**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

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

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MPUC Docket No.: E-002/CN-12-1240
OAH Docket No.: 8-2500-30760

Exhibit No.: ____ (PJH-1)

DIRECT TESTIMONY OF PAUL J. HIBBARD

ON BEHALF OF CALPINE CORPORATION

September 27, 2013

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I. INTRODUCTION

Q. Would you please state your name, business address, and occupation?

A. My name is Paul Hibbard. I am a Vice President at Analysis Group, Inc. (AGI), an economic, finance and strategy consulting firm headquartered in Boston, Massachusetts, where I work on energy and environmental market, policy, and strategy consulting. My business address is 111 Huntington Avenue, 10th Floor, Boston, Massachusetts 02199.

Q. Please describe your background and experience.

A. I have been with AGI for almost seven years since 2003. First, from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010, I served as Chairman of the Massachusetts Department of Public Utilities (DPU). While Chairman, I also served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. I also served as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnect States' Planning Council.

From 2000 to 2003 I worked in energy and environmental consulting with Lexecon, Inc.. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, State Implementation Plans and emission control programs for the electric industry, with a focus on criteria pollutants and carbon dioxide

(CO_2), as well as various policy issues related to controlling pollutants from electric power generators within the Commonwealth. From 1991 to 1998, I worked in the Electric Power Division of the DPU on cases related to the restructuring of the electric industry in Massachusetts, the setting of company rates, the quantification of environmental externalities, integrated resource planning, energy efficiency, utility compliance with state and federal emission control requirements, regional electricity market structure development, and coordination with other states on electricity and gas policy issues through the staff subcommittee of the New England Conference of Public Utility Commissioners.

I hold an M.S. in Energy and Resources from the University of California, Berkeley, and a B.S. in Physics from the University of Massachusetts at Amherst. My curriculum vitae is attached as Exhibit No. __ (PJH-2).

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a quantitative and qualitative comparative evaluation of proposals currently before Xcel Energy (Xcel or the Company) and the Minnesota Public Utilities Commission (Commission) to meet the estimated 500 megawatts of Xcel's forecasted capacity and energy need for the 2017 to 2019 timeframe. In particular, I have been asked by Calpine to compare the proposals for thermal generation capacity from Xcel, Invenergy, and Calpine. I compare these proposals from the perspectives of (1) ratepayer impacts on an equivalent levelized cost of electricity (LCOE) basis; (2) public policy, resource mix and system operations; and (3) considerations with respect to ratepayer risks.

Q. Would you please summarize your findings?

A. Yes. This is a unique time for Xcel's procurement of additional capacity resources; one that requires careful consideration of costs to ratepayers as well as energy and environmental policy; changing requirements for the generating fleet and emerging operational needs; and ratepayer risks associated with different asset ownership or contracting arrangements.

I have analyzed, from the perspective of Xcel's ratepayers, the levelized cost of electricity of the thermal resources offered in this procurement by Xcel, Invenergy, and Calpine. Using conservative assumptions regarding unit capacity factors (CF) and other financial and operational factors, Calpine's Mankato bid represents the best value for ratepayers by a wide margin, and under a wide range of assumptions.

In addition, significant changes to industry circumstances will have important consequences for Xcel's resource needs, system operations, and long-run costs. Emerging controls on carbon at existing power plants are a real possibility, making attention to existing resource attrition, the opportunities for economical supply of electric energy and capacity, and the emission rates and efficiency of new resources particularly important. Renewable standards and goals will change the operational requirements of the power grid in a time frame relevant to this procurement, increasing the need for resources that can continuously and economically offer operational flexibility across all hours of the year, and do so without diluting – from an emissions perspective – the environmental objectives of Minnesota's Renewable Energy Standard. The potential retirement of long-standing baseload resources in addition to unforeseen market-related or operational problems may require substitution with capacity that can play a similar baseload and/or intermediate role. And new utility contracts or investment in this context can carry significant and different ratepayer risks associated with exposure to development, cost and operational factors that should be considered carefully by Xcel and the Commission.

Attention to these issues suggests the Commission should ensure that resource decision making be disciplined by a level playing field, competition, and a fair, equal and transparent assessment of resource alternatives. Attention to ratepayer risks in turn suggests that all bidders should be held to cost recovery tied to specific prices, terms and conditions submitted with their offers, and the Commission should carefully review the different risk profiles of offered projects.

In consideration of all of these key factors – a comprehensive and transparent analysis of the levelized cost of electricity of resources competing in this procurement; the operational, efficiency, and environmental benefits of combined cycle technology relative to competing alternatives; and the value in shielding ratepayers from certain development, cost and operational risks – I conclude that Calpine's Mankato facility should be among the resources selected in this acquisition process.

Q. How is your testimony organized?

In Section III, I summarize my calculations with respect to the LCOE for each of the Xcel, Invenergy and Calpine proposals, including analytic method, assumptions, underlying data, scenarios reviewed, and results. In Section IV, I identify key public policy considerations, aspects of Minnesota's power system, and the operational and environmental characteristics of the thermal energy generating capacity proposed in this solicitation (that is, combined cycle (CC) and combustion turbine (CT) technologies) that should be considered in evaluating proposals in this procurement. Finally, in Section V, I address important considerations related to ratepayer risk, and the need for heightened attention to the different risk factors presented by resources bid into this procurement.

III. LEVELIZED COST OF ELECTRICITY

Q. Is it possible to construct an analysis that provides a clear and transparent comparison of proposals from the perspective of electric ratepayers?

A. Yes. It is not only possible, but it is critically important that a robust and transparent quantitative analysis of bids be considered by the Commission. One way to do this is through a levelized cost of electricity analysis, in which the capacity, energy, and other cost elements in project proposals are translated into an equivalent dollars-per-megawatt hour (MWh) metric, using consistent financial, market, and temporal assumptions across all proposals.

Q. What is the value of carrying out a LCOE calculation, and how have you approached the LCOE analysis in this instance?

A. In this docket the Commission is being asked to choose from among multiple resources with different terms, cost elements, technologies, and operational utilization factors. Most importantly, the projects in this solicitation differ in at least two fundamental ways. First, they include both firm power purchase agreement (PPA) proposals from merchant generators (with twenty-year terms, specific price points, and operational guarantees) and self-build project cost estimates from the incumbent utility (with life-of-asset terms, an incentive ratemaking proposal, and no operational guarantees). A comparison of bids under these circumstances must include a clear and transparent demonstration of how assumptions related to the different terms and payment structures affect the expected cost and value of different bids.

Second, the proposals in this solicitation include projects whose use in daily operations is fundamentally different from the standpoint of frequency, duration, and timing of commitment and dispatch. That is, CTs will have a very different operational profile and use (infrequent, short-duration operations) than that of CCs (frequent, long-duration operations). A comparison of bids under these circumstances must include a clear and transparent demonstration of how expectations or assumptions regarding resource use affect the expected cost and value of different bids.

A LCOE analysis is able to capture these fundamental differences in a transparent manner, and enables a relatively straightforward and consistent comparison of bids. Below, I present a LCOE analysis I conducted for the thermal energy generating resources offered in this solicitation. My purpose for and approach to the LCOE analysis was to construct a fully independent, objective, and transparent analysis that treats all offers on an equal and fair basis. However, since I am a witness for Calpine in this proceeding, I took an expressly conservative approach to the evaluation of Calpine's bid; that is, wherever there was uncertainty in bid or financial parameters, or the need to apply subjective judgment in analytic assumptions, I selected values that tend to disadvantage Calpine's proposal relative to other offers in this procurement.

The LCOE metric for each proposal represents the net present value of the expected annual costs – including variable and fixed operation and maintenance costs, capital costs, and the return on investment – divided by annual generation over the term of the proposal. The LCOE calculation establishes annual costs in accordance with contract terms (in the case of PPAs), or using traditional calculations of annual revenue requirements (in the case of utility self-build units), creating comparability across such structural differences in proposal pricing and asset lives. In addition, the LCOE analysis accounts for differences in utilization between resource types through variable capacity factor inputs that determine average annual generation.[1] LCOE analysis is an accessible and useful representation of the ultimate impact to ratepayers, against which any other analyses may and should be compared.

Q. Xcel and the Department of Commerce will be using Strategist to compare proposals in this proceeding. Is it your view that Strategist modeling is not useful?

A. No. Strategist can be a useful tool for considering at a high level and from a long-term resource planning perspective the potential implications of different resource combinations over time. However, Strategist has a number of limitations that need to be considered when interpreting results and comparing proposals in this proceeding. In particular, the Strategist model may fail to capture operational details that could be important in understanding the relative value of CC versus CT technologies on the Company's system, in particular as the level of variable renewable generation on the Company's system increases.[2] As Xcel Energy noted in its 2010 Resource Plan, the Strategist model has limitations, in that it "…loses the ability to capture some operational detail, such as the ramp rates on our generating units…" and "…uses a simplified

[1] The LCOE analysis compares ratepayer impacts of each proposal under a user-specified set of capacity factor assumptions. However, it does not include dispatch simulation, and thus it does not quantify the economic and environmental benefits of displacing generation. Ignoring such benefits would tend to underestimate the value of CC capacity relative to CT capacity, since the more efficient and more highly-utilized CC capacity would likely generate greater price and emission displacement than CT capacity.

[2] Xcel Energy has recognized the operational uncertainty associated with growing integration of wind on its system. See, e.g., Xcel Energy, "2010 Resource Plan" (hereafter, "Resource Plan"), Minnesota Public Utilities Commission Docket Number E002/RP-10-825, August 2, 2010, at p. 4-8.

approach to modeling load and wind patterns."[3] In effect, as variable renewable resources become a major contributor to generation, the dispatch model used in Strategist may not be well-suited to understanding how units will be committed and/or operated to manage potential variations in wind and solar output (and thus net load), particularly over the shortest timeframes (i.e., on the order of seconds to tens of minutes) when on-line resources will be needed to follow load and provide regulation service. The greater the level of net load variability due to renewable resource integration, the less confidence one should have in Strategist results with respect to the operations of CT and CC technologies.

I do not mean, however, to suggest that the Commission should not closely review and consider Strategist modeling results. To the contrary, the decision made in this proceeding will affect ratepayer costs, risks, and system operations/reliability for decades. Given the importance of this decision, the Commission should carefully consider all of the modeling and analyses presented by parties in the proceeding. I only mean to suggest that the Commission should keep in mind that Strategist is a proprietary "black box" model, one whose unit commitment and dispatch module is opaque and admittedly simplistic, in ways that are clearly of heightened importance in comparing technologies offered in this procurement. One value of the LCOE analysis I present is that it provides a fully transparent and straightforward assessment of the cost of proposals to ratepayers in a manner that provides the Commission with an additional analytical tool to inform its decision.

[3] Resource Plan at p. 4-10.

Q. Could you please provide a summary of the results of the LCOE analysis you conducted?

A. Yes. I estimated the LCOE for the bids using data contained in each proposal with respect to capital costs, energy costs, operating costs, financing costs, and pollutant emissions provided by each company. To complete the analysis, I made a number of additional operational and financial assumptions, which I summarize below. Key results are presented in Figure 1 below and in Exhibit No. __ (PJH-4), and include the following:

- Calpine's Mankato proposal offers the lowest LCOE across all gas-fired bids at **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**.
- The Invenergy Hampton and Cannon Falls bids are the most expensive gas-fired options. The LCOE for each bid is in excess of **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**.
- Xcel's Black Dog bid is the lowest cost option among the CT proposals. The LCOE for Black Dog - which accurately replicates Xcel's revenue requirement estimate for the Black Dog unit – is [**TRADE SECRET INFORMATION ENDS] TRADE SECRET INFORMATION ENDS]**.[4]

[4] Xcel estimated a revenue requirement of **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**. See Xcel Energy, "Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal and for a Certificate of Need, Appendix C" (hereafter, "Appendix C"), Minnesota Public Utilities Commission Docket No. E002/CN-12-1240, April 15, 2013, at p. C-5.

[TRADE SECRET INFORMATION BEGINS

Figure 1

TRADE SECRET INFORMATION ENDS]

- This finding is robust to a range of assumptions (discussed below)[5] and scenarios, including:
  - *Changes to discount rate and inflation rate* – the base case is calculated using an inflation rate of 2.36 percent, and a discount rate of 7.47 percent; I also reviewed results at inflation and discount rates of 2 percent and 5 percent, respectively.
  - *Changes to assumed capacity factors* – as discussed below, and presented in Exhibit No.__ (PJH-5), results can vary as a function of assumed (or realized) CFs of the resources. In the base case I assume **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** capacity factor for CTs, and 20 percent capacity factor for CCs. In the alternative capacity factor scenario, I review the results assuming capacity factors for CTs and CCs based on

[5] Exhibit No. __ (PJH-3) includes a full list of model assumptions and inputs.

actual CFs realized by these technologies on Xcel's system over the past three years.

- *Changes to assumed PPA term length* – In the base case, I assume bid terms for the PPAs (20 years), and the depreciation life assumed for the Xcel proposals (35 years). To test the sensitivity of results to difference in term lengths, I also analyze results with the PPA term lengths extended to 35 years, holding constant the pricing terms.
- *Changes to cost overruns and Xcel's Return on Equity (ROE)* – In the base case, I assume Xcel's self-build costs are equal to their estimates; in this scenario, I assume that Xcel's costs come in ten percent under budget (and with appropriate adjustments to investment ROE for the first five years).
- *Changes to estimated starts per turbine and related dispatch payments* – In the base case I assume 125 starts for CCs, and 75 starts for CTs. In this scenario I assume 75 starts for both technologies.
- *Technology controls* – In this scenario, I assume that CTs are required to install selective catalytic reduction (SCR) technology to minimize emissions in the same manner as CC technology; this adds approximately \$15 million (2017 dollars), and lowers nitrogen oxide (NO_x) emission rates to 2.5 parts per million.
- *CO_2 Emissions* – In this scenario I add a CO_2 cost to all resource emissions at \$21.50 per ton, escalating annually at the inflation factor.
- *Non-Firm Fuel Service* – In the base case, I price natural gas supply/transportation on a firm basis for all bids in order for them to qualify as year-round capacity resource, and to allow a level playing field analysis of all resources. In this scenario, I allow the Invenergy CT capacity to operate on non-firm natural gas supply/transportation bases.

The results under each of these scenarios are summarized in Exhibit No. __ (PJH-4). In short, under nearly every way to analyze the LCOE of proposals in this proceeding, against a wide range of potential future power system and financial conditions, and using assumptions (where needed) that conservatively overstate Mankato's costs or understate competitors' costs, Calpine's Mankato proposal offers substantial benefits from a ratepayer's perspective relative to the other bids in this solicitation. In particular, even using estimates of resource utilization that would seriously understate the value of Mankato relative to competing CT proposals, Mankato is the clear winner. Specifically, assuming average annual capacity factors of **[TRADE**

SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS] for CT units and 20 percent for the Mankato CC unit (my selection of these capacity factors is described below), the LCOE of Mankato is 42 percent less than the next closest proposal (Xcel's Black Dog CT), and 46 percent to 59 percent less than all other bids that I evaluated. At average annual capacity factor assumptions that are higher than 20 percent for the Mankato unit, or lower than **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** for CTs – both likely outcomes for reasons that I discuss later in this testimony – Mankato's advantage from a LCOE perspective increases.

Q. Could you please summarize the key assumptions in the LCOE analysis?

A. Yes. First, the bids (and associated Strategist Assumption Documents) were the source of all data used in the analysis for items specified in the proposals, such as unit size, availability, capacity payments or costs, energy pricing, start costs, contract term, and plant emission rates. Second, where possible I used financial and fuel cost assumptions consistent with those used by Xcel in recent Strategist analyses, or for ratemaking purposes, or provided by Xcel in responses to interrogatories in this proceeding. Finally, where for the purpose of LCOE calculations I needed to identify inputs that could not be found in proposals, interrogatories, or Xcel Strategist/rate documentation, I applied commonly-used industry data and assumptions. Specific key assumptions for the base case, and sources for those assumptions, include the following (more detail on the assumptions and calculation methods is included in Exhibit No. __ (PJH-3)):

- For the *Discount Rate* I applied the weighted average after-tax cost of capital of 7.47 percent used by Xcel Energy for modeling analysis in the 2010 Resource Plan;[6]
- Where I apply an *Inflation Rate* to nominal values that are not expressly bid with an escalation factor, I use 2.36 percent, consistent with the general inflation rate applied in the Sherco Life Cycle Management analysis;[7]
- For *Gas Prices*, I relied on information provided in this docket. Specifically, I used the total gas costs calculated using the original and supplemental responses to IR DOC-42 and later updated in IR-CAL-10 for firm service to each of the Calpine, Xcel and Invenergy bids.[8] For the annual demand charge for the Xcel bids, I relied on the Strategic Assumptions Documents;
- For variable costs associated with pollutant emissions, I used prevailing market prices for allowances of sulphur dioxide (SO_2) and NO_x;
- For capacity factors, I assumed **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS** for CTs, and 20 percent for CCs (discussed further below).

Q. Xcel Energy suggests in its Response to IR DOC-42 that the Commission may elect to allow non-firm natural gas transportation service for CT units (but not CC units), given their expected lower level of utilization. Do you believe that would be an appropriate assumption for your analysis?

A. No I do not; this would not allow for a comparison across bids with all resources on the same level playing field. First, the purpose of this solicitation is to procure capacity to meet Xcel Energy's capacity obligations as a load-serving entity within the Midcontinent Independent System Operator (MISO) system. Consequently, the capacity procured in this resource acquisition must have the same meaning with respect to being available to meet Xcel Energy's capacity supply obligations, and reliably serve Xcel's

[6] Resource Plan at p. 4-2.
[7] Xcel Energy, "Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2" (hereafter, "Sherco Study"), Minnesota Public Utilities Commission Docket Number E002/RP-13-368, July 1, 2013, at D-8.
[8] Xcel Energy response to the Department of Commerce, Supplement to Information Request No. 042, Docket E002/CN-12-1240, June 28, 2013, at p. 5. Xcel Energy response to Calpine Corporation, Information Request No. 010, Docket E002/CN-12-1240, August 20, 2013, at p. 2.

customers on a year-round basis. As Xcel notes in its response to IR DOC-42, however, allowing interruptible natural gas transportation service would mean *less reliable service*, noting that under these conditions the Commission "…should expect the plants to be unable to operate on most cold winter days due to interruption of gas transportation services…"[9] While CT units may operate mostly when nearing peak-load conditions, they also may be relied upon in winter months, and must be available to operate year-round in response to contingency events or otherwise as needed to meet system reliability needs. This may be particularly true under system conditions that require CTs to balance the state's increasing penetration of intermittent renewable resources, or otherwise require CT operation at higher CFs than realized historically. Further, while it is true that there is *generally* sufficient natural gas transportation during summer months when demand is highest, this cannot be guaranteed. Should there be flow restrictions due to a pipeline outage, maintenance, or other gas system condition, a customer that has firm transportation service will always have priority over one that does not. In order for the proposals submitted in this procurement to be evaluated on a comparable, apples-to-apples basis, the same assumptions and pricing inputs for natural gas transportation service should be used for all bids. Consequently I use the estimated cost of firm service for all bids in the base case LCOE analysis.[10]

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[9] Xcel Energy response to the Department of Commerce, Supplement to Information Request No. 042, Docket E002/CN-12-1240, June 28, 2013, at p. 5.

[10] As noted above, I also evaluate LCOE assuming non-firm service for the Invenergy facilities. While this changes the LCOE for the Invenergy bids, the difference is not significant, and does not alter my conclusions based on the LCOE analysis. For example, changing natural gas pricing to a non-firm basis for the Cannon Falls facility decreases its LCOE from **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**, which is still **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** higher than the result for the Mankato facility keeping Mankato on firm natural gas service and holding all other base case assumptions constant.

Q. Is this the only issue of comparability related to natural gas supply that needs to be considered in project evaluation?

A. No, it is not. One issue the Commission may want to consider to ensure comparable bid evaluation is how Xcel Energy positions its mix of existing natural gas commodity and transportation arrangements and incremental fuel procurement practices with respect to proposal evaluations. The result of this procurement may include some mix of natural gas-fired generation, including capacity constructed and operated by Xcel, Invenergy, or Calpine, or some combination thereof. But regardless of who owns the capacity procured, the responsibility for procurement of natural gas commodity and transportation will fall to Xcel, since the Invenergy and Calpine bids are tolling agreements. Consequently, for any thermal resource selected in this procurement, the new need for natural gas will be folded into Xcel's overall natural gas procurement strategy, which is designed to optimize the use of existing and new commodity, storage, and transportation assets, contracts, and spot purchases for use of natural gas in all owned and tolling contract resources.[11] To its credit, Xcel has appropriately recognized this fact, noting in response to Calpine Information Request No. 12 that "the demand cost to have firm gas transportation to the Calpine Mankato site uses a one time discounted expansion that NSP negotiated in the past. The cost of the expansion is irrelevant as NNG is obligated to provide the expansion at the discounted rate."[12] For the purpose of resource evaluation in the current procurement, this means that the *only* differences that

[11] See, Xcel Energy, "Fuel Acquisition and Risk Management Plan" (hereafter "Xcel Fuel Plan"), Minnesota Public Utilities Commission Docket Number E002/RP-10-825, July 1, 2013, at pp. 22-36 for a discussion of Xcel's coordinated approach to gas supply for owned assets and tolling agreements.
[12] Xcel Energy response to Calpine Corporation, Information Request No. 012, Docket E002/CN-12-1240, August 20, 2013, at p. 1.

should be assumed with respect to gas supply and transportation pricing for competing bids are known incremental investments specifically needed to meet gas transportation needs that are unique to a given facility's location (as well as any differences in local transportation costs in delivering natural gas to each unit).

Q. Please describe your approach to assigning capacity factors to resources for the purpose of the LCOE analysis.

A. As noted above, capacity factors can have a significant impact on the LCOE of competing proposals, and so need to be considered carefully in the context of estimating proposal value in this procurement. Ultimately, the annual average capacity factors that would be realized for the facilities in question will depend on a number of key factors, including (1) the potential for the retirement of existing resources, which could dramatically and differentially affect the CFs for resources that are competing in this solicitation; (2) the level of new variable resource integration in and around Xcel's service territory, and how that affects the need for on-line load-following service and the use of intermediate and baseload capacity; and (3) the contractually guaranteed heat rates of competing proposals, and how they compare to the heat rates of other resources on the system.

In my base case LCOE analysis, I assume annual average CFs of **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** for CT units based on the CF presented by Xcel Energy in its Strategist Assumption Document.[13] Based on a review of historical CF data presented in the Xcel Fuel Plan, this may overstate the CF for CTs. Table 4 in the Xcel Fuel Plan shows that

[13] Appendix C at p. C-3.

the vast majority of CFs for natural gas-fired CT units from 2010 through 2012 were between 1 and 3 percent in each year.[14]

In my base case LCOE analysis, I assume a 20 percent annual average CF for Calpine's Mankato facility, which I believe is lower than what would actually occur, for a number of reasons. First, Calpine's proposal provides for a guaranteed heat rate of **[TRADE SECRET INFORMATION BEGINS**

TRADE SECRET INFORMATION ENDS] Consequently, if selected in this procurement, one would expect the Mankato proposed facility to be committed and dispatched as often, or nearly as often (and thus have a CF on the same order as) the most efficient CC units on the system. Table 4 in the Xcel Fuel Plan shows that Xcel's two most efficient CC units (High Bridge and Riverside – **[TRADE SECRET INFORMATION BEGINS**

[15] **TRADE SECRET INFORMATION ENDS]** operated at 37 percent and 44 percent CF in 2012, and between 14 percent and 23 percent in 2010 and 2011. My choice of 20 percent for a CC CF is less than the three year average CF (25 percent) for these two plants over the 2010-2012 period. Of course, to the extent that over the next several years emerging CO_2 and other Environmental Protection Agency (EPA) requirements lead to the retirement of additional baseload coal-fired generation, I would expect the role and CFs of CC units on Xcel's system – particularly the most efficient,

[14] Xcel Fuel Plan at p. 23. Only 2 out of 15 entries for CT units between 2010 and 2012 were above 3 percent (yet still less than **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**) – 5 percent for Blue Lake and 4 percent for Cannon Falls, both in 2012.

[15] SNL Financial reports a heat rate of 7,203 for High Bridge in 2012 and a heat rate of 7,275 for Riverside in 2012.

highest heat rate units – to expand significantly relative to past performance and current expectations.

Q. Why are expectations regarding the CFs of CC and CT units so important in valuing the proposals in this procurement?

The addition of low heat rate, high-efficiency CC capacity on Xcel's system would generate significant savings for Xcel's ratepayers (and reductions in emissions) through displacement of less efficient, higher-emitting resources in many hours.[16] If only CT capacity is chosen – instead of CC capacity – the opportunity to generate these marginal energy cost savings would be lost. Consequently, the value to ratepayers of CC versus CT capacity varies significantly based on annual average CF expectations for each proposed unit. In addition, a straightforward impact of higher capacity factors is to spread the higher fixed costs of CC capacity across a greater number of hours, thereby reducing the realized LCOE. The specific impact on the LCOE of competing proposals is depicted graphically in Figure 2 (below) and Exhibit No. __ (PJH-5), which show the LCOE in $/MWh for each bid as a function of capacity factors. For example, at the intersection of the horizontal and vertical dashed lines in Figure 2, you see that at a CF of **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**, the LCOE for the Black Dog facility is **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**.[17] Following the horizontal dashed line to the right, you see that the Calpine Mankato facility's LCOE is equal to Black Dog's at a CF of approximately 8 percent, and *always*

[16] Importantly, as noted above, the LCOE analysis I present in this testimony does *not* capture the cost and emission benefits that stem from displacement of less-efficient, higher-emitting resources. All else equal, I would expect that inclusion of such benefits would improve the value of Mankato relative to the CT units offered in this procurement.

[17] Black Dog is used in this example because it is the next most cost-effective proposal.

lower than this at CFs above 8 percent. In other words, if the Black Dog CT is modeled at a **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**, Mankato will always be more cost effective at any CF above 8 percent than Black Dog (or any other proposed CT, as can be seen in Exhibit No. __ (PJH-5)). Furthermore, as can be seen in Exhibit No. __ (PJH-5), at any CF greater than approximately 14 percent, the Mankato proposal will always be the most cost-effective option on a $/MWh basis compared to any proposed CT operating at the same, or lower, CF.

[TRADE SECRET INFORMATION BEGINS

Figure 2

TRADE SECRET INFORMATION ENDS]

Q. At utilization rates for CTs and CCs similar to those actually experienced in 2012, how would the proposals in this procurement compare?

A. Figure 2 also can be used to consider how the LCOE of competing proposals varies as a function of expected annual average CFs. For example, if one assumes the Black Dog CT achieves a CF of not **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**, but 5 percent – equal to the 4 maximum CF for a CT in 2012 – its LCOE increases from **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** to approximately **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**. This can be seen by following the red line in Figure 2 from **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** to 5 percent (along the X axis), and seeing how this changes the intersection with levelized cost (along the Y axis). The lower the CF value, the steeper the curve; this illustrates the large difference CF assumptions make in changing the LCOE of the proposed unit. In contrast, if one assumes the Mankato CC achieves a CF of not 20 percent, but 44 percent (moving to the right along the X axis for the blue line) – equal to the maximum CF for a CC in 2012 – its LCOE decreases from **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**. Consequently, the difference between the Mankato and Black Dog bids at these values (44 percent and 5 percent, respectively) increases from **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** to approximately **[TRADE SECRET INFORMATION BEGINS TRADE SECRET**

INFORMATION ENDS] based only on assuming annual average capacity factors that are more in line with actual experience at best-performing CT and CC units in 2012.

Q. What conclusions do you draw from your review of LCOEs under different assumptions about CFs for CT and CC units?

A. It is clear that expectations about annual average CFs are a major factor in comparing the cost to ratepayers of the proposals submitted in this procurement. Consequently, of paramount importance is that the Commission carefully consider what its expectation is about future utilization of the resources bid into this procurement, in consideration of unit efficiency relative to the existing resource mix, potential future retirements, likely evolution of system load and operations, and Minnesota's energy policy goals. Based on my LCOE analysis, it appears that one has to expect highly unrealistic CFs of 8 percent or less for Mankato – which if selected would likely be among the most efficient and highly-utilized CC facilities on the Company's system – and 6 percent CFs for CT units in order to conclude that it is not in ratepayers interests to include Mankato among the winning resources stemming from this procurement.

IV. REGULATORY AND RESOURCE MIX CONSIDERATIONS

Q. In your view, are there important considerations relative to this procurement with respect to federal and state energy and environmental regulation and policy?

A. Yes, there are a number of federal and state policies and regulatory efforts that could significantly affect Xcel's resource mix and that, while uncertain at this time, need to be carefully considered when reviewing proposals in this procurement, especially when considering the 35 (or more) year useful lives of any new capacity resources. This includes, in particular, the implementation of Minnesota's existing greenhouse gas goals and potential for new federal requirements to control CO_2 from power plants, and policies to foster the significant expansion of variable renewable resources. The importance of these considerations is heightened by the fact that any thermal resources selected in this procurement may be the only such resources added to Xcel's system between now and close to the end of the decade, at which point system mix and operational needs could be very different from today.[18]

Q. What is important to consider regarding CO_2 emissions?

A. Resource planning and procurement always occur in the presence of uncertain forecasts of, for example, electrical load growth; resource performance, addition, and attrition; fuel prices; and the like. This resource planning process is no different – all elements of load growth, fuel pricing, and resource additions are based on assumptions and forecasts that may turn out to be wrong. But in one sense the current context is unique – perhaps the most important uncertainty that needs to be wrestled with is how to think about what current and potential CO_2 control requirements mean for resource selection in the current procurement. Xcel's Sherco study highlights the importance of considerations related to CO_2 control requirements, in that assumptions related to CO_2 control and pricing are the strongest influence on the wisdom of various capital investment strategies.[19]

While efforts to pass national CO_2 legislation stalled in Congress over the past few years, the state of Minnesota, the White House, and EPA all have implemented and/or are continuing to develop regulations or policies to control emissions of CO_2, and

[18] This assumes that the next resource acquisition process would not result in a procurement of resource offers until sometime in 2015 or 2016, and that the lead time between procurement and operation is on the order of three to four years.
[19] Sherco Study at p. 2.

achieve meaningful CO_2 reductions. In particular, President Obama's Administration and EPA are clearly heading down a path that would require states to address emission of CO_2 from existing electric generating facilities, with compliance timeframes that could become relevant within the first few years of operation of the resources that will be selected in this procurement. The State of Minnesota also has set CO_2 reduction goals that become meaningful within this time frame– the Next Generation Energy Act of 2007 (effective August 1, 2007) called for cutting greenhouse gas (GHG) emissions, setting a target of reducing Minnesota's GHG to 15 percent below 2005 emission levels by 2015, 30 percent by 2025, and at least 80 percent by 2050.[20]

Q. Could you please summarize the most important EPA initiative with respect to potential CO_2 control requirements?

A. Yes. As Xcel Energy notes in its Life Cycle Management Study for Sherco, EPA is expected to issue a proposal for GHG rules for existing power plants that may require the filing of State Implementation Plans in 2016, and compliance three (2019) to five (2021) years after this.[21] While the prospects of national GHG legislation or regulation have historically been frustrated or delayed by political disagreements and legal challenges, current circumstances are different in fundamental ways. This administration and EPA have made it clear that this is a high priority over the next two years. Further, action by the administration follows major rulings by the U.S. Supreme Court and the U.S. Court of Appeals for the District of Columbia Circuit upholding EPA's authority to regulate CO_2 as a pollutant under the Clean Air Act.[22]

[20] Next Generation Energy Act of 2007, Article 5, Section 2, Subdivision 1.
[21] See, e.g., Sherco Study at pp. 22-23.
[22] See, e.g., Sherco Study at p. 21.

On June 25, 2013, President Obama announced sweeping measures to reduce greenhouse gas pollution. In part, the President announced that he would use his executive powers to require reductions in the amount of carbon dioxide emitted by the nation's power plants.[23] The Presidential Memorandum containing this Plan directs the EPA to "work expeditiously to complete carbon pollution standards for both new and existing power plants."[24] For existing power plants, the Memorandum calls for EPA to issue proposed carbon pollution standards, regulations, or guidelines, for modified and existing power plants by no later than June 1, 2014 and issue final standards, regulations, or guidelines, by no later than June 1, 2015.[25] The carbon reductions at power plants are the centerpiece of a three-pronged Climate Action Plan that will also involve new federal funds to advance renewable energy technology, and support mitigation.[26] Following this, on September 20, 2013, EPA released its proposed New Source Performance Standard (NSPS) rules to regulate CO_2 emissions from new power plants.[27] EPA has also committed to working with states and stakeholders to develop emission guidelines for existing power plants and, in accordance with the Presidential Memorandum, "…will issue proposed standards for existing power plants by June 1, 2014."[28]

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[23] Landler, Mark. "Obama Outlines Ambitious Plan to Cut Greenhouse Gases," The New York Times, June 25, 2013 (hereafter "Landler"). Available at http://www.nytimes.com/2013/06/26/us/politics/obama-plan-to-cut-greenhouse-gases.html?pagewanted=all&_r=0.
[24] "The President's Climate Action Plan," Executive Office of the President, June 2013, accessed 9/23/2013. Available at http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.
[25] "Presidential Memorandum – Power Sector Carbon Pollution Standards," The White House Office of the Press Secretary, accessed 9/23/2013. Available at http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.
[26] Landler.
[27] Environmental Protection Agency, "EPA Proposes Carbon Pollution Standards for New Power Plants" (hereafter, "EPA News Release"), News Release, September 20, 2013. Available at http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument.
[28] EPA News Release.

In some sense, EPA is now obligated to move forward with controls on existing power plants. With its release of the proposed NSPS for CO_2 from new power plants, it has initiated a proceeding that may lead to a final NSPS rule. Promulgating the final NSPS rule would then trigger section 111(d) of the Clean Air Act – a provision that requires EPA and the states to create performance standards to limit emissions from existing power plants.[29]

Q. Why is the move towards meaningful controls on emissions of CO_2 from existing power plants important in the procurement at issue in this proceeding?

A. While now, in 2013, the potential for regulations and policies to control CO_2 emissions (as well as the potential for a further tightening of national ambient air quality standards and other environmental requirements) that would take effect in or around 2020 may seem distant, it is not at all distant in the context of this acquisition process. It is directly relevant to this procurement because the resources selected in this process will not be in operation until just one to three years prior to 2020. The resources chosen will thus have a direct bearing on both the difficulty and cost Minnesota faces in achieving compliance with various requirements, and the options and flexibility Minnesota has with respect to changes in the mix of resources and the GHG intensity of its power sector. Since roughly a third of Xcel Energy's resource portfolio (in terms of both capacity and energy) is coal-fired baseload resources, the availability of other resources that could operate as baseload or intermediate resources in this timeframe needs to be considered in

[29] "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts," Nicholas Institute for Environmental Policy Solutions Report, NI R 13-01, January 2013, at p.5. Available at http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

the selection of resources in the current procurement cycle.[30] In this context, the selection of CC technology rather than or at least in addition to CT technology provides a hedge against the risk that increasingly stringent control requirements lead to greater than expected retirements of baseload coal-fired capacity since CC capacity can operate in baseload and intermediate roles (whereas CT technology is not well-suited for this purpose). In particular, adding CC capacity at this time will increase the flexibility that Xcel and the Commission have to consider the implications of potential retirements due to environmental requirements or unforeseen market or operational circumstances.

Q. Please explain the context for growth in variable renewable resources in and around Xcel Energy's service territory.

A. In 2012, wind generation represented 11 percent of Xcel's resource mix, a number that is expected to grow substantially over the next decade.[31] Minnesota has implemented aggressive programs to promote the development and acquisition of new renewable resources. Specifically, through legislation in 2007 and 2013 Minnesota enacted a renewable energy standard (RES) requiring that renewable electricity amount to 31.5 percent of Xcel's retail electricity sales in Minnesota by the end of 2020, with at least 25.5 percent coming from wind (24 percent) and solar (1.5 percent) resources.[32] Similar requirements are in place for other electricity providers in Minnesota. While Minnesota has in place other incentives for the development of renewables (e.g., net

[30] Sherco Study at p. 7. It should also be noted that Xcel may not be able to rely on transactions with neighboring regions to help, should compliance raise resource mix challenges. MISO as a whole is heavily reliant on coal-fired baseload resources, and has identified potential retirement of such resources due to EPA requirements only (that is, not accounting for potential CO_2 requirements) as a risk to maintaining planning reserve margins. Potomac Economics, "2012 State of the Market Report for the MISO Electricity Markets," June 2013 at pp. 16-17.
[31] Sherco Study at p. 7.
[32] "Minnesota incentives/Policies for Renewables & Efficiency, Renewables Portfolio Standard," DSIRE, accessed 9/2/2013. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R.

metering), the RES will have by far the most significant impact on utility-scale variable renewable development over the next decade.

Q. Why is the level of renewable development important for this procurement?

A. This level of variable renewable integration has both reliability and environmental implications that should be considered by the Commission. With respect to reliability, Xcel Energy has noted that the Minnesota RES requires a penetration of wind on its system that is at the limits of what was studied from a reliability standpoint in the Minnesota Wind Integration Study; and that Xcel remains unsure about the impacts of variable renewable integration on its system.[33] Of course, Xcel and Minnesota are not alone in needing to consider the potential implications of integrating a vast amount of variable resources in system operations – but at a level of almost a third of the energy generated to meet customer demands on an annual basis, new variable resources will likely have a significant impact on the commitment and dispatch, economics, and emissions of the remainder of the generating fleet used to serve Xcel's load. In this respect, the choices made in this procurement can either support or frustrate the operational and environmental objectives of integrating variable renewable resources.

The challenge of supporting integration of variable resources covers time spans of seconds to minutes to hours to days. The significant increase in net load variability due to wind/solar forecasting uncertainty and variability in output that will be in play by 2020 – within a couple years of when this procurement's resources will come on line – will require adjustments in commitment and dispatch decisions across all time scales. Both CT and CC technologies are effective in responding from on- or off-line states to

[33] Resource Plan at p. 4-8.

expected variations in load that occur over several hours or more. Further, both on-line CCs and on- or off-line CTs can effectively be used to respond to sudden system events for which recovery is needed on the order of tens of minutes or hours, such as the loss of generation or transmission resources, or errors in daily demand forecasts or variable generation output. Finally, on-line CCs can effectively be used as a load-following or regulation resource for net load variations on the order of minutes and tens of minutes. While CTs are effective in managing changes that need to be responded to on the order of tens of minutes or more, the CT proposals in this proceeding may require **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** advance notice time.[34]

Q. What are the environmental implications associated with balancing renewable resources that should be considered in the context of this procurement?

A. The most obvious policy goal of the RES in Minnesota is to meet customer load on a going-forward basis with reduced emissions and other environmental impacts. The Commission should consider how the selection in this procurement may affect the degree to which Minnesota meets this policy objective. To the extent thermal generating resources are selected in this solicitation, it will be either only CT resources, only CC resources, or some combination of the two, at a time when Xcel will be integrating – and balancing from an operational perspective – vast amounts of variable renewable resources consistent with the RES. Thus the task of balancing the increased net load

[34] Invenergy, "Cannon Falls Peaking Expansion" Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 12; Invenergy, "Hampton Energy Center" Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 12; Xcel Energy, "Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal and for a Certificate of Need" (hereafter "Xcel Petition"), Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 1-12.

variability of the system will fall in part to the resources selected at this time. To the extent that CT resources are selected over CC resources in this procurement, the environmental impacts of the increased need to balance the integration of RES resources will be worse. This would be a perverse outcome given that the overall goal of promoting renewable energy is to ensure an environmentally responsible energy mix.

Q. Please explain how the environmental impacts may be worse.

A. The relative impact of CT versus CC technologies from an emission perspective is presented in Exhibit Nos. __ (PJH-6a) and (PJH-6b). This exhibit shows emission rates from each unit proposed in this solicitation on a pounds per MWh (lb/MWh) basis. In other words, the exhibit provides a true apples-to-apples environmental comparison of the projects with respect to the level of emissions that result from production of an equivalent amount of energy. The emission rates for the Mankato facility are lower than the next-closest option by **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** for nitrogen oxides (NO_x), and [**TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]** for CO_2. These emission rates are primarily a direct function of the relative energy efficiency (i.e., heat rates) of the respective projects; in simple terms, using less fuel per MWh results in less air pollution per MWh. With respect to NO_x, the differential is also due to the fact that Mankato includes back-end emission control technology that is not included in the CT bids.

Q. Are there policy options that could help at least partially mitigate this outcome?

A. Yes. First, the selection of the Mankato bid would help counter this potentially perverse outcome, by ensuring that the most efficient, lowest-emission resource capable of balancing variable renewable resources is added to the system. In addition, the Commission should consider the value of mitigating the environmental impacts of CT capacity used to help manage net load variability by requiring the installation of state-of-the-art selective catalytic reduction (SCR) technology on any CT resources that succeed in this procurement, and that the costs of that equipment – which are small relative to the overall costs of CT proposals in this procurement – be included in the economic evaluation of the bids.[35] Failure to do so would place Mankato at a competitive disadvantage, and would, in effect, punish Mankato for being a cleaner option. Considering the policy objectives of Minnesota's RES and other efforts to address power plant emissions, this requirement would help create a more level playing field from an emissions perspective for the resources under consideration and evaluation in this procurement. Relying on any argument that such equipment is not necessary strictly from a permitting perspective may be appropriate for a project that is being considered on a stand-alone basis, but would be shortsighted and contrary to the obvious state policy objectives associated with truly integrated resource planning efforts in the context of a comparative evaluation of new capacity resources.

Q. Would you please summarize your conclusions regarding important considerations related to the policy and resource mix context in this proceeding?

A. Yes. The Commission should carefully consider the combination of the potential requirements related to emissions of CO_2 from existing power plants, the environmental objectives of Minnesota's RES, and the vast quantity of variable renewable resources that

[35] Based on recent study for the PJM Interconnection, I estimate the cost of SCR installations on CT technology to be on the order of $15 million in 2017 dollars for a unit roughly the size of the CTs proposed in this procurement. This is a fraction of the capacity costs of the CT proposals. Brattle Group with CH2M Hill, "Cost of New Entry Estimates For Combustion-Turbine and Combined-Cycle Plants in PJM," August 24, 2011, Table 20 at p. 20.

will need to be integrated and balanced over time frames relevant to the resource procurement in this proceeding. All of these factors point to a fundamental change in the power system of Xcel and its neighbors; changes that could involve a significant reduction in existing baseload (coal-fired) capacity and substantially greater net load variability for many hours of the year and across all time frames – from on the order of seconds to days, in all seasons of the year, and in all times of the day. This type of system needs or will benefit from additional capacity that (1) is flexible; (2) is responsive to all balancing authority operating needs; (3) is available to help manage net load variability and uncertainty across all time frames; (4) is designed to operate continuously and/or frequently, across many hours of the year and under many different system conditions; and (5) is able to help integrate and balance a large amount of variable renewable resources at relatively high efficiency and low emission rates.

Q. What do you believe this implies for the resource selection at this time?

A. Both CT and CC capacity are effective in helping to manage net load variability and integrate a quickly growing portfolio of renewable resources, across a wide range of time frames of interest. However, considering the policy objectives and resource mix risks discussed above, combined cycle capacity – in particular Calpine's Mankato proposal – is perfectly suited to meet these needs, ranging from efficiently helping manage renewable resource integration to cost-effectively filling in as intermediate or baseload capacity should existing baseload capacity retire. Further, Calpine has offered the Mankato facility at a highly competitive price which, as is discussed in Mr. Thornton's testimony, takes advantage of the project's unique economies of scale.

Mankato, therefore, is both an economic and environmentally-appropriate resource for Xcel and its customers.

While Xcel may want to also add CT capacity to its system, I believe it would be a mistake to add CT capacity only, or to the exclusion of the Mankato facility. CT capacity is not designed to operate frequently or continuously, at high capacity factors, and thus may not be ideal in light of the policy and resource mix considerations discussed above. And while CT capacity can come on line fairly quickly, it is not ideal for balancing net load variability economically across many hours of the year, in all seasons, and can not always be on line to help balance such variability on a second-to-second or minute-to-minute basis, to the extent that becomes an important operational concern. Finally, the relatively high heat rate and high emission rates of CT capacity relative to CC capacity mean that the cost and environmental impact of using only CT capacity to balance renewable generation would be counterproductive to the purpose of Minnesota's RES and other economic and environmental objectives.

V. CONSIDERATIONS RELATED TO RATEPAYER RISKS

Q. In light of the fact that the proposals being reviewed by the Commission in this proceeding result from a competitive process, why do you think it is important to comment on ratepayer risks as part of your testimony?

A. I want to focus in this last section of my testimony on the question of who bears the risk of utility decisions, rather than whether processes (such as competitive procurements) lead to efficient outcomes for consumers.

Clearly, I recognize that for many years, the Commission has understood the value of competitive procurements as an important – essential – part of the electric utility's resource planning and supply strategy. I note, for example, the Commission's statement in 2006 that the "purpose of the competitive process – getting the best overall price for ratepayers – cannot be achieved without robust competition."[36] The Commission recognized that competition in the generation sector could result in greater efficiency in power production and lower costs to consumers.[37]

The goal of obtaining "the best overall price for ratepayers" relies not only on competition to allow for discovery of the best offer prices from suppliers, but it also depends upon discovering and weighing any differences in the risk profile of the competitive offers. Price is certainly one aspect of getting the best deal for ratepayers; the development status and the terms and conditions under which a product is proposed at a particular price also affects the relative value of different competitive offers to consumers.

Q. Please explain further what you mean by the impact on consumers of the terms and conditions under which a product is supplied.

A. We see this relative "risk" principal at work all the time in the electric industry. Utilities must make decisions at one point in time about investments and other commitments that could be greatly affected by events that will occur much later, and which may or may not comport with the original expectations. Development uncertainty can lead to delays, changes in costs, and unexpected outcomes. Labor and material costs change. Fuel prices change. Public policy changes. Consumer habits change. Countless

[36] Minnesota Public Utilities Commission, "Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, And Requiring Compliance Filing 'In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan'" (hereafter "Resource Acquisition"), Minnesota Public Utilities Commission Docket Number E-002/RP-04-1752, May 31, 2006, at p. 6.
[37] Resource Acquisition, at p. 2.

things can change, so that – after the fact – the original decision to select a particular power plant may end up looking like a very good deal or a bad failure. These conditions – variations in development status, open versus guaranteed pricing, and uncertain versus guaranteed performance – are exactly what is before the Commission in the instant case.

Q. In your view, does Calpine's proposal appropriately manage the risks related to new resource acquisition?

A. Yes. The risk profile, from the perspective of ratepayers, is different for the different offers made in response to this solicitation. Xcel, for example, seeks a cost-recovery arrangement under which the supplier (Xcel) passes through to ratepayers the actual dollars of power plant investment (into utility rate base), with the allowed return for the investment conditioned to a limited extent, and for only the first five years, on how the actual costs compare to project estimates.[38]

By contrast, Calpine has offered a proposal under which it bears all of the risk associated with construction and operating cost overruns.[39] In effect, the Commission knows now with a high level of certainty what ratepayers will pay over time for power from the Mankato proposal, and what performance Calpine is obligated to provide from the perspectives of capacity availability and operational performance. This is because in addition to proposing a specific offer price, Calpine has included heat rate and availability guarantees as part of its proposal.[40] Also, as discussed above, CC generation is a less risky proposition from a long-term market perspective because it more

[38] Xcel Petition, at p. 4-14.
[39] Calpine Corporation, "Mankato Energy Center Expansion Proposal," (hereafter "Mankato Proposal") Minnesota Public Utilities Commission Docket No. E002/CN-12-1240, April 15, 2013 at p. 4.
[40] Mankato Proposal, Appendix B at p. 2.

effectively hedges against uncertainty related to environmental policy, fuel price forecasts (due to CC's greater energy efficiency) and longer-term market trends.

In short, compared to other offers in this procurement, from the perspective of ratepayers, Calpine's proposal can be viewed as a low risk proposition that hedges ratepayer risk, via the terms of a binding contract, to the maximum extent possible. In my view this constitutes a meaningful difference in proposal attributes and allocation of risk, which should be factored into the Commission's decisions about which offers provide the best "price" and "value" to ratepayers.

VI. CONCLUSION

Q. Would you please summarize your testimony in this proceeding?

A. Yes. In summary, consideration of a range of economic, operational and environmental factors supports approval of Calpine's Mankato bid to meet at least part of Xcel's current resource need.

With respect to economic considerations, Mankato is the least expensive option among the thermal energy resources offered in this procurement by Xcel, Calpine, and Invenergy. This conclusion appropriately relates to long-term costs, based on the levelized cost of electricity, as seen from the perspective of Xcel's ratepayers. Using conservative assumptions regarding unit capacity factors and other financial and operational factors, Calpine's Mankato bid represents the best value for ratepayers by a wide margin, and under a wide range of assumptions, especially when delivered fuel costs (i.e. firm fuel for Cannon Falls and Hampton) and installation of equivalent emission controls (i.e. SCR for all CT projects) are evaluated on a level playing field compared with Mankato. Moreover, the Mankato CC proposal clearly exceeds the operational value of the CT bids that have been proposed with respect to energy production, environmental performance and overall operational flexibility.

Environmental performance is particularly important given the role any new thermal generation resource will play in terms of meeting state and federal policy goals and complementing the state's rapid growth of intermittent renewable generation. Indeed, even if the bids were deemed to be equivalent based on an economic analysis, the environmental attributes of CC generation would overwhelmingly tip the scale in favor of the Mankato proposal.

Renewable standards and goals will change the operational requirements of the power grid in a time frame relevant to this procurement, increasing the need for resources that can continuously and economically offer operational flexibility across all hours of the year, and do so without diluting – from an emissions perspective – Minnesota's well established environmental objectives. The potential retirement of long-standing baseload resources due to environmental regulation or other factors may require substitution with capacity that can play a similar baseload and/or intermediate role. In short, any and all new thermal generation resources that are developed to meet future capacity needs, hedge against potential retirements, and balance the state's increasing dependence on clean renewable resources should use the cleanest type of fossil fuel technology that is currently available. Combined cycle generation will always be preferable from an emissions standpoint due to heat rate considerations. While CTs cannot match the energy efficiency benefits of CC generation, Minnesota should at least consider requiring commercially available emissions controls on any future CT projects.

Attention to these issues suggests the Commission should ensure that resource decision making be disciplined by a level playing field, robust competition, and a fair, equal and transparent assessment of resource alternatives. Attention to ratepayer risks in turn suggests that all bidders should be held to cost recovery fully tied to specific prices, terms and conditions submitted with their offers, and the Commission should carefully review the different risk profiles of offered projects, including future market-related risks.

In consideration of a comprehensive and transparent analysis of the levelized cost of electricity of resources competing in this procurement; the operational, efficiency, and environmental benefits of combined cycle technology relative to competing alternatives; and the value in shielding ratepayers from certain development, cost and operational risks, I conclude that Calpine's Mankato facility should be among the resources selected in this acquisition process.

Q. **Does this conclude your testimony?**

A. Yes.

Exhibit No. ___ (PJH-2)
Curriculum Vitae

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EDUCATION

Ph.D. program (coursework), Nuclear Engineering, University of California, Berkeley

M.S. in Energy and Resources, University of California, Berkeley
Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs

B.S. in Physics, University of Massachusetts, Amherst

PROFESSIONAL EXPERIENCE

2010 - Present Analysis Group, Inc., Boston, MA
Vice President

2007 - 2010 MA Department of Public Utilities, Boston, MA
Chairman
Member, Energy Facilities Siting Board
Manager, New England States Committee on Electricity
Treasurer, Executive Committee, Eastern Interconnect States' Planning Council
Representative, New England Governors' Conference Power Planning Committee
Member, NARUC Electricity Committee, Procurement Work Group

2003 - 2007 Analysis Group, Inc., Boston, MA
Vice President
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2000 - 2003 Lexecon Inc., Cambridge, MA
Senior Consultant
Consultant ('00 – '02)

1998 - 2000 Massachusetts Department of Environmental Protection, Boston, MA
Environmental Analyst

1991 - 1998 Massachusetts Department of Public Utilities, Boston, MA
Senior Analyst, Electric Power Division

1988 - 1991 University of California, Berkeley, CA
Research Assistant, Safety/Environmental Factors in Nuclear Designs

OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Advanced Energy Economy (2011).

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"Economic Impacts of RGGI," presentation to the New Hampshire Environmental Business Council, April 2012.

Testimony of Paul J. Hibbard before the California Legislature, *The Economic Impacts of RGGI's First Three Years*, California Select Committee on the Environment, the Economy, and Climate Change, March 27, 2012.

Testimony of Paul J. Hibbard before the New Hampshire Legislature, *RGGI and the Economy – Following the Dollars*, NH House Committee on Science, Technology, and Energy, February 14, 2012.

Testimony of Paul J. Hibbard before the Massachusetts Legislature, *RGGI and the Economy – Following the Dollars*, Massachusetts Senate Committee on Global Warming and Climate Change, February 13, 2012.

"Economic Impacts of RGGI: Following the Dollars," presentation (with Sue Tierney) to the California Business Climate Network, February 2012.

Hibbard, Paul J. and Susan F. Tierney, *Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years*, The Electricity Journal, December 2011.

"Public Policy Transmission: Competition and Cooperation," presentation to the Energy Bar Association Renewables Subcommittee, Washington DC, November 2011.

"Competitive Markets and Wind Power: Challenge and Opportunity," presented to the Governors' Wind Energy Coalition, Washington DC, November 2011.

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"Interdependence and Opportunity: The Growing Link Between Electricity and Natural Gas," presentation to the COGA Energy Epicenter Conference, Denver CO, August 2011.

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Exhibit PJH-3 (page 1 of 2)

Base Case Assumption in Levelized Cost of Electricity Analysis

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Exhibit PJH-3 (page 2 of 2)

Base Case Assumption in Levelized Cost of Electricity Analysis

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Exhibit PJH-4

Levelized Cost of Electricity ($/MWh)

Base Case and Sensitivities

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Exhibit PJH-5

Levelized Cost ($/MWh) by Capacity Factor

Base Case Scenario

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Exhibit PJH-6a
Emission Rates by Technology:
Nitrous Oxide (NO_x)

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

Exhibit PJH-6b

Emission Rates by Technology:

Carbon Dioxide (CO_2)

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]