Xcel Energy®

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September 27, 2013

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

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

Dear Judge Lipman:

Northern States Power Company, doing business as Xcel Energy, submits in the above-referenced matter the Direct Testimony and Schedules of the following witnesses:

- *James R. Alders*: Proposal Overview, Cost Recovery, and Presentation of Witnesses
- *Gregory L. Ford*: Proposal Description
- *Steven W. Wishart*: Resource Need, Competitive Resource Analysis, and Company Recommendation
- *Jeffrey S. Savage*: Capital Lease Issues

This testimony has been filed with the e-Docket system and served on the attached service list. We are also serving the testimony on your office by U.S. Mail.

Certain information in the Direct Testimony and Schedules 2 and 3 of Mr. Wishart contains trade secret and/or highly sensitive trade secret data pursuant to Minnesota

Statutes §13.37, subd. 1(b). This filing includes the public version of Mr. Wishart's testimony and schedules. The trade secret version of his testimony and schedules is being separately e-filed in Docket No. E002/CN-12-1240, and the highly sensitive trade secret version of Mr. Wishart's Schedules 2 and 3 are being separately e-filed in Docket No. E002/CN-13-606. The trade secret and highly trade secret versions will be mailed to those parties that are eligible to review the nonpublic information they contain.

Please contact me at james.r.alders@xcelenergy.com or (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Direct Testimony and Schedules
James R. Alders

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition of Northern States Power Company d/b/a
Xcel Energy for Approval of Competitive Resource Acquisition Proposal and
Certificate of Need

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

Proposal Overview, Cost Recovery, and
Presentation of Witnesses Testimony

September 27, 2013

Table of Contents

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 DESCRIBE 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 provided as Exhibit___(JRA-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose is to provide an overview of the Company's resource proposal and the Strategist analysis the Company conducted of all the resource proposals that are the subject of this proceeding. I also introduce the witnesses we are sponsoring who provide testimony in support of our proposal.

Q. HOW IS YOUR TESTIMONY ORGANIZED.

A. I first review our resource proposal, which includes a cost recovery mechanism much like the one the Commission approved for Xcel Energy's

Metropolitan Emissions Reduction Project (MERP) in Docket No. E002/M-02-633, which maximizes savings for ratepayers. Next, I discuss the Company's recommendation of which resources should be selected to meet the range of the Company's potential need in the 2017-2019 time period. I conclude with a presentation of the witnesses whose testimony we are sponsoring in support of our proposal.

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

A. The portions of our proposal filing that I am sponsoring are Chapter 1- Summary; Chapter 2- General Information and Regulatory Permits; Section 4.5 of Chapter 4- Project Cost Recovery; Appendix E (MPUC Resource Plan and Competitive Acquisition Orders); and Appendix F (Completeness Checklist).

II. COMPANY PROPOSAL

Q. WHAT IS THE COMPANY'S RESOURCE PROPOSAL?

A. As described in our April 15th proposal filing, we propose to add to our system three 215 MW (208 UCAP rating) natural gas-fired, simple-cycle, combustion turbine (CT) generators. The first CT - Black Dog Unit 6 – is proposed to be constructed in 2017, 2018, or 2019 at the Company's existing Black Dog plant in Burnsville, Minnesota. Black Dog Unit 6 will utilize existing infrastructure at our plant and feed power directly to the existing 115 kV transmission system that directly serves distribution substations throughout our largest load center – the Minneapolis-St. Paul metropolitan area. Utilizing the existing Black Dog site with its existing natural gas and transmission infrastructure significantly reduces the cost of this CT.

We propose the second CT to be placed in service in 2018 or 2019 at Hankinson, North Dakota – becoming Red River Valley Unit 1 – which would take advantage of existing nearby transmission and natural gas infrastructure. The third CT would also be placed in Hankinson, and we proposed it would be added in 2019 to the existing plant site as Red River Valley Unit 2.

The Hankinson site identified for the Red River Units appropriately balances low cost and strategic location. This site is about 70 miles from our Fargo load center, near the juncture of the 230 kV transmission system and a large natural gas interstate pipeline in the area, thereby providing strong economic justification. At the same time, this site places generation closer to our regional load centers in North Dakota than our existing power plants. Company Witness Gregory Ford provides further discussion on our proposed generating units and implementation schedule.

Q. PLEASE DESCRIBE THE PRINCIPAL COMPONENTS OF THE COST ESTIMATES THE COMPANY PROVIDED IN ITS PROPOSAL.

A. The Company provided the estimated capital cost for the construction of (i) the generators and any associated plant facilities; (ii) transmission facilities required to interconnect the new generation to the transmission grid; and (iii) fuel supply facilities required to bring gas to the new generation.

Q. HOW DID THE COMPANY DEVELOP ITS COST ESTIMATES?

A. We worked closely with vendors to make our estimates as accurate as possible, including contingency estimates to address certain cost uncertainties in our proposal.

Q. PLEASE IDENTIFY THE CONTINGENCY ESTIMATES ASSOCIATED WITH COST UNCERTAINTIES IN THE COMPANY'S PROPOSAL.

A. The Black Dog Unit 6 cost estimate is relatively straightforward. There are no anticipated transmission interconnection costs other than those included in our estimate. Pipeline infrastructure, if any, will be the responsibility of the fuel supplier. We do not propose any mechanism to adjust the capital cost estimates presented in our proposal.

The specific site for the Red River Valley Plant has not been identified yet, and the specific routes for the transmission and gas supply infrastructure have not been determined and permitted. We also have not worked through the Midcontinent Independent System Operator (MISO) generator interconnection process to confirm what system upgrades may be necessary. Our estimates for the capital costs for transmission and gas supply to the Red River Valley plant are based on assumptions about location and routes. As a result, the estimates are indicative in nature. They are also conservative. It is very possible that actual project development estimates for transmission and gas infrastructure will be lower once a site and routes are established.

Q. HOW DOES THE COMPANY PROPOSE THESE CONTINGENCY ESTIMATES BE HANDLED FOR COST RECOVERY PURPOSES?

A. Rather than use indicative estimates for cost recovery, the Company proposes to update the transmission and pipeline components of the Red River Valley estimate after the site and routes have been permitted, and associated interconnection agreements have been executed. We would submit those updated estimates for Commission review to establish the baseline against which to measure actual costs.

Q. PLEASE DESCRIBE THE MERP-STYLE RECOVERY MECHANISM THE COMPANY IS PROPOSING.

A. We propose that a rate rider be established for each unit in our proposal that is selected by the Commission. As with MERP, we propose each unit's return on equity be adjusted up or down when placed into service to reflect any difference between its baseline estimated capital cost and the actual capital cost of the unit. The rider, with adjusted ROE, would be used during the first five years of rate recovery. After that the last authorized ROE would be used until the projects are included in base rates.

Q. WHAT WOULD THE ROE ADJUSTMENTS BE IF A UNIT IS ABOVE OR BELOW ITS ESTIMATED COSTS?

A. The proposed ROE adjustments would be applied to the Company's last authorized ROE at the time the unit is placed in service, as shown in the table below:

Proposed ROE Adjustments Based on Unit Costs

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

Q. HOW DOES THIS RECOVERY MECHANISM MAXIMIZE SAVINGS FOR

RATEPAYERS?

A. We appreciate the emphasis placed on establishing cost estimates that are as accurate as possible and employing a mechanism that imposes discipline to meet those estimates. For a regulated utility subject to ratemaking, we believe the incentive mechanism we propose effectively meets those objectives. Unlike a price cap, which simply disallows costs above a pre-determined amount, the Company's proposed recovery mechanism incentivizes the Company to deliver its proposal at the lowest possible cost below its estimate. The greater the cost reduction, the greater the savings to ratepayers. At the same time, the mechanism includes an ROE penalty should the actual costs exceed the estimated costs. The carrot and stick structure of the mechanism provides a balanced approach to protect ratepayer value.

III. COMPANY ANALYSIS OF PROPOSALS

Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

A. We used our Strategist resource planning program to evaluate the relative costs of all the proposals submitted in meeting the Company's resource need. Through dynamic optimization, Strategist identified the lowest-cost combination of proposals based on their present value of societal costs (PVSC). We also conducted sensitivity tests on the combinations of proposals to see if their rank order would change under different input assumptions. Company Witness Steven Wishart presents the Company's Strategist modeling in detail.

Q. WHAT IS THE COMPANY'S RESOURCE NEED?

A. In its March 5, 2013 order in the Company's 2010 resource plan proceeding, Docket No. E002/RP-10-825, the Commission found it may be appropriate to add approximately 150 MW in 2017 growing to up to 500 MW in 2019 for our five state, integrated NSP System. Since March, the Company has updated its need assessment as part of our regular business process based on new information. As Mr. Wishart explains in his testimony, our September 2013 Update of the Company's need indicates a capacity deficit of 93 MW in 2017, which grows to 307 MW by 2019. However, there are factors that create uncertainty and could materially affect our resource need assessment. As Mr. Wishart describes in more detail, the Midcontinent Independent System Operator's resource adequacy process is in flux.

Q. HOW DOES THE COMPANY PROPOSE USING THIS NEW NEED ASSESSMENT IN THIS PROCEEDING?

A. The new need assessment is another data point that should be considered in analyzing which resource proposals should be selected to address the range of the Company's potential need in the 2017-2019 timeframe. The September 2013 Update was therefore incorporated into our Strategist modeling assumptions, as explained by Mr. Wishart.

Q. WHAT WERE THE RESULTS OF THE STRATEGIST ANALYSIS?

A. The Strategist results show that Black Dog 6 is the lowest cost resource among all the proposals. The least cost portfolio includes Black Dog 6 and Invenergy's Cannon Falls Expansion proposal, while the next least cost portfolio includes Black Dog 6 and Calpine's Mankato Expansion proposal. Our Red River Valley Unit 1 in combination with other proposals is also highly ranked but slightly behind the others.

Q. WHAT IS THE COMPANY'S RESOURCE RECOMMENDATION?

A. The Company recommends that the Commission select Black Dog 6 in combination with either Cannon Falls Expansion or Mankato Expansion to address the Company's range of potential need in the 2017-2019 time period.

Black Dog 6 is part of all of the best performing combinations of new generation and provides significant value regardless of other choices.

However, based on the data included in the Cannon Falls Expansion and Mankato Expansion proposals, the Strategist analysis does not indicate a clear preference for one of the proposals over the other. We believe the negotiation of fully developed PPAs is necessary to clarify some cost considerations, and clearly identify risks born by the Company and its customers.

Furthermore, with the uncertainty surrounding our resource need, we believe it would be beneficial to explore contract options providing implementation flexibility similar to that we proposed. Our proposal includes the flexibility to adjust in-service dates or even cancel development of one or more units in the event of changed circumstances warrant. We believe it is important to establish similar flexibility options in the PPAs if possible. Such options may impact pricing and help the Company and the Commission judge the value of flexibility.

In addition, given the uncertainty surrounding resource assessments, we offered to file status reports in the fall of 2014 and 2015 so that the Commission could determine if customer benefits associated with delay warranted implementation changes. We continue to believe it is prudent to closely monitor changes in resource adequacy occurring in the MISO market that provide opportunities to adjust plans if customer benefits can be had.

Finally, we note that as with any significant negotiation process, maintaining competition though the negotiation phase better ensures that parties continue to negotiate in good faith towards a contract.

IV. PRESENTATION OF WITNESSES

Q. PLEASE INTRODUCE THE WITNESSES THE COMPANY IS SPONSORING IN THIS PROCEEDING.

A. In addition to me, the Company is sponsoring the following witnesses:

- *Gregory Ford* – who testifies regarding the Company's CT generators' design, operation and maintenance, and construction costs and schedule.
- *Steven Wishart* – who testifies regarding the Company's resource need for the 2017-2019 time period, the Strategist modeling of the resource proposals that are the subject of these proceedings, and the Company's recommendation of the resource proposals to select to meet the Company's need.
- *Jeffrey Savage* – who testifies regarding capital lease issues associated with PPAs and how they should be addressed in these proceedings.

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

Direct Testimony and Schedules
Gregory L. Ford

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need

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

Description of Proposal Testimony

September 27, 2013

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Gregory L. Ford. I am Director of Engineering, Design, and Document Services in the Energy Supply Engineering and Construction Department.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked in consulting and engineering management roles within the electric power industry for 39 years. Since joining Xcel Energy in 2004, I have managed the Energy Supply Engineering and Design Departments for all Xcel Energy jurisdictions, as well as the bidding and negotiation of major equipment supply and installation contracts. My Statement of Qualifications is provided as Exhibit___(GLF-1), Schedule 1.

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

A. I discuss the design, operation and maintenance, and construction costs and schedules for the Company's proposed addition of three 215 MW natural gas-fired, simple-cycle, combustion turbine (CT) generators to its system 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. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I describe the new Unit 6 that we propose to construct at our current Black Dog plant site, and summarize its integration into the NSP system. Then I discuss our selection of the Hankinson, North Dakota location for our proposed Red River Valley plant that will house Red River Valley Units 1 and

2, as well as how we will integrate the Red River Valley units into the NSP System. I conclude my testimony with a discussion of the construction costs and schedules for the three CT generating units.

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 Sections 4.1 through 4.4 of Chapter 4- Project Description; Chapter 6- Environmental Information; and Appendix C (Project Operational and Cost Data).

II. DESCRIPTION OF BLACK DOG UNIT 6

Q. PLEASE DESCRIBE THE COMPANY'S BLACK DOG GENERATING PLANT.

A. The Black Dog plant is currently a coal- and natural gas-fired generating station with four operating units. Units 1 and 2 were installed in the 1950s, and before being repowered with a natural gas combined-cycle facility in summer 2002, fired on coal. With the repowering, Unit 1 was retired and replaced with new Unit 5. Combined Units 2 and 5 increased output from the two original units by more than 100 MW.

Black Dog Units 3 and 4, which currently utilize coal as the primary fuel, were put into service in 1955 and 1960. Operating data indicates a declining reliability as the units continue to age. Their limited reliability, and the costs associated with continuing to run the units while meeting applicable environmental requirements, has led to our decision to retire the units by no later than early 2015. Upon their retirement, there will be no coal-fired generation at the Black Dog plant.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO LOCATE A CT GENERATOR AT THE BLACK DOG PLANT.

A. Key considerations in adding any new generating unit to the system is its ability to integrate into the transmission system and access the necessary fuel. The Company is proposing to add a 215 MW (208 UCAP rating) natural gas-fired, simple-cycle, CT as Unit 6 to the Black Dog plant, which will be a very cost-effective use of this plant facility upon retirement of Units 3 and 4. Constructing new Black Dog Unit 6 at this existing plant location will take advantage of the existing 115 kV transmission substation, existing natural gas infrastructure, and will be consistent with the current use of this property.

In terms of transmission, while minor modifications to the existing 115 kV switchyard will be required to connect it to the transmission system, no upgrades of the 115 kV transmission system are required. However, because Unit 6 will increase the plant's high pressure natural gas need, we will conduct a competitive process for supply to the plant. It may be necessary to replace the existing pipeline serving the plant with a new higher pressure natural gas line, which will be the responsibility of the fuel supplier and has been factored into our plans and proposal.

Q. PLEASE DESCRIBE THE DESIGN, OPERATIONS AND MAINTENANCE OF UNIT 6.

A. We will operate Black Dog Unit 6 as a peaking generator, with an anticipated annual capacity factor of four to ten percent. We expect annual availability will be greater than 95 percent, and that its service life will exceed 35 years. Unit 6 will be operated and maintained by the staff that will be retained for Units 2 and 5, the only other units that will remain after Units 3 and 4 are retired. No additional staff are planned to accommodate the new unit.

III. DESCRIPTION OF RED RIVER UNITS 1 AND 2

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO LOCATE TWO CT GENERATORS AT A NEW PLANT NEAR THE RED RIVER VALLEY.

A. We believe having cost-effective geographic diversity in our generation resources provides benefits to our customers. Choosing a location near the Red River Valley will place generation closer to our Fargo load center, and will moderate our reliance on the high voltage transmission system to deliver power to this part of our integrated system. Initially, we evaluated locating the plant near Fargo, North Dakota. However, we determined that the costs to connect a Fargo plant site to a natural gas pipeline, as well as the costs to interconnect with the transmission in the area, would not be cost-effective.

As a result, we investigated locating the plant in an area that provides easy access to the transmission system and a nearby major natural gas pipeline – identifying an area south of Fargo, in the general vicinity of Hankinson, North Dakota. The proximity to necessary infrastructure provided by the Hankinson site made this a cost-effective location that will provide the geographic diversity and other benefits to our system that I discussed above.

Q. HOW WILL THE NEW RED RIVER VALLEY PLANT INTERCONNECT WITH THE TRANSMISSION SYSTEM?

A. The Red River Valley plant would connect to the transmission network via a double circuit 230 kV line to either an expanded Otter Tail Power Hankinson 230 kV substation, or a new 230 kV substation constructed at another location. We have conducted a preliminary generation interconnection study to identify likely transmission upgrades needed for the interconnection. The study identified two potential system upgrades that may be required to support interconnection: 1) completion of the Big Stone-Brookings County 345 kV transmission line; and 2) rebuilding Otter Tail Power's existing Hankinson-Wahpeton 230 kV line.

The Red River Valley plant would not be directly responsible for any of the Big Stone-Brookings line cost, since it is part of the Midcontinent Independent System Operator (MISO) Multi-Value Portfolio of regional transmission improvements. The Hankinson-Wahpeton rebuild, however, would be necessary to support interconnection of Red River Valley Unit 2, so the plant would be responsible for its cost.

Q. PLEASE DESCRIBE THE RED RIVER VALLEY PLANT'S FUEL SUPPLY.

A. The plant site area is near the Alliance interstate natural gas pipeline. Multiple parties utilize this line to transport gas, and have indicated a willingness and ability to provide sufficient natural gas service for the Red River Valley plant. We anticipate securing the necessary natural gas supply through a competitive process. Additionally, if a future need develops, the layout of the Red River Valley plant will allow for addition of distillate oil storage and handling for backup purposes.

Q. PLEASE DESCRIBE THE DESIGN, OPERATIONS AND MAINTENANCE OF RED RIVER VALLEY UNITS 1 AND 2.

A. The layout of the plant would allow for two simple-cycle CTs to be installed, as well as for the conversion of the two units to a combined-cycle configuration in the future. It is anticipated that the tallest structure within the plant will be the stacks, at approximately 65 feet. The combustion turbines and building are all expected to be less than 40 feet in height. The facility will include the necessary infrastructure to accommodate a full time operating and maintenance staff, primarily for day shift operation. Consistent with Black Dog Unit 6, the units will be operated as peaking generators with an anticipated annual capacity factor of four to ten percent. Annual availability will be greater than 95 percent, and the service life of the units is anticipated to be in excess of 35 years.

IV. CONSTRUCTION COST AND SCHEDULES

Q. WHAT ARE THE COSTS FOR THE THREE CT GENERATORS?

A. The cost of the generators is non-public, and is provided in Appendix C of our proposal. Black Dog Unit 6 is the least cost unit among these three units because it will be located at an existing site and will be able to use existing facilities for housing and interconnection to the transmission system. Because Red River Valley Unit 1 will be at a greenfield site requiring all new infrastructure, its cost is approximately 38 percent greater than the cost for Black Dog Unit 6. Red River Valley Unit 2 will be able to enjoy some cost-efficiencies as a result of being able to use some of the infrastructure put into place for Unit 1, and is therefore 24 percent greater than the cost of Black Dog Unit 6.

Q. WHAT IS THE RECENT TRACK RECORD OF THE COMPANY IN ACTUAL VERSUS BUDGETED COSTS FOR FOSSIL AND RENEWABLE ENERGY GENERATION PROJECTS IN MINNESOTA?

A. The table below compares our budget to actual results for 2008 through 2012 for our fossil and renewable energy generation projects in Minnesota.

Year	Budget (millions)	Actual Cost (millions)	Variance %	Projects Completed
2008	$342.1	$343.0	Slightly over budget	93
2009	$169.8	$145.4	14% under budget	139
2010	$515.0	$511.6	Slightly under budget	203
2011	$80.1	$74.3	7% under budget	209
2012	$118.6	$115.1	Slightly under budget	214

Q. TO WHAT DO YOU ATTRIBUTE THE RESULTS BEING CLOSE TO, OR UNDER BUDGET?

A. We use realistic methodologies in developing our budgets and have a well defined program for project management and implementation as well as an experienced staff.

Q. HAVE YOU USED SIMILAR METHEDOLOGIES IN DEVELOPING YOUR BIDS IN THE CURRENT MATTER?

A. Yes. We have used similar realistic methodologies in developing our bids in the current proceeding.

Q. WHAT IS THE PROPOSED SCHEDULE FOR CONSTRUCTION OF THE THREE CT GENERATORS?

A. Assuming that all necessary regulatory approvals are received, Black Dog Unit 6 would be constructed first because it is the least-cost unit among the three units being proposed by the Company. Construction of Black Dog Unit 6 would begin in mid-2015 and end in late-2016 to be ready for service in 2017. This would require accelerating the retirement of Black Dog Unit 4 to September 2014. But the Company's proposal has flexibility, so that the in-service date of Black Dog Unit 6 could also be in 2018 or 2019 if the Commission determines that is appropriate.

If approved for a 2018 to 2019 in-service date, construction of the Red River Valley plant site and Unit 1 would start in mid-2016, and be completed in late-2017 for an early-2018 in-service date. Construction of Red River Valley Unit 2 would begin in mid-2017 for completion in late-2018, with service beginning in early-2019. Similar to Black Dog Unit 6, the Company's proposed Red River Valley Units also have flexibility with respect to their in-service dates, and the Company's proposal allows for both units to be have in-service dates in 2019.

Pricing for the flexibility of the in-service dates for all of these units is built into our proposals.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Gregory L. Ford

Statement of Qualifications

I am the Director of Engineering & Design Services in the Engineering & Construction Department. I have worked in the consulting and owners engineering management role within the electric power industry for 39 years. The experience has been with Gilbert/Commonwealth Engineering, Inc. in Jackson, MI for 11 years; HDR Engineering, Inc. in Minneapolis, MN for 13 years; and NRG Energy, Inc. in Minneapolis, MN for 7 years prior to joining Xcel Energy in 2004. Project experience has ranged from initial development through acceptance testing on both new and retrofitted projects and has included significant involvement in permitting activities. Technologies have included boilers (stoker, fluid bed, gas, oil, municipal solid waste, and pulverized coal); steam turbines (10 to 1200 MW); combustion turbines (4 to 240 MW) in both simple and combined cycle configurations; low and high head hydro; district heating and cooling; control systems; ash handling and disposal; coal handling; cooling water systems; environmental retrofits including fabric filters, precipitators, SCRs, low NOx burners, and fuel switching to PRB coal; and overall Balance of Plant systems and equipment.

I was the Power and Energy, as well as Environmental Section Manager for the Minneapolis office while at HDR Engineering and was the Executive Director of Engineering while at NRG Energy. NRG management responsibilities included bidding and negotiating major contracts for new and retrofitted projects domestically and internationally with construction budgets up to $1.0 billion.

While at Xcel Energy, I have been responsible for managing the bidding and negotiation of the major equipment supply and furnish and installation contracts for the Comanche 3 project near Pueblo, Colorado; the project development of the Fort St. Vrain Units 5 and 6 project near Platteville, Colorado; and the Clean Air Clean Jobs projects that include Cherokee Synchronous Condenser, Cherokee Units 5, 6, and 7 Combined Cycle, Pawnee AQCS, and Hayden Units 1 and 2 SCR projects. I have also been responsible for the management and administration of the Engineering and Design Departments within Engineering & Construction for all jurisdictions of Xcel Energy.

I am a registered Professional Engineer in Michigan and Minnesota. I am also a member of ASME. I have a BSME degree from Colorado State University.

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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

Table of Contents

Schedules

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

(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, 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.

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%.

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.

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

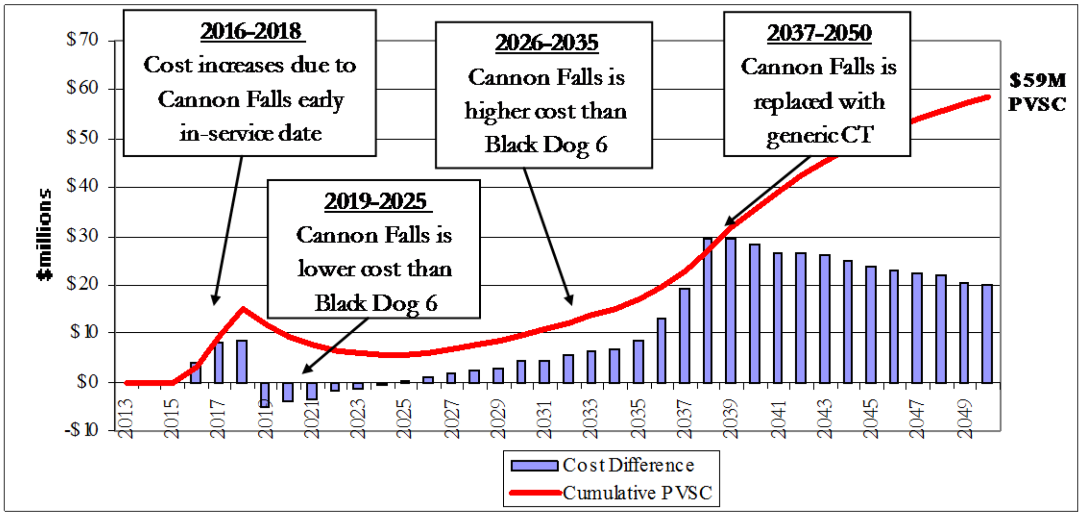
[TRADE SECRET DATA BEGINS:

…TRADE SECRET DATA ENDS]

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 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)

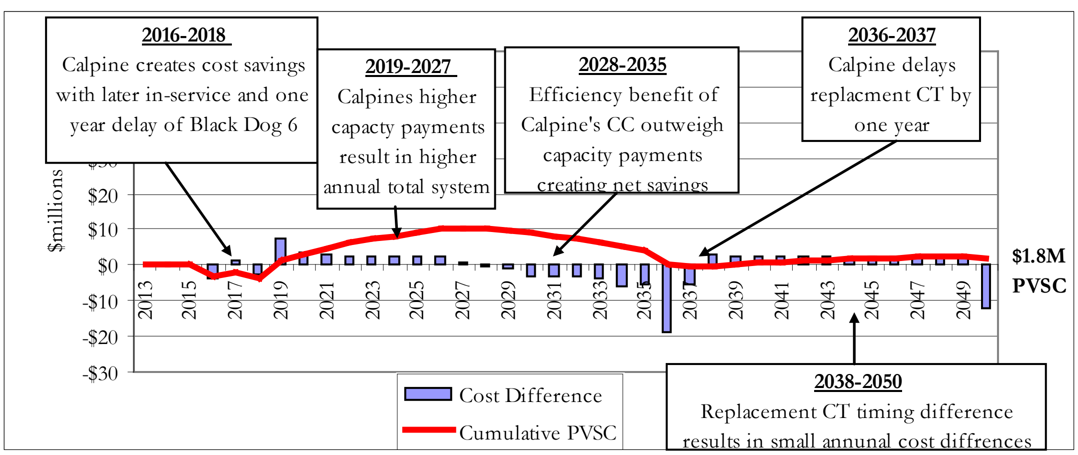
Q. WHY ARE THE PVSCS OF PLAN 1 AND PLAN 2, WHICH INCLUDE INVENERGY'S CANNON FALLS AND CALPINE'S MANKATO EXPANSIONS, SO CLOSELY MATCHED?

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.

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)

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

	PVSC $millions
Calpine Mankato Expansion	
Mankato Capacity Payments	$237
Combined Cycle Efficiency Benefit	($69)
Black Dog 6 One Year Delay	($10)
<u>Capacity Credit</u>	<u>($55)</u>
Net Calpine Costs	$103
Other Total System Cost Differences	
Long Term Expansion Plan Difference	($5)
<u>Net Emission Costs</u>	<u>$6</u>
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.

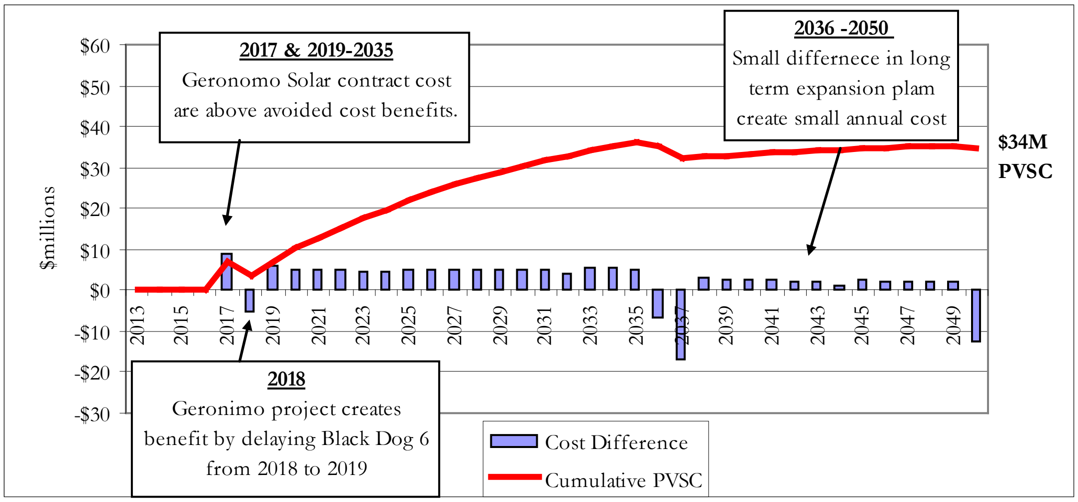
Q. HOW DOES THE COMPANY ASSESS THE VALUE OF GRE'S CAPACITY PROPOSAL TO DELAY THE NEED FOR GENERATION FURTHER OUT INTO THE FUTURE?

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.

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.

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

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.

(612) 508-0869 1814 Kohinoor Pl.
Steve@Wishart.com 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

				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)	**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**
			[TRADE SECRET DATA BEGINS…																																						
2013 $dollars		**Escalation Rate**																																							
Construction Expenditures					No Inflation, No Escalation																																				
On-Going Capital																																									
Transmission					No Inflation, No Escalation																																				
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Variable O&M ($/MWh)																																									
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)																																									
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	2	60%																																							
	3	70%																																							
	4	80%																																							
	5	90%																																							
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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
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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 ($000) — Modeled as a Fixed annual capacity rate — _TRADE SECRET DATA ENDS]
- Ventura Hub Forecast ($/mmBtu)
- Volumetric Charge ($/mmBtu) — [TRADE SECRET DATA BEGINS…
- Loss (% of volume)
- Total Delivered Price Of Gas ($/mmBtu)

		Ventura Hub Forecast ($/mmBtu)
	2014	
	2015	
	2016	
	2017	
1	2018	4.83
2	2019	5.24
3	2020	5.59
4	2021	5.87
5	2022	6.14
6	2023	6.56
7	2024	6.78
8	2025	7.02
9	2026	7.23
10	2027	7.39
11	2028	7.55
12	2029	7.78
13	2030	7.96
14	2031	8.11
15	2032	8.29
16	2033	8.49
17	2034	8.68
18	2035	8.89
19	2036	9.06
20	2037	9.24
21	2038	9.42
22	2039	9.6
23	2040	9.78
24	2041	9.97
25	2042	10.17
26	2043	10.36
27	2044	10.56
28	2045	10.77
29	2046	10.98
30	2047	11.19
31	2048	11.41
32	2049	11.63
33	2050	11.85
34	2051	
35	2052	
36	2053	
	2054	

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

Black Dog 6 - 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
						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 ($000)			[TRADE SECRET DATA BEGINS…																																						
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Construction Expenditures							No Inflation, No Escalation																																		
On-Going Capital																																									
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Variable O&M ($/MWh)																																									
Fuel Supply Expense																																									
Nominal $dollars																																									
Firm Service Annual Fixed Charge ($000)		Modeled as a Fixed annual capacity rate																																			_TRADE SECRET DATA ENDS]			
Ventura Hub Forecast ($/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				
Volumetric Charge ($/mmBtu)		[TRADE SECRET DATA BEGINS…																																							
Loss (% of volume)																																									
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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

Red River Valley 1 - 2018 In-Service

In-Service	March 1, 2018
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	
			[TRADE SECRET DATA BEGINS…																																						
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Firm Service Annual Fixed Charge ($000)																																							_TRADE SECRET DATA ENDS]		
Ventura Hub Forecast ($/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				
Basis Differential to Chicago Hub ($/mmBtu)		[TRADE SECRET DATA BEGINS…																																							
Volumetric Charge ($/mmBtu)																																									
Surcharge ($/mmBtu)																																									
Total Delivered Price Of Gas ($/mmBtu)																																									
Maximum Capacity																																									
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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

Red River Valley 2 - 2018 In-Service

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

[TRADE SECRET DATA BEGINS…

	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
						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)																																										
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 ($000)																																										
Ventura Hub Forecast ($/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				
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)																																										

TRADE SECRET DATA ENDS]

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

	% 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]

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

Red River Valley 1 - 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 2055 2056 2057 2058 2059 2060 2061 2062 2063 2064

[TRADE SECRET DATA BEGINS…

2013 $dollars	Escalation Rate	2014	2015	2016	2017	2018	2019	
Construction Expenditures								No Inflation, No Escalation
On-Going Capital								
Transmission								No Inflation, No Escalation
Natural Gas Pipeline								No Inflation, No Escalation

Operating & Maintenance Expense

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

Fuel Supply Expense

Nominal $dollars

	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
	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
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				
Basis Differential to Chicago Hub ($/mmBtu)																																				
Volumetric Charge ($/mmBtu)																																				
Surcharge ($/mmBtu)																																				
Total Delivered Price Of Gas ($/mmBtu)																																				

_TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS…

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]

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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
			[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 ($000)																																									
Ventura Hub Forecast ($/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]			

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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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
			1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*		
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)																									
Consumer Price Index Forecast																									
2016 Capacity Price $/kW-mo																									
Nominal Capacity Price $/kW-mo																									

[TRADE SECRET DATA BEGINS…

Monthly Capacity Payments = NC x CAF x (CP + EICA)

	Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		31	*28*	*31*	*30*	*31*	*30*	*31*	*31*	*30*	*31*	*30*	*31*
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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*		
Capacity Payments (reflects mid-yr change) Modeled as a capacity																								
Payment for Excess Capacity																								
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]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
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

[TRADE SECRET DATA BEGINS…

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter																					
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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*
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 Hampton Energy Center

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

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

[TRADE SECRET DATA BEGINS…

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Payments (CP)																					
Consumer Price Index Forecast																					
2016 Capacity Price $/kW-mo																					
Nominal Capacity Price $/kW-mo																					

Monthly Capacity Payments = NC x CAF x (CP + EICA)	Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		31	28	31	30	31	30	31	31	30	31	30	31
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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	
Total Capacity Payments (reflects mid-yr change)																							
Payment for Excess Capacity																							

Payment For Variable O&M and Start Charges	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	
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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Firm Service Annual Fixed Charge ($000)																					

_TRADE SECRET DATA ENDS]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
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

[TRADE SECRET DATA BEGINS…

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter																					
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	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
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

Calpine Mankato Expansion

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

	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
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21				
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

[TRADE SECRET DATA BEGINS…

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Capacity Payments (CP)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Nominal Capacity Price $/kW-mo																					

	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
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21				
Total Capacity Payments (reflects mid-yr change)																											

Energy Payments and Start Charges	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
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21				
Consumer Price Index Forecast																											
2012 Energy Payment ($/MWh)																											
Nominal Tolling Price (reflects mid year change)																											
<u>Turbine Start Payments</u>																											
Consumer Price Index Forecast																											
2012 Turbines Start Price (TSP)																											
Nominal TSP (reflects mid yr change)																											
Assumed # of Run Hours per Start																											
Equivalent Start Charge Per MWh																											
Total VOM Input for Strategist ($/MWh)																											

Fuel Supply Expense

Nominal $dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
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]

[TRADE SECRET DATA BEGINS…

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

Geronimo Distributed Solar Project

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

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
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

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Net Capability (NC)																		

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
31	10
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	

[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS

	2016	2017	2018	2019
Nominal Capacity Price $/kW-mo				
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

[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS

	2016	2017	2018	2019
Nominal Capacity Price $/kW-mo				
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
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
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/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 3	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

Red River 1		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Max Capacity	MW			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
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																	

Red River 1		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
Summer Accredited Capacity	MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh																		
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

Black Dog 6		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Max Capacity	MW				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
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																	

Black Dog 6		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
Summer Accredited Capacity	MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW	208MW
Generation	GWh																		
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
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																	

		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	$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
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	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 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]

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

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	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]

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
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
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
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
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
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
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
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
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
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
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]

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

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
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
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
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
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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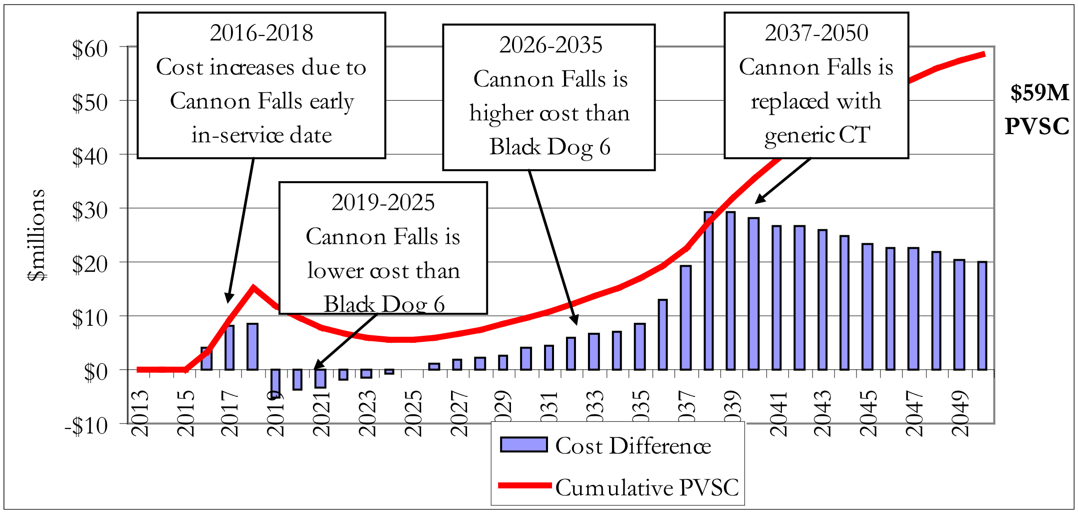
Average Energy Cost	$/MWh																																			
Fixed O&M / Capacity Payments	$000																																			
Average	$/kW-mo																																			
NOx	tons																																			
SOx	tons																																			
CO2	tons																																			
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

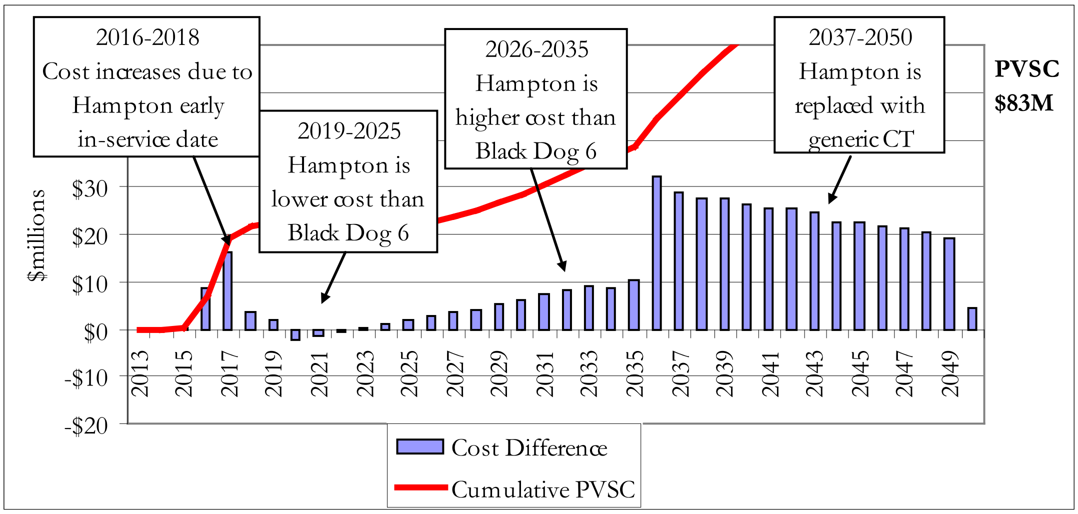
Plan 56: Calpine Mankato + Invenergy Cannon Falls
vs.
Plan 2: Calpine Mankato + Black Dog 6



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

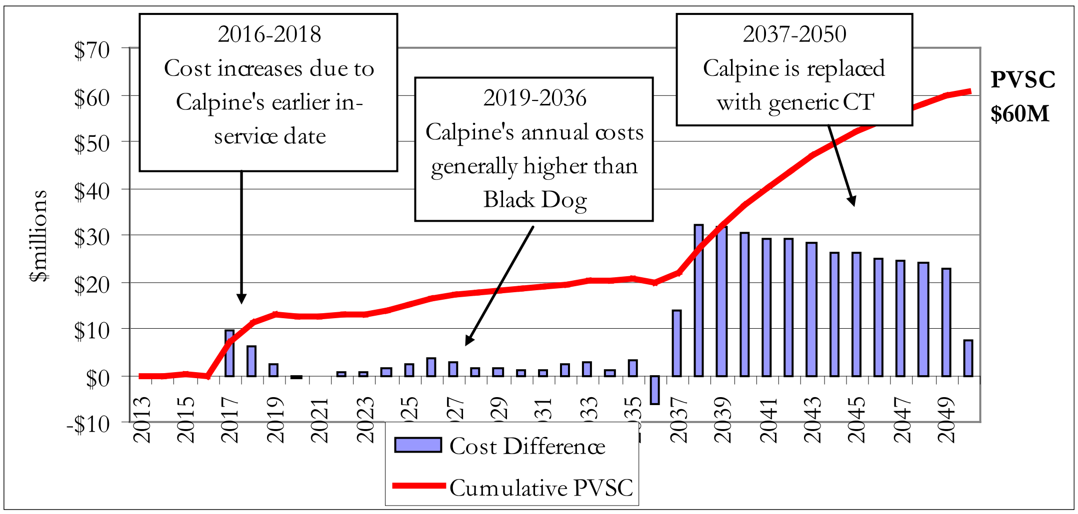
Plan 117: Invenergy Cannon Falls + Invenergy Hampton Energy Center
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6



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



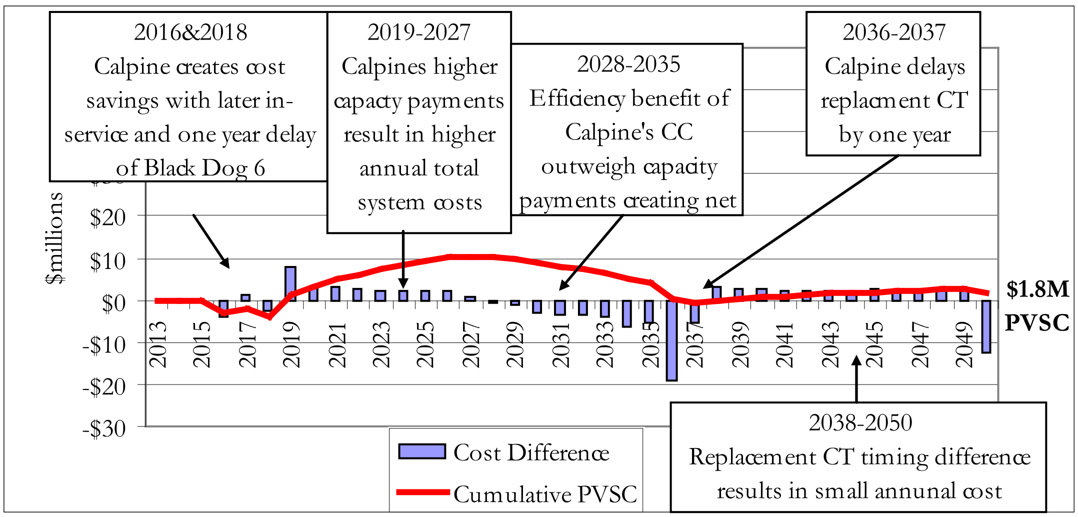
Calpine Mankato Expansion	**PVSC $millions**
Calpine Mankato Capacity Payment	$237
Calpine Efficency Benefit	($64)
Capacity Credit	($24)
<u>2037 Replacement CT</u>	<u>$53</u>
Cannon Falls Total Cost	$201
Net Emission Costs	$4

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

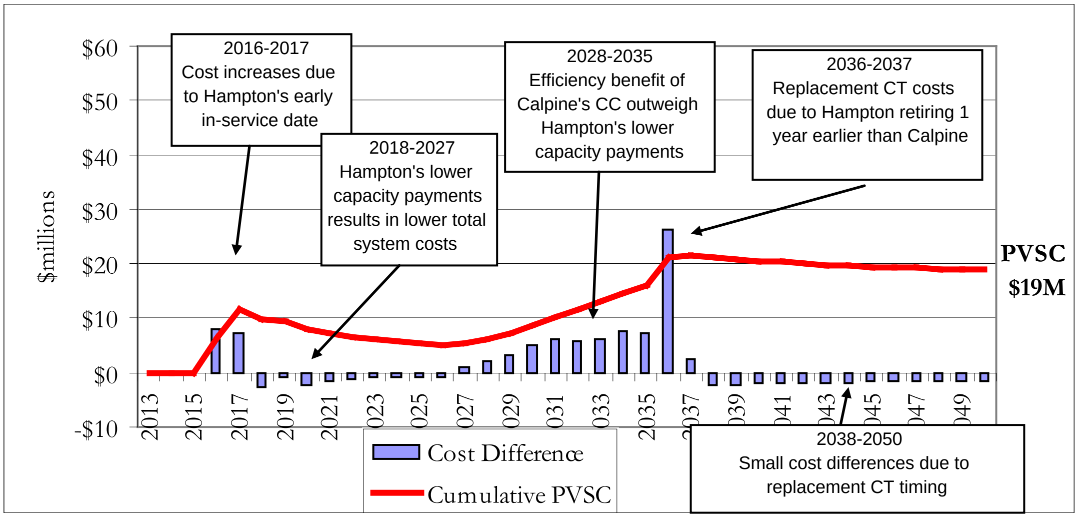
Other Total System Cost Differences	
Long Term Expansion Plan Difference	($5)
Net Emission Costs	$6
Net Costs	$1

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

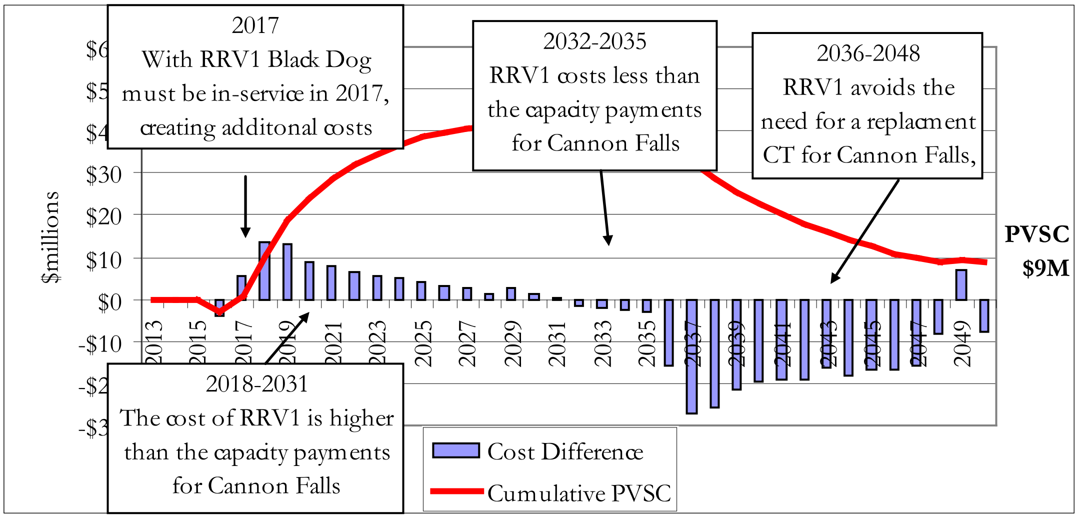


Invenergy Hampton Energy Center	**PVSC $millions**
Hampton Energy Center Capacity Payment	$204
Capacity Credit	($8)
Cannon Falls Total Cost	$196
Other Total System Cost Differences	
Long Term Expansion Plan Difference	$5
Net Emission Costs	($5)
Net Costs	($0.5)
Calpine Mankato Expansion	
Mankato Capacity 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

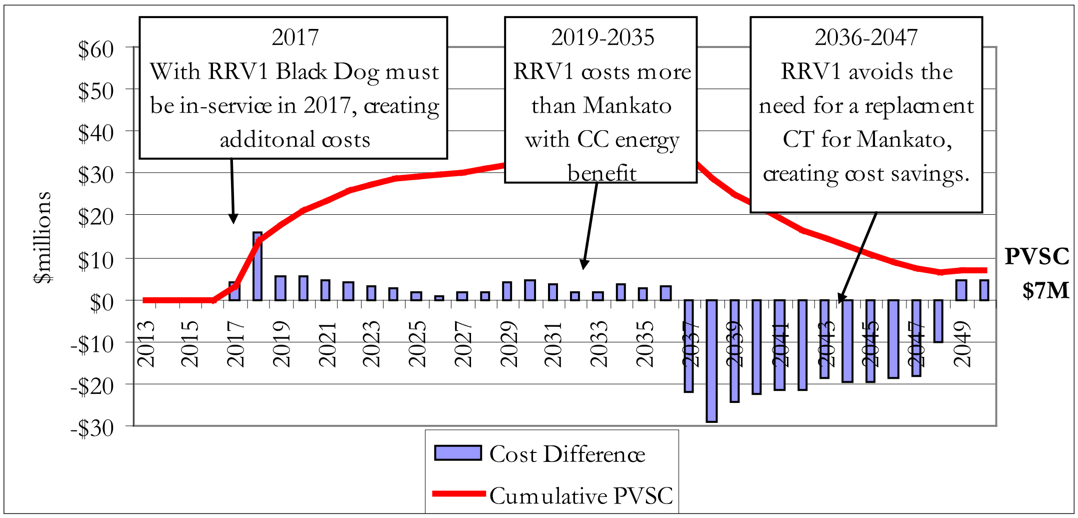
Plan 5: Red River Valley 1 + Black Dog 6 2017
vs.
Plan 1: Invenergy Cannon Falls + Black Dog 6 2018



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

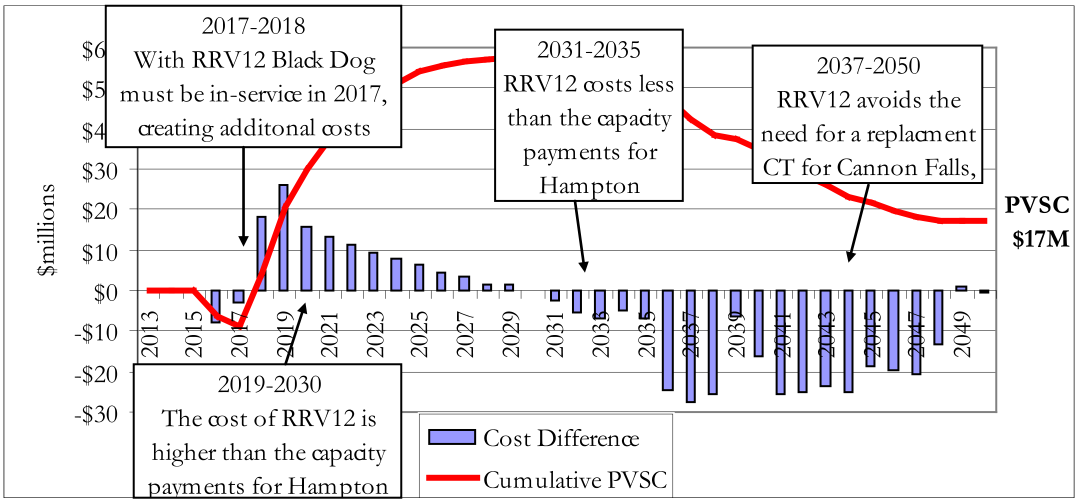
Total Net PVSC RRV1 + Other System Cost Differences - Cannon Falls	**$7**

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



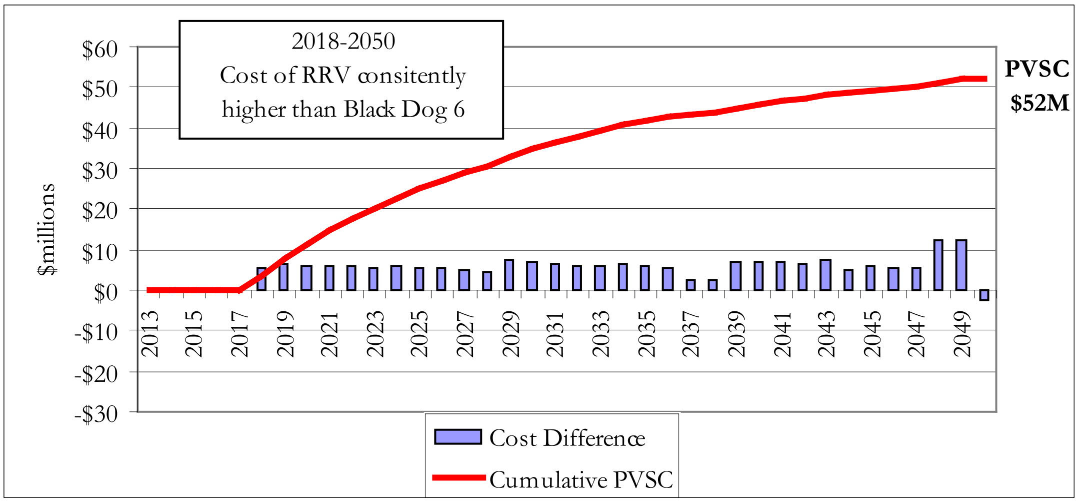
Red River Valley 1&2	**PVSC $millions**
RRV 12 Revenue Requirements	$353
Early Black Dog Costs	$24
Capacity Credit	($84)
RRV 12 Total Costs	$293
Net Emission Costs	$3.0

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

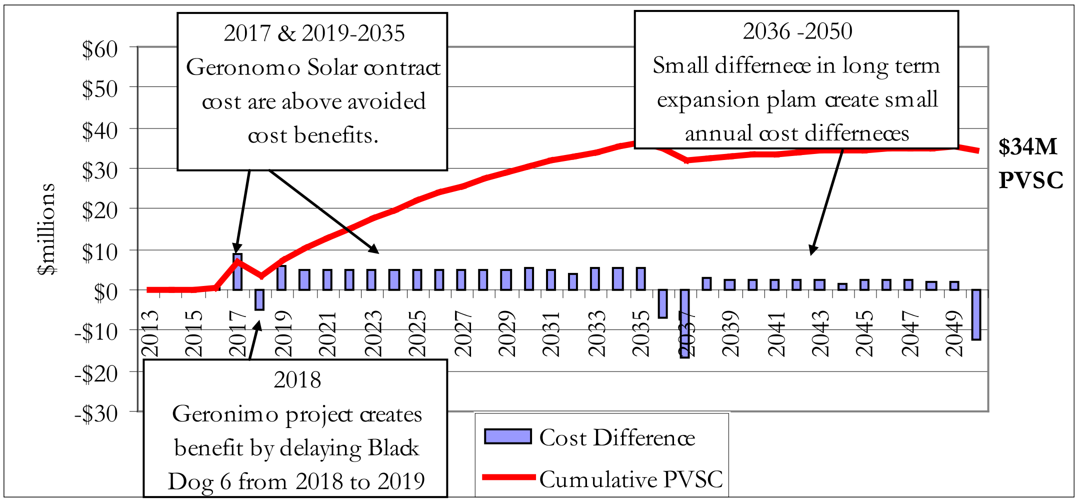
Black Dog 6

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**

Direct Testimony and Schedules
Jeffrey S. Savage

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need

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

Capital Lease Issues Testimony

September 27, 2013

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Jeffrey S. Savage. I am Vice President and Controller of NSP and Xcel Energy.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been responsible for various financial reporting and accounting functions since joining Xcel Energy Services Inc. ("XES") in 2007. I have been in my current position of Vice President and Controller of NSP and Xcel Energy since 2011. Prior to joining XES, I held positions with similar responsibilities, as well as oversight of functions including financial consolidation, Sarbanes-Oxley and internal audit, at The Mosaic Company and Regis Corporation. I also spent six years as an audit manager at PricewaterhouseCoopers. My statement of qualifications is provided as Exhibit___(JSS-1), Schedule 1.

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

A. The purpose of my testimony is to provide a high level overview of lease accounting; to explain the challenges the Company would face if a power purchase agreement (PPA) was to qualify as a capital lease; and to suggest that any PPA selection be structured to avoid capital lease treatment.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Accounting for a PPA as a capital lease may present significant financial challenges to the Company. The primary means of mitigation would be to work with any selected vendor to negotiate the transaction to avoid capital lease accounting.

II. BASIC ACCOUNTING FOR LEASES

Q. PLEASE SUMMARIZE HOW A PPA AGREEMENT IS EVALUATED TO DETERMINE THE APPROPRIATE ACCOUNTING TREATMENT.

A. In order to determine the appropriate accounting treatment for a PPA, the Company must determine if the terms and payment structure of a PPA require the agreement to be treated as a lease for accounting purposes based on the guidelines set forth in Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 840 *Leases*. These guidelines indicate that a PPA contains a lease if the power purchaser takes substantially all of the energy produced from the specified power plant and the PPA provides for a payment stream that is not directly associated with the output of the contracted facility. Because a capacity charge is generally associated with the capital costs of the plant rather than the actual variable output of energy produced by the facility, fixed capacity payments are often an indicator that a PPA contains a lease.

Once it has been established that a PPA contains a lease, under current accounting rules we must evaluate whether the lease should be treated as an operating or capital lease by performing a series of accounting tests. The first tests are typically to determine (1) whether the present value of future minimum lease payments (adjusted capacity payments) are greater than or equal to 90% of the fair market value of the plant, and (2) whether the lease term is greater than or equal to 75% of the estimated remaining economic life of the plant. The other tests, which would less typically qualify a PPA bid for capital lease treatment, are determination of whether (3) there is a bargain purchase option for the asset, or (4) the asset transfers to the purchaser at the end of the lease arrangement. If the contract satisfies any of these four required tests, the PPA must be accounted for as a capital lease.

III. ACCOUNTING AND FINANCIAL IMPACTS OF CAPITAL LEASES

Q. WHAT ARE THE PRIMARY ACCOUNTING AND FINANCIAL IMPACTS OF ACCOUNTING FOR A PPA AS A CAPITAL LEASE?

A. For capital leases, an asset and a liability must be recognized on the balance sheet. These are generally referred to as an asset under capital lease and a capital lease obligation. An asset under capital lease would be recorded at the lower of the present value of minimum lease payments or the fair value of the property, along with an equal liability for future payments (the capital lease obligation).

Expense recognition for a capital lease includes both depreciation of the leased asset and imputed interest expense on the lease obligation. Because depreciation is recorded on a straight line basis over the term of the lease while imputed interest expense decreases commensurate with the declining balance of the lease obligation, a front-loaded pattern of expense recognition occurs over the lease term, similar to interest on a home mortgage. Conversely, leased assets and lease obligations are not recognized for operating leases, and expense recognition is typically reasonably consistent with the cash payments made over the life of the lease.

As mentioned above, if the Company enters into a PPA that qualifies as a capital lease under current generally accepted accounting principles (GAAP), leased assets and capital lease obligation would need to be recognized on the balance sheet, resulting in an increase in the Company's economic debt to total capitalization ratio used by the credit rating agencies. In order to maintain NSP's economic debt to total capitalization ratio, Xcel Energy Inc. would need to infuse equity into NSP. The impacts of capital lease accounting have the effect of increasing the overall cost of capital for the Company. For these reasons, PPA terms and payment structures are closely scrutinized during the bidding and negotiation processes.

Q. ARE THERE CONCERNS FOR AN EXISTING FACILITY THAT PROPOSES TO EXPAND GENERATION FACILITIES?

A. Yes, a bid that proposes an expansion of generating facilities under an existing PPA may, depending on the specific terms of the expansion agreement, require the Company to re-evaluate its leasing conclusions on the existing PPA, which could result in capital lease treatment for the existing PPA.

IV. ADDRESSING CAPITAL LEASE ISSUES IN THE RESOURCE SELECTION PROCESS

Q. BASED ON THE ACCOUNTING AND OTHER NEGATIVE FINANCIAL IMPACTS OF CAPITAL LEASES, SHOULD THE BIDS THAT POTENTIALLY CONTAIN CAPITAL LEASES BE REJECTED?

A. No. Bids that appear to be at risk of capital lease treatment under current GAAP should not be rejected. If a particular bid is successful in the Commission selection process, to the extent capital lease risk exists, the Commission should encourage the Company and the selected vendor to seek to structure the transaction to avoid that risk. First, to verify that capital lease risk exists, the Company would perform further detailed analysis in conjunction with the selected vendor using the best available information, including the most recent indicators of plant fair value and updated forecasts for costs underlying the calculated lease payments to be used in the required accounting tests. Then PPA negotiation and structuring efforts could include shortening the life of the contract and/or shifting costs from fixed contractual payments for capacity to variable payments for energy.

Q. WHAT IF THE VENDOR AND THE COMPANY CANNOT AGREE?

A. If PPA negotiations were to fail for a project selected by the Commission, such that upon execution the contract would contain a capital lease, as provided by your order the Company would bring the dispute back to the Commission with suggested alternatives.

Q. YOU STATE THAT THE ACCOUNTING AND OTHER NEGATIVE FINANICAL STATEMENT IMPACTS OF CAPITAL LEASES ARE BASED ON "CURRENT GAAP." WILL THE ACCOUNTING FOR LEASES BE CHANGING?

A. A final revised lease accounting standard that would require all transactions classified as leases to be given financial statement recognition as lease assets and lease obligations, eliminating the off-balance sheet treatment of operating leases under current GAAP, is expected to be issued by the FASB and the International Accounting Standards Board (IASB) in 2014, to be effective in approximately 2017 or 2018.

Based on the ongoing work and tentative decisions of the FASB and IASB, the determination of whether an arrangement contains a lease may require a qualitative analysis of a purchaser's control over a specified asset. The current proposed accounting guidance for leases could impact the classification of certain types of PPA arrangements as leases. However, until a final standard is issued, it is difficult to determine the actual impacts on our current and future PPAs.

Q. SINCE IT IS POSSIBLE THAT THE AUTHORITATIVE GUIDANCE ON THE ACCOUNTING FOR LEASES WILL CHANGE IN THE NEAR TERM, WHAT ACCOUNTING RULES SHOULD BE APPLIED BY THE COMPANY IN EVALUATING BIDS FOR POTENTIAL GENERATING RESOURCES?

A. The Company will assess PPAs during bid evaluation and negotiation based on the applicable lease standard. If a new standard is issued, the Company will assess the PPA using the lease standards that will be in effect both before and after the effective date of the new standard, in order to identify all financial and accounting implications. In addition, in the event that probable future accounting impacts are identified based on ongoing work and tentative decisions of the FASB and IASB, we believe it may be appropriate, in certain circumstances, to utilize those considerations in the bid evaluation and negotiation process. It would be our intention during the course of PPA negotiations to take any steps available to mitigate future negative accounting and financial impacts that might arise when the final revised lease accounting standard is adopted.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Jeffrey S. Savage
Statement of Qualifications

I began my career with Xcel Energy Services Inc. ("XES") in 2007 as the Director, Financial Reporting and Technical Accounting. In 2009, I was promoted to the position of Senior Director, Financial Reporting, Corporate and Technical Accounting. In 2011, I was promoted to my current position of Vice President and Controller of SPS and Xcel Energy.

I am responsible for overall management and direction of a number of accounting operations for Xcel Energy and its subsidiaries, including managing the functional accounting areas of commercial accounting, regulatory accounting, transmission accounting, retail revenue accounting, capital asset accounting, corporate accounting, benefits accounting, technical accounting and financial reporting. I work closely with the Chief Financial Officer ("CFO") and other management within the CFO organization to establish, recommend, administer, and manage accounting and tax policies and procedures for Xcel Energy and its subsidiaries.

Prior to joining XES, I held financial reporting, technical accounting, financial consolidation, Sarbanes-Oxley and internal audit positions at The Mosaic Company and Regis Corporation. I also spent six years as an audit manager at PricewaterhouseCoopers.

I graduated from Colorado State University in 1994 with a Bachelor of Science degree in business administration with majors in accounting and finance, and I am a Certified Public Accountant (CPA) with an inactive license in Minnesota. From 1998 to 2008, I held an active CPA license in Minnesota. I am also an active member of the Edison Electric Institute (EEI) Accounting Executive Advisory Committee and the EEI Chief Accounting Officers organization.

In the Matter of Northern States Power Company to Initiate a Competitive Resource Acquisition Process	**CERTIFICATE OF SERVICE** **PUC DOCKET NO. E002/CN-12-1240** **OAH DOCKET NO. 8-2500-30760**

Rachel Rolseth certifies that on the 27th day of September, 2013, she filed a true and correct copy of **Direct Testimony and Schedules of James R. Alders, Direct Testimony and Schedules of Gregory L. Ford, Direct Testimony and Schedules of Steven W. Wishart, and Direct Testimony and Schedules of Jeffrey S. Savage,** by posting it on www.edockets.state.mn.us. Said document was also served via U.S. Mail and e-mail as designated on the Official Service List on file with the Minnesota Public Utilities Commission.

/s/ Rachel Rolseth

Rachel Rolseth

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