLICATION
CASE NO. PU-13-194
OAH FILE NO. 20130458

RE: NORTHERN STATES POWER COMPANY
RED RIVER VALLEY NG UNITES 1 & 2 – HANKINSON, ND PUBLIC CONVENIENCE & NECESSITY
CASE NO. PU-13-195
OAH FILE NO. 20130459

Dear Mr. Nitschke:

Enclosed for filing in the above-entitled matters please find the Supplemental Testimony and Schedules of James R. Alders. The Trade Secret version of the enclosed testimony contains data and information protected by the Order Granting Trade Secret Protection dated November 13, 2013.

Please feel free to contact me at 701-241-8632 or dave.sederquist@xcelenery.com should you have any questions or concerns.

Sincerely,

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION & FINANCE

Enclosures

cc: Michael Diller
Sara Cardwell
Jerry Lein
Mitch Armstrong
Dave Sederquist

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Supplemental Testimony and Schedules
James R. Alders

Before the North Dakota Public Service Commission
State of North Dakota

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THREE NATURAL GAS COMBUSTION TURBINE GENERATORS

Case No. PU-13-194
OAH File No. 20130458

Case No. PU-13-195
OAH File No. 20130459

Exhibit__ (JRA-1)

Resource Review Process Update Testimony

November 14, 2013

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is James Alders. I am Strategy Consultant for Rates and Regulatory Affairs for Northern States Power Company d/b/a Xcel Energy.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been employed by the Company for more than 37 years. Since 1994, I have been extensively involved in development of the Company's resource plans, representing the Company before state and federal regulators in various resource planning dockets. In this capacity, I have been responsible for regulatory filings in Minnesota, South Dakota, and North Dakota to present the Company's resource plans and to support specific proposals for resource acquisitions, power plant siting and development, and transmission siting. My Statement of Qualifications is included with my testimony as Exhibit ___ (JRA-1), Schedule 1.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IS THIS PROCEEDING?

A. No. The Company previously filed the testimony of three witnesses: Laura McCarten, Regional Vice President for Northern States Power Company; Steven W. Wishart, Director of Resource Planning and Bidding for Xcel Energy; and Gregory L. Ford, Director of Engineering, Design, and Document Services in the Company's Energy Supply Engineering and Construction Department.

Ms. McCarten provided an overview of our request for an Advance Determination of Prudence (ADP) to add three new 215 MW natural gas

combustion turbines (CT) – Black Dog Unit 6, Red River Unit 1, and Red River Unit 2 – to meet our identified resource needs in the 2017-2019 timeframe. Next, Mr. Wishart presented the Company's assessment of its anticipated generating capacity deficit for the 2017-2019 period, and the Company's analysis of resource options that led to its proposal to add the three new CTs to its system. Finally, Mr. Ford described the design, operation and maintenance, and construction costs and schedules for the Company's proposed CT generators at its Black Dog location in Burnsville, Minnesota, and a new generating plant to be located near the Red River Valley by Hankinson, North Dakota.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide an overview of the resource review process that our proposal is subject to in Minnesota as well as in North Dakota, which Ms. McCarten discussed in detail in her direct testimony. I then provide an update on the status of our proposal in the Minnesota review process, including the Company's resource selection recommendation to the Minnesota Public Utilities Commission (MPUC) in light the Strategist modeling conducted on all the proposals being considered in its review process.

II. OVERVIEW OF COMPETITIVE ACQUISITION PROCESS

Q. PLEASE SUMMARIZE THE REVIEW PROCESS FOR THE COMPANY'S RESOURCE PLANNING AND RESOURCE ADDITION PROPOSALS.

A. The NSP System is an integrated system that serves and benefits all of our customers in the five states it serves. Our Midwest Resource Plan and specific resource addition proposals are subject to review and stakeholder involvement

in all of the states we serve. In North Dakota, we have made commitments to make certain filings so that the Public Service Commission (Commission) and its Staff can have timely input into our plans. In Minnesota, we are subject to State statutes and rules under which the Public Utilities Commission (MPUC) must approve our resource plans and resource additions.

Q. PLEASE DESCRIBE THE COMPETITIVE ACQUISITION PROCESS.

A. When the Company proposes to meet an identified resource need with generation it will build and own, MPUC requirements establish a competitive acquisition process (CAP) be undertaken to determine the appropriate resources to meet the need. A CAP proceeding is currently underway to determine the appropriate resource(s) to meet the Company's identified 150-500 MW resource need in the 2017-2019 timeframe in accordance with MPUC requirements. As part of the proceeding, the Company's proposal for phased construction of three gas CTs competes against alternative resource proposals submitted by independent power producers to meet some or all of our identified need. The Company evaluates all submitted proposals and makes recommendations as to the most prudent way to meet its identified resource need.

This evaluation is overseen by an Administrative Law Judge who provides findings of fact and a report to the MPUC with respect to the Company's recommendations. The MPUC then considers the record and the ALJ's report in determining whether to either accept, reject or modify the Company's recommendation.

Q. HOW DOES THE CAP IMPACT THE CURRENT CASES?

A. The Company has committed to keep the Commission informed of its resource needs and its intended resource additions through the periodic filing of our Midwest Resource Plan with the Commission, as well as seeking ADPs for our intended resource additions. Through the ADP process, the Commission has the opportunity to evaluate our proposal and provide guidance as to the prudence of our intended resource addition. Because there is the potential for different positions to be taken by regulators in North Dakota and Minnesota regarding the optimum resource selection to meet the needs forecasted for the 2017-2019 period, Ms. McCarten committed in her testimony that the Company would keep the Commission fully- and timely-informed of any such developments, and work with both Commissions to address any issues or conflicts in a constructive manner. Consistent with this commitment, I provide an update on Minnesota's review of our proposal along with the five other proposals submitted that were submitted to meet our anticipated need in the 2017-2019 time period.

III. UPDATE ON MINNESOTA REVIEW OF COMPANY PROPOSAL

Q. PLEASE DESCRIBE THE OTHER PROPOSALS SUBMITTED FOR EVALUATION IN THE CAP PROCEEDING?

A. Three independent power producers - Calpine Corporation, Invenergy Thermal Development, and Geronimo Energy – offered alternative proposals to the Company's, as did Great River Energy, an electric cooperative. Calpine's proposal was to expand its existing Mankato Energy Center from a single CT to a combined cycle facility that would add 345 MW to our system; Invenergy proposed two different CT proposals - one for a 150 MW CT at its existing plant site at Cannon Falls, Minnesota, and the other for two 150 MW

CTs at a new site near Hampton Corners, Minnesota. Geronimo offered a solar proposal for 100 MW that would be generated by approximately 20 distributed solar facilities located across the Company's Minnesota service territory. GRE offered a short term capacity credit purchase of 100 to 200 MW for the 2017-2019 time period. Except GRE, all of the resources were proposed to be added to the Company's system as Power Purchase Agreements (PPAs) to be negotiated upon the proposal)s) selection to meet the Company's need.

Q. WHAT IS THE SCHEDULE FOR THE CAP?

A. Upon determining that all the proposals were complete, the MPUC referred them to an ALJ for contested case proceedings with a report on the proposals to be issued by the ALJ by January 1, 2014.

As part of the contested case proceeding, the ALJ ordered a discovery period from July 1 to October 21, 2013, with all intervention petitions due by August 2, 2013. The ALJ also ordered that the parties' direct testimony for the evidentiary hearings be filed by September 27, 2013, and their rebuttal testimony be filed by October 18, 2013.

A hearing to take public comment on the proposals was held on October 5, 2013, and the evidentiary hearings were held on October 22 and 23, 2013. The parties' initial post-hearing briefs are due to the ALJ on November 22, 2013, with rebuttal briefs due on December 6, 2013. The ALJ's Report and Recommendations is scheduled to be filed with the Commission by December 31, 2013. We anticipate that the MPUC will take up the matter for a decision in February 2014.

Q. DID THE COMPANY PERFORM ANY ADDITIONAL ANALYSES AS PART OF THE CAP?

A. Yes. Company witness Steve Wishart presented an update on our capacity need for the 2017-2019 period, and an exhaustive analysis of the relative costs of all the proposals using our Strategist model in direct and rebuttal testimony in the CAP. A copy of Mr. Wishart's trade secret direct testimony is included as Exhibit ___ (JRA-1), Schedule 2 to my testimony, and a copy of his trade secret rebuttal testimony is included as Exhibit ___ (JRA-1), Schedule 3.

Q. WHAT DID THE COMPANY'S UPDATE OF ITS RESOURCE NEED SHOW?

A. As part of our regular business process we update our capacity need assessment as new information becomes available. Our most current capacity assessment – September 2013 Update– indicates a system-wide generating capacity deficit of 93 MW starting in 2017, which grows to 307 MW by 2019, as shown in the table below from Mr. Wishart's direct testimony:

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 update included 1) the Company' new spring 2013 load forecast; 2) updated capacity ratings for system generating units; 3) capacity and energy requirements to address Minnesota's new solar legislation; and 4) an updated forecast of load management resources.

However, the update does not incorporate MISO's new reserve margin requirements or calculation methodology that was introduced for use in 2013. Instead our updated resource need assessment used the same reserve margin that was used in determining the Company's need in our Resource Plan proceeding. Because changes in MISO's reserve margin standards could reduce our need to only 26 MW by 2019, the Company recommended in its testimony that once the least cost resource(s) to meet the Company's anticipated need are identified, the question of the Company's total capacity need and the timing of the selected resource(s) be further reviewed in 2014 and 2015 as more information becomes available.

Q. WHAT DID THE COMPANY'S STRATEGIST ANALYSIS SHOW?

A. The Strategist results showed that Black Dog 6 is the lowest cost resource among all the proposals and was selected as a resource in each of Strategist's top 20 plans. The table below from Mr. Wishart's direct testimony summarizes the these top 20 plans.

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 portfolio in the table includes Invenergy's Cannon Falls proposal in 2016 followed by Black Dog 6 in 2018. This combination has a total of 358 MW of summer accredited capacity. The next least cost portfolio, consisting of Calpine's Mankato expansion in 2017 with Black Dog in 2019, delivers 486 MW of capacity and is only $1.8 million more expensive on a present value basis than the top plan. This net present value difference is so small that the top two plans should be considered to have essentially the same net present value.

Red River Valley Unit 1 has a comparable net present value to Mankato and Cannon Falls because this Company-owned resource has an expected operating life of at least 35 years versus the shorter 20-year contract terms for the Mankato and Cannon Falls PPAs. As a result, Strategist identified Red River Valley Unit 1 in combination with both Black Dog 6 and GRE's capacity credit proposal as the third least cost plan. The costs of the three top resource portfolios are very close together, and the top 5 portfolios are separated by less than $10 million.

Q. WHAT WAS THE COMPANY'S RECOMMENDED RESOURCE SELECTION TO THE COMMISSION AS A RESULT OF ITS STRATEGIST ANALYSIS?

A. The top four portfolios have very similar results, with Black Dog 6 common to all of them. Our proposed Black Dog CT will provide low cost capacity and long term benefits beyond some of the other proposed projects. Also Black Dog 6 offers flexibility regarding its exact in service date. The Company therefore recommended that Black Dog 6 be selected to meet whatever level of need is indicated by updated need information in 2014 and 2015.

Next, the Invenergy Cannon Falls Expansion and Calpine's Mankato Expansion have very similar costs in the Strategist modeling. Either of these projects could be cost effective resources for our customers. The Company, therefore, recommended proceeding to the contract negotiation stage with both of these proposals. During negotiations we hope to resolve issues regarding specific terms and conditions that are typically not resolved until a bid proceeds to final contract negotiations. At the end of negotiations, the Commission would select only one of the two projects to be awarded a contract with the Company. Because the costs of the two PPAs are likely to be similar, the Company recommended that the contract that offers the most security and flexibility be selected as the second resource to meet our capacity need.

In the event that neither of these two PPAs proceed after the PPA negotiation phase, we recommended construction of our Red River Valley Unit 1 as an excellent back stop option to ensure that we can successfully fill any identified capacity need.

Q. WHAT WERE THE RECOMMENDATIONS OF THE OTHER PARTIES IN THE CAP?

A. Yes, the Minnesota Department of Commerce recommended that the Commission select Black Dog 6, Invenergy's Cannon Falls project, and Calpine's Mankato project to move forward, and once the negotiation phase for the Calpine and Invenergy PPAs was completed, the Commission should determine which two of the three projects to select to meet the Company's need at the lowest cost. The parties submitting proposals in the CAP recommended that their projects be selected to meet the Company's need.

Q. IN LIGHT OF THE RECORD DEVELOPED IN TESTIMONY AND AT THE EVIDENTIARY HEARINGS, IS THE COMPANY'S PROPOSAL TO ADD CTS AT A NEW RED RIVER VALLEY PLANT STILL A VIABLE OPTION?

A. Yes. There are issues that must be resolved to finalize a PPA with Calpine or Invenergy which could adversely affect the cost of their proposals. The Company continues to believe that Red River Valley Unit 1 is a viable option that should be held in reserve in the event that the Calpine and Invenergy PPAs do not make it through the PPA negotiation phase.

Q. WOULD THE COMPANY'S ACCEPTANCE OF ANY OF THE PROPOSED PPA ARRANGEMENTS IN LIEU OF CONSTRUCTING THE PROPOSED CTS BE CONSISTENT WITH ITS REQUEST IN THESE CASES?

A. Yes. The Company always seeks to meet its resource needs in the most prudent and cost-effective way it can. If after thorough review any of the proposed PPAs, either separately or combined with our proposed CTs, are determined to be a more prudent approach to meeting our resource needs, we would pursue such a PPA in lieu of constructing some or all of our proposed CTs. Consistent with our prior commitments, we would bring the PPA(s) to the Commission for an advanced determination of prudence.

VII. CONCLUSION

Q. PLEASE SUMMARIZE THE CURRENT STATUS OF MINNESOTA'S RESOURCE REVIEW PROCESS.

A. Based on the information presented in the CAP, the Company is recommending that Black Dog 6, Calpine's Mankato Expansion, and Invenergy's Cannon Falls Expansion all be selected to move forward in the

resource review process, with the final resource selection(s) determined upon completion of the PPA negotiation phase. The Company's proposed Red River Units continue to be viable options should the need arise and prudent PPAs are unable to be negotiated with Calpine and/or Invenergy.

The evidentiary hearings in the contested case proceedings have been completed, and the parties' briefing on the record evidence supporting selection of their respective proposals to meet the Company's anticipated capacity need will be completed the first week of December. Once the ALJ issues his Report and Recommendation at the end of December 2013, the parties will submit to the MPUC any objections they have to the Report. We anticipate the MPUC will then consider the matter in February 2014.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

James R. Alders

Experience

June 2012 – Present	Strategy Consultant
April 2008 – June 2012	Director Regulatory Administration
July 1994 – April 2008	Manager Regulatory Administration
November 1989 - July. 1994	Manager New Facility Permitting
February 1984 - November 1989	Administrator Routing & Siting
August 1981 - February 1984	Administrator Environmental Activities
July 1978 - August 1981	Senior Environmental Planner
November 1975 - July 1978	Environmental Planner

1994 to present

Managed Certificate of Need and Resource Planning proceedings before the Minnesota Public Utilities Commission for large capital projects, including nuclear plant life extension and capacity upgrades, high voltage transmission liens, combustion turbines, and plant conversions.

1975 to 1994

Managed siting, routing, environmental review, and permitting for large capital projects, including high voltage transmission lines, power plants, ash landfills, and solid waste processing facilities. Represented Company in public forums of all types including public hearings, regulatory proceedings, citizen advisory committees, legislative hearings, rulemaking proceedings, and environmental forums.

Education

1989 to 1991 University of St. Thomas, Graduate School of Business
MBA

1971 to 1973 University of Minnesota
Bachelor of Science Degree, Urban Studies

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Direct Testimony and Schedules
Steven W. Wishart

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition to the Minnesota Public Utilities Commission Seeking Approval for a Competitive Resource Acquisition Proposal And For a Certificate of Need

Docket No. E002/CN-12-1240
Exhibit___(SWW-1)

Resource Need, Competitive Resource Analysis, and Company Recommendation Testimony

September 27, 2013

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Steven W. Wishart. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since 2005 in the areas of demand-side management and resource planning. In my current role, I am responsible for the direction and oversight of electric Resource Planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

My responsibilities include assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. I maintain our resource planning model, Strategist, conduct economic evaluations of resource additions, and manage processes for new resource acquisitions. My resume is provided as Exhibit___(SWW-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the Company's assessment of anticipated generating capacity need in the 2017 to 2019 timeframe and discuss factors that may decrease our need assessment. I then describe the analysis we performed to evaluate the proposals that are the subject of this proceeding. Next, I present the results of our Strategist analysis that demonstrates which projects are likely to be least cost additions for our customers. Finally, I discuss important considerations

that need to be addressed in the negotiations for power purchase agreements before making final selections, including the value of flexible in-service dates for our customers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I first review the Company's resource need assessment presented in our April 15, 2013 proposal filing, and then I present an assessment based on updated information regarding load and available resources. This update shows we have a capacity need of 93 MW in 2017 that grows to 307 MW by 2019. However, we note that changes in MISO's reserve margin standards may reduce our need to only 26 MW by 2019. Given this uncertainty, I recommend that after the least cost projects are selected through this process, the question of total capacity need and project timing be revisited in 2014 and in 2015 as more information becomes available.

Next, I review the pricing of the competitive bid proposals submitted by Calpine Corporation, Invenergy Thermal Development LLC, Geronimo Energy, Great River Energy, and the Company. I discuss how these proposals were evaluated using our Strategist resource planning software and the results of the analysis. Strategist identified a combination of the Company's proposed Black Dog Unit 6 with either Invenergy's Cannon Falls Expansion proposal or Calpine's Mankato Expansion proposal as the least cost resources to address the range of the Company's potential need in 2017-2019. The Present Value of Social Costs (PVSC) of the Black Dog 6/Cannon Falls combination and the Black Dog 6/Mankato combination are very close together. Differences in final PPA terms may be more significant than the small PVSC difference identified in the Strategist modeling.

I conclude with our recommendation that Black Dog Unit 6 be selected as the least cost resource. Combining Black Dog Unit 6 with either the Cannon Falls or Mankato resources could be considered the least cost portfolio of resources. Since the combination of Black Dog Unit 6 and either of these two PPAs could be cost effective resources for our customers, we recommend proceeding to the contract negotiations stage with both Cannon Falls and Mankato. This would allow the parties to address outstanding issues regarding specific contract terms and conditions affecting the costs and risks of their respective proposals, which I also review. The outcome of the negotiations would form the basis for the Commission to determine which proposal should be awarded a PPA with the Company.

Given the uncertainty around resource adequacy in the Midcontinent Independent System Operator (MISO) market, I also recommend the PPA negotiations include the development of options similar to those offered by the Company to allow adjustments in resource implementation if new information warrants. We also recommend the Company be required to provide the Commission with status assessments in the fall of 2014 and 2015 so that the Commission can determine if implementation adjustments should be made.

Q. WHAT PORTIONS OF THE COMPANY'S APRIL 15TH RESOURCE PROPOSAL FILING ARE YOU SPONSORING?

A. The portions of our proposal filing that I sponsor are Chapter 3- Resource Need; Chapter 4- Comparison of Company Proposal to Alternatives; Appendix A (Peak Demand and Annual Consumption Forecasts); Appendix B

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(Xcel Energy Demand Side Management Programs); and Appendix D (System Capacity Data).

II. RESOURCE NEED

Q. WHAT WAS THE COMPANY'S RESOURCE NEED ASSESSMENT IN THE RESOURCE PLAN PROCEEDING?

A. The following table presented in our April 15th proposal filing shows the critical elements of the Company's need assessment we presented in our resource planning proceeding, Docket No. E-002/RP-10-825.

Table 1 - Resource Plan Docket Need Assessment

	2016	2017	2018	2019	2020
Peak Demand	9,524 MW	9,613 MW	9,708 MW	9,799 MW	9,881 MW
Reserve Margin %	3.8%	3.8%	3.8%	3.8%	3.8%
Total Obligation	**9,885 MW**	**9,977 MW**	**10,076 MW**	**10,170 MW**	**10,255 MW**
Resources					
Coal	2,331 MW	2,331 MW	2,331 MW	2,331 MW	2,331 MW
Nuclear	1,610 MW	1,610 MW	1,610 MW	1,610 MW	1,610 MW
Gas	3,534 MW	3,437 MW	3,424 MW	3,424 MW	3,424 MW
Renewable	1,289 MW	1,287 MW	1,238 MW	1,212 MW	1,213 MW
Load Management	1,153 MW	1,157 MW	1,153 MW	1,149 MW	1,145 MW
Total	**9,917 MW**	**9,823 MW**	**9,757 MW**	**9,727 MW**	**9,724 MW**
Long (Short)	**32 MW**	**(154MW)**	**(319MW)**	**(443MW)**	**(532MW)**

Q. WHAT DID THE COMMISSION IDENTIFY AS THE COMPANY'S CAPACITY NEED?

A. The Commission's March 5, 2013 order in the Resource Plan Docket established a capacity need of approximately 150 MW in 2017, increasing to up to 500 MW by 2019.

Q. PLEASE DESCRIBE HOW FORECASTS OF CAPACITY NEED ARE CALCULATED.

A. An assessment of the need for new generating capacity 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. I discuss the details of these three factors below.

Demand Forecast: The Resource Plan analysis was based on the peak demand forecast developed in the fall of 2011, and included adjustments recommended by the Department of Commerce during the Resource Planning proceeding. The forecast also included an adjustment for Demand Side Management or DSM. DSM consists of conservation programs that reduce the overall amount of customer power use, which in turn reduces peak demand on our system.

Reserve Margin: "Reserve margin" refers to the amount of generation capacity each utility must have in excess of their expected peak demand. The reserve resources can be called upon to maintain the electric grid's reliability in the event of unplanned outages of generation and/or transmission facilities. MISO establishes a new reserve margin percent annually. MISO also establishes procedures on how to apply this reserve margin and how to calculate the value of the available capacity of all of the generation units in the region when evaluating compliance with the reserve margin. The value for the reserve margin is based on MISO's assessment of supply and demand

uncertainty, and the amount of back-up capacity necessary to maintain grid reliability given the uncertain conditions faced by the industry. The MISO reserve margin requirements applicable at the time of the forecasting are applied to peak demand estimates to establish an estimate of total generating capacity obligation.

Available Generation: The total existing generating capability of the system is measured using summer temperature and humidity conditions for disptachable units, and a calculated value for non-dispatchable resources, such as wind and hydrological resources. Each dispatchable unit's maximum capability is reduced by a percentage that represents the probability that it will not be available due to unplanned outages. The adjustment is based on each unit's historic reliability record, and the adjusted maximum capability is referred to as the 'unforced capacity' rating or UCAP. MISO also sets the calculated value for non-dispatchable resources. The calculation is based on the ability of the particular type of non-dispatchable resource to reliably contribute to meeting peak customer demand. For example, the calculated value for wind resources is only about 13% of a wind unit's nameplate capacity.

Our forecast of total UCAP capacity is adjusted for planned generation retirements, such as Black Dog Units 3 and 4, which are being retired in the spring of 2015 to comply with EPA air emission rules. The forecast is also adjusted for planned resource additions, such as Minnesota's new Solar Energy Mandate, and our planned extension of our contract with Manitoba Hydro in 2015. The forecast of resources also includes an estimate of the amount of customer load that can be interrupted during peak demand periods,

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thus reducing the peak demand, and is treated just like a generating resource in the tabulation.

Each of these factors - and the uncertainty associated with forecasting them - are described more fully in our April 15th proposal filing.

Q. SINCE THE COMMISSION'S MARCH 2013 ORDER, HAS THE COMPANY REASSESSED ITS CAPACITY NEED FORECAST?

A. Yes. As part of our regular business process we update our capacity need assessment as new information becomes available. Our most current capacity assessment – September 2013 Update- is presented below in Table 2. Table 2 shows a comparison between the September 2013 Update and the assessment used in the Resource Plan Docket.

Table 2 – 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 September 2013 Update indicates a generating capacity deficit of 93 MW starting in 2017, which grows to 307 MW by 2019. The update includes;

1) New spring 2013 load forecast

2) Updated unit capacity ratings

3) Minnesota Solar Mandate

4) Updated forecast of load management resources

Table 2 does not include MISO's new reserve margin requirements or calculation methodology that was introduced for use in 2013. Instead our updated resource need assessment uses the same reserve margin that was used in the Resource Plan.

Q PLEASE EXPLAIN THE NEW RESERVE MARGIN METHODOLOGY MISO INTRODUCED IN SUMMER 2013.

A. As we describe in our April 15th proposal filing, MISO implemented a new reserve margin calculation for Summer 2013 that significantly reduced the amount of capacity reserves that NSP is required to have. First, MISO increased the reserve margin percentage from 3.8% to 6.2%. However at the same time MISO changed the methodology of how to apply the reserve margin by no longer applying it to the Company's peak demand forecast, but rather applying it to a forecast of NSP's customer demand at the time when the MISO system reaches its total peak demand. The MISO system may reach its system peak at a different hour or even a different day than NSP. As presented in Table 3 below, NSP and MISO reached peak demand at the same time in some years, but in other years our customer demand was significantly lower at the time when MISO reached its peak. On average, our customer demand was 5% lower during MISO's peak than it was when the NSP system reached its own peak. As a result, MISO's procedures now require the Company to use a coincident peak reduction factor when calculating its resource needs and reserve margin requirements.

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Table 3 – NSP / MISO Average Peak Coincidence Calculation

	NSP System Peak			MISO System Peak			
Year	Day	Time	NSP Demand	Day	Time	NSP Demand	Diversity Factor
2006	July 31st	16:00	9,859	July 31st	16:00	9,859	0%
2007	July 26th	15:00	9,473	Aug 8th	16:00	8,184	14%
2008	July 29th	14:00	8,694	July 29th	17:00	8,596	1%
2009	June 23rd	14:00	8,609	June 25th	15:00	8,039	7%
2010	Aug 9th	17:00	9,131	Aug 10th	16:00	8,463	7%
2011	July 18th	16:00	9,623	July 20th	17:00	9,544	1%
2012	July 2nd	17:00	9,475	July 23rd	16:00	9,007	5%
					2006-2012 Average Coincidence Factor		5%

Q. HAVE THERE BEEN ANY SUBSEQUENT MODIFICATIONS TO MISO'S RESERVE MARGIN?

A. No, officially the MISO standard is still 6.2% applied to each utility's coincident peak. However on September 16th, MISO provided an update on their 2014 reserve margin calculations and, based on preliminary results, the reserve margin for 2014 would be 7.3%, and it still would be applied to each utility's coincident peak.

Q. WHAT IS THE IMPACT OF APPLYING EITHER MISO'S 2013 OR 2014 RESERVE MARGIN VALUES TO THE RESOURCE NEED ASSESSMENT?

A. The impact of the coincidence factor and associated reserve margin change is significant. Table 4 provides an example of how the 2017, 2018, and 2019 capacity need calculations change when the new MISO reserve margins are applied. The coincidence factor by itself causes a reduction in reserve obligation of almost 500 MW. But this decrease is partially offset by the higher associated reserve margin. The net impact is a decrease in reserve requirements of about 300 MW using 6.2%, and about 200 MW using 7.3%.

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Table 4 – 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)**

Q. HAS MISO SETTLED ON A LONG-TERM PLANNING CRITERIA FOR USE IN RESOURCE PLANNING?

A. No. Reserve requirements 5-10 years from now are not very predictable under the current process and several stakeholders have pointed out to MISO that a longer term planning metric needs to be put in place rather than year-to-year recalculations that vary over time. MISO appears to agree and they are in the process of refining their long-term planning reserve criteria. MISO has indicated that it will be looking at this issue in 2014 and hopes to provide an updated long-term planning criteria by next fall.

Q. HOW SHOULD THE UNCERTAINTY REGARDING MISO RESERVE MARGIN REQUIREMENTS BE ADDRESSED IN THIS PROCESS?

A. For our Strategist analysis I have used the reserve margin and MISO methodology that was available when the Resource Plan was reviewed, which

results in 307 MW of capacity need in 2019. Use of the historic MISO reserve margin methodology and resource need in Strategist results in a robust range of project portfolios consisting of 358 MW to 636 MW of new resources. I recommend that project selections be made based on these modeling results and subsequent negotiations with at least two of the project developers.

The projects the Company has proposed offer flexible in-service dates from 2017 to 2019. As presented in our proposal filing, we can push back the in-service dates or cancel units if conditions change and our resource need assessment indicates that it is prudent to do so. As filed on April 15, the proposals from Calpine and Invenergy did not offer similar flexibility. Should the Company's resource need diminish as MISO's reserve margin methodology evolves, the early implementation of the proposed PPAs will cause additional costs to be shouldered by our customers before it is necessary. We believe it is prudent to pursue the ability to delay or cancel the proposed projects with counterparties during negotiations so that we can secure contractual options that can adjust implementation of any project selected in a way similar to our proposal. Flexibility options may prove to be an important distinguishing factor.

In our proposal we also recommended that the Commission consider whether adjustments to implementation need to be made after the Company files an updated resource assessment in the fall of 2014 and 2015. We continue to believe ongoing monitoring of resource adequacy changes by MSIO and other factors affecting need is prudent. There may be an opportunity for significant customer savings. We continue to recommend status assessments in 2014 and 2015 be part of the Commission's Order in this proceeding.

III. COMPETITIVE RESOURCE PROPOSALS

Q. WHAT PROJECTS WERE PROPOSED FOR THE COMMISSION'S CONSIDERATION TO MEET THE COMPANY'S IDENTIFIED NEED?

A. There are four proposals to add natural gas generation to the Xcel Energy system: one from the Company, two from Invenergy Thermal Development LLC, and one from Calpine Corporation. Great River Energy proposed a short term capacity credit purchase, while Geronimo Energy submitted a solar proposal. I provide details on the cost and performance of each proposal, by year, in Schedule 2 to my testimony.

A. Xcel Energy's Natural Gas Peaking Proposal

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL.

A. The Company has proposed three new natural gas peakers: one at the existing Black Dog site, and two at a new site near Hankinson North Dakota (Red River Valley Units 1 and 2). Each of the natural gas combustion turbines (CTs) has an expected summer rated capacity of 208 MW, for a total of 624 MW.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR BLACK DOG?

The Company proposes adding a CT at our existing Black Dog plant site, referred to as Black Dog Unit 6, that would be placed in service in either 2017, 2018, or 2019. The total cost of the project is estimated to be **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** depending on the in-service year, which includes transmission

interconnection costs. As part of our existing agreement with Northern Natural Gas, we are able to secure firm natural gas supply at the Black Dog site for only **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** annually. This is a significant discount over the current market price for firm service. The 35-year levelized total price for Black Dog 6 is **[TRADE SECRET DATA BEGINS**: **…TRADE SECRET DATA ENDS]**. A peaking unit such as Black Dog 6 is expected to have an optimal summer heat rate of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** mm Btu/MWh. At this level of efficiency the unit will only be utilized a small number of hours per year with an annual capacity factor of around 5%.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RED RIVER VALLEY?

A. For Red River Valley Units 1 and 2 we have proposed in-service years of 2018 and 2019. The cost of the first unit is estimated to be **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS],** and the cost of the second **TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**. The cost of the first unit is higher as it bears more of the gas and transmission infrastructure costs at the site. The two units will require **[TRADE SECRET DATA BEGINS …TRADE SECRET DATA ENDS]** in new transmission to deliver power to the Fargo area. However, the Hankinson site is in close proximity to the Alliance pipeline and will require only **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** in new pipeline infrastructure. Our assessment is that the Alliance pipeline has adequate capacity to serve the Red River Valley units, and that fuel will be available with high reliability. The 35-year levelized capacity price of Red River Valley Units

1 and 2 is estimated to be **[TRADE SECRET DATA BEGINS:**
…TRADE SECRET DATA ENDS], respectively. The operating characteristics of the two units should be very similar to Black Dog Unit 6, with an optimal heat rate of **[TRADE SECRET DATA BEGINS**: …**TRADE SECRET DATA ENDS]** mm Btu/MWh, and an approximate capacity factor of 5%.

B. Invenergy's Natural Gas Peaking Proposal

Q. PLEASE DESCRIBE INVENERGY'S PROPOSALS.

A. Invenergy offered two separate proposals for new peakers: the first for one additional CT at its existing Cannon Falls site, and the second for two CTs at a new site located near the Hampton Corners Substation. These CTs are a different type than those proposed by the Company, and each has an estimated summer capacity value of 150 MW. The two proposals have similar cost and operating characteristics, with a 20-year PPA for each, and an in-service date of June 2016 for both projects.

Q. WHAT IS THE PRICING OF INVENERGY'S TWO PROPOSALS?

A. The proposed first-year pricing of Cannon Falls is **[TRADE SECRET DATA BEGINS**: **TRADE SECRET DATA ENDS]** and for Hampton Corners **[TRADE SECRET DATA BEGINS:**
…TRADE SECRET DATA ENDS], with both **[TRADE SECRET DATA BEGINS:** **…TRADE SECRET DATA ENDS]**. We researched the cost of firm natural gas supply and found that it was very costly, in the range of **[TRADE SECRET DATA BEGINS:**
…TRADE SECRET DATA ENDS] per year for each

project. The cost of interruptible fuel supply was much lower, around **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** per year. In our Strategist analysis we modeled both the firm and interruptible alternatives. Given the limited use of peaking units in the winter, we expect that the interruptible fuel supply would be a reasonable, lower-cost alternative for the near-term. With the added cost of interruptible fuel supply, the levelized costs of the projects are **[TRADE SECRET DATA BEGINS**: **…TRADE SECRET DATA ENDS]** for Cannon Falls and Hampton, respectively. On a qualitative basis, the benefit of relying on less expensive interruptible natural gas supplies must be weighed against the longer-term value of having a generation unit that is available on a firm basis the entire year.

These project costs do not include any costs for additional transmission that may be needed. Both projects plan to interconnect to the new Hampton Corners Substation that is being built as part of the CapX2020 Transmission Project. The Cannon Falls project will require approximately **[TRADE SECRET DATA BEGINS:**
…TRADE SECRET DATA ENDS], and Invenergy has budgeted **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** for this cost and included it in its proposed pricing. Because the final transmission costs are still unknown at this time, Invenergy has proposed a cost adjustment mechanism of **[TRADE SECRET DATA BEGINS:**

…TRADE SECRET DATA ENDS].

The Invenergy CTs are expected to have a summer heat rate of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** mm Btu/MWh and should also have annual capacity factors in the range of 5%. If selected, the cost of the projects' capacity payments would be added to base rates, and the cost of fuel would be passed through our fuel cost adjustment rider.

C. Calpine's Natural Gas Intermediate Proposal

Q. PLEASE DESCRIBE CALPINE'S PROPOSAL.

A. Calpine has proposed an expansion of their existing natural gas combined cycle (CC) plant located in Mankato. Combined cycle plants are typically defined as intermediate generation which has higher expected annual capacity factors. These types of units are more efficient than peaking facilities, but have higher construction costs and higher annual operation and maintenance (O&M) costs. The expansion of the Mankato facility would have a proposed in-service date of June 2017 with a term of 20 years, and would add approximately 278 MW of summer capacity to the Company's system.

Q. WHAT IS THE PRICING OF CALPINE'S PROPOSAL?

A. The first year capacity price is **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**. Because of its location, the Mankato facility is able to utilize our firm gas discount from Northern Natural Gas for a firm fuel supply that is estimated to cost **[TRADE SECRET DATA BEGINS**: **…TRADE SECRET DATA ENDS]** per year. The levelized capacity price of the Calpine proposal with firm fuel supply is **[TRADE SECRET DATA**

BEGINS: **…TRADE SECRET DATA ENDS]**. The fuel supply for the Calpine project would be comparable to the firm fuel supply assigned to the Black Dog Unit 6.

Calpine's $/kW-mo price cannot be directly compared to the price for the Company's and Invenergy's peaking proposals because its Mankato facility is a combined cycle type plant with an average heat rate of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** mm Btu/MWh. With this level of efficiency, the unit would operate as an intermediate type resource with capacity factors in the 20%-30% range. For comparison to the proposed peaking facilities, we estimated the levelized value of Calpine's efficiency advantage to be **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**, reducing the net price of Calpine's proposal to **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**.

D. Geronimo's Solar Proposal

Q. PLEASE SUMMARIZE GERONIMO'S SOLAR PROPOSAL.

A. Geronimo has offered a 100 MW (AC) solar project with a targeted in-service date of December 2016. The project will have up to 31 sites throughout the Company's service territory, with a capacity factor of approximately **[TRADE SECRET DATA BEGINS**: **…TRADE SECRET DATA ENDS]** and a summer accredited capacity of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**. Geronimo has offered two pricing options: one with a capacity payment of **[TRADE SECRET DATA BEGINS: …TRADE**

SECRET DATA ENDS], and an energy payment of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**. The second option only includes an energy payment of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**.

Q. CAN A SOLAR PROJECT MEET A PORTION OF THE COMPANY'S IDENTIFIED CAPACITY NEED?

A. Yes. MISO rules provide a methodology to calculate the accredited capacity for solar resources so they can be used to meet a portion of the capacity need. While Geronimo's bid contains information indicating the expected accredited capacity to be **[TRADE SECRET DATA BEGINS**: **…TRADE SECRET DATA ENDS]**, the Company's recent studies indicate accredited capacity for this type of solar PV installation is likely to be in the range of 50 MW to 60 MW. For the purposes of our bid evaluation, however, we used Geronimo's estimate of **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]**.

Q. WOULD THE GERONIMO PROJECT HELP THE COMPANY MEET THE NEW MINNESOTA SOLAR ENERGY MANDATE?

A. Yes, the renewable energy credits created by the project would help us meet our solar energy mandate. We estimate that it will require approximately 300 MW of new solar resources to meet the mandate's 1.5% standard, and selection of the Geronimo project would fulfill approximately one third of the mandate in 2016, four years before the 2020 compliance date.

E. Great River Energy System Capacity Proposal

Q. PLEASE SUMMARIZE THE SYSTEM CAPACITY PROPOSAL FROM GRE.

A. GRE offered a three-year capacity purchase for either 100 MW or 200 MW. This proposal would be for MISO Zone 1 resource credits only; no energy or generation would be associated with this purchase. The purchase would cover 2016, 2017, and 2018, potentially allowing a delay of the in-service dates of one or more of the other proposals. The average prices of the 100 MW and 200 MW options are included in Schedule 2 of my testimony.

IV. STRATEGIST ANALYSIS OF PROPOSALS

Q. HOW WERE THE COMPETITIVE BID PROPOSALS EVALUATED?

A. We used our Strategist resource planning software to evaluate all the proposals submitted to this acquisition process. Through dynamic optimization, Strategist identified the lowest-cost combination of the competitive resource proposals based on their present value of societal costs (PVSC). In addition to the least cost combination of proposed resources, Strategist identified numerous sub-optimal plans. We compared these to the least cost plan to identify which factors were driving the Strategist results. Finally, we conducted sensitivity tests on the least cost and sub-optimal plans to see if the rank order of the proposals would change under different input assumptions.

Q. PLEASE SUMMARIZE THE RESULTS.

A. The Strategist results show that Black Dog 6 is the lowest cost resource among all the proposals and is selected as a resource in each of Strategist's top 20 plans. The least cost portfolio includes Black Dog 6 and Invenergy's

Cannon Falls project. The next least cost portfolio includes Black Dog 6 and Calpine's Mankato expansion. The next ranked plan includes Black Dog and the Company's Red River Valley Unit 1 and GRE's short term capacity purchase. The PVSCs of the top plans are very close together, with the top 5 portfolios separated by less than $10 million.

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE STRATEGIST MODEL AND HOW IT HAS BEEN USED IN THE PAST.

A. 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 Xcel Energy and the Department of Commerce Division of Energy Resources have utilized the Strategist model in several other resource planning related dockets, and the software is used extensively throughout the country.

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 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.

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

Q. WHAT ARE SOME OF THE SPECIFIC INPUT ASSUMPTIONS USED IN THE STRATEGIST ANALYSIS?

A. We started with the same base model that we used in our recent wind RFP analysis. That Strategist model included the following important input assumptions:

1. Load Forecast – The load forecast used in this model was developed in the spring of 2013 and reflects our most current assessment of the impacts of conservation (DSM) on total customer demand. The forecasted peak demand during the resource acquisition period is 9,500 MW in 2017, 9,590 MW in 2018, and 9,676 MW in 2019.
2. Load Management Forecast – The forecast of load management or direct load control programs was developed in spring of 2013. Total load management is 985 MW in 2013 and grows at an average rate of 1% annually through 2020 reaching 1056 MW in that year.
3. Reserve Margin – To set reliability standards, the model uses a reserve margin of 3.8% as established in MISO's November 2011 loss of load expectation (LOLE) report.
4. Emission Pricing – The base model includes the midpoint values for the

Commission-established externality values, including $21.50/ton for CO2 starting in 2017

5. Accredited Capacity – The summer capacity values used in the model reflect the unforced capacity values (UCAP) used in this summer's MISO Module-E resource adequacy standard.
6. Retirements – The model includes the retirement of Black Dog 3 and 4 in the spring of 2015 for compliance with EPA's Mercury and Air Toxins rule (MATS). The model also assumes the retirement of Key City and Granite City at the end of 2016.
7. Resource Additions – We have budgeted capital for repair and return to service of our French Island 3 peaking unit in spring of 2016, and its return is reflected in the Strategist model.
8. Wind – The model includes the 750 MW of wind recently proposed by the Company. In addition, the model contains a long term wind expansion plan designed to achieve and then maintain our 30% renewable energy standard. The long term wind expansion plan starts in 2022 with a 100 MW addition, and grows to 1,500 MW of additional wind by 2030.
9. Solar – We have included a preliminary estimate of the solar expansion plan necessary to comply with the recent Minnesota Solar Energy Mandate. Our solar expansion plan reaches about 290 MW by 2020 (233 MW by 2019). Pending updated results from our effective load carrying capability (ELCC) study, we are assuming an accreditation factor of 42% (36% relative to DC rating).

The load forecast, reserve margin assumption, and the existing or planned resources resulted in a capacity need of 93 MW in 2017, growing to 307 MW in 2019. The resources available to the model for filling the identified capacity

need were those submitted in the April 15th proposal filing. Because most of the projects are smaller than the identified threshold minimum capacity need of 307 MW, Strategist selected combinations of multiple resources to meet the 307 MW minimum.

A. Summary of Strategist Results

Q. HOW WERE THE PROPOSALS MODELED IN STRATEGIST?

A. We used the data provided by each bidder as inputs to the Strategist model. For Calpine's proposal, we added our estimated cost of firm gas supply, and for Invenergy's proposals we added the estimated cost of interruptible gas supply. Schedule 2 of my testimony provides detail on all modeling inputs for each competitive bid.

Q. PLEASE SUMMARIZE THE RESULTS OF THE STRATEGIST MODELING.

A. Table 5 below presents the PVSC for the top 20 combinations of bids that had at least 307 MW of capacity by 2019.

The least cost plan identified by Strategist is a combination of Cannon Falls in 2016 followed by Black Dog 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 6 in 2019, delivers 486 MW of capacity and is only $1.8 million more expensive on a PVSC basis than the top plan. This difference is so small that the top two plans should be considered to have essentially the same net present value.

Given that the top plans are nearly identical on a PVSC basis we recommend that both Calpine's Mankato Expansion and Invenergy's Cannon Falls project be selected to move forward to contract negotiations. Through specific negotiation on contract terms one or the other of these project are likely to distinguish themselves as the most beneficial to customers. Our Red River Valley Unit 1 proposal is in the third ranked portfolio and could serve as a contingency option in the event that neither of the top PPAs can move forward for any reason.

The selection of GRE's short-term system capacity proposal of 100 or 200 MW was always selected in combination with two other proposals (see, e.g., Plans 3, 4, 7, etc.), thus enabling the in-service date of 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.

Red River Valley Unit 1 has a comparable PVSC to Mankato and Cannon Falls because this Company-owned resource has an expected operating life of at least 35 years versus shorter contract terms for the Mankato and Cannon Falls PPAs. As a result, Strategist identified Red River Valley Unit 1 in combination with both Black Dog 6 and GRE's capacity proposal as the third least cost plan. Invenergy's Hampton Energy Center appears in Plan 15 in combination with Black Dog 6. While similar in price to the Cannon Falls project, Hampton appears lower in the rankings primarily because the project adds over 300 MW in 2016 before the first year of identified capacity need. If Hampton's size and in-service date had been better matched to the identified need, the project would likely have been higher in the Strategist rankings.

Finally, as previously noted, Geronimo's proposal was not included in any of Strategist's top 20 plans. The highest ranked plan that included Geronimo was number 25.

Schedule 3 to my testimony provides the annual results for each bid in each of the top 20 plans, and an annual cost comparison to Plan 1 that shows the primary drivers of the PVSC differences.

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Table 5- 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

B. Comparison of Resource Proposals

Q. HOW CAN THE COST AND BENEFITS OF INDIVIDUAL BIDS BE EVALUATED BASED ON THE STRATEGIST RESULTS?

A. Information on the costs and benefits of individual bids can be determined by analyzing the annual cost differences between certain portfolios. For example, Plan 1 contains the Black Dog 6 and Cannon Falls projects, while Plan 2 contains Black Dog 6 and Calpine's Mankato project. Since the cost of Black Dog 6 is included in both plans, the remaining net difference between Plans 1 and 2 is only attributable to the difference between the Cannon Falls and Mankato projects. Given the number of proposal combinations generated by Strategist, we have been able to identify the cost differences between any two proposals in this docket. Schedule 4 of my testimony provides a comprehensive set of cost comparisons based on this method.

Q. WHY WAS BLACK DOG 6 SELECTED BY STRATEGIST IN ALL OF THE TOP 20 PLANS?

A. We are able to construct the unit at an existing site which keeps the capital cost low. In addition, our proposal is that Black Dog 6 can be built in any of 3 different in-service years, which allows the project to better match our customers' needs and thereby reduces the overall system cost. Also, since it is a utility asset, the unit's expected life is considerably longer than the terms of the proposed PPAs.

Figure 1 shows a simple comparison of the dollars per kilowatt per month cost ($/kW-mo) for each of the five natural gas proposals. The cost of the

Calpine proposal has been adjusted downward to account for the efficiency benefit of the combined cycle unit. The figure demonstrates that Black Dog 6 has long term cost advantages compared to the other proposals and illustrates the longer life time offered by the Xcel proposals.

FIGURE 1 – RESOURCE COST COMPARISON - $/KW-MO

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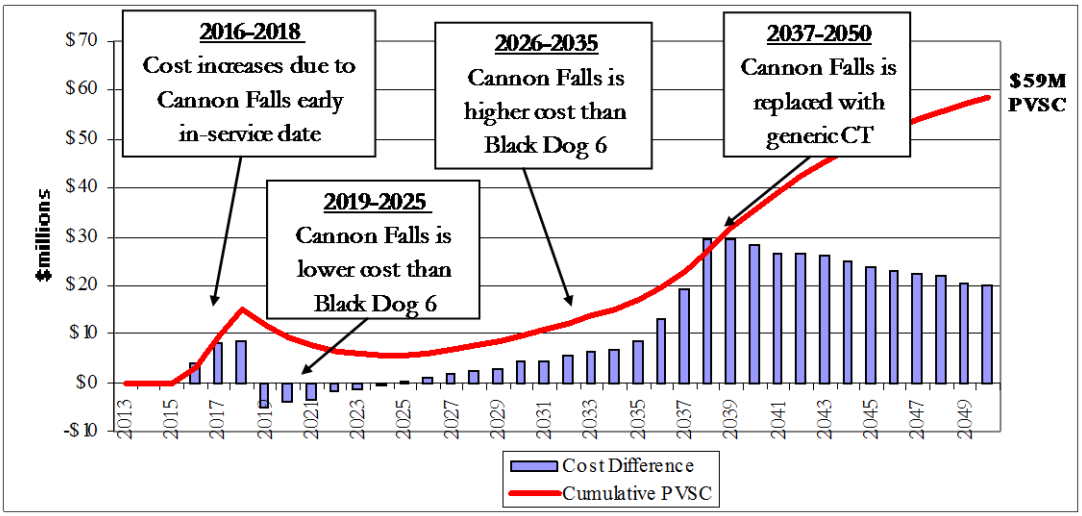
Figure 1 shows Black Dog 6's cost per kW-mo is initially higher than the costs for Calpine's and Invenergy's proposals but declines over time. For both Black Dog 6 and Red River Figure 1 shows periodic increases in the average cost for each unit. These increases correspond to major plant overhaul that will ensure reliable operation through the 35 year operating life and possibly beyond 2050.

Figure 2 below compares the total system costs for the Cannon Falls and Black Dog 6 proposals, showing in which years the Cannon Falls project is lower or higher in cost than Black Dog, and how significantly costs increase as

a result of the need for replacement capacity when the Cannon Falls PPA expires.

FIGURE 2 – ANNUAL COST OF INVENERGY CANNON FALLS RELATIVE TO BLACK DOG 6



Cost comparison based on Plan 2 (Calpine Mankato + Black Dog 6) vs. Plan 56 (Calpine Mankato + Invenergy Cannon Falls)

The cost differences between the projects can also be summarized by categorizing the various elements of their respective PVSCs, as shown in Table 6 below. To establish a fair comparison between the 35-year Black Dog project and the shorter term Invenergy project, the costs of a replacement CT is added by Strategist during its long term simulation. Also the Black Dog unit has an expected summer accredited value of 208 MW while the Cannon Falls project is only 150 MW. To account for this size difference, Strategist adds a capacity credit of $5.91/kW-mo levelized to Black Dog 6 from 2020 to 2035. In addition to these direct cost differences between Black Dog and Cannon Falls, there are also small differences in total fuel cost and emission costs that are tracked through Strategist's dispatch simulations. Comparing the PVSC of the two projects, Cannon Falls is $59 million more expensive than Black Dog 6. A comparison of Black Dog 6 to Invenergy's Hampton Corners

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project yields similar results, which are included in my Schedule 4.

Table 6 – PVSC Comparison of Invenergy Cannon Falls Relative to Black Dog 6

Invenergy Cannon Falls	**PVSC $millions**
Cannon Falls Capacity Payment	$102
2036 Replacement CT	$58
Cannon Falls Total Cost	$160
Energy and Emission Costs Differences	
Net Energy Costs	$5
Net Emission Costs	($2)
Net Costs	$3
Black Dog Unit 6	
Black Dog 6 Revenue Requirements	$135
Capacity Credit	($31)
Net Black Dog 6 Costs	$104
Total Net PVSC Cannon Falls + Energy & Emission Costs - Black Dog 6	**$59**

Cost comparison based on Plan 2 (Calpine Mankato + Black Dog 6) vs. Plan 56 (Calpine Mankato + Invenergy Cannon Falls)

Q. WHY ARE THE PVSCS OF PLAN 1 AND PLAN 2, WHICH INCLUDE INVENERGY'S CANNON FALLS AND CALPINE'S MANKATO EXPANSIONS, SO CLOSELY MATCHED?

A. There are a number of differences in the costs of the projects that happen to result in the two being very competitively priced in relation to one another. While the Mankato project has higher capacity payments than Cannon Falls, it is an intermediate combined cycle unit with higher efficiency than Cannon Falls. This creates substantial annual fuel cost savings that equalizes the net cost of the two projects. In addition, Invenergy projects were modeled with interruptible fuel supply contracts that substantially lowered their total costs.

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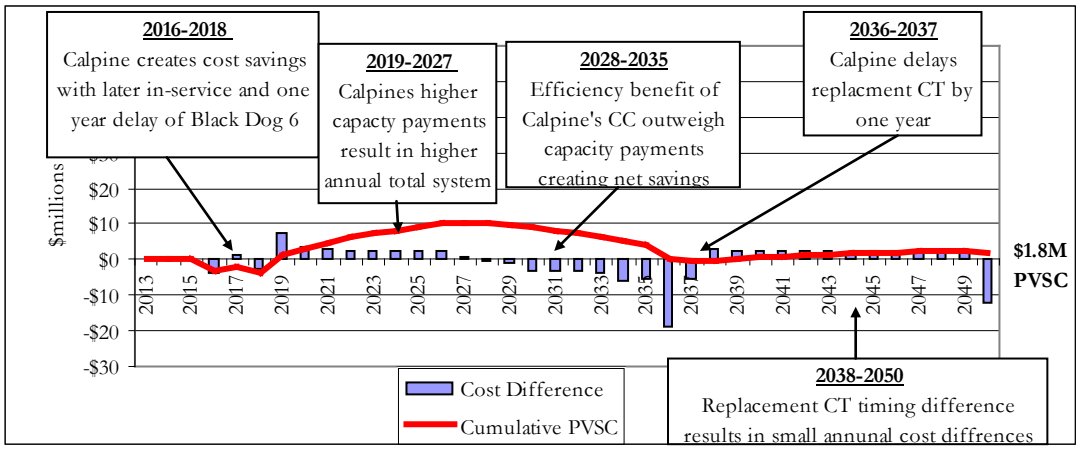
If the Invenergy projects were modeled with firm gas supply as Calpine's Mankato project and Black Dog Unit 6 were, the cost comparison would heavily favor Calpine.

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. Finally, because of Mankato's greater capacity – 278 MW versus 150 MW for Cannon Falls - Black Dog 6 can be delayed until 2019. This creates additional cost savings for the Mankato project over Cannon Falls. Figure 3 below presents the annual cost differences between the Calpine's Mankato and Invenergy's Cannon Falls expansions, and Table 7 summarizes their PVSC differences.

FIGURE 3 – ANNUAL COST COMPARISON OF CALPINE MANKATO RELATIVE TO INVENERGY CANNON FALLS



Cost comparison based on Plan 1 (Invenergy Cannon Falls + Black Dog 6) vs. Plan 2 (Calpine Mankato + Black Dog 6)

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Table 7 – PVSC Comparison of Calpine Mankato Relative to Invenergy Cannon Falls

Calpine Mankato Expansion	**PVSC $millions**
Mankato Capacity Payments	$237
Combined Cycle Efficiency Benefit	($69)
Black Dog 6 One Year Delay	($10)
Capacity Credit	($55)
Net Calpine Costs	$103
Other Total System Cost Differences	
Long Term Expansion Plan Difference	($5)
Net Emission Costs	$6
Net Costs	$1
Invenergy Cannon Falls	
Cannon Falls Capacity Payment	$102
Total Net PVSC Calpine + Other System Cost Differences - Cannon Falls	**$1.8**

Cost comparison based on Plan 1 (Invenergy Cannon Falls + Black Dog 6) vs. Plan 2 (Calpine Mankato + Black Dog 6)

Q. HOW DO THE RED RIVER VALLEY CTS COMPARE TO CALPINE'S AND INVENERGY'S NATURAL GAS UNITS?

A. While not as cost effective, the Red River Valley units have the same type of long-term benefits as Black Dog 6, and thus compare favorably to the Calpine and Invenergy proposals. Strategist identified Red River Valley Unit 1 in the 3rd ranked plan, with only a $2.2 million PVSC difference between that portfolio and the least cost plan. An additional 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. Also, the Red River

Valley units offer flexibility with the in-service dates. This allows us to adjust the timing of these projects to better match capacity need as new information becomes available. Schedule 4 of my testimony provides cost comparisons between each natural gas bid. The tables and figures that compare Red River Valley unit 1 to the natural gas PPAs illustrates how Red River will have higher cost over the first ten to twenty years of the project's life time and that significant cost savings do not occur until 2036 or 2037.

Q. HOW DOES THE COMPANY ASSESS THE VALUE OF GRE'S CAPACITY PROPOSAL TO DELAY THE NEED FOR GENERATION FURTHER OUT INTO THE FUTURE?

A. 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 6 from 2018 to 2019.

Q. WHY DID GERONIMO'S SOLAR PROPOSAL FAIL TO BE INCLUDED IN ANY OF STRATEGIST'S TOP 20 PLANS?

A. While there has been a steady decline in the cost for solar recently, it appears that solar is still not a cost effective resource. Geronimo's high cost is illustrated by comparing the highest ranking plan that includes the project - Plan 25 which consists of Cannon Falls in 2016, Geronimo in 2016, and Black Dog in 2019 - with Plan 1 which consists of Cannon Falls in 2016 and Black Dog in 2018. As shown in Figure 4 below, the Geronimo contract creates a net benefit by delaying the in-service date of Black Dog 6 by one year. But in every other year of the Geronimo PPA, total system costs are forecasted to be about $5 million higher as a result of the solar project.

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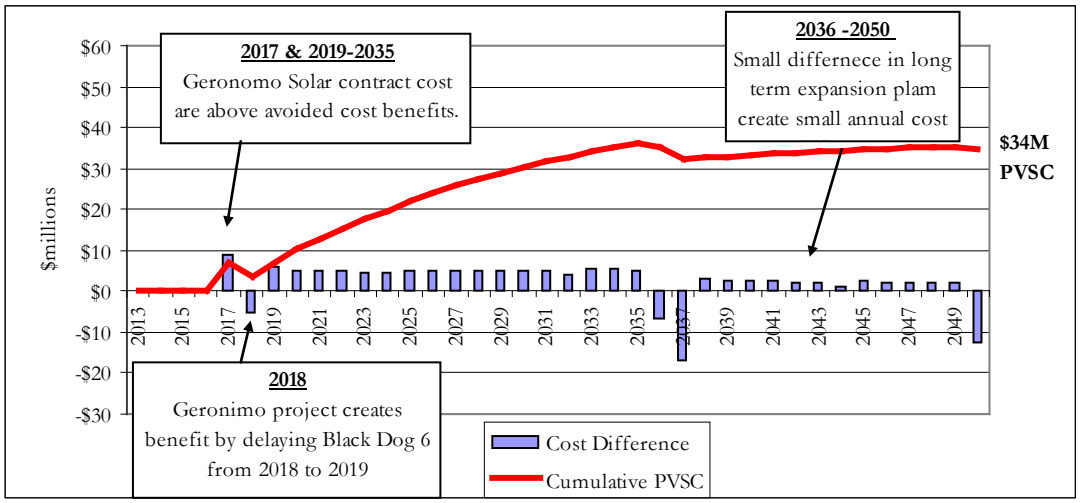
Figure 4 – Annual Cost Comparison of Cannon Falls/Black Dog/Geronimo Relative to Cannon Falls/Black Dog



Cost comparison based on Plan 1 (Invenergy Cannon Falls + Black Dog 6) vs. Plan 25 (Invenergy Cannon Falls + Black Dog 6 + Geronimo)

Table 8 below shows the PVSC of adding Geronimo to our system is $34 million. The PVSC categories also illustrate that a significant portion of the benefits of Geronimo's solar proposal come from the capacity credit given to the project, and from the $21.50/ton CO2 price assumption used in the Strategist modeling. The capacity credit is based on the **[TRADE SECRET DATA BEGINS: …TRADE SECRET DATA ENDS]** accreditation estimated by Geronimo. Recent analysis performed by the Company indicates that this estimate is likely to be 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 CO2 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.

Table 8– PVSC Impact of Geronimo Solar

Geronimo Solar Project	**PVSC $millions**
Geronimo Energy Payments	$186
Long Term Expansion Plan Difference	($1)
Costs Avoided By Solar	
Avoided Energy	$88
Avoided Capacity	$43
Avoided Emissions	$20
Total Avoided Costs	$151
Total Net PVSC Geronimo + LT Expansion Diff. - Avoided Cost of Solar	**$34**

Cost comparison based on Plan 1 (Invenergy Cannon Falls + Black Dog 6) vs. Plan 29 (Invenergy Cannon Falls + Black Dog 6 + Geronimo)

Geronimo has proposed to interconnect most of their solar projects at the distribution level. At this time the Company has not conducted a detailed analysis to determine what the line loss savings might be for the project, and line loss savings were not included in the Strategist analysis. For roof top solar projects that avoid all transmission and distribution line losses we estimate the savings to be equal to 7% of the energy and capacity benefits. Because Geronimo's project will not be located directly at customers load, however, the actual line loss savings are likely to be less than 7%. However, even if the full 7% is applied to the energy and capacity credit savings estimated for the Geronimo project, the PVSC of the line loss savings would only equal an additional $10 million, not enough to make the project cost effective.

Q. DOES THE NEED TO FULFILL MINNESOTA'S SOLAR ENERGY MANDATE OFFSET THE HIGH COST OF GERONIMO'S PROPOSAL?

A. No. The Company is committed to complying with the solar mandate, but must do so prudently and at the lowest cost possible. Because there are no other solar proposals in this docket, the Company is not in a position to assess the reasonableness of Geronimo's project pricing relative to other solar projects that could also help the Company meet its solar energy goals. We do not believe that it is prudent to fill approximately one third of our solar resource need without any evaluation of other potential solar resources. In the near future we expect to issue an RFP specifically for solar resources, which we anticipate will allow us to evaluate what Geronimo can offer at that time in comparison to other large scale solar projects. We will work with the Commission, the Department, and other interested parties on our solar acquisition plan.

C. Strategist Input Sensitivity Analysis

Q. WHAT INPUTS IN THE STRATEGIST MODEL SIGNIFICANTLY IMPACT THE PVSC RESULTS?

A. The price of natural gas is a critical element in the evaluation of these bids. The Calpine combined cycle project is much more efficient than the peakers offered by the Company and Invenergy, so Mankato will be more cost effective if the natural gas price assumption is higher. Geronimo's solar proposal will also be more attractive if evaluated in the context of higher gas prices. To test the impact of the natural gas price assumption we varied the growth rate of our price forecast by 50%. Under the base assumption, gas

prices grew at an average rate of 3.1%. Under the low gas price sensitivity, the price grows at 1.5%, and under the high gas price sensitivity the growth rate is 4.6%.

Another critical assumption is the capacity credit value used in the model. Because the various combinations of bids result in different total capacity, a capacity credit is used in the model to give additional value to larger portfolios. For 2016-2037, the levelized capacity credit is $6/kW-mo. To test the impact of this assumption we varied the price of the capacity credit up and down by one dollar, to $7/kW-mo and $5/kW-mo respectively.

There have also been questions regarding how our recent proposal to acquire 750 MW of new wind resources impacts the resource selection in this docket. First, our proposed wind resources are not expected to receive capacity accreditation until after 2019, so the identified capacity need is not impacted. However, the energy produced by the wind resources could impact the relative value of some of the bids. To test the impact of the additional wind, we removed the proposed 750 MW of wind and re-ran the top 20 plans identified by Strategist.

We also conducted sensitivity tests on CO2 values assumed in the model, although the CO2 assumption has little impact on comparisons between natural gas plants which have similar emission profiles. And we also re-ran Strategist with purchases from MISO turned off. This sensitivity allows us to see the impact that energy flowing from other areas of MISO might have on the results of the analysis.

As previously noted, we modeled Invenergy's proposals with interruptible natural gas, which lowers the total cost of the proposals considerably. To test the impact of this assumption, we included a sensitivity test where the bids from Invenergy were modeled with the more expensive firm gas supply.

Q. HOW DID THE INPUT SENSITIVITY TESTS CHANGE THE STRATEGIST RESULTS?

A. The impacts of the sensitivity tests are shown in Table 9 below. Because the Company's and Invenergy's proposed peaking units have similar operating characteristics, the cost differences between those proposals are not significantly impacted by the natural gas, CO2, and wind sensitivities. However, the value of Calpine's Mankato project was magnified considerably with different assumptions for gas and emissions. The high gas sensitivity plans that include Mankato become the lowest cost plans. Likewise, the high CO2 sensitivity plans ($34/ton CO2) with Mankato also have improved PVSC values. The wind sensitivity also had a large impact on the Mankato project. When the 750 MW of wind proposed by the Company was removed from the Strategist model the cost effectiveness of portfolios including Calpine Mankato improved significantly. This is because when wind is removed from the model, natural gas units must run more often to meet customer demand and the value of the Mankato unit's greater efficiency is enhanced.

The cost of year round firm gas increases the PVSC of the Invenergy Cannon Falls project by approximately $30 million. However, being the smallest bid, the cost effectiveness of Cannon Falls improves when a lower capacity credit is applied to the model.

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Table 9 – Strategist Input Sensitivity Tests (PVSC)
Top 20 Plans

	Selected Bids	Base Case	High Gas	Low Gas	Capacity Credit +$1	Capacity Credit - $1	No 750MW Wind	$0 CO2	$9 CO2	$34 CO2	PPA Extension	Invenergy Firm Gas
1	Invenergy Cannon Falls Black Dog 6											
2	Calpine Mankato Black Dog 6	+ $2	($27)	+ $25	($11)	+ $15	($13)	+ $23	+ $14	($18)	($7)	($29)
3	GRE Short Term Red River Valley 1 Black Dog 6	+ $2	+ $2	+ $4	($4)	+ $9	+ $2	+ $3	+ $3	+ $2	+ $28	($29)
4	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $5	+ $5	+ $4	+ $5	+ $5	+ $4	+ $4	+ $5	+ $5	+ $5	+ $5
5	Black Dog 6 Red River Valley 1	+ $9	+ $8	+ $12	+ $2	+ $15	+ $8	+ $10	+ $9	+ $9	+ $35	($22)
6	Calpine Mankato Black Dog 6	+ $9	($19)	+ $33	($4)	+ $22	($5)	+ $31	+ $22	($10)	+ $1	($22)
7	GRE Short Term Black Dog 6 Red River Valley 1	+ $10	+ $9	+ $12	+ $3	+ $16	+ $10	+ $11	+ $10	+ $10	+ $36	($21)
8	Invenergy Cannon Falls Black Dog 6	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11	+ $11
9	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $13	+ $13	+ $12	+ $13	+ $13	+ $12	+ $12	+ $12	+ $13	+ $13	+ $13
10	GRE Short Term Calpine Mankato Black Dog 6	+ $14	($14)	+ $37	+ $1	+ $27	($0)	+ $36	+ $27	($5)	+ $6	($17)
11	GRE Short Term Red River Valley 1 Black Dog 6	+ $17	+ $16	+ $18	+ $10	+ $23	+ $17	+ $18	+ $17	+ $16	+ $43	($14)
12	Invenergy Cannon Falls Red River Valley 1 Black Dog 6	+ $18	+ $18	+ $23	($4)	+ $39	+ $17	+ $20	+ $18	+ $18	+ $49	+ $18
13	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $20	+ $20	+ $19	+ $20	+ $20	+ $20	+ $19	+ $19	+ $19	+ $20	+ $20
14	Calpine Mankato Black Dog 6	+ $20	($9)	+ $44	+ $7	+ $33	+ $6	+ $43	+ $33	+ $1	+ $11	($11)
15	Hampton Corners Black Dog 6	+ $21	+ $21	+ $24	+ $5	+ $36	+ $20	+ $21	+ $21	+ $21	+ $25	+ $51
16	GRE Short Term Calpine Mankato Black Dog 6	+ $22	($7)	+ $45	+ $8	+ $35	+ $7	+ $43	+ $34	+ $2	+ $13	($10)
17	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $23	+ $23	+ $23	+ $23	+ $23	+ $23	+ $23	+ $23	+ $24	+ $23	+ $23
18	Invenergy Cannon Falls GRE Short Term Black Dog 6	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27	+ $27
19	GRE Short Term Calpine Mankato Black Dog 6	+ $29	+ $0	+ $51	+ $15	+ $42	+ $14	+ $50	+ $41	+ $9	+ $20	($2)
20	Invenergy Cannon Falls Calpine Mankato Black Dog 6	+ $29	+ $3	+ $54	+ $1	+ $58	+ $14	+ $53	+ $43	+ $10	+ $28	+ $29

Q. DID YOU PERFORM ANY OTHER SENSITIVITY TESTS ON THE STRATEGIST RESULTS?

A. Yes. One alternative to assuming that the PPAs are replaced with new CT units is to assume that the Calpine and Invenergy 20-year PPAs are extended

at their existing pricing levels, including escalation rates. Under this assumption, the cost difference between Black Dog 6 and the PPAs is reduced significantly. A comparison between Black Dog 6 and the Cannon Falls project illustrates this. As shown in Table 6 presented earlier in my testimony, the PVSC difference between Black Dog 6 and Invenergy Cannon Falls is $59 million. Using the assumption that the Cannon Falls contract would be extended through 2050, the total PVSC difference falls to $34 million.

V. COMPANY'S RECOMMENDATION

A. Recommendation of Proposals

Q. WHICH PROPOSALS DOES THE COMPANY RECOMMEND THE COMMISSION SELECT?

A. The top four portfolios have very similar PVSC results. Common between these portfolios is the Black Dog 6 project. This project will provide low cost capacity to our customers and long term benefits beyond some of the other proposed projects. Also Black Dog 6 offers flexibility regarding its exact in service date. As we normally do, we will continue to monitor MISO's reserve margin rules and other factors that impact our capacity need assessment. In the interest of minimizing costs for our customers, we are willing to adjust the in-service date 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 expansion have very similar PVSC results in the Strategist modeling. Either of these projects could be cost effective resources for our customers. 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, which I discuss below.

At the end of negotiations, the Commission would select only one of the two projects to be awarded a contract with Xcel Energy. Because the PVSC of the two 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.

In the event that the two PPAs do not proceed forward, construction of our Red River Valley Unit 1 provides an excellent 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.

Q. IS IT UNUSUAL TO HAVE MULTIPLE BIDS MOVE FORWARD TO THE CONTRACT NEGOTIATION PHASE OF THE PROCESS?

A. No. A typical bid selection process will narrow the pool of applicants to a small number that are identified as the most cost effective. Then multiple projects are moved forward to the contract negotiation phase. This ensures that, in the event that mutually agreeable terms cannot be reached with one party, there are alternative projects 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.

Q. WHAT ABOUT THE PROJECTS THAT ARE NOT SELECTED THROUGH THIS PROCESS?

A. Unfortunately a process such as this results in only a few successful projects and must pass over several otherwise attractive proposals. We appreciate the proposals from Calpine and Invenergy and hope that unselected projects will be proposed in our next resource acquisition process. Likewise, we hope that Geronimo resubmits its proposal within a solar specific RFP in the near future.

With regard to our Red River Valley proposal we intend to continue to explore the local reliability benefits of citing generation near our Fargo load center. Currently, the regional transmission grid and North Dakota generation resources owned by other companies have provided reliable service to the area. However, generation located near load centers in the Fargo and Grand Forks areas would enhance local reliability and put these areas on par with the service that is delivered in the Twin Cities metro area. Also the Red River Valley units will continue to be attractive alternatives if the capital lease or other contractual details cannot be resolved with the other bidders.

Q. WHAT ARE THE EXPECTED RATE IMPACTS FOR BLACK DOG 6, CALPINE MANKATO, AND INVENERGY CANNON FALLS?

A. In the context of the Company's system, these projects are rather small and their rate impacts are expected to be minimal. In the first full year of the

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Black Dog 6 project - 2020 - the forecasted rate impact is 0.05¢/kWh. In the first full year of the Calpine PPA - 2018 - the rate impact associated with the capacity payments is forecasted to be 0.07¢/kWh. This cost increase will be partially offset by the fuel efficiency gains from the project, which are projected to be about 0.01¢/kWh. Invenergy Cannon Fall would have the smallest rate impact of only 0.02¢/kWh. But Cannon Falls is also the smallest resource considered for selection. The total impact of Black Dog 6 and either of the two PPAs should be less than 1% of average rates. These rate impact estimates are summarized in Table 10.

Table 10 – Calpine Mankato and Black Dog 6
Average Rate Impact Estimate

Total Costs ($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
[TRADE SECRET DATA BEGINS:							
Calpine Mankato Capacity Payments							
Calpine Efficiency Benefit							
Invenergy Cannon Falls Capacity Payment							
Black Dog 6 Revenue Requirements							
…TRADE SECRET DATA ENDS]							
Average Rate Impact (¢/kWh)	**2017**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Calpine Mankato Capacity Payments		0.04¢	0.07¢	0.07¢	0.07¢	0.07¢	0.07¢
Calpine Efficiency Benefit		-0.02¢	-0.01¢	-0.01¢	-0.01¢	-0.01¢	-0.01¢
Invenergy Cannon Falls Capacity Payment	0.01¢	0.03¢	0.03¢	0.03¢	0.03¢	0.03¢	0.03¢
Black Dog 6 Revenue Requirements		0.00¢	0.00¢	0.04¢	0.05¢	0.05¢	0.04¢

Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATION FOR RESOURCE SELECTION.

A. We recommend that the Commission identify Black Dog 6 in combination with either Invenergy's Cannon Falls proposal or Calpine's Mankato Energy Center expansion as the least cost projects in this process. Because Strategist

does not indicate a clear preference for either of the PPA proposals, we also recommend that both PPAs be moved forward to the contract negotiation phase so that all specific contract terms can be clearly identified.

Also due to changes in MISO's reserve margin calculations and other factors, it will be in our customers best interest to explore contract options that allow the same in-service date flexibility as our proposals. In our April 15th filing, we describe our willingness to delay the in-service date of our projects or even cancel them if the capacity need does not materialize as expected. This protects our customer from unnecessary costs associated with excess capacity. We believe it is important that PPAs include similar in-service date flexibility in order to protect rate payers.

Given the uncertainty surrounding future resource needs, our April 15th filing also offered to submit status reports in the fall of 2014 and 2015 so that the Commission could determine if customer benefits associated with delay warranted changing the expected in-service date of selected projects. We continue to believe it is prudent to closely monitor resource need forecasts and to adjust plans if customer benefits can be realized.

B. PPA Negotiation Process

Q. PLEASE BRIEFLY DESCRIBE THE PPA NEGOTIATION PROCESS THAT WILL BE FOLLOWED IN THIS DOCKET.

A. PPA negotiations will be held in the event the Commission chooses one or more of the proposals submitted by Calpine, Invenergy, or Geronimo. After the Commission's selection, the Company and successful bidder(s) will have

four months to determine the terms and conditions of the PPA for their respective resources, after which the parties' final proposed PPA(s) will be presented to the Commission for approval.

The negotiation process will focus on arriving at a prudent and reasonable PPA that reflects the economic, operational, and reliability terms contained in the successful bid(s). If the parties should reach an impasse during the negotiations, they will bring the issue(s) causing the impasse back to the Commission for direction on how to proceed.

Q. DID CALPINE AND INVENERGY INCLUDE A PROPOSED PPA IN THEIR PROPOSALS?

A. No. Calpine stated in Appendix A of its proposal that it "intends to follow the PPA structure used in the Purchased Power Agreement between MEC (Mankato Energy Center) and Northern States Power Company executed on March 11, 2004 ("MEC PPA") for expediency, cost effectiveness and negotiating efficiency." Calpine also provided a term sheet and summary of proposed PPA terms and conditions in Appendix B of its proposal.

In Section 9 of its Cannon Falls Expansion proposal, Invenergy stated it wants "to sell its capacity and energy to NSP with terms and conditions substantially similar to the existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005." Invenergy also included in Section 9 of its proposals a Commercial Terms sheet, and a description of several other proposed terms and conditions.

However, we have modified our model PPA for dispatchable resources since the time the Calpine and Invenergy PPAs were executed, over eight years ago. The Company would prefer to use that contract form as the beginning point for negotiations.

Q. IS THE COMPANY'S DISPATCHABLE MODEL PPA MATERIALLY DIFFERENT THAN THE CURRENT CALPINE AND CANNON FALLS PPAS?

A. Generally, yes. Since the current Calpine Mankato and Invenergy Cannon Falls PPAs were negotiated PPAs nearly eight years ago, there are a number of differences compared to the Model PPA. Also, some of the differences with the Model PPA are the result of terms that have been updated to reflect new external regulatory related issues, such as MISO transmission and interconnection issues. Other provisions were updated to reflect Company requirements, such as credit and security issues. In addition, terms were revised to clarify and refine contract language, and some provisions have been moved to other places in the PPA.

C. PPA Negotiation Issues

Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUES TO BE RESOLVED IN NEGOTIATIONS WITH CALPINE AND INVENERGY.

A. A PPA not only contains the material terms and conditions that most directly determine its price, but must also reasonably and prudently assign various contract performance risks appropriately between the seller and the purchaser, which can also affect the PPA's price. These risks include, among others, 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.

The Company's primary focus will be to reasonably mitigate counterparty risk for the protection of our ratepayers. When a bidder seeks a term or condition that we believe inappropriately shifts either risk or cost to the Company, we will as an alternative propose the bidder agree to other contractual changes that restore what we consider to be the proper risk-reward balance. In practice, this process often provides benefits to both contracting parties, as each party has an interest in building and maintaining cooperative value-enhancing relationships with each other, and each party may value various contractual provisions differently.

Q. IS MITIGATING COUNTERPARTY RISK OF REAL BENEFIT TO RATEPAYERS?

A. Yes. Xcel Energy customers should not be exposed to various financial and operational performance risks that are solely within the seller's sphere of control. For example, we will try to mitigate the exposure of our customers to the possibility of a counterparty default of the PPA. That is why we propose using the Dispatchable Model PPA as the basis for negotiations, and seek in that process to scrutinize as much financial and performance information as possible from the counterparty. Our goal is to negotiate a PPA that reasonably assures our customers that the counterparty will perform its

obligations under the PPA to enable the Company to meet its service obligations to our customers.

Q. ARE THERE PARTICULAR PPA PROVISIONS THE COMPANY HAS IDENTIFIED THAT COULD IMPACT THE PRICING OF THE CALPINE OR INVENERGY PROPOSALS?

A. Yes. Many issues can come up during negotiations, and at this point we are not in the negotiation stage so we do not have marked up PPAs, but the following material terms are addressed in any PPA negotiations and could impact PPA costs and hence pricing:

(1) Security Fund: The model PPA requires a pre-COD and post-COD security fund from the seller no later than 30 days after regulatory approval of the PPA. 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. The security fund may be in the form of cash, corporate guarantee, or irrevocable stand-by letter of credit. There are strict credit requirements associated with the issuer of a guaranty and letter of credit. The seller must replenish the security fund within 15 business days after Xcel Energy makes a draw on the security fund. The pre-COD security fund is comprised of $175/kW of net capability, and the post–COD security fund is comprised of $100/kW of net capability.

(2) Carbon Dioxide ("CO_2") Emission Costs and Allowances: In the model PPA, the Company shall reimburse the seller for CO_2 emission

costs as specifically set forth in the PPA. In the event that seller receives any CO_2 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. NSP will not accept responsibility for costs associated with other plant emissions.

(3) Capital Lease: In determining the appropriate accounting for a PPA, 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's near-term earnings, and increase its debt to total capitalization ratio. To maintain the Company's debt to total capitalization ratio, equity would need to be infused into the Company, most likely at a higher cost because of the debt to total capitalization imbalance. For these reasons, PPA terms and payment structures are closely scrutinized during the bidding and negotiation processes. It should also be noted that expanding the generating facilities under an existing PPA may, depending on the specific terms of the expansion agreement, result in capital lease treatment for the existing PPA.

Q. DID YOU IDENTIFY ANY MATERIAL ISSUES SPECIFIC TO INVENERGY'S CANNON FALLS PROPOSAL THAT NEED TO BE ADDRESSED IN THE PPA NEGOTIATIONS?

A. Yes, we have identified four outstanding issues so far that would have to be resolved before finalizing a contract with Invenergy and other issues could be identified during the course of negotiations. First, the cost of a firm natural gas supply to the Cannon Falls plant is expected to be prohibitive. While

Invenergy mentioned in its proposal that the Cannon Falls unit could run on oil, the fuel tank at tanks at the site are barely sufficient to support the operation of a single turbine. For reliable winter operation the amount of on-site fuel storage would need to be expanded. Invenergy has not included these costs in their bid and has not provided supplemental information on the issue.

Second the proposed in-service date of 2016 for Cannon Falls is before the first year of identified capacity need in 2017. This conceptually creates unnecessary costs for our customers. In their proposal Invenergy mentions the possibility of a different in-service date, but has not specified how their contract and pricing term might change.

Third, Invenergy has included **[TRADE SECRET DATA BEGINS:**

…TRADE SECRET DATA ENDS]. We will continue to work with Invenergy to find the lowest cost transmission solution possible.

Fourth, we have identified the possibility that the Invenergy proposals could trigger a capital lease treatment under current accounting rules. Xcel Energy witness Jeffrey Savage provides testimony regarding the capital lease issues.

Q. HAVE YOU IDENTIFIED ANY MATERIAL ISSUES THAT NEED TO BE ADDRESSED IN THE PPA NEGOTIATIONS WITH CALPINE?

A. Yes, I have noted four outstanding issues so far, but other issues could be identified during the course of negotiations. First, Calpine mentioned the possibility of running the second CT at Mankato on fuel oil, but has not proposed any pricing changes associated with that option. This is less of a concern in comparison to the Invenergy project, as we have modeled the Mankato project with year round firm natural gas supply.

Second, Calpine has indicated in response to an information request that it would not use the Company's model PPA in the negotiating process. Our Dispatchable Model PPA has provisions that protect the Company and our customers in the event that a counter party fails to fulfill their obligations under the contract. Calpine may require pricing modifications in exchange for the security terms that we would require in the PPA.

Third, the Mankato project is also at risk for classification as a capital lease. Mr. Savage addresses the capital lease issues.

Fourth, Calpine currently has a Moody's and S&P credit rating of B+, which is below investment grade. Its creditworthiness and security would need to be addressed during negotiations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Steven W. Wishart Jr.

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Steve@Wishart.com
1814 Kohinoor Pl.
Golden CO, 80401

EXPERIENCE

Xcel Energy, Minneapolis MN, Denver CO 5/12-Current
Director – Resource Planning & Bidding

Xcel Energy, Minneapolis MN, Denver CO 4/06-05/12
Manager / Sr. Analyst / Analyst – Strategic Analytics

Responsibilities:

- Oversee economic evaluation of large power supply projects for Xcel Energy.
- Prepare analysis for senior leadership that reports on expected value and value at risk for new generation assets, power purchases, conservation programs, wholesale sales, and other projects.
- Maintain complex model of the three Xcel Energy power systems for use in, project evaluation, rate forecasting, and policy analysis.
- Manage a group of quantitative analysts that evaluate various supply and demand side alternatives for all three Xcel Energy service territories.
- Serve as quantitative expert for resource planning and purchased power related dockets.

Major Projects:

- Colorado Clean Air Clean Jobs Act – Retire/repower 900MW of existing coal units in PSCo service territory for compliance with regional NOx legislation.
- 2010 Minnesota Resource Plan – 10 year projection of new resource acquisitions, retirements, renewable energy standard compliance, and enhanced conservation programs.
- Jones Station Repowering – Convert existing 240MW gas steam unit to 650MW combined cycle in SPS service territory.
- 2009 PSCo All-Source Solicitation – Modeling/evaluation of bids totaling 20,000MW. Including Gas, wind, solar PV, solar thermal with storage, compressed air storage, pumped hydro, wind/battery combo, and solar augmented combined cycle.
- Manitoba Hydro CON – Economic valuation of 10yr $1.6B purchase from MH.
- Nuclear Uprate Projects – Economic evaluation and expert witness for Prairie Island and Monticello nuclear uprate proceeding in NSP service territory.
- CO2 Regulation - Forecasted rate impacts of American Clean Energy and Security Act (ACES) on the Xcel Energy operating companies.
- Other - Bottom up redesign of Xcel's long-range planning models, focusing on consistency across jurisdictional operating companies and integration of best practices including Monte-Carlo simulation for risk evaluation. Represented Xcel Energy at MISO board of directors/stakeholder meetings on the topic of wind integration. Long range rate forecasts for management and stakeholders. Financial and economic analysis for Excelsior IGCC project. Analysis of long term power purchase from Manitoba Hydro. EEI regulatory accounting seminar.

Software:

- Strategist, Matlab, Prosym, Excel, Access.

Xcel Energy, Minneapolis MN
Demand Side Management (DSM) Technical Analyst 2/05-4/06

Responsibilities:

- Managed cost/benefit analysis of NSP's $45 million annual conservation and load management activities, including forecasting of financial incentives, and strategic planning.

Projects:

- Evaluation and contract negotiations of DSM bids in Colorado service territory.
- Conservation rulemaking in New Mexico, including design of financial incentive mechanism.
- Cost benefit analysis of NSP's three-year conservation and load management strategic plan.

Software:

- Strategist, DSManager, Matlab, Excel.

The Solar Store, Tucson AZ 10/98-8/00
Accountant

- AR/AP, payroll, inventory management, sales, solar energy system design & installation.
- Member of Concerned Arizonans for Renewable Energy (CARE) lobbied in support of solar tax credits in Arizona.

EDUCATION

PhD (all but dissertation) **Applied Economics, University of Minnesota, 3.7GPA** 8/02-1/05

Course Work:

- Emphasis - environmental and natural resource economics. Other course work - Financial economics, econometrics, dynamic programming, production economics, non-parametric frontier analysis, managerial economics, international trade, macro- and microeconomics.

Software:

- SAS, Matlab, Gauss, Stata, Mathematica.

MS Economics, University of Arizona, 3.8GPA 8/00-5/02

Course Work:

- Environmental economics, environmental law, econometrics, linear and quadratic programming, production economics, consumer economics.

Software:

- SAS, Stata, LimDep, Gams, Lindo, Gauss.

BS Finance, University of Arizona 8/92-12/96

Course Work:

- Financial markets and instruments, corporate finance, accounting, statistics, economics, marketing, Russian, French.

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Black Dog 6 - 2017 In-Service

In-Service	March 1, 2017
Operating Life (Years)	35

Capital ($000)	2014	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	22 2038	23 2039	24 2040	25 2041	26 2042	27 2043	28 2044	29 2045	30 2046	31 2047	32 2048	33 2049	34 2050	35 2051	36 2052	2053	2054
			[TRADE SECRET DATA BEGINS…																																						
2013 $dollars		**Escalation Rate**																																						
Construction Expenditures					No Inflation, No Escalation																																				
On-Going Capital																																								
Transmission					No Inflation, No Escalation																																				
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Operating & Maintenance Expense																																								
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Fuel Supply Expense																																								
Nominal $dollars																																								
Firm Service Annual Fixed Charge ($000)																																							TRADE SECRET DATA ENDS]	
Ventura Hub Forecast ($/mmBtu)				4.36	4.83	5.24	5.59	5.87	6.14	6.56	6.78	7.02	7.23	7.39	7.55	7.78	7.96	8.11	8.29	8.49	8.68	8.89	9.06	9.24	9.42	9.6	9.78	9.97	10.17	10.36	10.56	10.77	10.98	11.19	11.41	11.63	11.85		
Volumetric Charge ($/mmBtu)	[TRADE SECRET DATA BEGINS…																																						
Loss (% of volume)																																								
Total Delivered Price Of Gas ($/mmBtu)																																								
Maximum Capacity																																								
Winter (Dec-Feb)																																								
Shoulder (March-May & Sept-Nov)																																								
Summer (June-Aug)																																								

Heat Rate Profile	**% of Maximum Capacity**	**Average Heat Rate**
1	50%	
2	60%	
3	70%	
4	80%	
5	90%	
6	100%	
7		

Emission Rates																																								
SO2 - lbs/MWh																																								
NOx - lbs/MWh																																								
CO2 - lbs/mmBtu																																								
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Pb - lbs/MWh																																								

Planned Maintenance (weeks/yr)																																								
Forced Outage Rate (%)																																							TRADE SECRET DATA ENDS]	

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Black Dog 6 - 2018 In-Service

In-Service	March 1, 2018
Operating Life (Years)	35

Capital ($000) — 2014, 2015, 2016, 2017, 2018 ... 2054

[TRADE SECRET DATA BEGINS...

2013 $dollars — **Escalation Rate**

Construction Expenditures — No Inflation, No Escalation
On-Going Capital
Transmission — No Inflation, No Escalation
Natural Gas Pipeline

Operating & Maintenance Expense
2013 $dollars — **Escalation Rate**
Fixed O&M ($000)
2013 $dollars — **Escalation Rate**
Variable O&M ($/MWh)

Fuel Supply Expense
Nominal $dollars
Firm Service Annual Fixed Charge ($000) — Modeled as a Fixed annual capacity rate — _TRADE SECRET DATA ENDS]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Ventura Hub Forecast ($/mmBtu)	4.83	5.24	5.59	5.87	6.14	6.56	6.78	7.02	7.23	7.39	7.55	7.78	7.96	8.11	8.29	8.49	8.68	8.89	9.06	9.24	9.42	9.6	9.78	9.97	10.17	10.36	10.56	10.77	10.98	11.19	11.41	11.63	11.85				

Volumetric Charge ($/mmBtu) — [TRADE SECRET DATA BEGINS...
Loss (% of volume)
Total Delivered Price Of Gas ($/mmBtu)

Maximum Capacity
Winter (Dec-Feb)
Shoulder (March-May & Sept-Nov)
Summer (June-Aug)

Heat Rate Profile — **% of Maximum Capacity** — **Average Heat Rate**

	% of Maximum Capacity
1	50%
2	60%
3	70%
4	80%
5	90%
6	100%
7	

Emission Rates
SO2 - lbs/MWh
NOx - lbs/MWh
CO2 - lbs/mmBtu
HG - lbs/MWh
PM_10 - lbs/MWh
CO - lbs/MWh
Pb - lbs/MWh

Planned Maintenance (weeks/yr)
Forced Outage Rate (%) — _TRADE SECRET DATA ENDS]

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Black Dog 6 - 2019 In-Service

In-Service	March 1, 2019
Operating Life (Years)	35

Capital ($000)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
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Transmission							No Inflation, No Escalation																																		
Natural Gas Pipeline																																									

Operating & Maintenance Expense

2013 $dollars		**Escalation Rate**																																							
Fixed O&M ($000)																																									
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Variable O&M ($/MWh)																																									

Fuel Supply Expense

Nominal $dollars																																									
Firm Service Annual Fixed Charge ($000)	Modeled as a Fixed annual capacity rate																																								_TRADE SECRET DATA ENDS]
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Emission Rates

SO2 - lbs/MWh																																										
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Pb - lbs/MWh																																										

Planned Maintenance (weeks/yr)																																									
Forced Outage Rate (%)																																									_TRADE SECRET DATA ENDS]

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Red River Valley 1 - 2018 In-Service

In-Service March 1, 2018
Operating Life (Years) 35

Capital ($000)	2014	2015	2016	2017	1 2018	2 2019	3 2020	4 2021	5 2022	6 2023	7 2024	8 2025	9 2026	10 2027	11 2028	12 2029	13 2030	14 2031	15 2032	16 2033	17 2034	18 2035	19 2036	20 2037	21 2038	22 2039	23 2040	24 2041	25 2042	26 2043	27 2044	28 2045	29 2046	30 2047	31 2048	32 2049	33 2050	34 2051	35 2052	36 2053	2054
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Operating & Maintenance Expense

2013 $dollars	**Escalation Rate**																																								
Fixed O&M ($000)																																									
2013 $dollars	**Escalation Rate**																																								
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Fuel Supply Expense

Nominal $dollars																																									
Firm Service Annual Fixed Charge ($000)																																									_TRADE SECRET DATA ENDS]
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Basis Differential to Chicago Hub ($/mmBtu)	[TRADE SECRET DATA BEGINS…																																								
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Surcharge ($/mmBtu)																																									
Total Delivered Price Of Gas ($/mmBtu)																																									

Maximum Capacity

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Heat Rate Profile

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7		

Emission Rates

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Planned Maintenance (weeks/yr)																																									
Forced Outage Rate (%)																																									_TRADE SECRET DATA ENDS]

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Red River Valley 2 - 2018 In-Service

In-Service	March 1, 2018
Operating Life (Years)	35

Capital ($000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
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Ventura Hub Forecast ($/mmBtu)							4.83	5.24	5.59	5.87	6.14	6.56	6.78	7.02	7.23	7.39	7.55	7.78	7.96	8.11	8.29	8.49	8.68	8.89	9.06	9.24	9.42	9.6	9.78	9.97	10.17	10.36	10.56	10.77	10.98	11.19	11.41	11.63	11.85			
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PUBLIC DOCUMENT
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Red River Valley 1 - 2019 In-Service

In-Service	March 1, 2019
Operating Life (Years)	35

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36										
Capital ($000)			[TRADE SECRET DATA BEGINS…																																																
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Fuel Supply Expense																																																			
Nominal $dollars																																																			
Firm Service Annual Fixed Charge ($000)																																								_TRADE SECRET DATA ENDS]											
Ventura Hub Forecast ($/mmBtu)						5.24	5.59	5.87	6.14	6.56	6.78	7.02	7.23	7.39	7.55	7.78	7.96	8.11	8.29	8.49	8.68	8.89	9.06	9.24	9.42	9.6	9.78	9.97	10.17	10.36	10.56	10.77	10.98	11.19	11.41	11.63	11.85														
Basis Differential to Chicago Hub ($/mmBtu) [TRADE SECRET DATA BEGINS…																																																			
Volumetric Charge ($/mmBtu)																																																			
Surcharge ($/mmBtu)																																																			
Total Delivered Price Of Gas ($/mmBtu)																																																			
Maximum Capacity																																																			
Winter (Dec-Feb)																																																			
Shoulder (March-May & Sept-Nov)																																																			
Summer (June-Aug)																																																			
Emission Rates																																																			
SO2 - lbs/MWh																																																			
NOx - lbs/MWh																																																			
CO2 - lbs/mmBtu																																																			
HG - lbs/MWh																																																			
PM_10 - lbs/MWh																																																			
CO - lbs/MWh																																																			
Pb - lbs/MWh																																																			
Planned Maintenance (weeks/yr)																																																			
Forced Outage Rate (%)																																								_TRADE SECRET DATA ENDS]											

Heat Rate Profile

	% of Maximum Capacity	Average Heat Rate
1	50%	
2	60%	
3	70%	
4	80%	
5	90%	
6	100%	
7		

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TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Red River Valley 2 - 2019 In-Service

In-Service March 1, 2019
Operating Life (Years) 35

Capital ($000)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36					
2013 $dollars	**Escalation Rate**	[TRADE SECRET DATA BEGINS…																																							
Construction Expenditures							No Inflation, No Escalation																																		
On-Going Capital																																									
Transmission							No Inflation, No Escalation																																		
Natural Gas Pipeline																																									

Operating & Maintenance Expense

2013 $dollars	**Escalation Rate**																																								
Fixed O&M ($000)																																									
2013 $dollars	**Escalation Rate**																																								
Variable O&M ($/MWh)																																									

Fuel Supply Expense

Nominal $dollars																																									
Firm Service Annual Fixed Charge ($000)																																									
Ventura Hub Forecast ($/mmBtu)	5.24	5.59	5.87	6.14	6.56	6.78	7.02	7.23	7.39	7.55	7.78	7.96	8.11	8.29	8.49	8.68	8.89	9.06	9.24	9.42	9.6	9.78	9.97	10.17	10.36	10.56	10.77	10.98	11.19	11.41	11.63	11.85	_TRADE SECRET DATA ENDS]								
Basis Differential to Chicago Hub ($/mmBtu)	[TRADE SECRET DATA BEGINS…																																								
Volumetric Charge ($/mmBtu)																																									
Surcharge ($/mmBtu)																																									
Total Delivered Price Of Gas ($/mmBtu)																																									

Maximum Capacity

Winter (Dec-Feb)																																									
Shoulder (March-May & Sept-Nov)																																									
Summer (June-Aug)																																									

Heat Rate Profile	**% of Maximum Capacity**	**Average Heat Rate**																																							
1	50%																																								
2	60%																																									
3	70%																																									
4	80%																																									
5	90%																																									
6	100%																																									
7																																									

Emission Rates

SO2 - lbs/MWh																																									
NOx - lbs/MWh																																									
CO2 - lbs/mmBtu																																									
HG - lbs/MWh																																									
PM_10 - lbs/MWh																																									
CO - lbs/MWh																																									
Pb - lbs/MWh																																									

Planned Maintenance (weeks/yr)																																									
Forced Outage Rate (%)																																									_TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Invenergy Cannon Falls

In-Service June 1, 2016
PPA Term (Years) 20

	2014	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037	2038
Net Capability (NC)			178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW	178.4 MW			
Capacity Payments (CP)			[TRADE SECRET DATA BEGINS…																						
Consumer Price Index Forecast																									
2016 Capacity Price $/kW-mo																									
Nominal Capacity Price $/kW-mo																									

Monthly Capacity Payments = NC x CAF x (CP + EICA)	Average	31 Jan	28 Feb	31 Mar	30 Apr	31 May	30 Jun	31 Jul	31 Aug	30 Sep	31 Oct	30 Nov	31 Dec
Seasonal Deration Profile													
Seasonal Net Capability													
Schedule Maintenance Energy (SME)													
Expected Forced Outage Rate (EFOR)													
Force Outage Energy (FOE) = EFOR x Seasonal NC x Hours													
Available Energy (AE) = Seasonal NC x Hours - SME - FOE													
Period Energy (PE) = NC x Hours													
Capacity Availability Factor = CAF = (AE+SME)/PE													

	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037	2038
Capacity Payments (reflects mid-yr change) Modeled as a capacity																							
Payment for Excess Capacity																							

	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037	2038
Payment For Variable O&M and Start Charges																								
Consumer Price Index Forecast																								
2016 Monthly Tolling Price																								
Nominal Tolling Price (reflects mid year change)																								
Turbine Start Payments																								
Consumer Price Index Forecast																								
2016 Turbines Start Price (TSP)																								
Nominal TSP																								
Assumed # of Run Hours per Start																								
Equivalent Start Charge Per MWh																								
Total VOM Input for Strategist																								

Fuel Supply Expense

Nominal $dollars																								
Firm Service Annual Fixed Charge ($000)																								
																			_TRADE SECRET DATA ENDS]					
Ventura Hub Forecast ($/mmBtu)		$4.08	$4.36	$4.83	$5.24	$5.59	$5.87	$6.14	$6.56	$6.78	$7.02	$7.23	$7.39	$7.55	$7.78	$7.96	$8.11	$8.29	$8.49	$8.68	$8.89	$9.06		
Winter		[TRADE SECRET DATA BEGINS…																						
Volumetric Charge ($/mmBtu)																								
Loss (% of volume)																								
Total Delivered Price Of Gas ($/mmBtu)																								
Summer																								
Volumetric Charge ($/mmBtu)																								
Loss (% of volume)																								
Total Delivered Price Of Gas ($/mmBtu)																								
Average																								
Volumetric Charge ($/mmBtu)																								
Loss (% of volume)																								
Total Delivered Price Of Gas ($/mmBtu)																								

Heat Rate Profile

	% of Maximum Capacity	Average Heat Rate (mmBtu/MWh)
1	50%	
2	60%	
3	70%	
4	80%	
5	90%	
6	100%	
7	0%	

Emission Rates	
SO2 - lbs/MWh	
NOx - lbs/MWh	
CO2 - lbs/mmBtu	
HG - lbs/MWh	
PM_10 - lbs/MWh	
CO - lbs/MWh	
Pb - lbs/MWh	

	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036
Planned Maintenance (weeks/yr)																						
Forced Outage Rate (%)																						
																		_TRADE SECRET DATA ENDS]			

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TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Invenergy Hampton Energy Center

In-Service June 1, 2016
PPA Term (Years) 20

	2014	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037
Net Capability (NC)			357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW	357.5 MW		
Capacity Payments (CP)			[TRADE SECRET DATA BEGINS…																					
Consumer Price Index Forecast																								
2016 Capacity Price $/kW-mo																								
Nominal Capacity Price $/kW-mo																								

Monthly Capacity Payments = NC x CAF x (CP + EICA)	Average	31 Jan	28 Feb	31 Mar	30 Apr	31 May	30 Jun	31 Jul	31 Aug	30 Sep	31 Oct	30 Nov	31 Dec
Seasonal Deration Profile													
Seasonal Net Capability													
Schedule Maintenance Energy (SME)													
Expected Forced Outage Rate (EFOR)													
Force Outage Energy (FOE) = EFOR x Seasonal NC x Hours													
Available Energy (AE) = Seasonal NC x Hours - SME - FOE													
Period Energy (PE) = NC x Hours													
Capacity Availability Factor = CAF = (AE+SME)/PE													

	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037
Total Capacity Payments (reflects mid-yr change)																							
Payment for Excess Capacity																							
Payment For Variable O&M and Start Charges	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036	2037
Consumer Price Index Forecast																							
2016 Monthly Tolling Price																							
Nominal Tolling Price (reflects mid year change)																							

Turbine Start Payments

Consumer Price Index Forecast																							
2016 Turbines Start Price (TSP)																							
Nominal TSP																							
Assumed # of Run Hours per Start																							
Equivalent Start Charge Per MWh																							
Total VOM Input for Strategist																							

Fuel Supply Expense
Nominal $dollars

Firm Service Annual Fixed Charge ($000)																							
																			_TRADE SECRET DATA ENDS]				
Ventura Hub Forecast ($/mmBtu)		$4.08	$4.36	$4.83	$5.24	$5.59	$5.87	$6.14	$6.56	$6.78	$7.02	$7.23	$7.39	$7.55	$7.78	$7.96	$8.11	$8.29	$8.49	$8.68	$8.89	$9.06	
Winter		[TRADE SECRET DATA BEGINS…																					
Volumetric Charge ($/mmBtu)																							
Loss (% of volume)																							
Total Delivered Price Of Gas ($/mmBtu)																							
Summer																							
Volumetric Charge ($/mmBtu)																							
Loss (% of volume)																							
Total Delivered Price Of Gas ($/mmBtu)																							
Average																							
Volumetric Charge ($/mmBtu)																							
Loss (% of volume)																							
Total Delivered Price Of Gas ($/mmBtu)																							

Heat Rate Profile

	% of Maximum Capacity	Average Heat Rate (mmBtu/MWh)
1	50%	
2	80%	
3	100%	
4	0%	
5	0%	
6	0%	
7	0%	

Emission Rates	
SO2 - lbs/MWh	
NOx - lbs/MWh	
CO2 - lbs/mmBtu	
HG - lbs/MWh	
PM_10 - lbs/MWh	
CO - lbs/MWh	
Pb - lbs/MWh	

	2015	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035	21 2036
Planned Maintenance (weeks/yr)																						
Forced Outage Rate (%)																						
																		_TRADE SECRET DATA ENDS]			

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TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Calpine Mankato Expansion

In-Service	June 1, 2017
PPA Term (Years)	20

	2014	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Net Capability (NC)				345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW	345.0 MW				

Seasonal Deration	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
[TRADE SECRET DATA BEGINS…												

Capacity Payments (CP)
Nominal Capacity Price $/kW-mo

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Total Capacity Payments (reflects mid-yr change)																											

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Energy Payments and Start Charges																											
Consumer Price Index Forecast																											
2012 Energy Payment ($/MWh)																											
Nominal Tolling Price (reflects mid year change)																											
Turbine Start Payments																											
Consumer Price Index Forecast																											
2012 Turbines Start Price (TSP)																											
Nominal TSP (reflects mid yr change)																											
Assumed # of Run Hours per Start																											
Equivalent Start Charge Per MWh																											
Total VOM Input for Strategist ($/MWh)																											

Fuel Supply Expense
Nominal $dollars

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Firm Service Annual Fixed Charge ($000)																											
Ventura Hub Forecast ($/mmBtu)			$4.36	$4.83	$5.24	$5.59	$5.87	$6.14	$6.56	$6.78	$7.02	$7.23	$7.39	$7.55	$7.78	$7.96	$8.11	$8.29	$8.49	$8.68	$8.89	$9.06	$9.24				

_TRADE SECRET DATA ENDS]

Winter

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Volumetric Charge ($/mmBtu) [TRADE SECRET DATA BEGINS…																											
Loss (% of volume)																											
Total Delivered Price Of Gas ($/mmBtu)																											

Summer

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Volumetric Charge ($/mmBtu)																											
Loss (% of volume)																											
Total Delivered Price Of Gas ($/mmBtu)																											

Average

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21 2037	2038	2039	2040	2041
Volumetric Charge ($/mmBtu)																											
Loss (% of volume)																											
Total Delivered Price Of Gas ($/mmBtu)																											

Heat Rate Profile

	% of Maximum Capacity	Average Heat Rate (mmBtu/MWh)
1	51%	
2	84%	
3	100%	
4	0%	
5	0%	
6	0%	
7	0%	

Emission Rates

SO2 - lbs/MWh	
NOx - lbs/MWh	
CO2 - lbs/mmBtu	
HG - lbs/MWh	
PM_10 - lbs/MWh	
CO - lbs/MWh	
Pb - lbs/MWh	

	2015	2016	1 2017	2 2018	3 2019	4 2020	5 2021	6 2022	7 2023	8 2024	9 2025	10 2026	11 2027	12 2028	13 2029	14 2030	15 2031	16 2032	17 2033	18 2034	19 2035	20 2036	21
Planned Maintenance (weeks/yr)																							
Forced Outage Rate (%)																							

_TRADE SECRET DATA ENDS]

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TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Geronimo Distributed Solar Project

In-Service December 1, 2016
PPA Term (Years) 20

	2014	2015	2016 (1)	2017 (2)	2018 (3)	2019 (4)	2020 (5)	2021 (6)	2022 (7)	2023 (8)	2024 (9)	2025 (10)	2026 (11)	2027 (12)	2028 (13)	2029 (14)	2030 (15)	2031 (16)	2032 (17)	2033 (18)	2034 (19)	2035 (20)	2036 (21)	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Net Capability (NC)			100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW	100 MW																		
Pricing Option 1																																									
Capacity Payments (CP)			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20																				
Nominal Capacity Price $/kW-mo	[TRADE SECRET DATA BEGINS…																																								
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Total Capacity Payments (reflects mid-yr change)																																									
Energy Payments			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20												2046	2047	2048	2049	2050	2051	2052	2053	2054
Nominal $																																									
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Total Energy Payments (reflects mid-yr change)																																									
Pricing Option 2 (Strategist Inputs)																																									
Energy Payments			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20												2046	2047	2048	2049	2050	2051	2052	2053	2054
Nominal $																																									
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Total Energy Payments (reflects mid-yr change)																								TRADE SECRET DATA ENDS]																		

[TRADE SECRET DATA BEGINS…

Monthly Energy Pattern	
31	1
28	2
31	3
30	4
31	5
30	6
31	7
31	8
30	9
30	11
31	12

TRADE SECRET DATA ENDS]

Typical Week Shapes [TRADE SECRET DATA BEGINS…

	Month	Day of Week	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12	Hour 13	Hour 14	Hour 15	Hour 16	Hour 17	Hour 18	Hour 19	Hour 20	Hour 21	Hour 22	Hour 23	Hour 24
345.62	1	SUNDAY																								
259.90	1	MONDAY																								
220.04	1	TUESDAY																								
295.41	1	WEDNESDAY																								
319.17	1	THURSDAY																								
293.43	1	FRIDAY																								
315.14	1	SATURDAY																								
400.59	2	SUNDAY																								
400.69	2	MONDAY																								
455.54	2	TUESDAY																								
488.15	2	WEDNESDAY																								
469.02	2	THURSDAY																								
388.19	2	FRIDAY																								
386.27	2	SATURDAY																								
605.11	3	SUNDAY																								
664.42	3	MONDAY																								
543.70	3	TUESDAY																								
415.57	3	WEDNESDAY																								
470.29	3	THURSDAY																								
600.22	3	FRIDAY																								
494.40	3	SATURDAY																								
712.68	4	SUNDAY																								
681.85	4	MONDAY																								
733.37	4	TUESDAY																								
745.39	4	WEDNESDAY																								
767.04	4	THURSDAY																								
677.14	4	FRIDAY																								
553.37	4	SATURDAY																								
759.16	5	SUNDAY																								
808.02	5	MONDAY																								
749.52	5	TUESDAY																								
765.35	5	WEDNESDAY																								
790.47	5	THURSDAY																								
867.89	5	FRIDAY																								
790.07	5	SATURDAY																								
882.08	6	SUNDAY																								
895.46	6	MONDAY																								
853.09	6	TUESDAY																								
941.27	6	WEDNESDAY																								
744.81	6	THURSDAY																								
795.46	6	FRIDAY																								
850.63	6	SATURDAY																								
989.10	7	SUNDAY																								
752.54	7	MONDAY																								
734.60	7	TUESDAY																								
904.44	7	WEDNESDAY																								
870.54	7	THURSDAY																								
641.46	7	FRIDAY																								
804.41	7	SATURDAY																								
677.74	8	SUNDAY																								
723.88	8	MONDAY																								
660.67	8	TUESDAY																								
698.37	8	WEDNESDAY																								
834.88	8	THURSDAY																								
763.85	8	FRIDAY																								
650.48	8	SATURDAY																								
585.50	9	SUNDAY																								
565.53	9	MONDAY																								
627.33	9	TUESDAY																								
473.15	9	WEDNESDAY																								
637.02	9	THURSDAY																								
549.76	9	FRIDAY																								
510.27	9	SATURDAY																								
389.80	10	SUNDAY																								
422.54	10	MONDAY																								
487.64	10	TUESDAY																								
386.87	10	WEDNESDAY																								
296.84	10	THURSDAY																								
512.91	10	FRIDAY																								
478.78	10	SATURDAY																								
315.88	11	SUNDAY																								
246.89	11	MONDAY																								
292.20	11	TUESDAY																								
197.62	11	WEDNESDAY																								
202.93	11	THURSDAY																								
263.52	11	FRIDAY																								
251.56	11	SATURDAY																								
188.28	12	SUNDAY																								
205.90	12	MONDAY																								
167.80	12	TUESDAY																								
177.93	12	WEDNESDAY																								
230.29	12	THURSDAY																								
240.38	12	FRIDAY																								
203.52	12	SATURDAY																								

24
48
72

TRADE SECRET DATA ENDS]

GRE Capacity Purchase

In-Service	June 1, 2016
PPA Term (Years)	3

Option 1

	1	*2*	*3*
	2016	**2017**	**2018**
Net Capability (NC)	100 MW	100 MW	100 MW

Capacity Payments (CP)

	2016/17	2017/18	2018/19
Nominal Capacity Price $/kW-mo	[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS		

	2016	**2017**	**2018**	**2019**
Total Capacity Payments (reflects mid-yr change)				_HIGHLY SENSITIVE TRADE SECRET DATA ENDS]

Option 2

	2016	**2017**	**2018**
Net Capability (NC)	200 MW	200 MW	200 MW

Capacity Payments (CP)

	2016/17	2017/18	2018/19
Nominal Capacity Price $/kW-mo	[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS		

	2016	**2017**	**2018**	**2019**
Total Capacity Payments (reflects mid-yr change)				_HIGHLY SENSITIVE TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	358 MW	$45,366

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000																																			
Payments For PPAs	$000																																			
Capacity Credit/Replacement Units	$000																																			
Net Fuel / Energy Costs	$000							-NA-																												
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 2	Calpine - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,368

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			...TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			...TRADE SECRET DATA ENDS]
Capital Revenue Requirements	$000																																			

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit/Replacement Units	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			...TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 5	Great River Energy - 2016 - 100 MW Red River 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,368

Annual Bid Performance / Costs

Red River 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 4	Great River Energy - 2016 - 100 MW Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2019 - 208MW	358 MW	$45,371

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS...																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			...TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS...																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			...TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS...																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			...TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 5	Red River 1 - 2018 - 208MW Black Dog 6 - 2017 - 208MW	416 MW	$45,375

Annual Bid Performance / Costs

Red River 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																		…TRADE SECRET DATA ENDS]	

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																		…TRADE SECRET DATA ENDS]	

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																		…TRADE SECRET DATA ENDS]	

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 6	Calpine - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,375

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																		…TRADE SECRET DATA ENDS]	

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																		…TRADE SECRET DATA ENDS]	

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																		…TRADE SECRET DATA ENDS]	

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 7	Great River Energy - 2016 - 100 MW Red River 1 - 2018 - 208MW Black Dog 6 - 2018 - 208MW	416 MW	$45,376

Annual Bid Performance / Costs

Red River 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

Plan 8	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2017 - 208MW	358 MW	$45,377

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW		150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS...																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			...TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW		208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS...																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			...TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS...																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			...TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 9	Great River Energy - 2016 - 100 MW Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	358 MW	$45,379

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 10	Great River Energy - 2016 - 100 MW Calpine - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,381

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																		…TRADE SECRET DATA ENDS]	

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																		…TRADE SECRET DATA ENDS]	

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																		…TRADE SECRET DATA ENDS]	

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 11	Great River Energy 2 - 2016 - 200 MW Red River 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,383

Annual Bid Performance / Costs

Red River 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 12	Invenergy Cannon Falls - 2016 - 150MW Red River 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	566 MW	$45,384

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Red River 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 13	Great River Energy 2 - 2016 - 200 MW Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2019 - 208MW	358 MW	$45,386

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 14	Calpine - 2017 - 278MW Black Dog 6 - 2017 - 208MW	486 MW	$45,386

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW		208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 15	Invenergy Hampton - 2016 - 300MW Black Dog 6 - 2019 - 208MW	508 MW	$45,387

Annual Bid Performance / Costs

Invenergy Hampton

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW	358MW															
Summer Accredited Capacity	MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW	300MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 16	Great River Energy - 2016 - 100 MW Calpine - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,388

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 17	Great River Energy - 2016 - 100 MW Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2017 - 208MW	358 MW	$45,389

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW		208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

Plan 18	Great River Energy 2 - 2016 - 200 MW Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	358 MW	$45,393

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW			232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW			208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 19	Great River Energy 2 - 2016 - 200 MW Calpine - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,395

Annual Bid Performance / Costs

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			…TRADE SECRET DATA ENDS]

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																			…TRADE SECRET DATA ENDS]

Total System Costs Comparison to Plan 1

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																			…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA AND HIGHLY SENSITIVE TRADE SECRET DATA HAS BEEN EXCISED

Plan 20	Invenergy Cannon Falls - 2016 - 150MW Calpine - 2017 - 278MW Black Dog 6 - 2019 - 208MW	636 MW	$45,396

Annual Bid Performance / Costs

Invenergy Cannon Falls

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW	178MW															
Summer Accredited Capacity	MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW	150MW															
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																		…TRADE SECRET DATA ENDS]	

Calpine

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW		345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW	345MW														
Summer Accredited Capacity	MW		278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW	278MW														
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
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Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																		…TRADE SECRET DATA ENDS]	

Black Dog 6

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max Capacity	MW				232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW	232MW
Summer Accredited Capacity	MW				208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh	[TRADE SECRET DATA BEGINS…																																		
CF	%																																			
Total Fuel Cost	$000																																			
Total Fuel Consumed	000mmBtu																																			
Average HR	mmBtu/MWh																																			
Ave Fuel Cost	$/mmBtu																																			
Total VOM	$000																																			
Ave VOM	$/MWh																																			
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
Capital Revenue Requirements	$000																																		…TRADE SECRET DATA ENDS]	

Total System Costs Comparison to Plan 1

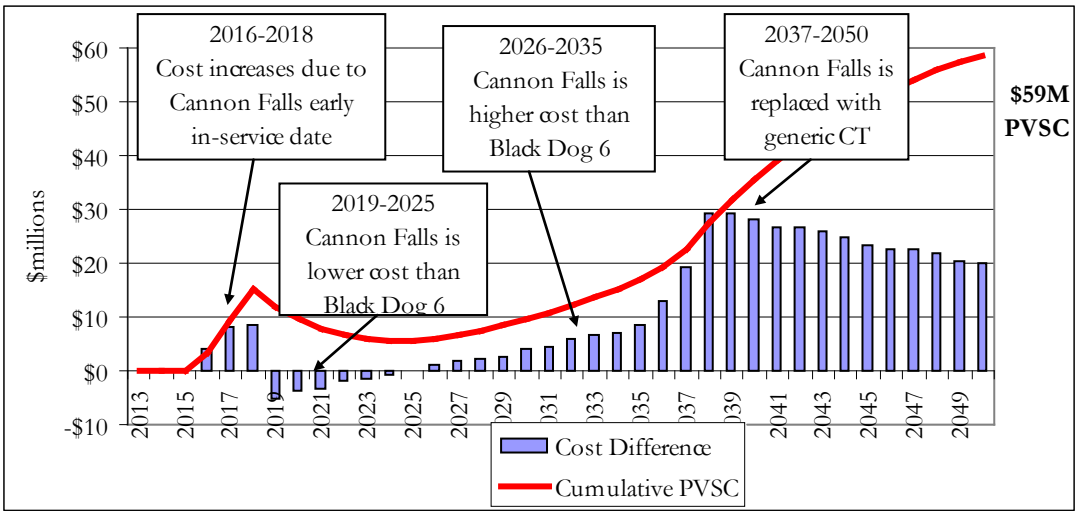
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Owned Project Revenue Requirements + Fixed O&M	$000	[TRADE SECRET DATA BEGINS…																																		
Payments For PPAs	$000																																			
Capacity Credit	$000																																			
Net Fuel / Energy Costs	$000																																			
Net Fuel / Emission Costs	$000																																			
Annual Net System Costs	$000																																			
Cumulative PVSC	$000																																		…TRADE SECRET DATA ENDS]	

Invenergy Cannon Falls vs Black Dog 6

Plan 56: Calpine Mankato + Invenergy Cannon Falls

vs.

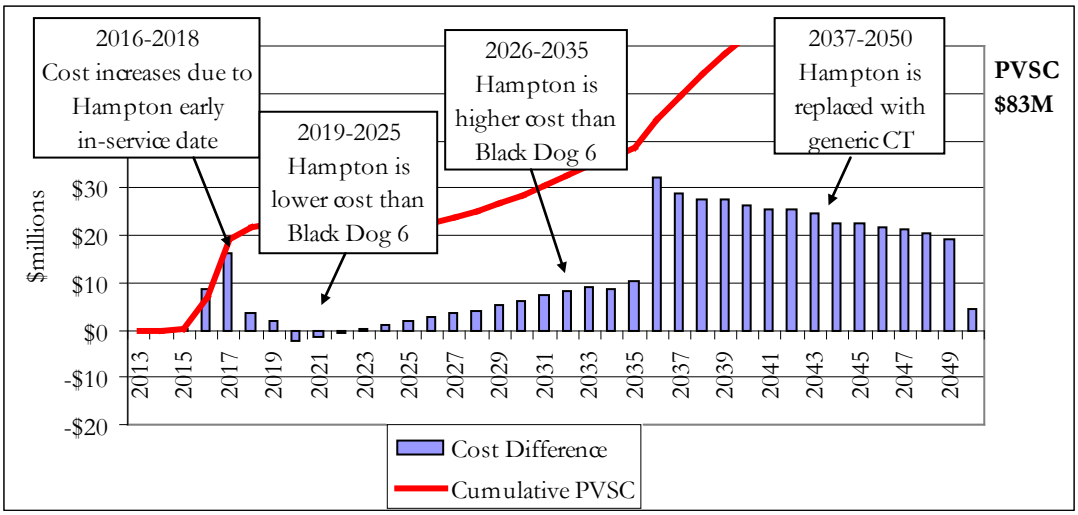
Plan 2: Calpine Mankato + Black Dog 6



Invenergy Cannon Falls	**PVSC $millions**
Cannon Falls Capacity Payment	$102
2036 Replacement CT	$58
Cannon Falls Total Cost	$160
Energy and Emission Costs Differences	
Net Energy Costs	$5
Net Emission Costs	($2)
Net Costs	$3
Black Dog Unit 6	
Black Dog 6 Revenue Requirements	$135
Capacity Credit	($31)
Net Black Dog 6 Costs	$104
Total Net PVSC	
Cannon Falls + Energy & Emission Costs - Black Dog 6	**$59**

Invenergy Hampton Energy Center vs. Black Dog 6

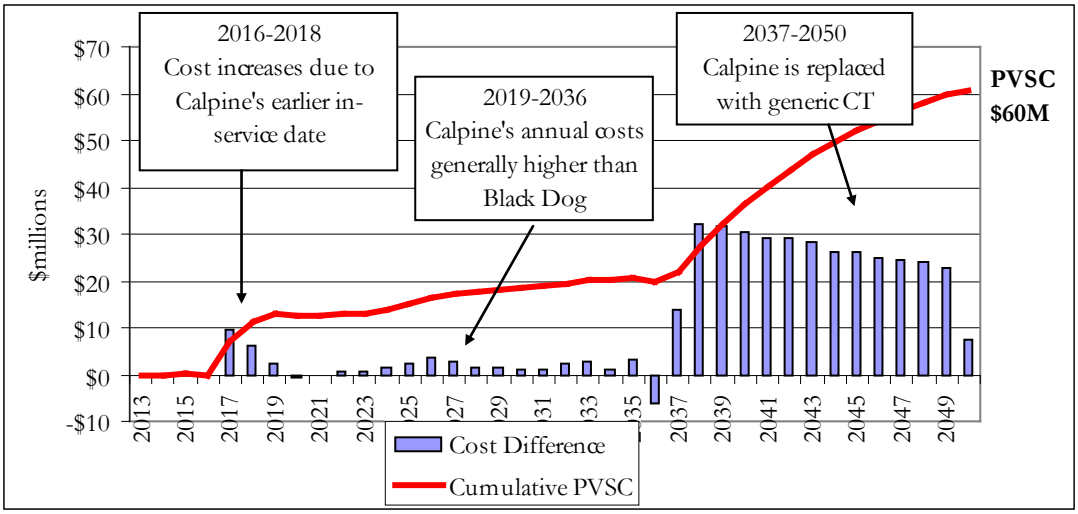
Plan 117: Invenergy Cannon Falls + Invenergy Hampton Energy Center
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6



Invenergy Hampton Energy Center	**PVSC $millions**
Hampton Capacity Payment	$204
Capacity Credit	($35)
2036 Replacement CT	$63
Cannon Falls Total Cost	$232
Energy and Emission Costs Differences	
Net Energy Costs	($2)
Net Emission Costs	($2)
Net Costs	($4)
Black Dog Unit 6	
Black Dog 6 Revenue Requirements	$145
Total Net PVSC Hampton + Energy & Enviro Costs - Black Dog 6	**$83**

Calpine Mankato vs. Black Dog 6

Plan 56: Invenergy Cannon Falls + Calpine Mankato
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6



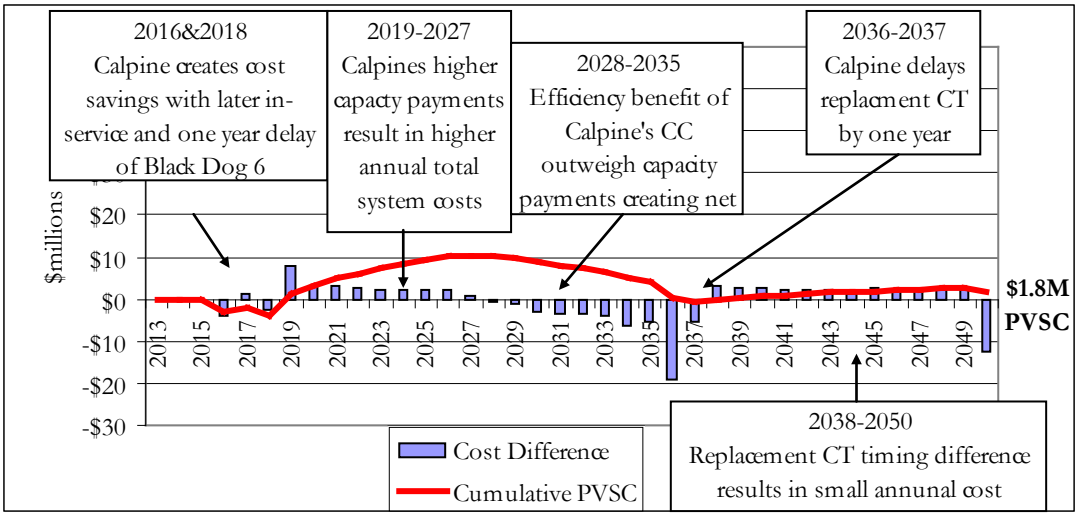
Calpine Mankato Expansion	**PVSC $millions**
Calpine Mankato Capacity Payment	$237
Calpine Efficency Benefit	($64)
Capacity Credit	($24)
2037 Replacement CT	$53
Cannon Falls Total Cost	$201
Net Emission Costs	$4

Black Dog Unit 6	
Black Dog 6 Revenue Requirements	$145

Total Net PVSC	
Calpine + Net Emission Costs - Black Dog	**$60**

Calpine Mankato vs. Invenergy Cannon Falls

Plan 2: Calpine Mankato + Black Dog 6 2019
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6 2018



Calpine Mankato Expansion	**PVSC $millions**
Mankato Capacity Payments	$237
Combined Cycle Efficiency Benefit	($69)
Black Dog 6 One Year Delay	($10)
Capacity Credit	($55)
Net Calpine Costs	$103

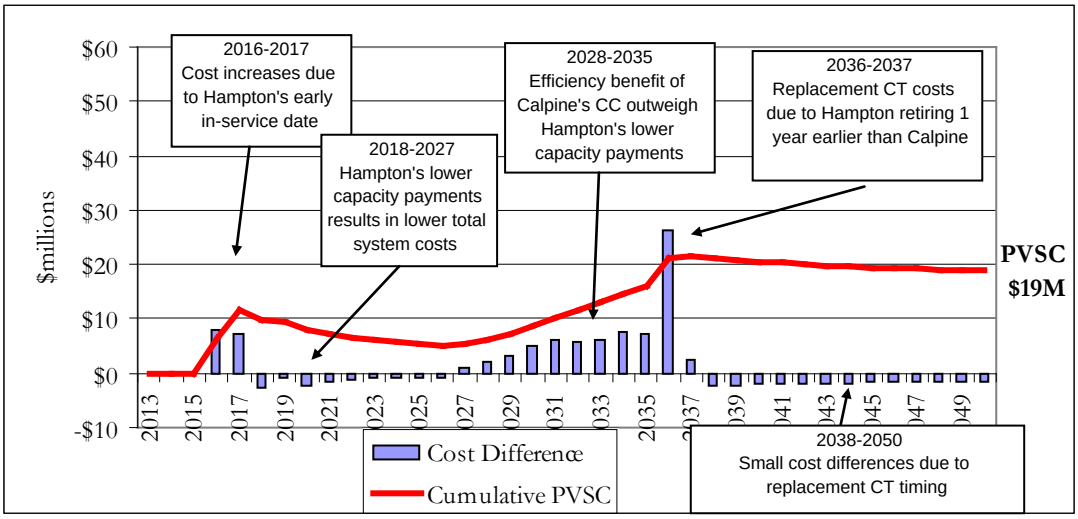
Other Total System Cost Differences	
Long Term Expansion Plan Difference	($5)
Net Emission Costs	$6
Net Costs	$1

Invenergy Cannon Falls	
Cannon Falls Capacity Payment	$102

Total Net PVSC	
Calpine + Other System Cost Differences - Cannon Falls	**$1.8**

Invenergy Hampton Energy Center vs. Calpine Mankato

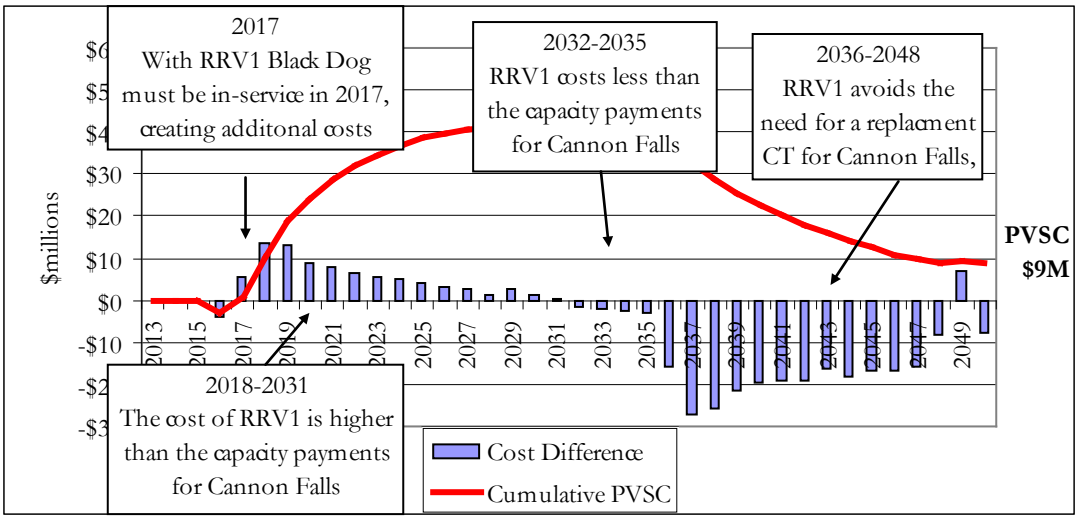
Plan 15: Invenergy Hampton Energy Center + Black Dog 6
vs.
Plan 2: Calpine Mankato + Black Dog 6



Invenergy Hampton Energy Center	**PVSC $millions**
Hampton Energy Center Capacity Payment	$204
Capacity Credit	($8)
Cannon Falls Total Cost	$196
Other Total System Cost Differences	
Long Term Expansion Plan Difference	$5
Net Emission Costs	($5)
Net Costs	($0.5)
Calpine Mankato Expansion	
Mankato Capacity Payments	$237
Combined Cycle Efficiency Benefit	($60)
Net Black Dog 6 Costs	$177
Total Net PVSC	
Hampton - Calpine + Other System Cost Differences	**$19**

Red River Valley Unit 1 vs. Invenergy Cannon Falls

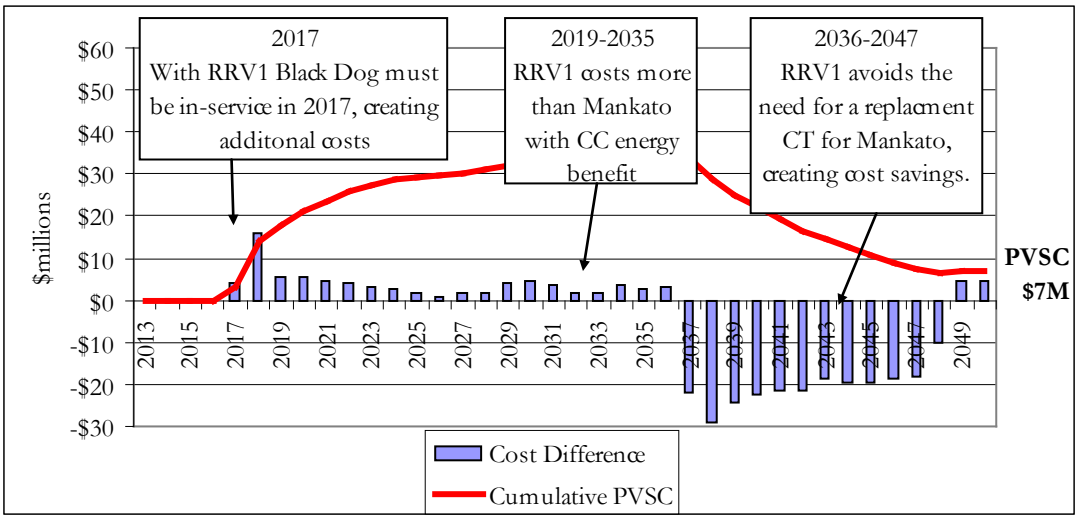
Plan 5: Red River Valley 1 + Black Dog 6 2017
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6 2018



Red River Valley 1	**PVSC $millions**
RRV 1 Revenue Requirements	$193
Early Black Dog Costs	$14
Capacity Credit	($27)
RRV 1 Total Costs	$180
Other Total System Cost Differences	
Net Fuel Costs	($7)
Net Emission Costs	$1
Net Costs	($6)
Invenergy Cannon Falls	
Cannon Falls Capacity Payments	$102
Replacement CT	$63
Total Cannon Falls Costs	$165
Total Net PVSC RRV1 + Other System Cost Differences - Cannon Falls	**$9**

Red River Valley Unit 1 vs. Calpine Mankato

Plan 11: Red River Valley 1 + Black Dog 6 2017
vs.
Plan 2: Calpine Mankato + Black Dog 6 2019



Red River Valley 1	**PVSC $millions**
RRV 1 Revenue Requirements	$193
Early Black Dog Costs	$24
RRV 1 Total Costs	$217
Net Emission Costs	($5)

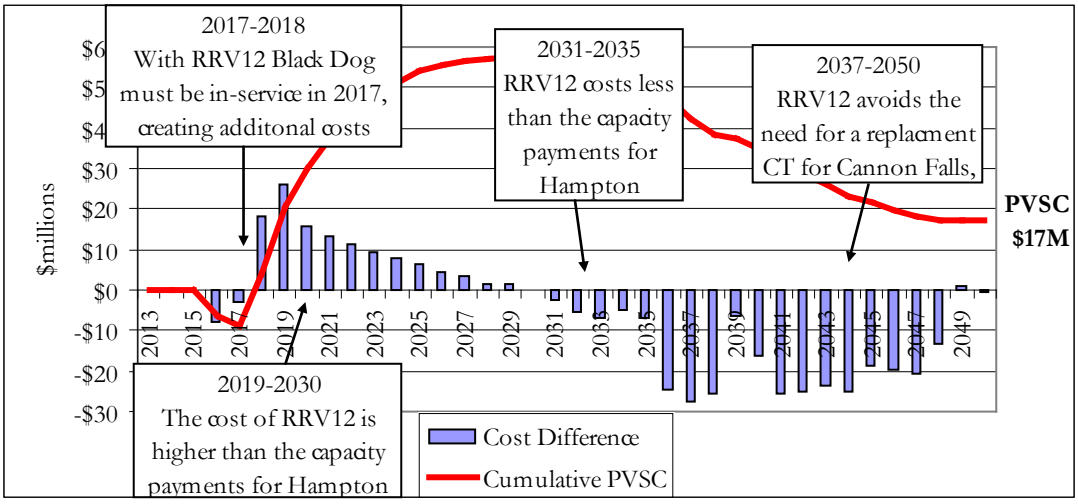
Calpine Mankato Expansion

Mankato Capacity Payments	$237
Capacity Credit	($28)
Net Fuel Costs	($62)
Replacement CT	$58
Total Cannon Falls Costs	$205

Total Net PVSC	
RRV1 + Other System Cost Differences - Cannon Falls	**$7**

Red River Valley Units 1&2
vs. Invenergy Hampton Energy Center

Plan 42: Red River Valley 1&2 + Black Dog 6 2017
vs.
Plan 15: Invenergy Hampton Energy Center + Black Dog 6 2019



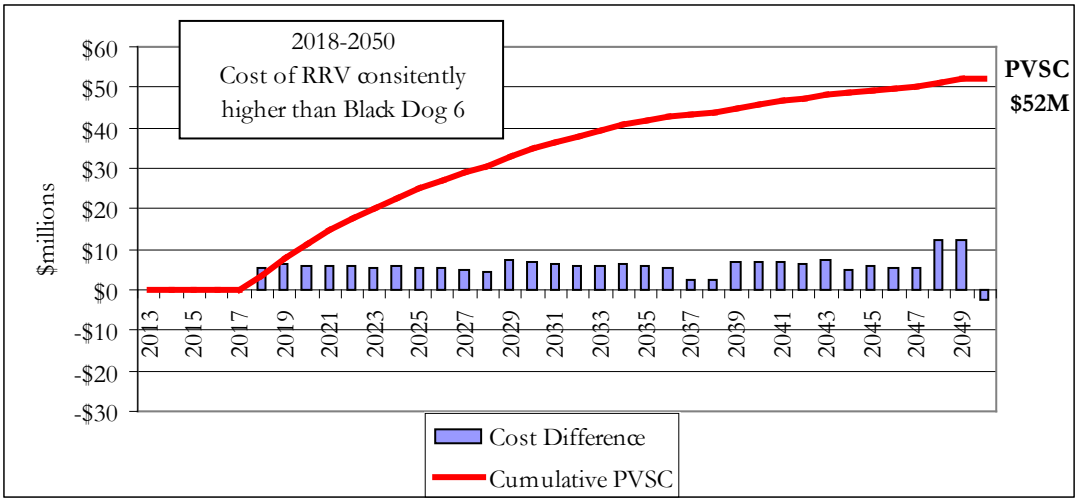
Red River Valley 1&2	**PVSC $millions**
RRV 12 Revenue Requirements	$353
Early Black Dog Costs	$24
Capacity Credit	($84)
RRV 12 Total Costs	$293
Net Emission Costs	$3.0

Invenergy Hampton Energy Center	
Hampton Capacity Payments	$204
Net Fuel Costs	$12
Replacement CT	$63
Total Cannon Falls Costs	$279

Total Net PVSC	
RRV12 + Other System Cost Differences - Hampton	**$17**

Red River Valley Unit 1 vs. Black Dog 6

Plan 60: Invenergy Cannon Falls + Red River Valley 1
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6



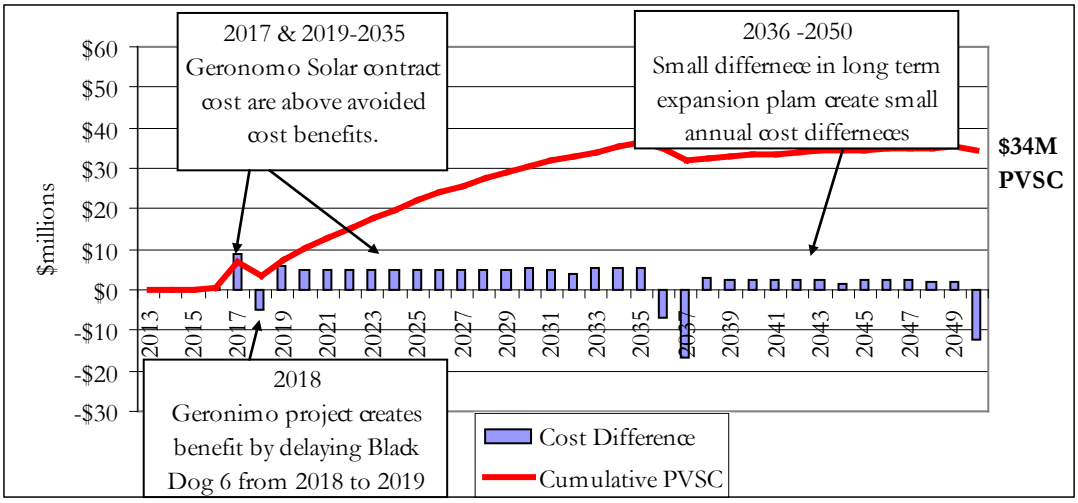
Red River Valley 1	**PVSC $millions**
RRV 1 Revenue Requirements	$193
Other System Costs	$4

Black Dog 6	
Black Dog Revene Requirements	$145

Total Net PVSC RRV1 + Other System Cost Differences - Black Dog	**$52**

Geronimo Solar

Plan 29: Invenergy Cannon Falls + Black Dog 6 + Geronimo Solar
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6



Geronimo Solar Project	**PVSC $millions**
Geronimo Energy Payments	$186
Long Term Expansion Plan Difference	($1)

Costs Avoided By Solar	
Avoided Energy	$88
Avoided Capacity	$43
Avoided Emissions	$20
Total Avoided Costs	$151

Total Net PVSC	
Geronimo + LT Expansion Diff. - Avoided Cost of Solar	**$34**

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

Rebuttal Testimony and Schedules
Steven W. Wishart

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition to the Minnesota Public Utilities Commission Seeking Approval for a Competitive Resource Acquisition Proposal
And For a Certificate of Need

Docket No. E002/CN-12-1240
Exhibit___(SWW-2)

Department of Commerce Strategist Analysis, Calpine Levelized Cost of Energy Analysis, Firm v. Interruptible Natural Gas Supply, and Other Strategist Issues

October 18, 2013

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TRADE SECRET DATA EXCISED

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Schedules

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Steven W. Wishart. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, I provided direct testimony on (i) the Company's assessment of anticipated generating capacity deficits in the 2017 to 2019 timeframe; (ii) the Strategist analysis we performed to evaluate the proposals that are the subject of this proceeding; (iii) the Company's recommendation regarding which proposals should be selected by the Commission; and (iv) important considerations that need to be addressed in the next phase of the process, the negotiation of power purchase contracts.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to various issues raised in the Strategist analysis provided by Department witness Dr. Steve Rakow and the Least Cost of Energy (LCOE) analysis of Calpine witness Mr. Paul Hibbard. I also provide an analysis of the benefits of firm versus interruptible natural gas supply as requested by Department witness Mr. Sachin Shah. I conclude by responding to various Strategist issues raised by other witnesses regarding the proposals in this proceeding.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. A summary of the principal issues in my rebuttal testimony is provided below:

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A. The Department's Strategist Analysis

The direct testimony of Dr. Rakow provided an alternative Strategist analysis to the Company's comparing the cost and benefits of the proposals in various portfolios. Although our methodologies were substantially different, we both identified a combination of Black Dog 6 and Calpine's Mankato Expansion as the least cost alternative to meet the Company's identified need. However by only evaluating projects through 2036, Dr. Rakow does not address the long-term cost savings that Company-owned projects offer our customers in comparison to power purchase agreements (PPAs). When the long-term benefits are considered, Black Dog 6 is the most attractive proposal in this process, and Calpine's Mankato Expansion project and Invenergy's Cannon Falls Expansion project are in close competition for second place.

The Department's analysis also did not recognize the timing flexibility that our projects have. Changes in both our and the Department's assessments of the Company's future capacity need underscore the value of flexibility regarding in-service date. To minimize costs for our customers, we are willing to adjust the in-service date of our proposal to best match the first year of actual capacity need.

B. Calpine's Levelized Cost of Energy

We used Strategist modeling because it provides a complete cost-benefit analysis. Mr. Hibbard presented an analysis of the proposals in this proceeding based on their estimated levelized cost of energy. The primary short coming of the LCOE method is that it compares the proposals based on

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their costs alone, completing ignoring the avoided costs the Company would realize as the result of each project being added to our system. Thus the LCOE approach is only a partial analysis. I recommend Mr. Hibbard's LCOE analysis not be considered in the selection of resources in this proceeding.

C. Firm vs. Interruptible Natural Gas Supply

In response to Mr. Shah's request, I attempt to clarify the costs and benefits of firm natural gas supply in comparison to interruptible service. Currently, the Company's system has approximately 1,800 MW of excess winter capacity in comparison to 800 MW of excess capacity in the summer. Although we would typically prefer year-round firm natural gas supply, interruptible service that may be curtailed in the winter does not significantly impact our ability to reliably serve customers, and it offers significant cost savings. In our analysis, we consider interruptible natural gas service only to be a viable option for peaking units. Peaking units such as those proposed by the Company and by Invenergy are typically only dispatched in the summer during periods of high customer demand. Intermediate units such as the combined cycle unit proposed by Calpine are dispatched frequently during the winter months, and therefore firm natural gas service is mandatory fort those types of units.

II. DEPARTMENT OF COMMERCE STRATEGIST ANALYSIS

Q. WHAT IS THE DEPARTMENT'S RESOURCE SELECTION RECOMMENDATION?

A. Dr. Rakow states on page 40 of his direct testimony that Calpine's Mankato Expansion in 2017 combined with our Black Dog Unit 6 in 2019 is the least cost package that "covers Xcel's capacity deficit to 2023 under the normal

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forecast and to 2025 and beyond under the mid-low and low forecasts." Dr. Rakow then goes on to state that if the Commission is concerned about "the size of the package," the second ranked package under base case conditions is Calpine's proposal. He concludes with the observation that Black Dog 6 in 2017 or a combination of Invenergy's and Calpine's proposals are also options depending upon "which contingencies are of greatest concern" to the Commission.

Q. DO YOU AGREE WITH THE DEPARTMENT'S RECOMMENDATION?

A. In part. We agree that the combination of Black Dog 6 and Calpine represents one least-cost package. However as presented in our direct testimony, our analysis shows the combination of Black Dog 6 and Invenergy Cannon Falls represents another least-cost package, and therefore we recommend that both Calpine and Invenergy should proceed to the PPA negotiation phase of these proceedings.

In addition, we believe that Black Dog 6 should be selected under any resource need assessment. This is based on the fact that Black Dog 6 has the lowest PVSC of all the proposed resources, and the unit offers the Commission the flexibility to delay its implementation to achieve the best match possible with the Company's actual need in the 2017-2019 time period.

Q. WHAT IS YOUR ASSESSMENT OF THE STRATEGIST ANALYSIS PERFORMED BY THE DEPARTMENT?

A. First, Dr. Rakow's Strategist analysis is well thought out and clearly presented. The Company appreciates the Department choosing to conduct a Strategist

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analysis because it acts as a check and balance to our own Strategist simulations. An examination of the similarities and differences between our respective results provides an opportunity to determine which of the proposals in this proceeding can most cost-effectively address our potential range of need in the 2017-2019 time period.

With respect to the principal differences between the Department's results and our own, the Company's analysis showed that due to a longer operating life and flexible in-service date, Black Dog Unit 6 offers significant savings for customers in comparison to other proposals. Dr. Rakow's First Round analysis confirmed this finding.[1] But in the Second Round analysis the results flipped,[2] and the Department ends up recommending Calpine's Mankato Expansion over Black Dog 6. Second, the Company's analysis showed that Calpine's Mankato Expansion and Invenergy's Cannon Falls project costs are closely matched, while the Department's analysis shows a considerable gap between the two projects.

A. Department Analysis of Black Dog Unit 6

Q. WHY SHOULD BLACK DOG 6 BE CHOSEN UNDER ANY RESOURCE NEED ASSESSMENT?

A. As demonstrated in my direct testimony, Black Dog 6 provides long-term cost benefits compared to all of the other proposals. These benefits are not reflected in the Department's analysis.

[1] See Rakow Direct, Attachment SR-4a at pages 9-10.

[2] See Rakow Direct, Attachment SR-5A at page 1.

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Q. PLEASE ELABORATE ON THE BENEFITS OF BLACK DOG 6 WHICH WERE NOT REFLECTED IN THE DEPARTMENT'S ANALYSIS.

A. Based on review of the Department's analysis, I have identified two instances where their Strategist model is undervaluing the Black Dog 6 project:

1) from 2019 through 2036, the Department's decision not to 'lock' the model's long-term expansion plan resulted in Strategist adding additional costs to the project; and
2) the 2013-2036 simulation period chosen by the Department does not capture the long term benefits of the project. Worse yet, the "end effects" adjustment that was supposed to represent Black Dog 6's long-term savings actually resulted in a $10 million penalty for the project.

Q. PLEASE EXPLAIN THE BENEFITS OF BLACK DOG 6 FROM 2019 THROUGH 2036.

A. Through lower annual fixed costs, our Black Dog 6 unit offers considerable cost savings in comparison to Calpine's Mankato Expansion. From 2019 through 2036, the average annual fixed costs of Black Dog are **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, while the fixed costs of Calpine over the same period are **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. While Calpine's higher efficiency does provide additional savings through lower fuel costs, these savings are not enough to offset the higher fixed costs.

Q. IF BLACK DOG HAS LOWER ANNUAL COSTS FROM 2019 THROUGH 2036, WHY DOES THE DEPARTMENT'S ANALYSIS SHOW CALPINE'S PROJECT HAS LOWER

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COSTS?

A. After reviewing the Department's analysis, I have determined that its modeling of the expansion plan in Strategist inadvertently added costs to our proposal which in my opinion were not appropriate. As explained by Dr. Rakow in his direct testimony, the Department did not 'lock' the long-term expansion plan in their model.[3] This means that for each bid portfolio studied, Strategist created a different portfolio of resources for the period 2020 through 2036. The result is that the Department's results are not a direct comparison between bid proposals, but rather a comparison of the bids plus the cost of some generic natural gas plants that were added by Strategist.

Our Strategist analysis locked the long-term expansion plan, and thus created a direct comparison between bid costs. The results of our model show that the net cost of Black Dog 6 is lower than the net cost of Calpine's proposal in almost every year for the period 2019 through 2036, as shown in Figure 1 below. By 2036, Black Dog 6 creates a net PVSC savings of $20 million in comparison to Calpine's project.

Q. PLEASE ELABORATE ON THE IMPACTS OF THE DEPARTMENT'S DECISION TO ONLY RUN STRATEGIST THROUGH 2036.

A. The proposals from Calpine, Invenergy, and Geronimo are all for 20-year PPAs, expiring by spring of 2037. However, the Company's proposed Black Dog Unit 6 and Red River Valley Units 1 and 2 have an expected operating life of 35 years, retiring in the 2050 to 2052 timeframe. Because the Department limited its Strategist simulations to the 2013 to 2036 period only,

[3] See Rakow Direct at pages 31-32.

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they do not capture the long-term benefits identified in the Company's analysis. Dr. Rakow acknowledges this impact at page 28, lines 8 and 9, of his direct testimony:

> *"However such an end date [(2036)], even with end effects, likely does not account for the full value of Xcel's bids…"*

To illustrate the impact of the shorter simulation period, I compare the annual cost difference between Calpine and Black Dog 6 from the Company's Strategist analysis to the Strategist analysis of the Department. Figure 1 below illustrates the Company's Strategist results, showing that after the savings realized as a result of Black Dog's later in-service date, the two projects have only small cost differences through 2036. Then in 2037, the Calpine project must be replaced by a new combustion turbine at the forecasted 2037 market price. This will be significantly more expensive than the cost of the depreciated Black Dog unit at that time, and thus Black Dog 6 offers significant cost savings in the 2037 to 2050 time period.

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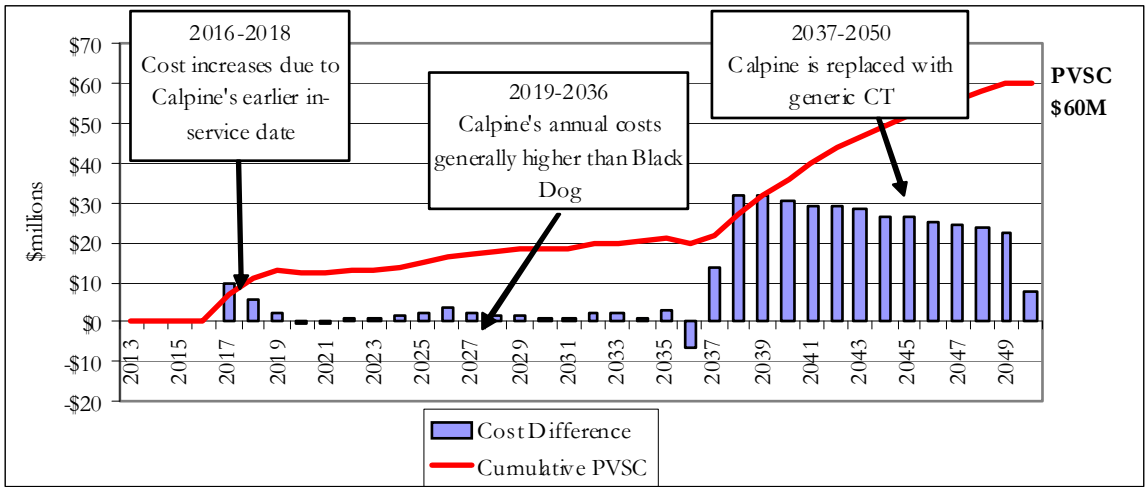
Figure 1 - Calpine Mankato vs. Black Dog 6
Xcel Energy Strategist Modeling



(Plan 56: Invenergy Cannon Falls + Calpine Mankato vs. Plan 1: Invenergy Cannon Falls + Black Dog 6)

Figure 2 below shows the results of the Department's Strategist modeling which is limited to the 2013 to 2036 time period. Its model begins with a similar pattern of cost savings, but then there are periodic jumps and swings in the net costs and net benefits of Black Dog depending on when Strategist chooses to add generic power plants. This is a result of the Department not locking the expansion plan in Strategist. Then at the end of the simulation period, Strategist adds a $10 million "end effects" penalty to the Black Dog scenario. The "end effects" adjustment is a lump sum estimate of the long-term cost of the unit after the year 2036. This adjustment is a short-cut alternative to actually modeling the cost of the unit to the end of its life as our Strategist analysis did. Based on the Company's decades-long experience with Strategist modeling, we have found the "end effects" adjustment is very unreliable. Much more accurate results are achieved by modeling the full lifetime of the resource being evaluated.

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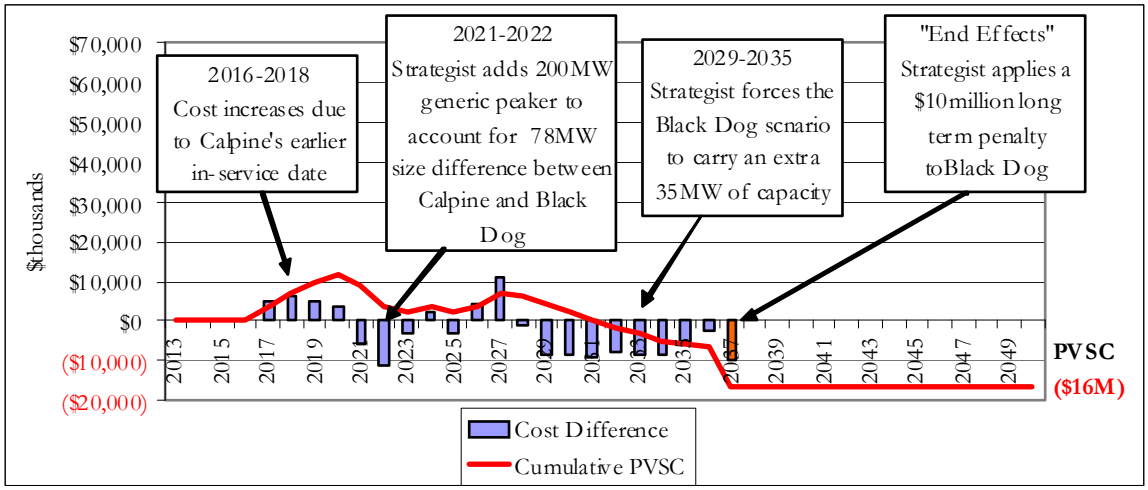
Figure 2 - Calpine Mankato vs. Black Dog 6
Department Strategist Modeling



(Master Scenario 1 - ICT1 CCC1 vs. BD618 ICT1)

Q. PLEASE EXPLAIN HOW THE 2037 TO 2050 BENEFIT OF BLACK DOG 6 PRESENTED IN FIGURE 1 CAN BE SO LARGE.

A. The net benefit is based on the cost difference between Black Dog 6 in the future and the cost to build a new plant to replace the retiring Calpine contract. A CC plant that would cost $120 million today will cost $193 million in 2037 using a simple inflation rate of 2 percent. By that time the book value of Black Dog 6 will be largely depreciated so its cost will be well below the market price for capacity at that time. On page 28, line 6 of my direct testimony I present a graph that shows that the costs of Black Dog 6 in 2037 will be 40 percent lower than its first year costs due the impacts of book depreciation.

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Q. CAN YOU PROVIDE EXAMPLES OF THE ACTUAL LONG TERM BENEFITS OF OWNED UNITS?

A. Yes. The cost of the natural gas proposals in this docket range from **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This can be considered the current market price for capacity. In comparison, some of the older plants we own have capacity prices as low as $0.15/kW-mo. This is a very large benefit for our customers. We expect that towards the end of its operating life, Black Dog 6 will have similar benefits. To provide context, Table 1 below summarizes the average cost of some of our older peaking facilities for comparison.

Table 1 – Approximate Cost of Xcel Energy Peaking Units (per kW/mo)

	Inverhills 1-6	Blue Lake 1-4	Key City 2-4	Granite City 1-4	Wheaton 1-6
In-Service Year	1972	1974	1970	1969	1973/74
Max Capacity	371 MW	194 MW	41 MW	64 MW	383 MW
Average Capacity Cost	**$0.63**	**$0.15**	**$0.13**	**$1.13**	**$0.79**

Q. EARLIER YOU MENTIONED THAT THE RESULTS OF THE DEPARTMENT'S ANALYSIS OF BLACK DOG 6 CHANGED BETWEEN THE FIRST ROUND AND SECOND ROUND. PLEASE ELABORATE.

A. Department Attachment SR-4a at pages 9 and 10 shows the First Round results for the Master Scenario 3, which identifies Black Dog 6 with an in-service date of 2017 (BD617) as being lower in cost than Calpine Mankato (CCC1). Later in his testimony, Dr. Rakow presents the results of the

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Department's Second Round analysis, which he states are based on the Master Scenario 3, which is at page 1 of Attachment SR-5A of his direct testimony. These Second Round results show Black Dog 6 being higher in cost than Calpine, and it is these results on which Dr. Rakow bases his resource selection recommendation. Table 2 below summarizes the different cost results for Black Dog 6 and Calpine in the two rounds of the Department's Strategist analysis.

Table 2 – Department Evaluation of Black Dog 6 and Calpine

	Master Scenario 3 PVSC Results ($000)	
	Round 1	**Round 2**
Black Dog 6 – 2017 (BD617)	$41,410,496	$41,326,470
Calpine Mankato (CCC1)	$41,419,740	$41,315,664
Black Dog +/-	($9,244)	$10,806

Dr. Rakow provides no explanation why the two simulations, purportedly based on the same input assumptions, would be so dramatically different. While we obtained the Strategist files from the Department, we were unable to replicate the Department's results, shown in Table 2 above.

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION REGARDING BLACK DOG 6.

A. We believe that the analysis conducted by the Company more accurately reflects the benefits of Black Dog 6 by simulating its costs over the full life-time of the project. Our analysis demonstrates that Black Dog 6 is the least cost resource among the proposals in this proceeding and should be selected under any resource need assessment. Compared to the Calpine proposal, our

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project creates benefits though a flexible in-service date, considerably lower annual fixed costs than Calpine from 2019 through 2036, and the long-term savings of a Company-owned project that cannot be offered by 20-year PPAs.

B. Department Analysis of Invenergy Cannon Falls

Q. YOU NOTED THAT THE COMPANY'S ANALYSIS SHOWED THAT CALPINE'S MANKATO EXPANSION AND INVENERGY'S CANNON FALLS PROJECT COSTS ARE CLOSELY MATCHED, WHILE THE DEPARTMENT'S ANALYSIS SHOWS A CONSIDERABLE GAP BETWEEN THE TWO PROJECTS. DO YOU HAVE AN EXPLANATION FOR THESE DIFFERENT RESULTS?

A. Yes, I believe so. Over the first few years of the Strategist simulations, the Department's and the Company's results are very similar, but starting in 2022 the Department's model starts changing the underlying expansion by moving the in-service dates of generic power plants to account for capacity differences among the projects proposed for selection. This is the result of the Department deciding not to 'lock' its expansion plan. In the Company's analysis, however, the expansion plan is locked so that it is the same across all scenarios, and capacity credits are used to address the capacity differences between the proposed projects.

Although our methodologies differ, our results are reasonably similar through 2036. However, at the end of 2036, the Department's model applies a $50 million "end effects" penalty to the Invenergy bid. As I mentioned in my discussion of the Department's modeling of Black Dog 6, the "end effects" adjustment attempts to represent an estimate of the long-term cost of a

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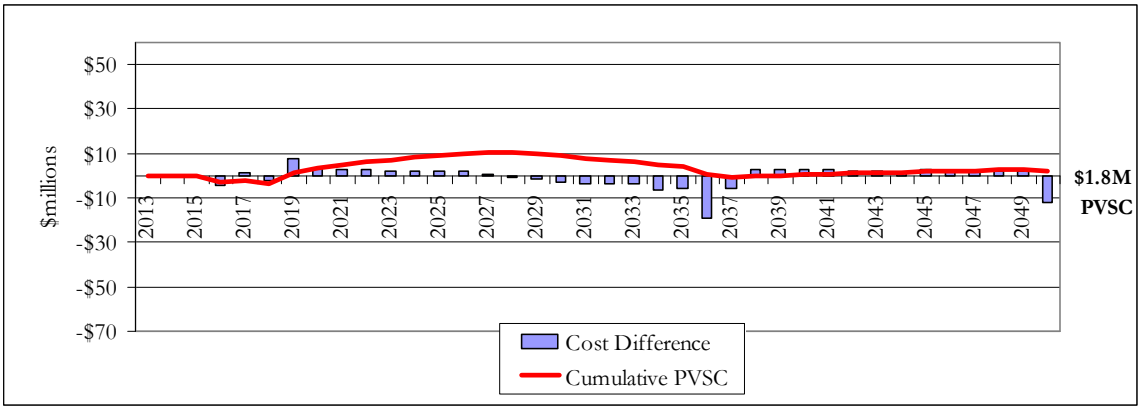
resource instead of modeling the long-term cost. The magnitude of this "end effects" adjustment is very non-intuitive. Figure 3 below shows the Company's modeled cost of Invenergy's Cannon Falls proposal while Figure 4 shows the Department's modeled cost of the proposal. Conceptually, there should not be so large a cost difference between the two since each retires in approximately the same time frame.

Figure 3 - Calpine Mankato vs Invenergy Cannon Falls
Xcel Energy Strategist Modeling



(Plan 1: Invenergy Cannon Falls + Black Dog 6 vs. Plan 2: Calpine Mankato + Black Dog 6)

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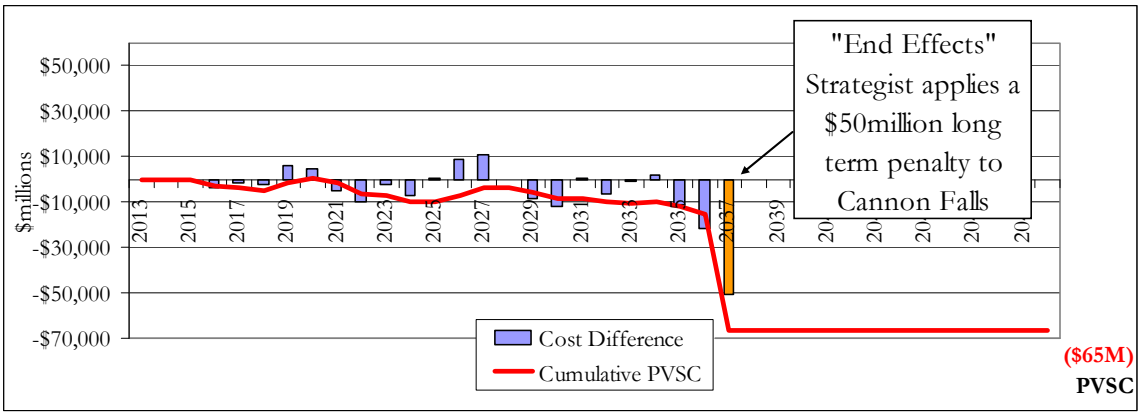
Figure 4 - Calpine Mankato vs Invenergy Cannon Falls
Department Strategist Modeling



(Master Scenario 1 - BD619 CCC1 vs. BD618 ICT1)

Eliminating the apparent disproportionate impact of the "end effects" adjustment in the Department's Strategist analysis of Invenergy Cannon Falls would be consistent with the Company's analysis showing that the least cost potential of Cannon Falls in combination with Black Dog 6 is comparable to the combination of Calpine with Black Dog 6. We therefore continue to recommend that both Calpine Mankato and Invenergy Cannon Falls be selected by the Commission to move forward to the PPA negotiation stage of these proceedings.

III. CALPINE LEVELIZED COST OF ENERGY ANALYSIS

Q. WHAT IS YOUR ASSESSMENT OF THE LEVELIZED COST OF ENERGY ANALYSIS PRESENTED BY CALPINE WITNESS MR. HIBBARD?

A. A LCOE analysis only looks at costs, and 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,

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however, we have a great variety of resources: peaking and intermediate resources, dispatchable and nondispatchable resources, and natural gas, solar, and short-term "paper" capacity resources. LCOE simply does not work in a situation like this. 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.

The limitations of the LCOE approach were recently addressed by the Energy Information Administration (EIA), which annually publishes levelized cost estimates for various generation resources for use in its Annual Energy Outlook. This year's EIA analysis included the following cautionary note regarding the use of levelized costs:[4]

> Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, 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. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments, which may then be divided by average annual output of the project to develop a figure that expresses the "levelized" avoided cost of the project. This levelized avoided cost may then be compared to the levelized cost of the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's levelized avoided cost to

[4] http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf, last viewed on October 17, 2013.

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> its levelized project cost may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than for simple levelized costs, because they require tools to simulate the operation of the power system with and without any project under consideration.

Q. DO YOU HAVE AN EXAMPLE OF HOW MR. HIBBARD'S LCOE IS PROBLEMATIC WHEN ASSESSING THE COST-EFFECTIVENESS OF DIFFERENT RESOURCES, AS THE EIA CAUTIONS?

A. Yes. For example, Mr. Hibbard contends that in order not to "punish" Calpine's CC unit for being a more expensive and cleaner generation resource (pages 29-30 of Hibbard Direct), $15 million of SCR technology costs should be added to each CT proposal so that their emissions are as low as Calpine's proposal (page 11 of Hibbard Direct). First, as Company witness Mr. Gregory Ford explains in his rebuttal, our proposed CT units will meet all current applicable environmental standards for emissions just as Calpine's proposed unit does. Adding millions of dollars in costs to our units so that they reach emission levels that they are not required to meet does nothing more than arbitrarily increase the capital costs of our CTs in relation to the more expensive capital costs of a CC unit.

Second, Mr. Hibbard's SCR adjustment does not address the real issue that he has identified: what is the value of any avoided emissions that would be realized if Calpine's CC project is added to our system rather than our proposed CTs? The Strategist simulations performed by the Company and the Department answer that question. The Strategist modeling presented in this proceeding has determined the impact each project has on our entire system's emissions over the life of the project. The model then assigns the

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Commission's annually updated environmental externality values to establish the cost incurred or avoided as a result of the project being added to our system. Strategist thus directly calculates the value of Calpine's avoided emissions, while Calpine's LCOE analysis assigns an additional, unwarranted capital cost to our CTs because its cost-only approach cannot properly value the avoided emission costs of the Calpine project.

IV. BENEFITS OF FIRM VS. INTERRUPTIBLE NATURAL GAS SUPPLY

Q. PLEASE SUMMARIZE THE REQUEST OF DEPARTMENT WITNESS MR. SHAH REGARDING NATURAL GAS SUPPLY.

A. In his conclusion and recommendation, Mr. Shah requests that the Company address in rebuttal:

1. The use of current interstate pipelines in relation to the proposals in this proceeding;
2. The benefits and costs of firm vs interruptible natural gas; and
3. The operational impact of firm vs interruptible natural gas supply and its impact on the reliability impact to our customers.

Q. HOW WILL THE COMPANY USE ITS CURRENT INTERSTATE PIPELINE CONTRACTS IN RELATION TO THE PROPOSALS IN THIS PROCEEDING?

A. We reviewed a variety of options to achieve an appropriate balance between reliability and cost. The decision to supply a power plant with firm or interruptible transportation service should be made on a case-by-case basis applying the unique circumstances of that plant and the upstream interstate transporter's operational and market conditions. As noted previously, the Company expects to use firm transport contracts to serve the Black Dog and

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Mankato plants if our Black Dog 6 and the Calpine's Mankato Expansion projects are selected by the Commission. As detailed in the Company's supplemental response to Department Information Request No. 42, included as Schedule 1 to my rebuttal testimony, we expect to use a combination of existing and new firm contracts.

The Mankato plant would be served by a new, firm transportation contract. The Black Dog plant would be served using existing firm contracts with a small amount of new, firm additional transport capacity from Northern Natural Gas (NNG). In both cases, the Company modeled the transportation supply options as reported in DOC-042. The Company plans to use firm transport because of the need for a high level of certainty of service and a pressure guarantee from NNG to ensure plant operations. We also plan to use firm gas transport because the plants are located within an area of NNG's system that is generally fully subscribed. An added benefit is that the firm transport service for both the Mankato and Black Dog locations may be acquired at a prearranged discounted rate from NNG, resulting in comparatively lower costs for the service.

Q. WHAT ARE SOME OF THE COSTS AND BENEFITS OF FIRM VERSUS INTERUPTABLE NATURAL GAS SUPPLY?

A. Firm service is certain; it will provide reliable fuel supply to a plant every day except for the rare occurrence of a force majeure or scheduled maintenance event. Pipeline companies do everything in their power to minimize the impact of maintenance on firm customers. However, during these infrequent events, firm customers are reimbursed for the lack of service. The downside

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of firm service is the cost. Firm service contracts can be expensive and the monthly charges are paid whether the delivery service is used or not.

Interruptible service provides less certainty but can be less expensive. On days when the demand for natural gas supply is high, interruptible customers are not likely to receive service to their locations. However interruptible customers are only charged on the quantities delivered to their site. For a peaking resource that only operates a few times a year, usually to meet peak customer demand in the summer, the use of an interruptible natural gas supply can deliver significant costs savings without a significant impact on reliability, so long as the unit can operate on back-up fuel oil or there are other system units available to meet the demand.

Q. WHAT ARE SOME OF THE COSTS AND BENEFITS OF FIRM VERSUS INTERRUPTIBLE NATURAL GAS SUPPLY WITH RESPECT TO INVENERGY'S CANNON FALLS PROJECT?

A. To evaluate the costs and benefits of interruptible natural gas supply to the Cannon Falls Expansion, we re-ran the Strategist simulation for Plan 1, which includes Invenergy's Cannon Falls proposal plus the Company's Black Dog 6 project.

The modeling made natural gas unavailable to the Cannon Falls project from November through February. This reflects an assumption that natural gas is completely unavailable at the site and there is no additional back-up fuel oil to serve the new unit. The result of the simulation was that even in the unlikely event Cannon Falls cannot operate at all from November through February,

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the project's cost effectiveness does not change. Table 3 shows that the PVSC of Plan 1 increases by less than $1 million.

Table 3 – Strategist PVSC Results
Invenergy Cannon Falls Unavailable November – February

	Selected Bids	2013-2050 PVSC $millions Wishart Direct Testimony	2013-2050 PVSC $millions Cannon Falls Unavailable Nov - Feb
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	$45,366	$45,367
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	$45,368	$45,368
	Net Difference	**$1.8**	**$1.5**

The results of this simulation are not surprising. Our customers' demand is significantly lower in the winter so our peaking resources very infrequently operate during the winter season. Figure 5 shows monthly generation at the existing Cannon Falls site since its commercial operation date of 2008.

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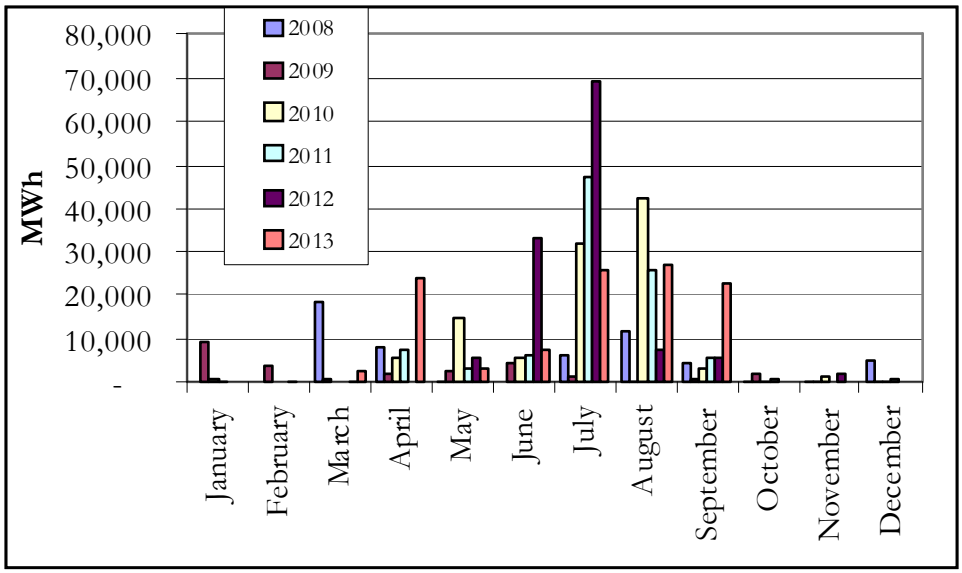
Figure 5 – Cannon Falls Monthly Generation



Q. WHAT WOULD BE THE COST OF THE CANNON FALLS PROJECT IF FIRM NATUAL GAS SUPPLY WERE PROCURED FOR THE PROJECT?

A. Our supplemental response to Department Information Request No. 42, which is Schedule 1 of my rebuttal testimony, provides our cost estimates for firm and interruptible service for all the natural gas projects proposed in this docket. To test the cost impacts of firm natural gas supply at Cannon Falls, we again re-ran the Plan 1 Strategist simulations, but this time with year-round firm natural gas supply. Table 4 shows that the total PVSC for Plan 1 increases by about $30 million with the addition of firm gas at Cannon Falls, making it uncompetitive with the Calpine proposal.

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Table 4
PVSC Impact of Firm Gas at Cannon Falls

	Selected Bids	2013-2050 PVSC $millions Wishart Direct Testimony	Cannon Falls Unavailable Nov - Feb
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	$45,366	$45,397
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	$45,368	$45,368
	Net Difference	**$1.8**	**-$29.3**

Q. WHAT ARE THE EXPECTED OPERATIONAL AND RELIABILITY IMPACTS OF INTERRUPTABLE SERVICE AT CANNON FALLS?

A. The simulations of Plan 1 with Cannon Falls unavailable from November though February showed that generation from other peaking resources with firm gas supply would increase from 900 GWh to 903 GWh. In the context of our total natural gas generation portfolio, this is a very small change.

To gauge the impact on reliability, I utilized our winter loads and resources (L&R) table. Just like our summer L&R that I presented in my direct testimony, the winter L&R shows how much excess generation capacity we will have over and above our customers' forecasted peak winter demand. Table 5 below shows that we currently have a very large amount of excess capacity to meet our customer's peak demand in the winter. In 2019 our total winter reserve margin is forecasted to be 22 percent, while MISO's minimum required reserve margin is 3.8 percent.

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Table 5 – Xcel Energy Winter Loads and Resources

	2017	2018	2019
Peak	6,606	6,671	6,733
RM%	3.8%	3.8%	3.8%
Total Obligation	**6,857**	**6,924**	**6,988**
Resources			
Coal	2,367	2,367	2,367
Nuclear	1,708	1,610	1,610
Gas	3,547	3,533	3,533
Wind, Hydro, Bio	573	521	515
Solar	49	66	83
Load Management	379	379	379
Total Resources	**8,624**	**8,477**	**8,487**
Long (Short)	**1,767**	**1,553**	**1,499**
Reserve %	27%	23%	22%

V. OTHER STRATEGIST ANALYSIS ISSUES

Q. INVENERGY WITNESS MR. DANIEL EWAN IDENTIFIES A NUMBER OF ISSUES RELATED TO STRATEGIST AT PAGES 15-16 OF HIS DIRECT TESTIMONY. WHAT IS YOUR RESPONSE?

A. Mr. Ewan objects to Strategist's evaluation of a resource's costs over its expected life, that it compares resource options on a PVSC basis which results in the timing of the resources being critical, and that it is not clear how Strategist can address the costs and benefits of including or not including dual fuel capabilities in the proposals like Invenergy's. Addressing this last issue first, we did model the costs and benefits of using an interruptible gas supply for Invenergy's Cannon Falls project, which I discuss in the preceding section of my rebuttal testimony. Assuming the highly unlikely scenario of the gas supply to Cannon Falls being interrupted for the period November through

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February and its back-up fuel oil being unavailable, Strategist showed the project's cost effectiveness would be essentially unchanged.

Mr. Ewan's concerns with respect to evaluating a project's costs over its life and the use of net present value in the evaluation of proposals do not seem justified to me. An evaluation showing that the costs of a proposed Company-owned project over its lifetime are less than the costs of a proposed PPA that must be extended through the addition of plant, or another PPA to cover the same time period, does not "punish" the PPA proposal. It simply shows that the owned project is more cost-effective in the long run. With respect to the timing of the various proposals submitted for the Commission's consideration, this is a critical issue because we do not want to impose the costs of additional resources on our customers before they are needed.

Q. DID THE COMPANY'S STRATEGIST ANALYSIS ADDRESS THE MODELING ISSUES THAT GERONIMO WITNESS MS. ELIZABETH ENGELKING IDENTIFIED AT PAGE 6 OF HER DIRECT TESTIMONY?

A. Our initial Strategist analysis did not address Ms. Engelking's request that Geronimo's proposal be modeled to apply towards meeting Minnesota's new Solar Energy Standards mandate. I explained at page 36 of my direct testimony that we did not do so because there are no other solar proposals in this docket, so the Company cannot assess the reasonableness of Geronimo's proposed pricing relative to other solar projects that could also help the Company meet its solar energy goals. However, the pricing of the generic solar used in our Strategist modeling to comply with the solar energy standard was priced below the Geronimo proposal. If the generic solar had been

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removed from the model, Geronimo's proposal would have contributed to meeting the solar energy standard, but would have resulted in a larger PVSC impact for Geronimo because the model would be replacing cheaper solar with more expensive solar.

Ms. Engelking also stated in her direct estimony that Geronimo would be examining how our modeling incorporated the environmental costs of the various alternatives and whether it would include the savings associated with Geronimo's line loss reductions. As I discussed earlier, our Strategist analysis evaluated the environmental costs of the various proposals, and while we did not include line loss savings in our Strategist analysis, we did calculate what those savings would be based on Geronimo's estimate of its energy and capacity benefits. As explained at page 36 of my direct testimony, the savings were not enough to make Geronimo's project cost effective.

Q. DID THE COMPANY'S STRATEGIST ANALYSIS EVALUATE THE BENEFIT OF GREAT RIVER ENERGY'S (GRE) PROPOSAL OF TWO DIFFERENT CAPACITY LEVELS TO ALLOW THE COMPANY TO DEFER ADDING NEW CAPACITY RESOURCES WITHIN THE 2017 TO 2019 TIME PERIOD, AS NOTED BY GRE WITNESS MR. STAN SELANDER AT PAGE 3 OF HIS DIRECT TESTIMONY?

A. Yes. I addressed this issue at page 33 of my direct testimony, explaining that our Strategist analysis showed the total cost of the GRE contract is larger than the savings derived from delaying new construction during the 2018 to 2019 time period. Specifically, the cost of the GRE contract is greater than the savings realized from shifting the in-service year of Black Dog 6, which is the least cost proposal in this proceeding, from 2018 to 2019.

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Q. CAN YOU SUMMARIZE THE COMPANY'S RESOURCE SELECTION RECOMMENDATIONS FOR THE COMMISSION?

A. We recommend that Black Dog 6 in combination with Calpine Mankato or Invenergy Cannon Falls be selected to meet the Company's resource need, and that both the Mankato and Cannon Falls proposals should go to the PPA negotiation stage to establish which one is more beneficial to our customers. We also recommend that under any resource need assessment, Black Dog 6 should be selected because it is the least cost resource option among the proposals in this proceeding. We also believe that given the current uncertainty over our resource need, the Commission should direct the Company to provide updates on its resource need assessments in the fall of 2014 and 2015. Consistent with this, we recommend that the Commission direct that the PPA negotiations address the viability of delay and/or cancellation options for the Calpine and Invenergy projects.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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

Xcel Energy			
Docket No.:	E002/CN-12-1240		
Response To:	Department of Commerce	Information Request No.	042
Requestor:	Sachin Shah & Steve Rakow		
Date Received:	June 28, 2013	**SUPPLEMENT**	

Question:

Subject: Information provided by Xcel Energy -- Northern States Power Company, A Minnesota Corporation (Xcel Energy, NSP or Company) in its *Petition to the Minnesota Public Utilities Commission Seeking Approval For A Competitive Resource Acquisition Proposal and For A Certificate of Need:*

Subject: Information provided by Invenergy Thermal Development LLC in the bids: *Cannon Falls Peaking Expansion: Goodhue County, Minnesota* and *Hampton Energy Center: Dakota County, Minnesota* (dated April 15, 2013 and May 9, 2013).

Subject: Information provided by Calpine Corporation and its affiliate Mankato Energy Center, LLC in the bid: *Calpine's Mankato Energy Center Expansion Proposal* (dated April 15, 2013 and May 8, 2013).

In Docket No. E002/CN-12-1240, the Company in its Certificate of Need (CN) filing, indicates the use of natural gas prices by existing generating units in its strategist base case.

On page 4 of the *Cannon Falls Peaking Expansion Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Cannon Falls Peaking Expansion and sell the capacity and energy to NSP with terms and conditions substantially similar to the existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Hampton Energy Center Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Hampton Energy Center with a design and configuration that is very similar to Invenergy's existing Cannon Falls Facility this is located in Goodhue County. Furthermore, Invenergy proposes to sell the capacity and energy to NSP with terms and conditions substantially similar to the

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existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Consistent with the Commission's directive that parties be held to the cost information provided in their bids,4 the specific pricing, terms and conditions of Calpine's Proposal represent a fixed-price indicative offer5 with long-term performance guaranties wherein Calpine will assume the construction, delivery date and long term operating risk of the Mankato Expansion.

---

5. Subject to any material changes in project timing and/or scope required by the Commission or identified during final tolling agreement negotiations. Proposed pricing assumes a 2017 commercial operation date.

In Appendix A, on page 3 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Calpine intends to follow the PPA structure used in the Purchased Power Agreement between MEC and Northern States Power Company executed on March 11, 2004 ("MEC PPA") for expediency, cost effectiveness and negotiating efficiency.

1. It is the Department's understanding, based on the above references, that Invenergy's *Bids* and Calpine's *Proposal* assume that Xcel would pay all of the fuel costs of purchasing and delivering natural gas to Cannon Falls facility's and Mankato Energy Center's points of delivery, respectively. Is this understanding correct?

2. If the answer to part (1) is in the affirmative, then please fully explain in detail if the natural gas fuel prices contained in Xcel's strategist base case for the existing Cannon Falls facility and the Mankato Energy Center would be appropriate to use in comparing the *Bids* and *Proposal* of Invenergy and Calpine, respectively, given the above references.

3. Please fully explain the type of natural gas being provided to the existing facilities at Cannon Falls and Mankato Energy Center (i.e., Firm, Interruptible, or a combination of Firm and Interruptible).

4. Please fully explain and identify the associated natural gas commodity costs in parts (2) and (3) above.

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5. Please fully explain and identify in detail the amount and type of interstate pipeline transportation and fixed reservation (demand) costs that are included in parts (2) and (3) above.

6. Please fully explain and identify the amount, if any, of local pipeline distribution service costs that are included in parts (2) and (3) above.

Where applicable for any and all parts above, please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, please provide your response in both a Microsoft Word and Adobe PDF format.

In addition, whenever acronyms are used in the data given in your response above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If this information has already been provided in written testimony, filing, or in response to an earlier Department of Commerce (DOC) information request, please identify the specific testimony, and/or filing cite(s) or DOC information request number(s).

Response:

1. Yes, the bidders are proposing that Xcel be responsible for the costs of fuel purchasing and delivery for these projects and we are currently developing estimates of those costs. However, the bidder is responsible for installing and maintaining the incremental back-up fuel oil facilities.

2. No, it would not be appropriate to use the costs currently contained in Xcel's strategist base case to evaluate the *Bids* and *Proposal* of Invenergy and Calpine. The cost contained in the Strategist base case are natural gas commodity costs, plus the variable transport costs to deliver gas to the existing facilities based on the existing transport agreements. Although the natural gas commodity costs are likely to be representative of the supply cost, it is likely that the variable transport charges will be different. In addition, the Strategist base case does not include the annual fixed charges associated with fuel delivery at those sites.

   Both variable transport cost and annual fixed charges for fuel supply will be dependent on whether or not firm or interruptible fuel supply will be used at

the facility. We are currently developing these estimates and propose to provide these costs in a supplemental response in approximately three weeks (Aug 9th). If the estimates are completed sooner than expected we will supply them as soon as they are available.

3. NSP uses a combination of firm and interruptible upstream transportation service to deliver firm gas supplies to Cannon Falls and Mankato, in addition to the back-up fuel oil. Gas supply is purchased at Ventura, Iowa on Northern Natural Gas (NNG) and then transported by NNG to the plants. Mankato is directly connected to NNG via a plant line. Cannon Falls is served from NNG via Greater Minnesota Gas (an intrastate pipeline).

4. Please see Attachment A for the associated natural gas commodity costs.

5. Attachment A also includes the volumetric transportation charges currently being used in Strategist for the two existing plants. The Strategist base case does not include the specific annual fixed charges (reservation / demand charge) associated with fuel delivery at those sites.

Please note that portions of Attachment A are marked "Non-Public" as it contains information the Company considers to be trade secret as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as trade secret.

SUPPLEMENT:

5. Please see Attachment B for details regarding the estimated upstream pipeline transportation costs to provide fuel to the Mankato, Hampton, and Cannon Falls plants. All three plants would be sited in an area where the interstate natural gas pipeline is essentially fully subscribed, requiring construction of additional pipeline facilities to make the plants' fuel supply highly reliable. Mankato would be served by transportation service from Northern Natural Gas. Since Mankato is proposed as a combined cycle, intermediate load facility, it will require firm gas transportation on a year-round basis.

Hampton and Cannon Falls would be served by transportation from Northern Natural Gas and Greater Minnesota Transmission. Attachment B shows estimated costs to provide firm year-round transportation service to Hampton and Cannon Falls to make the plants' fuel supply highly reliable. In the alternative, if the

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Commission elects less reliable service for these two plants, Attachment B separately shows costs for interruptible transportation service to the plants. Using interruptible service, the Commission should expect the plants to have regular fuel supply in the summer months (April through October) except during periods of pipeline maintenance and emergency operations. However, in the winter months (November through March), the Commission should expect the plants to be unable to operate on most cold winter days due to interruption of gas transportation services on Northern Natural Gas. The interruptible service option is cheaper for low-load factor peaker plants; however, the plants will not be available on many winter days.

6. There are no local distribution charges for Mankato in NSP's Strategist base case; however, Cannon Falls and Hampton rely on Greater Minnesota Transmission as described in (3) above. The Greater Minnesota Transmission system, which is considered an intrastate facility, would also be used to serve the Hampton and Cannon Falls plants. Those costs are detailed in Attachment B to Response 5 above. There are no other distribution charges anticipated for these plants.

Preparer:	Curt Dallinger/Steve Wishart	
Title:	Director/Director	
Department:	Gas Planning/Resource Planning	
Telephone:	303-571-2784/612-330-6128	
Date:	July 23, 2013	**SUPPLEMENT: August 15, 2013**

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Strategist natural gas fuel prices vary monthly. Strategist fuel prices are input as an annual average which is then adjusted by a factor for monthly seasonality. The monthly Cannon Falls cost (Column H) is annually averaged (Column M). To calculate the seasonality factor, the monthly cost (Column H) is divided by the corresponding annual average (Column M) for the years 2012 through 2020. The seasonality for years 2021 through 2050 in the analysis below uses the 2021 seasonality.

	Cannon Falls Yearly Avg ($/mmBtu)
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Cannon Falls Total Gas Commodity Cost = Ventura Hub Price + (Fuel Percentage * Ventura Hub Price) + Interruptible Rate (Winter Only) + Firm Rate (Summer Only) + Intrastate Pipeline Commodity Rate

Cannon Falls is subject to an Intrastate Pipeline Commodity Rate for intermediate pipeline connecting Northern Natural Gas to Plant.

Cannon Falls

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Nov-49							
Dec-49							
Jan-50							
Feb-50							
Mar-50							

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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
Apr-50							
May-50							
Jun-50							
Jul-50							
Aug-50							
Sep-50							
Oct-50							
Nov-50							
Dec-50							

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Strategist natural gas fuel prices vary monthly. Strategist fuel prices are input as an annual average which is then adjusted by a factor for monthly seasonality. Mankato seasonality is assumed to follow the seasonality of the forecast of Ventura Hub Price. The monthly Ventura Hub Price (Column C) is annually averaged (Column L). To calculate the seasonality factor, the monthly cost (Column C) is divided by the corresponding annual average (Column L) for the years 2012 through 2020. The seasonality for years 2021 through 2050 in the analysis below uses the 2021 seasonality.

	Mankato Yearly Avg ($/mmBtu)	Ventura Yearly Avg ($/mmBtu)
	[TRADE SECRET DATA BEGINS….	
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
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2042		
2043		
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2045		
2046		
2047		
2048		
2049		
2050		
	ADE SECRET DATA ENDS]	

	Avg
1	Jan
2	Feb
3	Mar
4	Apr
5	May
6	Jun
7	Jul
8	Aug
9	Sep
10	Oct
11	Nov
12	Dec

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2050
[TRADE SECRET DATA BEGINS….									
… TRADE SECRET DATA ENDS]									

Mankato Total Gas Commodity Cost = Ventura Hub Price + (Fuel Percentage * Ventura Hub Price) + Firm Rate

Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
	[TRADE SECRET DATA BEGINS….				
Jan-12					
Feb-12					
Mar-12					
Apr-12					
May-12					
Jun-12					
Jul-12					
Aug-12					
Sep-12					
Oct-12					
Nov-12					
Dec-12					
Jan-13					
Feb-13					
Mar-13					
Apr-13					
May-13					
Jun-13					
Jul-13					
Aug-13					
Sep-13					
Oct-13					
Nov-13					
Dec-13					
Jan-14					

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Northern States Power Company
Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Feb-14					
Mar-14					
Apr-14					
May-14					
Jun-14					
Jul-14					
Aug-14					
Sep-14					
Oct-14					
Nov-14					
Dec-14					
Jan-15					
Feb-15					
Mar-15					
Apr-15					
May-15					
Jun-15					
Jul-15					
Aug-15					
Sep-15					
Oct-15					
Nov-15					
Dec-15					
Jan-16					
Feb-16					
Mar-16					
Apr-16					
May-16					
Jun-16					
Jul-16					
Aug-16					
Sep-16					
Oct-16					
Nov-16					
Dec-16					
Jan-17					
Feb-17					
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Apr-17					
May-17					
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Dec-18					
Jan-19					
Feb-19					
Mar-19					
Apr-19					
May-19					
Jun-19					
Jul-19					
Aug-19					
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Oct-19					
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Apr-20					
May-20					
Jun-20					
Jul-20					
Aug-20					
Sep-20					
Oct-20					
Nov-20					
Dec-20					
Jan-21					
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Jan-22					
Feb-22					
Mar-22					
Apr-22					
May-22					
Jun-22					
Jul-22					
Aug-22					
Sep-22					
Oct-22					
Nov-22					
Dec-22					
Jan-23					
Feb-23					
Mar-23					
Apr-23					
May-23					
Jun-23					
Jul-23					
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Jan-26					
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Nov-27					
Dec-27					
Jan-28					
Feb-28					
Mar-28					
Apr-28					
May-28					
Jun-28					
Jul-28					
Aug-28					
Sep-28					
Oct-28					
Nov-28					
Dec-28					
Jan-29					
Feb-29					
Mar-29					
Apr-29					
May-29					
Jun-29					
Jul-29					
Aug-29					
Sep-29					
Oct-29					
Nov-29					

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Dec-29					
Jan-30					
Feb-30					
Mar-30					
Apr-30					
May-30					
Jun-30					
Jul-30					
Aug-30					
Sep-30					
Oct-30					
Nov-30					
Dec-30					
Jan-31					
Feb-31					
Mar-31					
Apr-31					
May-31					
Jun-31					
Jul-31					
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Apr-36					
May-36					
Jun-36					
Jul-36					
Aug-36					
Sep-36					
Oct-36					
Nov-36					
Dec-36					
Jan-37					
Feb-37					
Mar-37					
Apr-37					
May-37					
Jun-37					
Jul-37					
Aug-37					
Sep-37					
Oct-37					

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Nov-37					
Dec-37					
Jan-38					
Feb-38					
Mar-38					
Apr-38					
May-38					
Jun-38					
Jul-38					
Aug-38					
Sep-38					
Oct-38					
Nov-38					
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Sep-44					
Oct-44					
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Sep-45					

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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Oct-45					
Nov-45					
Dec-45					
Jan-46					
Feb-46					
Mar-46					
Apr-46					
May-46					
Jun-46					
Jul-46					
Aug-46					
Sep-46					
Oct-46					
Nov-46					
Dec-46					
Jan-47					
Feb-47					
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Jun-47					
Jul-47					
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Oct-47					
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Jan-48					
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Dec-50					

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Northern States Power Company

Gas Supply Costs for MN IPP Bids

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Firm Option

Plant	Connecting Pipeline	Capacity (MW)	Heat Rate (MMBtu/MWh)	Demand Volume (Dth/hour)	Demand Volume (Dth/day)	Minimum Delivery Pressure (psig)	Market Price	Annual Demand ($/year)	Total Variable Costs ($/Dth) (1)	Fuel 1/	Comments
								TRADE SECRET BEGINS:			[TRADE SECRET BEGINS:
Calpine Mankato	Firm NNG	345	7.25	2,501	40,020	550	Ventura		$0.0377	.27 % 1.37%	
Invenergy Hampton	Firm NNG	357	10.9	3,891	62,261	550	Ventura		$0.0377	.27 & 1.37%	
	GMT								$0.0100		
	Total								$0.0477		
Invenergy Cannon Falls	Firm NNG	179	10.9	1,951	31,218	550	Ventura		$0.0377	.27 & 1.37%	
	GMT								$0.0100		
	Total								$0.0477		
								TRADE SECRET ENDS]			TRADE SECRET ENDS]

Interruptible Option

								[TRADE SECRET BEGINS:			
Invenergy Hampton	Int NNG	357	10.9	3,891	62,261	550	Ventura		0.2675 & 0.6275	.27 & 1.37%	Plant subject to interruption (2)
	GMT								$0.0100		
	Total								$0.0100		
Invenergy Cannon Falls	Int NNG	179	10.9	1,951	31,218	550	Ventura		0.2675 & 0.6275	.27 & 1.37%	Plant subject to interruption (2)
	GMT								$0.0100		
	Total								$0.0100		
								TRADE SECRET ENDS]			

(1) Rates are lower during the summer months of April - October and higher in the winter months of November - March.

(2) Using interruptible services only, plant may be without fuel occasionally in the summer due to pipeline maintenance and emergency operations. In the winter, service will be interrupted on many days due to firm customer demand.

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company Advance Determination of Prudence – NG Generator Application	Case No. PU-13-194 OAH File No. 20130458
Northern States Power Company Red River Valley NG Unites 1 & 2 – Hankinson, ND Public Convenience & Necessity	Case No. PU-13-195 OAH File No. 20130459

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

James Alders, being first duly sworn on oath, deposes and says that he is Strategy Consultant for Rates and Regulatory Affairs for Northern States Power Company, d/b/a Xcel Energy, a Minnesota corporation, in the above captioned matters, that the supplemental testimony and schedules submitted in the above captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

James Alders

Subscribed and sworn to before me this 13th day of November, 2013.

James G. Erickson
Notary Public
Minnesota
My Commission Expires January 31, 2014

Notary Public
My Commission Expires: 1-31-14

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