BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

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	MPUC Docket No. E-002/CN-12-1240 **PETITION FOR REHEARING AND RECONSIDERATION**

Pursuant to Minnesota Statutes § 216B.27 and Minnesota Rules Part 7829.3000, Invenergy Thermal Development LLC ("Invenergy") files this Petition For Rehearing And Reconsideration ("Petition") of the Minnesota Public Utilities Commission's ("Commission") February 5, 2015 Order Approving Power Purchase Agreement With Calpine, Approving Power Purchase Agreement With Geronimo, And Approving Price Terms With Xcel ("Order") in this matter. As it stands, the Order contravenes the public interest by: (1) acting on incomplete information regarding interconnection risks associated with one of the selected projects; (2) undermining the competitive bidding process; (3) imposing excessive and unnecessary costs on ratepayers; and (4) failing to accurately reflect the record of this proceeding. If uncorrected, the Order will pass substantial and unnecessary costs on to Xcel ratepayers. Therefore, Invenergy requests oral argument on this Petition and rehearing before the Commission so that the Commission can make a fully informed decision that minimizes ratepayer costs and maintains the integrity of the bidding process.

INTRODUCTION

The Commission opened this docket following Xcel's 2010 Integrated Resource Plan docket, which found a potential need for 150 to 500 MW of new capacity in the 2017 to 2019 time frame. Since that finding, Xcel has added 750 MW of wind to its system, a solar energy standard has been enacted requiring still more new resources to be added, and Xcel's more recent forecasts consistently show lower needs. However, at the Commission's direction, Xcel negotiated and filed three power purchase agreements ("PPAs") and pricing terms for its Black Dog plant, as options to fill the perceived need.

The record establishes that the PPA associated with the Invenergy Cannon Falls project ("Invenergy PPA"): (1) causes the lowest rate impact of the four projects evaluated in this proceeding; (2) places the lowest overall costs on the Xcel system, including environmental costs, under the lower forecast contingencies that are consistent with the more recent Xcel forecasts; (3) did not add new costs or shift risks on to ratepayers when compared to Invenergy's bid, while other PPAs did so; and (4) is the resource most appropriately sized for Xcel's need. Presumably for all of those reasons, the Order correctly found that "<u>the terms of Invenergy's proposal are consistent with the public interest</u> and consistent with the prices and terms used to evaluate its bid in this process."[1]

Nonetheless, with a capacity need that appears to be well lower than the original 170 to 500 MW assumed to be needed, <u>the Order approves the three most expensive</u>

[1] Order, p. 21 (emphasis added).

resources for ratepayers, totaling over 650 MW, while not approving the Invenergy PPA. As such, the Order must be reconsidered and reversed.

I. IN APPROVING THE CALPINE POWER PURCHASE AGREEMENT, THE ORDER IMPOSES SIGNIFICANT INTERCONNECTION RISKS ON XCEL AND ITS RATEPAYERS.

In its May 23, 2014 Order Directing Xcel to Negotiate Draft Agreements with Selected Parties ("May 2014 Order") the Commission stated that, in negotiating PPAs:

> **[E]ach bidder will be held to the prices and terms used to evaluate its bid. The terms should not put ratepayers at risk for costs that are higher than bid**, or for promised levels of accredited capacity, energy, or other benefits that do not fully materialize. **The Commission is not likely to regard as reasonable any terms that shift risk or unknown costs to ratepayers.**[2]

After a thorough review of the PPAs, the Department of Commerce – Division of Energy Resources ("DER") stated as follows:

> In evaluating the Calpine proposal in Strategist, the Department included $1.5 million in potential transmission interconnection costs. During the proceeding, the Department made clear that it did not view proposals that place unknown financial risks on ratepayers to be reasonable. Further, as noted above, the Commission stated that: **The Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers.**
>
> **Despite this directive from the Commission, the draft PPA with Calpine places the risk for additional interconnection costs on Xcel and its ratepayers. According to Xcel, the Company sought to limit its exposure to this risk, but Calpine would not agree.** In response to a Department Information Request, the Company indicated that it did not know the likelihood or extent to which interconnection costs may exceed $1.5 million. As **the treatment of interconnection costs places an unknown cost on Xcel ratepayers**, the Department concludes that this portion of the draft PPA is unreasonable.[3]

---

[2] May 2014 Order, p. 35 (emphasis added).
[3] DER Comments, October 23, 2014, p. 17 (emphasis added).

Calpine's demand that Xcel bear the full risk of interconnection costs above the amount originally set forth in Calpine's bid is understandable. No developer wishes to bear the risk of increased costs. These risks are not insignificant. In fact, the overall risk associated with Calpine's interconnection may have increased dramatically since the submission of the PPA.

On December 12, 2014, after oral argument in this matter and on the eve of the Commission's deliberations, the Federal Energy Regulatory Commission ("FERC") issued a Deficiency Letter to Midcontinent Independent System Operator, Inc. ("MISO"), related to Calpine's Amended and Restated Generator Interconnection Agreement ("GIA") for the Mankato expansion.[4] Specifically, the Deficiency Letter points out that the GIA amends the Commercial Operation Date for the Mankato expansion from June 1, 2007 to June 1, 2018 without an explanation of why such an 11 year extension is appropriate.[5]

On January 30, 2015, Invenergy filed a Motion to Intervene and Protest with FERC on this matter.[6] While the issues surrounding the GIA are properly before FERC, not this Commission, the Commission should be aware that the issue of interconnection risk associated with the Calpine project is not trivial or hypothetical, but real and potentially significant. Under the Order, and the PPA between Calpine and Xcel that the Order approves, Xcel and its ratepayers now bear the additional costs associated with this risk – a result not consistent with the public interest.

[4] FERC Deficiency Letter attached as Exhibit A.
[5] Exhibit A, pp. 1-2.
[6] Motion to Intervene and Protest attached as Exhibit B.

II. BY APPROVING POWER PURCHASE AGREEMENTS INCONSISTENT WITH PARTIES' ORIGINAL BIDS, THE ORDER CONTRADICTS PRIOR COMMISSION DIRECTION AND UNDERMINES THE COMPETITIVE BIDDING PROCESS IN MINNESOTA.

Perhaps equally troubling to the magnitude of the risks shifted to Xcel and its ratepayers is the fact that under the Commission's prior Order in this matter, such a shift should never have occurred. The May 2014 Order clearly stated that, in negotiating PPAs:

> **[E]ach bidder will be held to the prices and terms used to evaluate its bid. The terms should not put ratepayers at risk for costs that are higher than bid**, or for promised levels of accredited capacity, energy, or other benefits that do not fully materialize. **The Commission is not likely to regard as reasonable any terms that shift risk or unknown costs to ratepayers.**[7]

Again, in reviewing the PPAs, DER noted that:

> **Despite this directive from the Commission, the draft PPA with Calpine places the risk for additional interconnection costs on Xcel and its ratepayers. According to Xcel, the Company sought to limit its exposure to this risk, but Calpine would not agree.** In response to a Department Information Request, the Company indicated that it did not know the likelihood or extent to which interconnection costs may exceed $1.5 million. As **the treatment of interconnection costs places an unknown cost on Xcel ratepayers,** the Department concludes that this portion of the draft PPA is unreasonable.[8]

Commission Staff similarly noted that:

> **Calpine's PPA shifts the interconnection cost risk to ratepayers.** During the PPA evaluation, the Department included $1.5 Million as an estimated transmission interconnection cost. The draft PPA does not cap the transmission line interconnection cost at $1.5 million; therefore,

[7] May 2014 Order, p. 35 (emphasis added).
[8] DER Comments, October 23, 2014 ("DER Comments"), p. 17 (emphasis added).

> **<u>ratepayers are exposed to the interconnection cost risk in any amount above $1.5 million.</u>**[9]

Of course, since none of the economic analysis conducted in this proceeding included any such additional interconnection related costs, the Commission is left to speculate, not just to the magnitude of these costs, but to their impact on the overall economic analysis of the various projects considered. At minimum, these prior economic analyses of the Calpine proposal now have diminished value, since they do not reflect the full potential cost of the project.

Moreover, interconnection costs were not the only area where the Calpine PPA deviated from the terms included in the Calpine bid. DER also noted that:

> In addition, the price terms were changed from those bid to mirror the same terms in the existing Mankato Energy Center PPA. **<u>This change added a dispatchability payment that was not included in Calpine's bid</u>**.[10]

Staff Briefing Papers too noted this change from the terms bid, stating that:

> Calpine's draft PPA also **<u>includes a dispatchability payment that was not included in Calpine's bid.</u>** The Department concludes that the dispatchability payment is an unreasonable addition to the draft Calpine PPA since the Commission's order required all parties to be held to the prices of their initial bid.[11]

Again, since the dispatchability payment was not presented in the bid terms, these payments have not been included in any economic modeling of the Calpine proposal.[12] Therefore, the Commission is left with an inaccurate and overly conservative picture of the full economic impact of the Calpine proposal.

---

[9] Staff Briefing Papers for December 8 and December 15, 2014 ("Briefing Papers"), p. 20 (emphasis added).
[10] DER Comments, p. 16 (emphasis added).
[11] Briefing Papers, p. 20.
[12] The Order states that there may be offsetting revenues to balance out the increased costs. Order, p. 14. However, there is no record evidence to support this speculation, put forth by Xcel and Calpine for the first time during Commission deliberations of this matter.

The inclusion of new terms and the shifting of risk from a bid to a PPA have broader impacts than just the direct ratepayer impacts. In this proceeding, the Commission could not have been clearer on its expectations. The Commission's May 2014 Order directly commanded:

> Calpine, Geronimo, Invenergy, and Xcel **shall be held to the prices and terms used to evaluate each bid** for the purpose of cost recovery from Xcel ratepayers. **Ratepayers must not be put at risk for costs that are higher than bid** or for benefits assumed in bids that do not materialize.[13]

Invenergy followed these instructions and negotiated a PPA that shifted no risks to ratepayers and that added no new costs. In contrast, the Calpine PPA adds a new dispatchability payment to Calpine and shifts potentially significant interconnection risks off of Calpine and to Xcel and its ratepayers. Not only do these changes render the prior comparative economic analyses of Calpine's proposal little value, they undermine the competitive bidding process in Minnesota going forward.

If the Order stands, all future bidders will need to enter PPA negotiations knowing that other bidders may well alter the terms of their bids and that changed terms may well be accepted by the Commission. The result will be to encourage all bidders to re-negotiate from the terms originally bid.

If the Order stands, future bidders and Xcel will need to speculate as to the magnitude of the changes from bid terms that the Commission may approve.

If the Order stands, a once reasonably transparent process becomes significantly less transparent in its next iteration.

---

[13] May 2014 Order, p. 36 (emphasis added).

None of this fosters competitive bidding in Minnesota and none of this breeds public or bidder confidence in the integrity of the process.

III. THE ORDER APPROVED THE THREE MOST EXPENSIVE RESOURCES FOR RATEPAYERS.

As discussed above, the change in terms from Calpine's bid to its PPA impacts the conclusions that can be drawn from the prior Strategist modeling conducted by Xcel and DER. However, even without reflecting the additional costs of the Calpine proposal, the record demonstrates that the Invenergy Cannon Falls project is the least cost resource for ratepayers.

Both DER and Commission Staff noted that under the lower forecast contingencies, Invenergy's Cannon Falls project was commonly a least-cost result.[14] Moreover, when looking at the direct ratepayer impact, Xcel acknowledged that the Cannon Falls project will impose substantially lower revenue requirements demands on ratepayers than the Calpine proposal.[15] In fact, Xcel even acknowledged that the Cannon Falls project would have a smaller rate impact than its own Black Dog facility.[16] Finally, as the Order itself states, "the record also shows that when analyzed as part of a system, Geronimo's proposal incurs the highest costs."[17]

Invenergy respectfully submits that it cannot be in the public interest for the Order to approve the three highest cost projects, while rejecting the lowest cost project. Similarly, it cannot be in the public interest for the Order to approve the highest cost

[14] DER Comments, p. 14; Briefing Papers, p. 21.
[15] Xcel September 23, 2014 Compliance Filing, Trade Secret version, pp. 15 and 17.
[16] Ex. 44, pp. 42-43 (Wishart Direct).
[17] May 2014 Order, p. 32 (emphasis added).

project for ratepayers (Geronimo) and to approve a project with unknown total costs (Calpine) but that indisputably imposes higher revenue requirements on ratepayers, while at the same time not approving the one project that entered into a PPA consistent with the terms of its bid (Invenergy).

IV. THE ORDER FAILS TO ACCURATELY REFLECT THE RECORD OF THIS PROCEEDING.

In its brief discussion of the Invenergy Cannon Falls project, the Order fails to accurately reflect the record, requiring correction. First, the Order states that "when the Department identified the least-cost package of generators to meet Xcel's forecasted need, it did not include Invenergy's proposal as part of the package."[18] The statement misstates the record in multiple ways. As discussed above, the Department's modeling did not consider the full cost of the Calpine PPA, since Calpine added new costs and shifted interconnection cost risk on to ratepayers after the completion of all modeling. Further, in referring to "Xcel's needs," presumably the Order continues to refer to the needs as determined in Xcel's 2010 Resource Plan docket and not the more recent forecasted needs showing a lower overall need. In fact, as discussed above, under the lower forecast scenarios the Department's analysis consistently showed the Invenergy project to be the least cost alternative. Finally, the Order neglects the analysis of Xcel itself that shows substantially lower overall revenue requirements associated with the Invenergy Cannon Falls project as compared to either Black Dog or the Calpine project.

[18] Order, p. 31.

Second, the Order raises concerns regarding the interruptible gas supply to be used at Cannon Falls, stating:

> Securing fuel on an interruptible basis is cheaper, but exposes the generator to a risk that the fuel supply would be cut off, especially during periods of peak demand for natural gas. It is unclear how well a 28-hour supply of fuel oil would offset this risk, especially in extreme cold when demand for gas is likely to be at its highest.[19]

In fact, the record demonstrates that operating a peaking facility such as Cannon Falls with interruptible gas supply makes sense and saves ratepayers significant expense.[20] As both Invenergy and Xcel explained, the Xcel system peaks in the summer when gas supply is readily available.[21] Both companies also explained that the existing Cannon Falls facility operated by Invenergy has historically seen the vast majority of its operating hours in the summer, to meet those peak needs, with only forty hours of operation in the past four winters combined.[22] In addition, the Cannon Falls facility will have an ample back-up supply of fuel oil in the unlikely event that the facilities will be called upon when natural gas is not available.[23]

The current Cannon Falls facility operates with an interruptible gas supply and the record is devoid of evidence indicating that this has created concerns.[24] The record demonstrated that Xcel has other peaking plants on its system that use an interruptible gas supply and the company has always found itself "to have more than sufficient resources during the winter months. We've always found ourselves to have plenty of capacity in

---

[19] *Id.*
[20] Ex. 69, pp. 8-9 (Ewan Rebuttal).
[21] *Id.*; Ex. 47, p. 21 (Wishart Rebuttal).
[22] *Id.*
[23] Ex. 69, p. 9 (Ewan Rebuttal).
[24] *See, e.g.,* Transcript Vol. 2, pp. 33-34 (Shah).

the winter and having those units on interruptible gas has not been a problem."[25] Similarly, "the units have always run reliably during the summer months."[26]

Xcel acknowledged that "the use of an interruptible natural gas supply can deliver significant cost savings without a significant impact on reliability, so long as the unit can operate on back-up fuel oil or there are other system units available to meet the demand."[27] Xcel further testified that it is "very unlikely" that the Invenergy project would ever be dispatched in the winter and that it is "very unlikely" that gas supply to the facility would ever be interrupted in the summer.[28] Even so, Xcel modeled the Invenergy project assuming no available natural gas in the winter months and no back-up fuel oil supply. Even with these extreme assumptions, "the project's cost effectiveness does not change."[29] As such, the record cannot possibly support a finding that Invenergy's use of an interruptible gas supply causes any concern that would warrant selection of higher cost resources.

CONCLUSION

The stakes in this docket are high. The decisions made by the Commission will result in tens of millions of dollars being borne by ratepayers over the next twenty years. As it stands, the Order selects the three highest cost resources for ratepayers, one of which also passes unknown future costs on to ratepayers. In addition, the Order permits one bidder to add new terms and to change other terms, shifting risk on to Xcel and its

---

[25] Transcript Vol. 1, p. 118 (Wishart).
[26] *Id*., p. 119.
[27] Ex. 47, p. 20 (Wishart Rebuttal) (emphasis added).
[28] Transcript Vol. 1, pp. 117-118 (Wishart).
[29] Ex. 47, pp. 20-21 (Wishart Rebuttal).

ratepayers, creating a dangerous precedent for future bidding dockets. For these reasons and as discussed above and in its prior pleadings, Invenergy respectfully requests that the Commission rehear this matter, reconsider its Order and approve the Invenergy PPA – the lowest cost resource for Xcel ratepayers.

Dated: February 25, 2015

WINTHROP & WEINSTINE, P.A.

By: */s/ Eric F. Swanson*
Eric F. Swanson

225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402
(612) 604-6400

ATTORNEYS FOR INVENERGY THERMAL DEVELOPMENT LLC

10029606v1

EXHIBIT A

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Midcontinent Independent System
Operator, Inc.
Docket No. ER15-104-000

December 12, 2004

Midcontinent Independent System Operator, Inc.
P.O. Box 4202
Carmel, IN 46082-4202

Attention: Jacob T. Krouse
Attorney for Midcontinent Independent System Operator, Inc.

Reference: Filing of Amended and Restated Generator Interconnection Agreement

Dear Mr. Krouse:

On October 15, 2014, Midcontinent Independent System Operator, Inc. (MISO) submitted an Amended and Restated Generator Interconnection Agreement (Interconnection Agreement) between Mankato Energy Center, LLC (Interconnection Customer), Northern States Power Company, a Minnesota corporation (Transmission Owner), and MISO. MISO requests that the Commission accept the Interconnection Agreement for filing effective October 16, 2014.

Please be advised that your filing is deficient and that additional information is required by the Commission in order to process the filing. Please provide the information requested below:

> On page 2 of its transmittal letter, MISO states that this filing amends the original interconnection agreement to reflect that the Interconnection Customer is completing its build out of the Large Generating Facility, which requires installation of Network Upgrades on the Transmission Owner's Transmission System, and that Phase 1 has been completed and updates have been reflected in the Interconnection Agreement. MISO specifically discusses amendments to section 5.9 and section 11.4.1 of the Interconnection Agreement. MISO does not, however, discuss the fact that various appendices to the

> Interconnection Agreement have also been amended. Among other changes, the Commercial Operation Date for Phase 2 of the project has been amended from June 1, 2007 to June 1, 2018.
>
> With respect to the proposed new Commercial Operation Date of Phase 2 of the project, please provide an explanation for why the proposed extension of 11 years (June 1, 2007 to June 1, 2018) is appropriate under MISO's Generation Interconnection Procedures and this agreement. In your response, please explain all factors that MISO took into consideration in reaching its conclusion that the proposed extension is appropriate.

This letter is issued pursuant 18 C.F.R. § 375.307 (a)(1)(v) and is interlocutory. This letter is not subject to rehearing pursuant to 18 C.F.R. § 385.713. MISO must respond to this letter within 30 days of the date of this letter by making an amendment filing in accordance with the Commission's electronic tariff requirements.[1]

Please also email an additional electronic copy of the response to Mr. Nicholas Snyder at Nicholas.Snyder@ferc.gov.

The information requested in this letter will constitute an amendment to your filing, and a new filing date will be established, pursuant to *Duke Power Company*, 57 FERC ¶ 61,215 (1991), upon receipt of MISO's electronic tariff filing. A notice of amendment will be issued upon receipt of your response.

Failure to respond to this deficiency letter within the time period specified may result in an order rejecting your filing. Until receipt of the amendment filing, a filing date will not be assigned to your filing.

Sincerely,

Penny Murrell, Director
Division of Electric Power
Regulation – Central

---

[1] *Electronic Tariff Filings*, 130 FERC ¶ 61,047, at PP 3-8 (2010) (an amendment filing must include at least one tariff record even though a tariff revision might not otherwise be needed).

Document Content(s)

EXHIBIT B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	))	Docket Nos. ER15-104-000 ER15-104-001

MOTION TO INTERVENE AND PROTEST OF
INVENERGY THERMAL DEVELOPMENT LLC AND
INVENERGY WIND DEVELOPMENT LLC

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] Invenergy Thermal Development LLC and Invenergy Wind Development LLC (collectively, "Invenergy") hereby move to intervene and protest the filing submitted by the Midcontinent Independent System Operator, Inc. ("MISO") of an Amended and Restated Generation Interconnection Agreement ("Amended GIA") among MISO, Northern States Power Company, and Mankato Energy Center, LLC ("Mankato).[2] As discussed herein, MISO has not adequately responded to the Commission's deficiency letter concerning MISO's proposal to amend Mankato's 2004 Large Generator Interconnection Agreement ("Original Agreement") to extend the commercial operation date ("COD") for Phase II of Mankato's generation facility from June 1, 2007 to June 1,

---

[1] 18 C.F.R. §§ 385.212 and 214 (2014).

[2] *See* Midcontinent Independent System Operator, Inc., "Filing of Amended and Restated Generator Interconnection Agreement" Docket No. ER15-104-000 (Oct. 15, 2014).

2018.[3] In addition, the information provided in the Deficiency Response indicates that MISO has improperly applied Section 2.3.1 of the Original GIA to have allowed Mankato to extend the suspension period set forth in the Original GIA from three years to six years. While Invenergy believes that there is no absolute bar in the Original GIA or in MISO's Generator Interconnection Procedures ("GIP")[4] to an extension of the COD for eleven years, MISO failed to follow the proper procedures in changing the COD here. Specifically, MISO failed to evaluate whether the revised COD would constitute a Material Modification under the Original GIA and the MISO GIP. Accordingly, Invenergy requests that the Commission specifically seek further explanations from MISO and also generally clarify the applicability of Section 2.3.1 of the Original GIA and Section 3.3.1 of the MISO GIP in processing requests for COD extensions. MISO also should be required to show that MISO has applied its practices consistently to developers of generation projects in MISO, or that Invenergy and others developing generation projects in MISO have not otherwise been harmed by MISO's practices.

Market participants have no way routinely to monitor MISO's administration of its queue and GIAs. Accordingly, they must rely on the Commission's oversight. Therefore, the Commission should take the steps recommended herein to determine

---

[3] *See* Staff Letter to MISO, Docket No. ER15-104-000 (Dec. 12, 2014) ("Deficiency Letter") (advising MISO of deficiency in filing) and MISO Response to Letter Requiring Additional Information, Docket No. ER15-104-001 (Jan. 9, 2015) ("Deficiency Response").

[4] *See* MISO Transmission and Energy Markets Tariff ("MISO Tariff"), Attachment X.

whether MISO is properly and consistently administering its tariff and its interconnection queue.

I. MOTION TO INTERVENE

Invenergy Wind Development LLC and Invenergy Thermal Development LLC are limited liability companies organized and existing under the laws of the state of Delaware, each having its principle place of business in Chicago, Illinois. Invenergy and its affiliates develop, own, operate and manage large-scale electricity generation assets in North America. Invenergy-affiliated companies currently have over 2,200 MW of natural gas-fueled electric generating projects in operation, 900 MW in construction and wind energy projects totaling over 5,400 MW in operation around the country.

Invenergy has a substantial interest in the outcome of this proceeding that no other party can adequately represent, and therefore moves to intervene. Its participation in this docket is in the public interest.

II. COMMUNICATIONS

Invenergy requests that all pleadings, correspondence and other communications concerning this docket be directed to the following persons, and their names and addresses be placed on the official service list for this docket:

Jason Minalga Manager, Commercial Analytics and Regulatory Affairs Invenergy LLC One South Wacker Drive Suite 1900	Pat Alexander Matthew B. Welling Crowell & Moring LLP 1001 Pennsylvania Ave., NW Washington, DC 20004-2595 Tel: (202) 624-2788

Chicago, IL 60606
Tel: (312) 582-1500
Fax: (312) 224-1444
jminalga@invenergyllc.com

Fax: (202) 628-5116
palexander@crowell.com
mwelling@crowell.com

III. BACKGROUND

The facts surrounding this filing are extraordinary in that Mankato first submitted its request to interconnect its two phased project on October 11, 2002, more than 13 years ago, requesting a COD of June 1, 2007 for the second phase of the project, more than seven years ago.[5] In 2004, Mankato entered into an interconnection agreement governing both phases (the "Original Agreement"). However, Mankato failed to develop Phase II in a timely manner and, now, in the Amended GIA, MISO proposes to allow Mankato to extend its June 1, 2007 COD to June 1, 2018—more than 16 years after the interconnection request was filed and more than 11 years after the COD set forth in the Original Agreement.[6]

Under Section 5.16 of the Original Agreement, Mankato could have suspended construction of the transmission owner interconnection facilities and network upgrades for up to three years. Had it done so, other key milestones, such as the COD, also

[5] Deficiency Response at 2.

[6] *See* Interconnection and Operating Agreement entered into by the Midwest Independent Transmission System Operator, Inc., Northern States Power Company d/b/a Xcel Energy, and Mankato Energy Center, LLC, Docket No. ER05-344-000, Appendix B (Dec. 16, 2004).

would have been extended.[7] Accordingly, under the Original Agreement, Mankato could have extended its Phase II COD to June 1, 2010. What is not clear, though, about the Amended GIA and the accompanying filing, is which provisions of the Original GIA or of MISO's GIP ostensibly permit Mankato to extend its COD eight years more—to June 1, 2018, more than 11 years after the initial June 1, 2007 COD set forth in the Original Agreement. It also is unclear what tariff rules or policies MISO relies upon in deciding not to terminate the Original GIA upon Mankato's failure to develop its project on the required schedule.

In light of these circumstances, on December 12, 2014, Commission staff issued the Deficiency Letter noting that, in its October 15 Filing, MISO failed to disclose the fact that it had agreed to extend the proposed COD for Mankato by more than eleven years, and requiring that MISO explain why it thought this eleven year extension was appropriate under MISO's GIP, and to include in such explanation all the factors MISO took into account in reaching its conclusion.[8]

MISO's rather terse Deficiency Response, though, raises more questions than it answers. MISO simply says that, pursuant to Section 2.3.1 of the Original GIA, it waited an additional three years beyond the extension permitted under the suspension provisions before "considering whether to file to terminate Phase II of the GIA for

[7] *See PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,079 at PP 63, 65 (2012) (noting that milestone dates, including COD, may be revised to account for the impact of suspension).

[8] Deficiency Letter at 1-2.

failing to reach Commercial Operation."[9] MISO says that at some point between June 1, 2010 and June 1, 2013 (which date is not disclosed in the Deficiency Response), Mankato informed MISO it was ready to proceed with Phase II. MISO then decided to restudy the Phase II interconnection "before recommencing the interconnection process."[10] After performing those studies (which are not described as to substance or timing in the Deficiency Response), MISO determined that a June 1, 2018 COD would allow Phase II to "reliably enter Commercial Operation due to the timing of other projects that must be in-service for Phase II to proceed."[11] MISO further asserts that, although interconnection customers "may choose to utilize MISO's limited operations provisions prior to completion of other projects' Network Upgrades (often with long-term In-Service Dates), such customers are not required to do so."[12] Since certain of the contingent transmission upgrades have In-Service Dates in 2018, MISO states it agreed to a COD of June 1, 2018.

IV. PROTEST

A. The Commission Should Request Further Information

Although Invenergy has developed and is continuing to develop projects in MISO, Invenergy is surprised to learn that MISO's interpretation of its GIP and its GIA

---

[9] Deficiency Response at 2.

[10] *Id.*

[11] *Id.*

[12] *Id.* at 2-3.

terms are as flexible as those apparently applied to Mankato. As a developer, Invenergy—and no doubt other developers—could benefit from the flexibility afforded Mankato in this proceeding. At the same time, lack of clarity as to how MISO's GIP and GIA terms will be applied obviously creates operational challenges and regulatory uncertainty, threatening the ability of project developers to successfully bring projects to market. All developers, regardless of size, must be assured of nondiscriminatory treatment.

As noted above, MISO has yet to provide a fulsome recital of the facts surrounding its processing of Mankato's interconnection request—making it difficult to determine whether MISO properly implemented its tariff or implemented it in a nondiscriminatory manner.

Invenergy believes that the Deficiency Response falls short of providing the Commission with the information needed to evaluate the reasonableness of the Amended GIA and MISO's administration of its interconnection queue. Only with this information in hand might the Commission be able to resolve the issues raised in the October 15 Filing and the Deficiency Response. Accordingly, Invenergy recommends that MISO be directed to:[13]

[13] To the extent that MISO asserts that any of the following information should receive confidential treatment, Invenergy requests that the Commission direct MISO to update the Protective Agreement in this docket to cover such information. *See* MISO's Filing of Amended and Restated Generator Interconnection Agreement, Docket No. ER15-104-000 at Tab C (CEII Protective Agreement) (Oct. 15, 2014).

1. Identify the date when Mankato provided MISO with a suspension notice and the date Mankato specified as the end of the suspension period, and provide a copy of the suspension notice.
2. Identify the date following June 1, 2010 when Mankato informed MISO that it intended to develop Phase II; identify the proposed COD that Mankato proposed at the time it provided such notification; provide copies of the relevant documentation; and, to the extent this date was not on or around June 1, 2010, explain what steps MISO took to evaluate Mankato's plans with respect to Phase II prior to receiving such notification.
3. To the extent MISO did not immediately agree to allow Mankato to extend its COD beyond June 1, 2010, subject to restudy, identify the date when MISO determined it would accommodate Mankato's request subject to restudy.
4. Explain whether MISO performed a Material Modification analysis, which is required when an interconnection customer seeks to extend its commercial operation date.[14] If MISO did perform a Material Modification analysis, provide details as to the analysis performed and

---

[14] *See* MISO Tariff, Attachment X and Article 1 of the Original Agreement and the Amended GIA. Material Modification is defined as a modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

support for its determination that there would be no impact of the timing or costs of other projects in the queue as a result of extending Mankato's COD. If no Material Modification study was performed, explain why not.

5. Explain what study process was adopted; whether MISO put Mankato into the next scheduled Definitive Planning Phase ("DPP") study; and if it did not, why it did not; what study process was undertaken, and what assumptions were made as to (i) which projects in the generation queue would be in service, (ii) which as yet unconstructed interconnection-related upgrades were assumed to be in service, (iii) which other transmission projects were expected to be in service, and (iv) how these assumptions compare to those made with respect to the next scheduled DPP.
6. Explain whether Mankato was required to post security in accordance with the GIP revisions adopted after the Original GIA was executed,[15] and if not, why not.
7. Explain whether and as of when Mankato's Phase II capacity has been included in interconnection study models, i.e., reserved to Mankato, at all times since the submission of Mankato's interconnection request.

---

[15] MISO Tariff, Attachment X at Section 8.2.

8. Identify the dates when the contingent transmission projects will go into service, and if those dates differ from the proposed June 1, 2018 COD, explain the discrepancy.
9. Explain the basis for MISO's belief that Section 2.3.1 allows interconnection customers an additional three years before being required to forfeit any capacity not developed in accordance with the schedule in the applicable GIA; whether MISO has afforded all interconnection customers this flexibility and, if not, why not; identify all GIAs that have been modified or terminated after their stated COD to reduce interconnection capacity; demonstrate that on all such occasions the interconnection customers were afforded the three year benefit that MISO believes is provided under Section 2.3.1; and when applying Section 2.3.1 in this manner, explain whether MISO has applied the same protocol to projects that failed to meet a COD but did not request suspension, and, if not, explain the differing treatment.
10. Explain whether Mankato met all applicable milestones in the Original GIA in a timely manner and, if not, explain MISO's practice with respect to termination of a GIA for failure to meet milestones.

B. The Commission Should Address Two Key GIP and GIA Provisions.

However, there are already two issues that clearly require Commission clarification.[16]

1. Applicability of Section 2.3.1

Section 2.3.1 of the Original Agreement and the Amended GIA states:

> Written Notice: This LGIA may be terminated by Interconnection Customer after giving the Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice or by Transmission Provider if the Generating Facility has ceased Commercial Operation for three (3) consecutive years, beginning with the last date of Commercial Operation for the Generating Facility, after giving the Interconnection Customer ninety (90) Calendar Days advance written notice. The Generating Facility will not be deemed to have ceased Commercial Operation for purposed of this Section 2.3.1 if the Interconnection Customer can document that it has taken other significant steps to maintain or restore operation readiness of the Generating Facility for the purpose of returning the Generating Facility to Commercial Operation as soon as possible.

MISO says this section provides for an automatic three year extension of the COD for a yet-to-be constructed generation facility, and that such three year period is in addition to the three year suspension period. However, based on past experience, Invenergy understood this provision to address circumstances in which a project has gone into commercial operation but subsequently gone out of service, e.g., was on an extended outage, idled for economic reasons, mothballed, or retired. In fact, when

[16] Obviously, the issues here implicate similar provisions similar provisions in the Commission's *pro forma* Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA") and, thus, have import not only for MISO, but for other transmission providers and independent system operators.

MISO requested permission to depart from the *pro forma* LGIA Section 2.3.1 language to adopt this provision, MISO explained:

> In furtherance of robust wholesale markets, interconnection (and transmission) capacity should not be held indefinitely. If after an extended dormant period, the Interconnection Customer wishes to <u>again</u> operate its Large Generating Facility, system conditions may have changed, warranting a review of the Facility's operation by way of an Interconnection Request. The proposed three-year period in which <u>the Facility</u> has been <u>essentially retired</u> corresponds to the maximum time (i.e., three years) that a developer may suspend interconnection facility construction with regard <u>to a prospective generating facility</u> without also facing requirements to re-examine system conditions. In both instances the Generating Facility should not be allowed to impede commerce if it has not achieved commercial operation or subsequently ceases commercial operation for three years.[17]

Clearly, when MISO justified this provision to the Commission, it did not suggest it could be used to provide an automatic three-year extension to the COD of a yet to be constructed project, in addition to the three year suspension period. To the contrary, the basis for revising Section 2.3.1 was to better define when MISO could deem a project which had been in commercial operation to have been retired and to justify the choice of three years because it was consistent with—not additive to—the three year suspension.

Consequently, because Section 2.3.1 did not provide Mankato with the automatic right to a second three year deferral of its Phase II COD, MISO had no authority under the GIA even to grant Mankato an extension to June 1, 2013, let alone to June 1, 2018.

---

[17] Midwest Independent Transmission System Operator, Inc., Docket No. ER04-458-003 (Sept. 7, 2004), Transmittal Letter at 8 (emphasis added). MISO was required to support this departure from the *pro forma* LGIA, Section 2.3.1 which provides only that the Transmission Provider can terminate an LGIA by notifying FERC after the Generating Facility permanently ceases Commercial Operation.

This does not mean that Mankato could not have requested a revised COD. It does mean, however, that such a request should have been evaluated as a Material Modification and granted only if MISO determined that this would have no material impact on the cost or timing of any interconnection customer with a later queue date.[18] Based on the limited information that MISO has shared with the Commission at this point, it does not appear that the Commission-approved process was followed.

2. Applicability of Section 3.3.1 of the MISO's GIP

Invenergy notes that some transmission providers take the position that, under Section 3.3.1 of the LGIP (which is consistent with Section 3.3.1 of the MISO GIP), there is a prohibition on proposing at the application stage a COD that extends more than ten years beyond the date of an Interconnection Request (which here would be a date in 2012).[19] This provision by its own terms applies only to the COD requested at the application stage. Thereafter, a COD can be extended day-for-day beyond the ten year period to account for the impact of a suspension period; it can be extended under the Material Modification procedures and standards; it can be extended to the extent MISO

---

[18] *See Judith Gap Energy LLC and Northwestern Corporation*, 125 FERC ¶ 61,169 at PP 14 and 20 (2008).

[19] Section 3.3.1 of the LGIA provides, *inter alia*, that the proposed In-Service Date shall not exceed seven years from the date of the Interconnection Request, unless the customer demonstrates that engineering, permitting and construction of the facility will take longer than the regional expansion planning period. It also says that the In-Service Date may succeed the date of the Interconnection Request "by a period of up to ten years, or longer where Interconnection Customer and Transmission Provide agree, such agreement not to be unreasonably withheld." The In-Service Date, the day upon which the Interconnection Customer reasonably expects to be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power, precedes the COD. However, COD is used throughout the discussion here for simplicity.

is unable to complete its studies prior to the requested COD; and it can be extended to the extent the initial upgrade studies indicate that the time needed to construct such upgrades require a schedule delay and the interconnection customer is willing to extend its COD accordingly. Accordingly, the Commission should clarify that, even if MISO misapplied certain aspects of its GIP and provisions of the Original Agreement, this does not mean that Section 3.3.1 of the GIP in and of itself prohibits accommodating a COD for any project that extends more than ten years beyond the date of the Interconnection Request.

3. Inconsistencies in MISO's Application of GIPs and GIAs

Invenergy is concerned that MISO might have been inconsistent in how it deals with projects that fail to meet their CODs. In previous discussions with MISO as to what provisions, if any, require an interconnection customer to forfeit capacity that was not developed by the COD set forth in the GIA, MISO's position has been that it had an obligation to to amend GIAs to reduce or "free-up" unused capacity, and that if the developer wanted to develop the rest of the planned capacity, it would be required to make a new Interconnection Request. The Commission should ensure that there is no inconsistency in applying the MISO GIP and GIA to different developers, and that developers receive the nondiscriminatory treatment necessary to foster competition in MISO.

Market Participants have no way to routinely monitor MISO's administration of its queue and GIAs. Accordingly, they must rely on the Commission's oversight. As discussed herein, this filing raises a number of concerns about whether MISO is properly administering its tariff and its interconnection queue, and the Commission should require MISO to address the issues raised herein.

V. CONCLUSION

Invenergy requests that the Commission require further explanations from MISO as to its administration of the Original Agreement and Mankato's COD extension, and clarify the applicability of Section 2.3.1 of the Original Agreement and Section 3.3.1 of the MISO GIP as discussed herein, and take steps to ensure that MISO administers its interconnection process consistently.

Respectfully submitted,

/s/ Larry F. Eisenstat

Larry F. Eisenstat
Matthew B. Welling
Crowell & Moring LLP
1001 Pennsylvania Avenue NW
Washington, DC 20004
Tel: (202) 624-2600
leisenstat@crowell.com
mwelling@crowell.com

Counsel for Invenergy Thermal Development LLC and Invenergy Wind Development LLC

Pat Alexander
Senior Policy Advisor
Crowell & Moring LLP
1001 Pennsylvania Avenue NW
Washington, DC 20004
Tel: (202) 624-2788
palexander@crowell.com

January 30, 2015

CERTIFICATE OF SERVICE

I hereby certify that the foregoing document has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 30th day of January, 2015

/s/ Matthew B. Welling
Matthew B. Welling
Crowell & Moring LLP
1001 Pennsylvania Ave., NW
Washington, DC 20004
mwelling@crowell.com