OVERLAND LAW OFFICE/LEGALECTRIC

1110 WEST AVENUE
RED WING, MN 55066
(612) 227-8638

Docket Number: ET6675/CN-12-1053 Date of Request: February 17, 2014

Requested From: David Grover Response Due: February 27, 2014

Party Requesting Information: Carol A. Overland for No CapX2020 and CETF

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
1	Please provide No CapX 2020 and CETF with electronic copies of all Information Requests made by Commerce, and provide all responses to Information Requests from parties other than No CapX 2020 and CETF made to date and in the future throughout this entire proceeding.
Response:	The only information requests that ITC Midwest has received and responded to were from the Department of Commerce, Division of Energy Resources ("DOC-DER"). Attached are ITC Midwest's responses to the following DOC-DER Information Requests: Nos. 1-19 and 26-29. DOC-DER Information Requests Nos. 20-25 were directed to MISO. Also attached are supplemental responses to Information Request Nos. 11 and 13. ITC Midwest will provide responses to future Information Requests to NoCapX 2020 and CETF.

Response by: David Grover

Title: Manager

Department: Regulatory Strategy

Telephone: (651) 222-1000 x2308

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053   Date of Request: May 29, 2013

Requested From: David Grover   Response Due: June 10, 2013
Manager, Regulatory Strategy

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
1	Please explain how ownership of each of the segments of Minnesota portion of the project was determined.
Answer	As discussed in Sections 1.2 and 2.2 of the Application, MVP Project 3 facilities in Minnesota and Iowa are being constructed jointly by ITC Midwest and MidAmerican Energy. MVP Project 3 connects the facilities of ITC Midwest and MidAmerican, and under the provisions in Section VI of Appendix B of the Transmission Owners' Agreement[1] the ownership and responsibility to construct the project belong equally to ITC Midwest and MidAmerican. As usually occurs for joint projects in MISO, ITC Midwest and MidAmerican met to determine the facilities to be constructed by each transmission owner and divided the responsibility to construct project facilities on a basis that results in each Owner constructing approximately 50% of MVP Project 3. [continues on next page]

[1] Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (MISO).

ITC Midwest owns the existing facilities[2] in Minnesota (Lakefield Junction and Winnebago substations). ITC Midwest also owns the first MVP Project 3 connection point in Iowa from Minnesota (Winnco Substation). The existing 161 kV transmission line between these facilities that parallels the Minnesota portion of MVP 3 is also owned by ITC Midwest. Based on these factors, ITC Midwest and MidAmerican agreed that ITC Midwest would own the MVP Project 3 facilities in Minnesota.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	651.222.1000, Ext. 2308	

[2] The substation names referenced in this response refer to the names that were identified by MISO in its analysis and approval of MVP Project 3.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: May 30, 2013

Requested From: David Grover Response Due: June 11, 2013
Manager, Regulatory Strategy

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
2	Please provide copies of all information request responses made by ITC Midwest to parties or participants to date and in the future for the duration of the proceeding.
Answer	ITC Midwest has not received any requests for information as of the date of this response. ITC Midwest will copy the Department-DER on responses to formal information requests ITC Midwest provides in the future in this docket.

Response by: David Grover List sources of information:

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number:	ET6675/CN-12-1053	Date of Request:	May 30, 2013
Requested From:	David Grover Manager, Regulatory Strategy	Response Due:	June 11, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
3	Please expand Attachment E of the Petition such that it shows the estimated project annual revenue requirement in Minnesota for each year of the proposed project's life.
Answer	ITC Midwest's annual revenue requirements are calculated using FERC-approved formula rates that are part of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff. ITC Midwest does not forecast annual project revenue requirements over long-term timeframes, such as a new project's approximately 60-year lifetime, as such a forecast would require that we prepare a forecast for every component in the formula. We can however, provide an illustration of how certain calculations in specific formulas change over a project's lifetime. As discussed in Section 2.6 of the Certificate of Need Application, the recovery of approximately 97% of the MN-IA 345 kV Project's cost will be under MISO's Schedule 26-A, the Multi-Value Project Usage Rate. The Schedule 26-A rate is calculated based on the revenue requirement calculation in Attachment MM of MISO's Tariff, which is a rate formula updated annually based on project-specific [continues on next page]

parameters as well as data from a Transmission Owner's Attachment O rate formula. The initial fixed charge rate of 18.62% shown in Attachment E of the Petition was calculated based on ITC Midwest's 2013 projected Attachment MM template, which is posted on OASIS, dividing the projected 2013 Attachment MM revenue requirement by Attachment MM project gross plant.

The calculation in Attachment MM is a fully allocated project annual revenue requirement, which is the sum of a project's projected return on net plant, income taxes, project depreciation expense, plus a share of system-wide transmission O&M allocated based on accumulated depreciation and other system-wide O&M charges (A&G, property taxes and depreciation expense on general and common plant) allocated based on gross plant. Attachment MM is updated annually and will track with any changes in the many parameters on which it is based.

Exhibit 1 is an illustrative summary of how the annual revenue requirement calculation based on ITC Midwest's estimated cost for its portion of MVP 3 of $275.1 million, shown as an effective annual fixed charge rate based on Attachment MM, and the amount collected based on the load of Minnesota customers would change over the Project's lifetime, where the year-to-year changes shown are based **only** on how the Project's depreciation impacts the calculation of return and income taxes and the allocation of transmission O&M. The exhibit illustrates the net impact of the increased allocation of transmission O&M cost to an individual project in the Attachment MM formula and the decreased return on net plant and income taxes as project facilities depreciate. In this illustration, no attempt has been made to forecast how other system-wide inputs to the rate formula, could change over time, since ITC Midwest does not prepare long term forecasts for these parameters. A 60-year Project life has been assumed, based on ITC Midwest's composite depreciation for all transmission plant. The zonal portion of the project (3%) is also included in Exhibit 1, assuming there are no incremental O&M charges included in the annual revenue requirement since this portion of the project is a rebuild of existing facilities.

Note that the first year revenue requirement in this conceptual illustration doesn't precisely match the revenue requirement that ITC Midwest previously showed in Attachment E. This is because of simplifying assumptions made in this example to illustrate how the formula output changes as a project depreciates while Attachment E was based on an actual first year fixed charge rate calculated based on the Attachment MM template we used to calculate 2013 projected charges.

Response by: David Grover

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

List sources of information:

Illustrative Example of Changes in Minnesota Revenue Requirement for MN-IA 345 kV Project over Project Lifetime

	MVP Capital Cost ($) =		$275,100,000	Zonal (69 kV) Capital Cost ($) =		$7,400,000	Total Cost ($) = $282,500,000
		MVP Cost Allocation			Zonal Cost Allocation		
Year	Attachment MM Fixed Charge Rate	Total Annual Revenue Requirement ($)	Minnesota Revenue Requirement ($)	Zonal Fixed Charge Rate	TotalAnnual Revenue Requirement ($)	Minnesota Revenue Requirement ($)	Total Annual Project Revenue Requirement in Minnesota ($)
1	19.10%	$52,542,285	$6,993,378	16.69%	$1,234,813	$172,874	$7,166,252
2	19.02%	$52,312,094	$6,962,740	16.44%	$1,216,715	$170,340	$7,133,080
3	18.93%	$52,081,903	$6,932,101	16.20%	$1,198,617	$167,806	$7,099,908
4	18.85%	$51,851,713	$6,901,463	15.95%	$1,180,519	$165,273	$7,066,736
5	18.76%	$51,621,522	$6,870,825	15.71%	$1,162,421	$162,739	$7,033,563
6	18.68%	$51,391,331	$6,840,186	15.46%	$1,144,323	$160,205	$7,000,391
7	18.60%	$51,161,140	$6,809,548	15.22%	$1,126,225	$157,671	$6,967,219
8	18.51%	$50,930,949	$6,778,909	14.97%	$1,108,127	$155,138	$6,934,047
9	18.43%	$50,700,758	$6,748,271	14.73%	$1,090,029	$152,604	$6,900,875
10	18.35%	$50,470,568	$6,717,633	14.49%	$1,071,931	$150,070	$6,867,703
11	18.26%	$50,240,377	$6,686,994	14.24%	$1,053,833	$147,537	$6,834,531
12	18.18%	$50,010,186	$6,656,356	14.00%	$1,035,735	$145,003	$6,801,359
13	18.10%	$49,779,995	$6,625,717	13.75%	$1,017,637	$142,469	$6,768,186
14	18.01%	$49,549,804	$6,595,079	13.51%	$999,539	$139,935	$6,735,014
15	17.93%	$49,319,613	$6,564,441	13.26%	$981,441	$137,402	$6,701,842
16	17.84%	$49,089,422	$6,533,802	13.02%	$963,343	$134,868	$6,668,670
17	17.76%	$48,859,232	$6,503,164	12.77%	$945,245	$132,334	$6,635,498
18	17.68%	$48,629,041	$6,472,525	12.53%	$927,147	$129,801	$6,602,326
19	17.59%	$48,398,850	$6,441,887	12.28%	$909,049	$127,267	$6,569,154
20	17.51%	$48,168,659	$6,411,249	12.04%	$890,951	$124,733	$6,535,982
21	17.43%	$47,938,468	$6,380,610	11.80%	$872,853	$122,199	$6,502,810
22	17.34%	$47,708,277	$6,349,972	11.55%	$854,755	$119,666	$6,469,637
23	17.26%	$47,478,087	$6,319,333	11.31%	$836,657	$117,132	$6,436,465
24	17.17%	$47,247,896	$6,288,695	11.06%	$818,559	$114,598	$6,403,293
25	17.09%	$47,017,705	$6,258,057	10.82%	$800,461	$112,065	$6,370,121
26	17.01%	$46,787,514	$6,227,418	10.57%	$782,363	$109,531	$6,336,949
27	16.92%	$46,557,323	$6,196,780	10.33%	$764,265	$106,997	$6,303,777
28	16.84%	$46,327,132	$6,166,141	10.08%	$746,167	$104,463	$6,270,605
29	16.76%	$46,096,942	$6,135,503	9.84%	$728,069	$101,930	$6,237,433
30	16.67%	$45,866,751	$6,104,865	9.59%	$709,971	$99,396	$6,204,260
31	16.59%	$45,636,560	$6,074,226	9.35%	$691,873	$96,862	$6,171,088
32	16.51%	$45,406,369	$6,043,588	9.11%	$673,775	$94,329	$6,137,916
33	16.42%	$45,176,178	$6,012,949	8.86%	$655,677	$91,795	$6,104,744
34	16.34%	$44,945,987	$5,982,311	8.62%	$637,579	$89,261	$6,071,572
35	16.25%	$44,715,797	$5,951,673	8.37%	$619,481	$86,727	$6,038,400
36	16.17%	$44,485,606	$5,921,034	8.13%	$601,383	$84,194	$6,005,228
37	16.09%	$44,255,415	$5,890,396	7.88%	$583,285	$81,660	$5,972,056
38	16.00%	$44,025,224	$5,859,757	7.64%	$565,187	$79,126	$5,938,884
39	15.92%	$43,795,033	$5,829,119	7.39%	$547,089	$76,593	$5,905,711
40	15.84%	$43,564,842	$5,798,481	7.15%	$528,991	$74,059	$5,872,539
41	15.75%	$43,334,652	$5,767,842	6.90%	$510,893	$71,525	$5,839,367
42	15.67%	$43,104,461	$5,737,204	6.66%	$492,795	$68,991	$5,806,195
43	15.58%	$42,874,270	$5,706,565	6.41%	$474,697	$66,458	$5,773,023
44	15.50%	$42,644,079	$5,675,927	6.17%	$456,600	$63,924	$5,739,851
45	15.42%	$42,413,888	$5,645,289	5.93%	$438,502	$61,390	$5,706,679
46	15.33%	$42,183,697	$5,614,650	5.68%	$420,404	$58,856	$5,673,507
47	15.25%	$41,953,507	$5,584,012	5.44%	$402,306	$56,323	$5,640,335
48	15.17%	$41,723,316	$5,553,373	5.19%	$384,208	$53,789	$5,607,162
49	15.08%	$41,493,125	$5,522,735	4.95%	$366,110	$51,255	$5,573,990
50	15.00%	$41,262,934	$5,492,097	4.70%	$348,012	$48,722	$5,540,818
51	14.92%	$41,032,743	$5,461,458	4.46%	$329,914	$46,188	$5,507,646
52	14.83%	$40,802,552	$5,430,820	4.21%	$311,816	$43,654	$5,474,474
53	14.75%	$40,572,362	$5,400,181	3.97%	$293,718	$41,120	$5,441,302
54	14.66%	$40,342,171	$5,369,543	3.72%	$275,620	$38,587	$5,408,130
55	14.58%	$40,111,980	$5,338,905	3.48%	$257,522	$36,053	$5,374,958
56	14.50%	$39,881,789	$5,308,266	3.24%	$239,424	$33,519	$5,341,785
57	14.41%	$39,651,598	$5,277,628	2.99%	$221,326	$30,986	$5,308,613
58	14.33%	$39,421,407	$5,246,989	2.75%	$203,228	$28,452	$5,275,441
59	14.25%	$39,191,217	$5,216,351	2.50%	$185,130	$25,918	$5,242,269
60	14.16%	$38,961,026	$5,185,713	2.26%	$167,032	$23,384	$5,209,097

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: May 30, 2013

Requested From: David Grover Response Due: June 11, 2013
Manager, Regulatory Strategy

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
4	Please provide ITC Midwest's overall cost of capital.
Answer	ITC Midwest's overall cost of capital for 2012 was 9.45%, based on its FERC-approved 60/40 equity/debt capital structure, the FERC approved MISO ROE of 12.38% and ITC Midwest's long term debt cost of 5.06% yielding the overall return ((0.60 x .12.38%) + (0.40 x 5.06%) = 9.45%). ITC Midwest's Actual 2012 MISO Attachment O Formula Rate, showing this calculation is posted on OASIS as item 77 at: http://www.oasis.oati.com/ITCM/index.html [continues on next page]

The revenue requirement calculations in the Application were based on ITC Midwest's 2013 projected cost of capital of 9.41%, due to a lower assumption for the cost of long term debt (4.95%) for 2013 projected rates.

Response by: David Grover

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

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[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
5	Please provide an estimate of the annual operation and maintenance costs for 161 kV transmission lines in the ITC Midwest system.
Answer	ITC Midwest spent approximately $1,250 per mile on O&M in 2012 for the 161 kV transmission lines in its system. This includes vegetation, tower painting, helicopter patrols, and line maintenance.

Response by: Jim Spicer/Amy Ashbacker

Title: Senior Project Engineer

Department: Project Engineering/Field Supervision

Telephone: 319.297.6795 / 319.297.6818

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053   Date of Request: May 30, 2013

Requested From: David Grover   Response Due: June 11, 2013
Manager, Regulatory Strategy

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Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
6	Please provide ITC Midwest's Fixed Charge Rate that would be applicable to the 161 kV rebuild alternative (equivalent to the Fixed Charge Rates shown in Appendix E).
Answer	The ITC Midwest zonal Fixed Charge Rate (FCR) shown in Attachment E of the Certificate of Need Application (16.35%) would also be applicable to the 161 kV Rebuild Alternative. The zonal FCR is calculated in the same manner as the Attachment MM FCR also shown in Attachment E, except that cost allocations for all O&M expenses, excluding property taxes, was assumed to be zero, since both this alternative and the 69 kV facilities are rebuilds of existing facilities whose costs are currently recovered in the ITC Midwest MISO zonal rate.

Response by: David Grover   List sources of information:

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: May 30, 2013

Requested From: David Grover Response Due: June 11, 2013
Manager, Regulatory Strategy

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
7	Please explain whether ITC Midwest's estimated cost for the 161 kV Rebuild Alternative of $52 million (see Appendix J page 21) is in nominal dollars or real dollars. If the answer is nominal dollars please provide the year the activity is presumed to take place. If the answer is real dollars please provide the year of the real dollars and the year the activity is presumed to take place.
Answer	The cost of the 161 kV Rebuild Alternative is in nominal 2012 dollars. Since this is not an MTEP-approved project, there is not an official in-service date for this project. For study purposes it has been presumed to be 2017.

Response by: David Grover List sources of information:

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: May 30, 2013

Requested From: David Grover Response Due: June 11, 2013
Manager, Regulatory Strategy

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Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
8	Please provide an estimate of the Minnesota portion of the annual revenue requirement for the 161 kV Rebuild Alternative.
Answer	The Minnesota portion of the annual revenue requirement for the 161 kV Rebuild Alternative would be calculated in the same manner as the Zonal Portion (69 kV) of the MN-IA 345 kV Project was calculated in Attachment E of the Certificate of Need Application. Based on the $52 million cost estimate, the Minnesota portion of the annual revenue requirement would be $1,190,280 ($52 million x 0.1635 x 0.14).

Response by: David Grover List sources of information:

Title: Manager

Department: Regulatory Strategy

Telephone: 651.222.1000, Ext. 2308

BRIGGS
BRIGGS AND MORGAN
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Minneapolis MN 55402-2157
tel 612.977.8400
fax 612.977.8650

August 23, 2013

Lisa M. Agrimonti
(612) 977-8656
lagrimonti@briggs.com

VIA E-MAIL

Sharon Ferguson
Minnesota Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed are ITC Midwest LLC's responses to the Department of Commerce, Division of Energy Resources, Information Requests 9 through 15.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email): Julia Anderson
Adam Heinen

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

<u>Utility Information Request</u>

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[X] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
9	**Subject: Forecasting**
	Reference: Revised Appendix 53
	A. Please provide the above reference in an editable Microsoft Excel format with all links and formulae intact.
Answer	The table used to create Appendix 53 is a MS Word document. Attached as Attachment 9-1 is a MS Excel version of the table, including summation formulas.
	B. Please provide a full explanation of how the Applicant defines the project area mentioned in the above reference.
Answer	The Project area was first identified in ITC Midwest's reply comments to the comments submitted by the Department on ITC Midwest's request for exemptions from certain application content requirements in this proceeding. The Department had requested that ITC Midwest: • identify and specify all of the company-owned and non-company-owned (distribution and transmission) substations in the Project area, that are relevant to ITC Midwest's proposed Project; • provide all of the relevant load data proposed above at the company-owned and non-company-owned detailed substation-specific level if they are relevant to ITC Midwest's proposed Project;

In response to this request, ITC Midwest defined the Project area as the portion of its transmission system in Minnesota near the proposed Project facilities and provided a list of relevant substations in its reply comments. As discussed in those comments and in the Project application, the load in this area is relevant to the proposed Project primarily to demonstrate that the local load is not sufficient, or expected to increase enough, to eliminate the need for additional facilities to export new renewable generation in and adjacent to the Project area to MISO loads south and east.

C. Please provide a detailed discussion of whether there are any substations outside of the project area that contribute need to this project. If so, please provide any, and all, data, in Microsoft Excel format, related to these other substations.

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

Answer

Note that the substations in the Project area do not directly "contribute need to this project" in the traditional sense, as described in the response to (B) above. Additional load outside the Project area does not mitigate the need for this Project since additional transmission would still be needed to deliver electricity generated in the Project area to load in adjacent areas.

Response by: Joe Berry

Title: Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

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Analyst Requesting Information: Adam J. Heinen

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If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
10	**Subject: Forecasting** **Reference: Page 85 of Application** **In the above reference, ITC-Midwest states that its economic evaluation based on wind curtailment estimates is on-going. Please provide the following:** **A. An update of the status of this analysis.** **B. If this analysis has been completed, the entire report and any, and all, supporting data and information, in Microsoft Excel format, associated with this evaluation.** **C. If this analysis is still on-going, a status report and anticipated completion date.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	ITC Midwest submitted a Supplement to its original March 22, 2013 Certificate of Need Application on April 9, 2013, providing the results of the additional analysis referenced on page 85 of the original Application, including an additional economic evaluation as a new Appendix N to the Application. There is no further ongoing analysis relating to the economic evaluation provided in the Certificate of Need Application. As noted in responses to Requests No. 11 and 13, additional economic analysis will be undertaken to respond to the Department's request.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[X] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
11	**Subject: Forecasting** **Please provide, at a high level, what impact failure to construct MVP4, MVP5, and both projects, would have on Minnesota LMPs, and the cost and benefits associated with MVP3.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	The Certificate of Need Application, Appendices M and N provide information regarding the Minnesota LMP impact if MVP 3 and 4 were constructed and if MVP 3 were constructed, but not MVP 4. ITC Midwest has not prepared an analysis of how the Minnesota LMP would be affected if MVP 5 or any other MVP were not constructed. Additional studies to examine the impact on Minnesota LMPs if MVP 5 is not constructed or both MVP 4 and MVP 5 are not constructed will be performed and a response detailing those impacts will be submitted after these studies are completed. ITC Midwest estimates it can provide this information by November 1, 2013.

Response by: David Grover

Title: Manager

Department: Regulatory Strategy

Telephone: (651) 222-1000, Ext. 2308

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[X] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
12	**Subject: Forecasting** **Reference: Appendix I, Section 6.1** **At the beginning of this section, the Applicant references MTEP11 Reliability Analyses that are included in Appendix D2-D8. While reviewing the application, it is unclear if these information are in the application (only D1 and D2 appear present). As such, please provide Appendices D2-D8.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	Appendix I is a report prepared by MISO for MTEP 11. On Page 121 of the report, MISO notes that Appendices D2 through D8 to MTEP 11 are confidential and only available on the MISO MTEP 11 FTP site. ITC Midwest has contacted MISO to obtain the documents for production to the Department. MISO has advised that the documents contain non-public Critical Energy Infrastructure Information, and there are confidentiality concerns that must be addressed before the documents can be produced, specifically, how the documents will be protected from public disclosure by governmental entities both during the proceeding and after the proceeding concludes. ITC Midwest will continue to work with MISO and the Department to clarify the scope of the data requested and the protections necessary to protect that data from public disclosure.

ITC Midwest also notes that the information in MISO's MTEP 11 document is unrelated to the information in Appendix D of the Certificate of Need Application, which shows technical drawings of transmission structures proposed for the Project.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[X] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
13	**Subject: Forecasting** **Reference: MVP3 Planning Study** **The Applicant provides significant discussion regarding alternatives in the above reference. The majority of the analysis is focused on engineering studies, but there is some discussion of costs. Focusing on economic cost, please provide the following:** **a) The projected impact to LMP costs, in 5-year intervals, for each alternative discussed in the above reference;** **b) The total construction cost for each alternative; and** **c) Total lifetime operating cost, in Net Present Value, for each alternative.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	ITC Midwest has not conducted this analysis and does not have the requested data. Additional studies to examine the impact on Minnesota LMPs from the 161 kV rebuild alternative will be performed and a response detailing those impacts will be submitted after these studies are completed. The response will include analysis of the additional impacts on Minnesota LMPs if MVPs 4 and 5, or both are not constructed. The study will examine years 2021 and 2026, consistent with the LMP cost impacts discussed in the Application. ITC Midwest estimates it can provide this information by November 1, 2013.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

<u>Utility Information Request</u>

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[X] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
14	**Subject: Forecasting** **Reference: Application Chapter 4, Page 56** **Please provide an estimate of how many wind projects in MISO's SPA that will be interconnected if MVP3 and MVP4 are constructed. As part of this response, please also include the amount of MWs associated with each discussed wind project.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	It is not possible to determine precisely how many of the wind projects in MISO's SPA will be able to interconnect if MVP 3 and MVP 4 are constructed as ITC Midwest has not performed studies specific to the projects in the SPA phase. Even if such studies were performed, there would likely be many feasible scenarios. As reported in Appendix N of the Application in the report entitled "LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis," on page A3 of Appendix A, ITC Midwest estimated that 1,130 MW less wind capacity could be added to the MISO system without the MVP 3 and MVP 4 projects. This assumption was developed using the same methodology MISO used to determine the benefits of the MVP portfolio. In addition, ITC Midwest's analysis of MVPs 3 and 4, discussed on page 74 of the Application and in the Planning Study report included as Appendix J of the Application, provides estimates

of the Incremental Transfer Capability provided by MVPs 3 and 4 under a range of locations for future wind generation as well as for two load level scenarios (summer shoulder and summer peak) and under scenarios for delivery in Minnesota and delivery to eastern MISO. Incremental transfer capability ranged from 543 MW to 3,317 MW in these scenarios.

Response by: David Grover

Title: Manager

Department: Regulatory Strategy

Telephone: (651) 222-1000, Ext. 2308

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053	Date of Request: August 13, 2013
Requested From: ITC-Midwest	Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[X] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
15	**Subject: Forecasting** **Reference: Appendix I, Page 8: Figure 1-4** **Please provide a detailed derivation, including all supporting data in Microsoft Excel format, of the benefit/cost estimates, for each zone impacted by this project. As part of this discussion, please specify whether the analysis is fully quantitative or does it also include qualitative measures. If qualitative measures are included in the analysis, please fully explain how these qualitative measures are quantified numerically.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	ITC Midwest does not possess the information requested. As discussed in the response to Request No. 12, Appendix I is the MTEP 11 report prepared by MISO. ITC Midwest has contacted MISO to provide the requested information MISO has raised confidentiality concerns regarding how the data is protected from public disclosure by government entities during the contested case proceedings and after the case has concluded. ITC Midwest will continue to work with MISO and the DOC to clarify the scope of the data requested and the protections necessary to protect that data from public disclosure.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

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Minneapolis MN 55402-2157
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fax 612.977.8650

December 10, 2013

Lisa M. Agrimonti
(612) 977-8656
lagrimonti@briggs.com

<u>VIA E-MAIL</u>

Sharon Ferguson
Minnesota Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed are ITC Midwest LLC's responses to the Department of Commerce, Division of Energy Resources, Information Requests 16 through 19.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email): Julia Anderson

Briggs and Morgan, Professional Association
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Member - Lex Mundi, a Global Association of Independent Law Firms

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number:	ET6675/CN-12-1053	Date of Request:	November 22, 2013
Requested From:	David Grover Manager, Regulatory Strategy ITC Midwest LLC	Response Due:	December 6, 2013 Extension granted to December 13, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
16	**The Petition screens out the Lakefield Junction – Rutland 345 kV alternative at page 89:**

> **While it is true that a Lakefield Junction – Rutland 345 kV line would help relieve constraints on the Fox Lake to Rutland section of the 161 kV line, it resulted in constraints elsewhere. Specifically, the termination of the 345 kV line at Rutland resulted in constraints farther east on the 161 kV system, increasing loading on the 161 kV line between Rutland and Winnebago Junction.**

Meanwhile, MTEP09 states at page 196:

> **One concern raised by the TRG was the potential overload of the Rutland - Winnebago 161 kV line, with the 345 kV upgrade ending at the Rutland substation. Additional economic sensitivity analysis was performed with the Rutland - Winnebago 161 kV included in the list of monitored elements. The economic benefit results are provided in Table 8.3-11.**
>
> **Compared to the original case the total benefits go down slightly as expected; however, the project still exceed the 2.0 B/C ratio threshold and is qualified for Appendix B consideration.**

Please explain why a project (Lakefield Junction – Rutland 345 kV) with a 2.0 benefit cost ratio after accounting for the constraints referenced in the Petition was not carried forward in the analysis for further consideration.

Answer

As discussed in more detail in the MISO responses to IR # 21 and IR # 22, the Lakefield-Rutland 345 kV project was carried forward in subsequent analyses after MTEP 09. The Lakefield-Rutland 345 kV project was part of several projects that were being evaluated to address a broader scope of issues than were considered in the economic studies MISO performed in MTEP 09 to assess potential Market Efficiency Projects.

Response by: Joe Berry

Title: Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053

Date of Request: November 22, 2013

Requested From: David Grover
Manager, Regulatory Strategy
ITC Midwest LLC

Response Due: December 6, 2013
Extension granted to December 13, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
17	**Can ITCM explain why MTEP09 states at page 196 that the Lakefield Junction–Rutland 345 kV alternative is qualified for Appendix B consideration while the file MTEP09 Appendices ABC (available at : https://www.misoenergy.org/Planning/Pages/StudyRepository.aspx) lists the Lakefield Junction–Rutland 345 kV alternative as Target Appendix C?**
Answer	MISO, not ITC Midwest determines in which appendix projects are listed in the MTEP reports. *See* MISO response to IR # 20.

Response by: Joe Berry

Title: Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053

Date of Request: November 22, 2013

Requested From: David Grover
Manager, Regulatory Strategy
ITC Midwest LLC

Response Due: December 6, 2013
Extension granted to December 13, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
18	**MTEP09 determined (see page 196) that the Lakefield Junction–Rutland 345 kV alternative had a benefit/cost ratio greater than 2.0. Subsequently, MTEP10 determined (see page 205) that the:** • **Lakefield Jct–Winnebago–Adams 345kV;** • **Lakefield Jct–Winnebago–Webster–Blackhawk–Hazelton 345kV; and** • **Lakefield Jct–Mitchell Co 345kV;** **all had a benefit/cost ratio less than 1.0. Nonetheless, MTEP10 states at page 205 that "The Lakefield Junction–Winnebago project as well as a variation of the Lakefield Junction–Winnebago–Webster–Blackhawk–Hazelton 345kV project are currently proposed to be included in the Candidate MVP Portfolio analysis to be studied for MVP eligibility."** **Can ITCM explain why a project with a benefit/cost ratio greater than 2.0 was not considered further while projects with a benefit/cost ratio less than 1.0 were proposed to be included in the Candidate MVP Portfolio analysis?**
Answer	MISO, not ITC Midwest determined the projects to consider in the Candidate MVP Portfolio analysis. The Lakefield-Rutland 345 kV project facilities were part of the first two options listed in this question; thus the project facilities were considered in the Candidate MVP Portfolio analysis as part of larger projects intended to address broader issues. *See* MISO response to IR # 22.

Response by:	Joe Berry	List sources of information:
Title:	Engineer	
Department:	Transmission Planning	
Telephone:	(563) 585-3641	

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053

Date of Request: November 22, 2013

Requested From: David Grover
Manager, Regulatory Strategy
ITC Midwest LLC

Response Due: December 6, 2013
Extension granted to December 13, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
19	**MTEP11 at page 106 states:**

MTEP11 at page 106 states:

> **Lakefield to Winnebago to Winco-Burt, Lime Creek to Emery to Blackhawk to Hazleton, Sheldon to Burt to Webster 345kV**

These lines facilitate transfer of wind from MISO's West Region closer to large load centers in Illinois and Wisconsin by connecting existing wind heavy areas around Lakefield and Sheldon, and further accessing wind in central Iowa from the Lime Creek area to Hazleton. It provides on and off ramps for power transfer through intermediate transformations.

Does ITCM agree that alternatives in this proceeding should be evaluated based upon an ability to facilitate transfer of wind from MISO's West Region to large load centers in Illinois and Wisconsin.

Answer

Yes, ITC Midwest agrees that alternatives in this proceeding should be evaluated based on an ability to facilitate transfer of wind from MISO's West Region to large load centers further east in the MISO footprint. The alternatives should also be evaluated on their ability to address all other attributes of MVP #3 and the Minnesota-Iowa 345 kV project facilities, including local reliability benefits in Minnesota.

Response by: Joe Berry

Title: Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

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tel 612.977.8400
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January 6, 2014

Lisa M. Agrimonti
(612) 977-8656
lagrimonti@briggs.com

VIA E-MAIL

Sharon Ferguson
Minnesota Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed are ITC Midwest LLC's responses to the Department of Commerce, Division of Energy Resources, Information Requests 26 and 27.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email): Julia Anderson

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

<u>Utility Information Request</u>

Docket Number: ET6675/CN-12-1053 Date of Request: December 18, 2013

Requested From: David Grover, Mgr. Regulatory Strategy Response Due: January 6, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
26	Regarding the *ITC Midwest LLC Multi-Value Project #3 Planning Study* (Appendix J of the Petition) please explain why the first entry for Appendices 16, 29, 32, 52 (page 58), and 52 (page 59) is not the lowest number in the "AC FCITC" column. **Response:** The output of the PSS®MUST software used for the FCITC analysis gives two values, an AC FCITC and a DC FCITC. The AC FCITC values are most accurate and are the values used in this analysis, but the output in the tables referenced in this question was inadvertently sorted based on the DC FCITC values, which is why the AC FCITC values are not in ascending order with the most limiting value listed first. This error resulted in the incorrect FCITC values being carried forward to Tables and Figures in the body of the planning study report and well as the summary tables on pages 51 through 54 of the Appendices. Attached are corrected Appendices 16, 29, 32, 52 (page 58) and 52 (page 59) sorted by AC FCITC, as well as corrected Tables 1, 3 and 5 from pages 12, 13 and 17 of the planning study, corrected Figures 4, 6 and 7 from pages 14, 15 and 16 of the planning study, corrected Summary Tables 2 and 4 from Appendix 51 (pages 51 and 52) and a corrected Appendix 52 summary (page 54). In addition, the range reported in the first paragraph of page 13 of the planning study for the increase in outlet capacity for generation when MVP 4 is added should be 516 to 543 MW.

Response by:	Joe Berry	List sources of information:
Title:	Senior Engineer	
Department:	Transmission Planning	
Telephone:	(563) 585-3641	

Appendix 16: SUM MVP 3 Buffalo Ridge 50%N / 50%S Gen – MN Scenario

AC FCITC	Limiting Constraint	Contingency	PreShift	PostShift	Rating	AC TDF
3351.4	L:602003 BLUEETA5 161 631043 WINBAGO5 161 1		86.7	200.2	200.0	0.03386
		C:601032 FIELD_S3 345 601033 FIELD_N3 345 1				
		Open 601032 FIELD_S3 345 601033 FIELD_N3 345 1				
3351.4	L:602003 BLUEETA5 161 631043 WINBAGO5 161 1		86.7	200.1	200.0	0.03382
		C:601004 WILMART3 345 601033 FIELD_N3 345 1				
		Open 601004 WILMART3 345 601033 FIELD_N3 345 1				
3352.0	L:602003 BLUEETA5 161 631043 WINBAGO5 161 1		86.7	200.2	200.0	0.03387
		C:601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
		Open 601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
3484.5	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		191.4	319.5	320.0	0.03678
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
3484.5	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		191.4	319.5	320.0	0.03678
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
3546.7	L:631043 WINBAGO5 161 631180 FREEBORN5 161 1		47.0	167.0	167.0	0.03382
		C:601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
		Open 601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
3546.8	L:631043 WINBAGO5 161 631180 FREEBORN5 161 1		47.0	167.0	167.0	0.03383
		C:601004 WILMART3 345 601033 FIELD_N3 345 1				
		Open 601004 WILMART3 345 601033 FIELD_N3 345 1				
3548.0	L:631043 WINBAGO5 161 631180 FREEBORN5 161 1		47.0	167.0	167.0	0.03382
		C:601032 FIELD_S3 345 601033 FIELD_N3 345 1				
		Open 601032 FIELD_S3 345 601033 FIELD_N3 345 1				
3646.3	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		94.6	211.9	212.0	0.03216
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3646.3	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		94.6	211.9	212.0	0.03216
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				

Appendix 29: SU70 MVP 3 and 4 Buffalo Ridge 25%N / 75%S Gen – MISO East Scenario

AC FCITC	Limiting Constraint	Contingency	PreShift	PostShift	Rating	AC TDF
2717.1	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		45.2	147.0	147.0	0.03746
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2717.1	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		45.2	147.0	147.0	0.03746
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2743.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		155.6	320.1	320.0	0.05997
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
2743.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		155.6	320.1	320.0	0.05997
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
2974.7	L:631110 WAPELLO5 161 631115 OTTUMWA5 161 2		252.2	334.8	335.0	0.02779
		C:ITCM-C207-SE-BF(OGS-Wap-OGS345-161)				
		Open 631110 WAPELLO5 161 631115 OTTUMWA5 161 1				
		Open 631115 OTTUMWA5 161 631143 OTTUMWA3 345 1				
3090.7	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		35.0	147.0	147.0	0.03626
		C:GRIMES-B905				
		Open 635600 GRIMES 3 345 635700 SYCAMOR3 345 2				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3541.3	L:631110 WAPELLO5 161 631115 OTTUMWA5 161 2		213.4	334.6	335.0	0.03423
		C:631110 WAPELLO5 161 631115 OTTUMWA5 161 1				
		Open 631110 WAPELLO5 161 631115 OTTUMWA5 161 1				
3622.5	L:635201 RAUN 5 161 640377 TEKAMAH5 161 1		32.1	217.2	217.0	0.05110
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
3712.0	L:631110 WAPELLO5 161 631115 OTTUMWA5 161 2		208.5	334.9	335.0	0.03406
		C:ITCM-B111-SW-OGS-WAPELLO-1				
		Open 631110 WAPELLO5 161 631115 OTTUMWA5 161 1				
		Open 630048 WAPELLO8 69.0 631110 WAPELLO5 161 1				

Appendix 32: SUM MVP 3 Buffalo Ridge 25%N / 75%S Gen – MISO East Scenario

AC FCITC	Limiting Constraint	Contingency	PreShift	PostShift	Rating	AC TDF
2005.4	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		130.5	212.0	212.0	0.04064
		C:ITCM-C918-LN-LN(Emry-Flyd-Emry-Shfd)				
		Open 631048 EMERY 5 161 636300 FLOYD 5 161 1				
		Open 631048 EMERY 5 161 656201 SHEFFLD5 161 1				
2014.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		191.4	320.0	320.0	0.06385
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
2014.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		191.4	320.0	320.0	0.06385
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
2126.8	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		94.6	212.0	212.0	0.05520
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2126.8	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		94.6	212.0	212.0	0.05520
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2451.3	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		39.7	147.0	147.0	0.04376
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2451.3	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		39.7	147.0	147.0	0.04376
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
0.0	L:631043 WINBAGO5 161 631180 FREEBORN5 161 1		0.0	0.0	167.0	*****
		C:B-MT-960				
		Open 636000 WEBSTER3 345 636010 LEHIGH 3 345 1				
		Open 636000 WEBSTER3 345 B$0195 1.00 1				
		Open 636001 WEBSTER5 161 B$0195 1.00 1				
		Open 636002 WEBS1XT9 13.8 B$0195 1.00 1				
0.0	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		0.0	0.0	147.0	*****
		C:GRIMES-B905				
		Open 635600 GRIMES 3 345 635700 SYCAMOR3 345 2				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
0.0	L:635201 RAUN 5 161 640377 TEKAMAH5 161 1		0.0	0.0	217.0	*****
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				

Appendix 52 (page 58): SU70 FXLK-RTLD-WNBG and MVP#4 Buffalo Ridge 25%N / 75%S Gen – MISO Scenario

AC FCITC	Limiting Constraint	Contingency	PreShift	PostShift	Rating	AC TDF
2449.9	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		37.3	147.0	147.0	0.04479
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2449.9	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		37.3	147.0	147.0	0.04479
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2469.7	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		159.1	320.1	320.0	0.06515
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
2469.7	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		159.1	320.1	320.0	0.06515
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
2764.7	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		27.1	147.0	147.0	0.04337
		C:GRIMES-B905				
		Open 635600 GRIMES 3 345 635700 SYCAMOR3 345 2				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3005.7	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		25.9	212.4	212.0	0.06207
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3005.7	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		25.9	212.4	212.0	0.06207
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3015.2	L:631110 WAPELLO5 161 631115 OTTUMWA5 161 2		250.5	334.8	335.0	0.02795
		C:ITCM-C207-SE-BF(OGS-Wap-OGS345-161)				
		Open 631110 WAPELLO5 161 631115 OTTUMWA5 161 1				
		Open 631115 OTTUMWA5 161 631143 OTTUMWA3 345 1				
3017.7	L:636001 WEBSTER5 161 636050 WRIGHT 5 161 1		12.3	212.1	212.0	0.06620
		C:MEC-C519				
		Open 636000 WEBSTER3 345 636010 LEHIGH 3 345 1				
		Open 636001 WEBSTER5 161 636020 FT.DODG5 161 1				
3223.7	L:635201 RAUN 5 161 640377 TEKAMAH5 161 1		35.5	217.0	217.0	0.05631
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				

Appendix 52 (page 59): SU70 FXLK-RTLD-WNBG and MVP#4 Buffalo Ridge 50%N / 50%S Gen – MISO Scenario

AC FCIT(	Limiting Constrai	Contingency	PreShift	PostShif	Ratin	AC TD
2569.6	L:631183 CAYLER5 161 656570 WISDOM5 161 1		132.5	209.0	209.0	0.02976
		C:ITCM-B102-NW-LAKEFIELD_SPS				
		Open 601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
		Open 601034 NOBLES 3 345 631138 LAKEFLD3 345 1				
		Set bus 615100 GRE-TRIMWNDW.575 generation to0.0 MW				
		Set bus 615041 GRE-LGS 31G13.8 generation to0.0 MW				
		Set bus 615042 GRE-LGS 32G13.8 generation to0.0 MW				
		Set bus 615043 GRE-LGS 33G13.8 generation to0.0 MW				
		Set bus 615044 GRE-LGS 34G13.8 generation to0.0 MW				
		Set bus 615045 GRE-LGS 35G13.8 generation to0.0 MW				
		Set bus 615046 GRE-LGS 36G13.8 generation to0.0 MW				
2649.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		159.1	320.1	320.0	0.06073
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
2649.8	L:640386 TWIN CH4 230 652565 SIOUXCY4 230 1		159.1	320.1	320.0	0.06073
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
2917.5	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		37.3	147.0	147.0	0.03762
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2917.5	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		37.3	147.0	147.0	0.03762
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
2967.3	L:631102 TRIBOJI5 161 631124 DKSN_CO5 161 1		115.6	223.1	223.0	0.03623
		C:ITCM-B102-NW-LAKEFIELD_SPS				
		Open 601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
		Open 601034 NOBLES 3 345 631138 LAKEFLD3 345 1				
		Set bus 615100 GRE-TRIMWNDW.575 generation to0.0 MW				
		Set bus 615041 GRE-LGS 31G13.8 generation to0.0 MW				
		Set bus 615042 GRE-LGS 32G13.8 generation to0.0 MW				
		Set bus 615043 GRE-LGS 33G13.8 generation to0.0 MW				
		Set bus 615044 GRE-LGS 34G13.8 generation to0.0 MW				
		Set bus 615045 GRE-LGS 35G13.8 generation to0.0 MW				
		Set bus 615046 GRE-LGS 36G13.8 generation to0.0 MW				
3150.6	L:631102 TRIBOJI5 161 631124 DKSN_CO5 161 1		123.2	223.2	223.0	0.03174
		C:601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
		Open 601029 LKFLDXL3 345 601032 FIELD_S3 345 1				
3150.8	L:631102 TRIBOJI5 161 631124 DKSN_CO5 161 1		123.1	223.2	223.0	0.03175
		C:601032 FIELD_S3 345 601033 FIELD_N3 345 1				
		Open 601032 FIELD_S3 345 601033 FIELD_N3 345 1				
3305.2	L:631079 BNE JCT5 161 636020 FT.DODG5 161 1		27.1	147.0	147.0	0.03627
		C:GRIMES-B905				
		Open 635600 GRIMES 3 345 635700 SYCAMOR3 345 2				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3497.7	L:635201 RAUN 5 161 640377 TEKAMAH5 161 1		35.5	217.1	217.0	0.05192
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				

Table 1 Maximum Incremental Transfer Capability of MVP #3 (MW)

Minnesota Transfer	Summer Shoulder	Summer Peak
Buffalo Ridge- 25% N/75% S	809.3	2463.3
Buffalo Ridge- 50% N/50% S	1640.7	~~3045.6~~2912.5
Buffalo Ridge- 75% N/25% S	1432.2	2459.7
MISO East Transfer		
Buffalo Ridge- 25% N/75% S	-25	15~~7~~68.~~1~~7
Buffalo Ridge- 50% N/50% S	-47	1753.8
Buffalo Ridge- 75% N/25% S	607.6	1973.1

As Table 1 demonstrates, MVP #3's principal impact is in Minnesota. That is, MVP #3 increases outlet capacity for wind generation to be transferred to Minnesota in all generation scenarios in both the summer shoulder and summer peak conditions. In comparison, MVP #3 would actually decrease outlet capacity for generation to be transferred to MISO East under two of the three generation scenarios during summer shoulder.

Table 2 shows the level of incremental transfer capability of the 161 kV Rebuild Alternative based on the analysis of the study area for each generation scenario.

Table 2 Maximum Incremental Transfer Capability of the 161 kV Rebuild Alternative (MW)

Minnesota Transfer	Summer Shoulder	Summer Peak
Buffalo Ridge- 25% N/75% S	573.7	2113.7
Buffalo Ridge- 50% N/50% S	1237.7	2785.8
Buffalo Ridge- 75% N/25% S	792.8	2394.7
MISO East Transfer		
Buffalo Ridge- 25% N/75% S	0.3	1405.9
Buffalo Ridge- 50% N/50% S	142.9	1544.1
Buffalo Ridge- 75% N/25% S	29.2	1610.8

Like MVP #3, the principal impact of the 161 kV Rebuild Alternative is also in Minnesota. The FCITC analysis shows the alternative provides additional transfer capability to the Minnesota sink. However, like MVP #3, the 161 kV Rebuild Alternative provides minimal additional transfer capability to the MISO East sink. Moreover, the 161 kV Rebuild Alternative does not increase generation outlet capacity for Minnesota as much as MVP #3 in four of the six generation scenarios.

Table 3 shows how the combination of MVPs #3 and #4 increase the transfer capability of the transmission system in the study area under the three generation scenarios.

Table 3 Maximum Incremental Transfer Capability of MVPs #3 & #4 (MW)

Minnesota Transfer	Summer Shoulder	Summer Peak
Buffalo Ridge- 25% N/75% S	1484.0	2875.9
Buffalo Ridge- 50% N/50% S	1919.8	3317.9
Buffalo Ridge- 75% N/25% S	1464.2	2498.8
MISO East Transfer		
Buffalo Ridge- 25% N/75% S	~~773.7~~516.1	1742.3
Buffalo Ridge- 50% N/50% S	543.2	1935.9
Buffalo Ridge- 75% N/25% S	1228.0	2176.8

The principal impact of adding both MVPs to the transmission system is to improve the outlet capacity for generation to be transferred to MISO East across all six generation scenarios. For example, the 25 to 47 MW decrease in outlet capacity during summer shoulder under two of the scenarios (Buffalo Ridge- 25% N/75% S and Buffalo Ridge- 50% N/50% S respectively) with only MVP #3 added to the system becomes a ~~543~~ 516 to ~~774~~ 543 MW increase when MVP #4 is added to the system as well.

The outlet capacity also increases across all generation scenarios for the Minnesota sink with the addition of MVP #4, with the largest increase being 675 MW for the 25% north zone/75% south zone generation scenario in the summer shoulder season.

The FCITC Analysis also demonstrates that MVP #3 is better suited to increase transfer capability under the scenario where most of the new wind generation is located in the North Zone in Minnesota. Table 4 shows the transfer capability achieved by MVP #3 alone and in combination with MVP #4 as compared to the 161 kV Rebuild Alternative under the Buffalo Ridge- 75% N/25% S generation scenario. At best, the 161 kV rebuild provides only 55% of the transfer capability of MVP #3 alone, or of MVP #3 in combination with MVP #4.

Table 4 Maximum Incremental Minnesota Transfer Capability-Buffalo Ridge 75% N/25% S Generation (MW)

Transmission Option	Summer Shoulder	Summer Peak
MVP #3	1432.2	2459.7
MVPs #3 and #4	1464.2	2498.8
161 kV Rebuild Alternative	792.8	2394.7

An FCITC analysis was also completed on a hypothetical scenario in which the 161 kV Rebuild Alternative and MPV #4 were constructed. Under this scenario, the 161 kV facilities do not interconnect with MVP #4. As anticipated, FCITC analyses showed that no additional transfer capability (neither for the Minnesota sink nor MISO East sink) would be achieved under any of the three generation scenarios. The results of this analysis are shown in Appendix 52.

additional generators would seek to connect directly to a newly upgraded 345 kV or 161 kV alternative.

An analysis was performed to determine how much generation could be connected to the area transmission system before the capacity provided by the 161 kV Rebuild Alternative would be depleted.[16] Using the Summer Peak base case described in Section 2.2 (MRO 2017 Summer Peak (FXLK_RTLD_WNBG)), the 161 kV Rebuild Alternative was monitored under contingency conditions while generation was increased in the surrounding area. The results showed that directly connecting 500 MWs to the rebuilt line would consume all the capacity provided by the line's upgrade.

Another important consideration when evaluating the 161 kV Rebuild Alternative is its regional impact. MVP #3 in combination with MVP #4 is a needed 345 kV connection between the Minnesota and Iowa 345 kV systems, and that is currently the most efficient voltage system in the region for moving large amounts of energy long distances, such as from the Buffalo Ridge region to load centers in the Twin Cities, Iowa metropolitan areas, and points east. This connection also provides system operators with flexibility in reliably operating the electrical grid when conditions warrant larger transfers of energy between states. While the 161 kV Rebuild Alternative could potentially resolve local overloading problems on the 161 kV system in southwest Minnesota, it provides no regional reliability benefit. As Table 5 demonstrates, the maximum transfer capability of the 161 kV Rebuild Alternative and MVP #4 combined is virtually no different than the maximum transfer capability of the 161 kV Rebuild alone.[17]

Table 5 Maximum Gross Transfer Capability of 161 kV Rebuild Alone and Combination of 161 kV Rebuild and MVP #4 (MW)

	161 kV Rebuild		Combination of 161 kV Rebuild and MVP #4	
Minnesota Transfer	**Summer Shoulder**	**Summer Peak**	**Summer Shoulder**	**Summer Peak**
Buffalo Ridge- 25% N/75% S	3087.6	2559.4	3287.2	2559.0
Buffalo Ridge- 50% N/50% S	3841.5	3224.7	3677.6	3272.9
Buffalo Ridge- 75% N/25% S	3490.1	2827.1	3358.9	2841.1
MISO East Transfer				
Buffalo Ridge- 25% N/75% S	2201.3	1842.6	~~2469.7~~2449.9	1883.5
Buffalo Ridge- 50% N/50% S	2576.8	1974.3	~~2649.8~~2569.6	2019.4
Buffalo Ridge- 75% N/25% S	2067.5	2034.8	1989.7	1945.6

1. Special Protection System ("SPS") Analysis

There are currently two SPSs affecting ITCM's transmission system in southwestern Minnesota the Fieldon Capacitor Bypass SPS and the Nobles County – Wilmarth SPS. Generally, an SPS is

[16] Appendix 55 contains the generation sensitivity analysis for the 161 kV Rebuild Alternative.
[17] Appendix 52 contains a summary table detailing the maximum gross transfer capability of the 161 kV Rebuild Alternative and MVP #4 combined, including the corresponding limiting element under the base cases and each generation scenario, followed by the the complete FCITC results for that combination under each generation scenario.

Figures showing the performance of each of the alternatives in summer peak and summer shoulder conditions are provided. Figures 4 and 5 show that MVP #3 alone and MVP #3 and MVP #4 together outperform the 161 kV Rebuild Alternative in improving generation outlet capacity in Minnesota.

Figure 4 Incremental Transfer Capability of Transmission Options
Minnesota Summer Shoulder

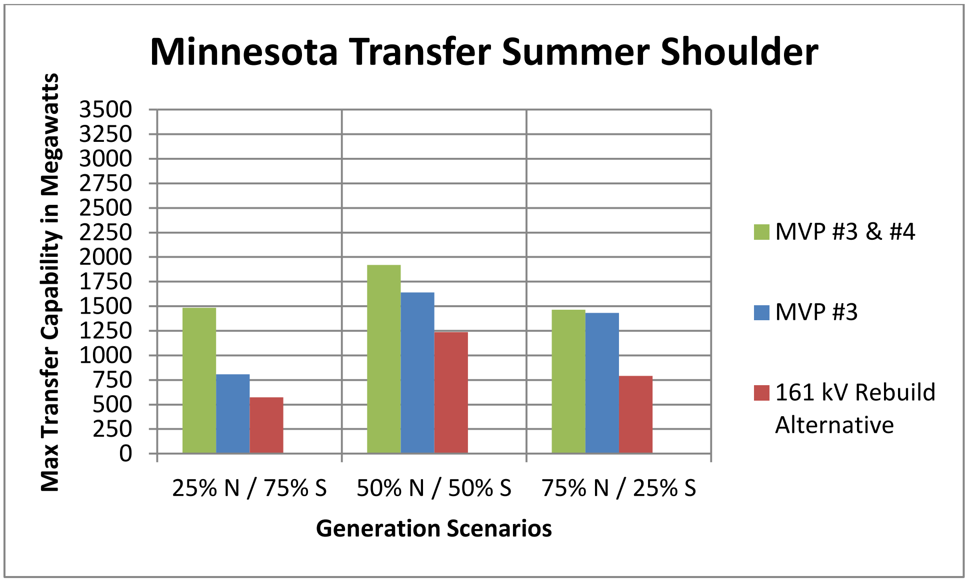


Figure 5 Incremental Transfer Capability of Transmission Options
Minnesota Summer Peak

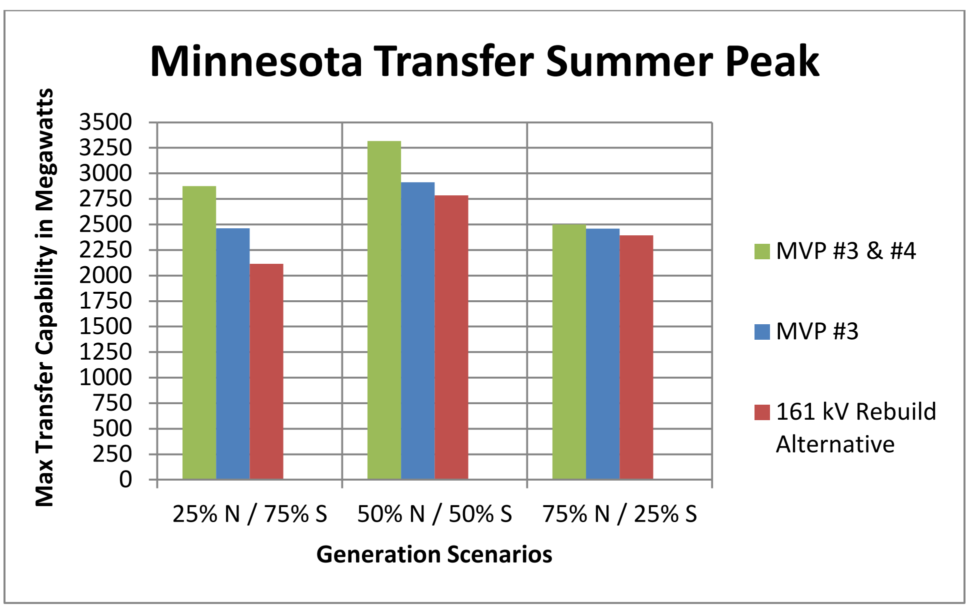


Figure 6 shows that neither MVP #3 nor the 161 Rebuild Alternative significantly increase generation outlet capacity for the eastern portion of the MISO footprint under two of the three generation scenarios during the high wind season. However, a significant increase in generation outlet capacity is achieved under all generation scenarios by a combination of MVPs #3 and #4.

Figure 6 Incremental Transfer Capability of Transmission Options
MISO East Summer Shoulder

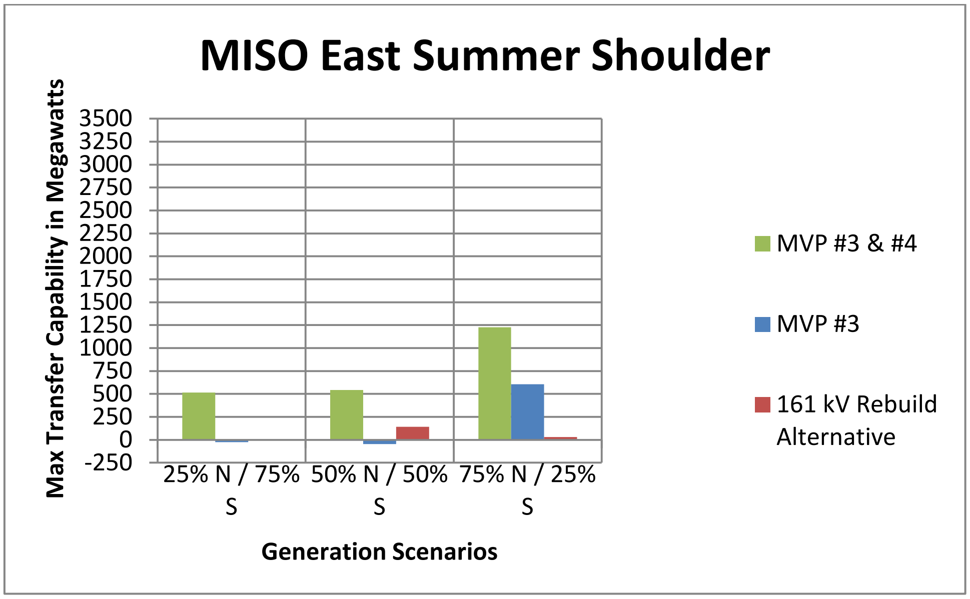
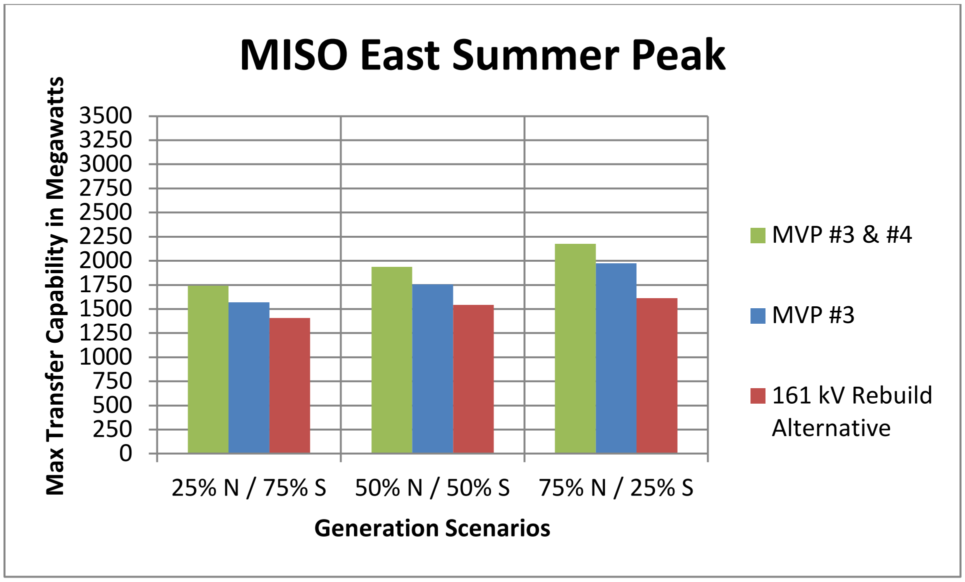


Figure 7 shows that while all three options significantly increase transfer capacity during summer peak, MVP #3 alone and in combination with MVP #4 again outperforms the 161 kV Rebuild Alternative.

Figure 7 **Incremental Transfer Capability of Transmission Options MISO East Summer Peak**



1.1 Fox Lake-Rutland-Winnebago Jct. 161 kV Constraint

Tables 1 through 6 in Appendix 51 identify the existing Fox Lake-Rutland-Winnebago Jct. 161 line as the "limiting element" that determines the maximum transfer capability under all six generation scenarios for the summer peak base case (i.e., the case before the addition of MVP #3, MVPs #3 and #4, or the 161 kV Rebuild Alternative).[14] This line is also the limiting element under three of the six generation scenarios for the summer shoulder base case.[15]

After the addition of MVP #3, MVPs #3 and #4, or the 161 kV Rebuild Alternative, the Fox Lake-Rutland-Winnebago Jct. 161 kV line is no longer a limiting element in any of the cases under any of the generation scenarios.

1.2 Special Considerations

The wind zones and scenarios analyzed above capture, at a system level, the different transfer capabilities that would be present under those scenarios. Because the ultimate location of actual wind development has a significant effect on its system impacts, further sensitivity analyses were undertaken to evaluate how the 161 kV Rebuild Alternative and MVP #3 alternatives would perform on a more micro level. Specifically, how would each perform if generation were geographically concentrated near the existing 161 kV system. This scenario is particularly realistic in evaluating wind generation areas because existing wind generators seek to take advantage of the best combination of available wind and transmission resources which can be geographically limited. Given the strong wind resources in the area, it is very likely that

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[14] App. 51, Tables 1-6.
[15] App. 51, Tables 1-3.

Table 2: Buffalo Ridge 50%N / 50%S – Minnesota Scenario Results

Case	Maximum Gross Transfer Capability (MW)	Limiting Element
SU 70 Base Case	2603.8	Rutland – Fox Lake 161 kV
SU 70 MVP #3	4244.5	Twin Church – Sioux City 230 kV
SU 70 MVP #3 and #4	4523.6	Twin Church – Sioux City 230 kV
SU 70 FXLK-RTLD-WNBG	3841.5	Lakefield – Fox Lake Ckt. 1 161 kV
SUM Base Case	438.9	Rutland – Fox Lake 161 kV
SUM MVP #3	3351.4~~484.5~~	Twin Church – Sioux City 230 kV
SUM MVP #3 and #4	3756.8	Twin Church – Sioux City 230 kV
SUM FXLK-RTLD-WNBG	3224.7	Twin Church – Sioux City 230 kV

Table 4: Buffalo Ridge 25%N / 75%S – MISO East Scenario Results

Case	Maximum Gross Transfer Capability (MW)	Limiting Element
SU 70 Base Case	2201.0	Boone Jct. – Fort Dodge 161 kV
SU 70 MVP #3	2176.0	Boone Jct. – Fort Dodge 161 kV
SU 70 MVP #3 and #4	2717.1~~974.7~~	Wapello – Ottumwa 161 kV
SU 70 FXLK-RTLD-WNBG	2201.3	Boone Jct. – Fort Dodge 161 kV
SUM Base Case	436.7	Rutland – Fox Lake 161 kV
SUM MVP #3	20~~14~~05.4~~8~~	Twin Church – Sioux City 230 kV
SUM MVP #3 and #4	2179.0	Twin Church – Sioux City 230 kV
SUM FXLK-RTLD-WNBG	1842.6	Twin Church – Sioux City 230 kV

Appendix 52: Transfer Capability of 161 kV Rebuild Alternative with MVP #4

Fox Lake – Rutland – Winnebago and MVP #4 Scenario Summary

Scenario	Maximum Gross Transfer Capability (MW)	Limiting Element
SU 70 BR 25% - 75% - MN	3287.2	Webster – Wright 161 kV
SU 70 BR 50% - 50% - MN	3677.6	Lakefield – Fox Lake 161 kV
SU 70 BR 75% - 25% - MN	3358.9	Triboji – Dickinson Co. 161 kV
SU 70 BR 25% - 75% - MISO	24~~6~~49.9~~7~~	Boone Jct. – Fort Dodge 161 kV~~Twin Church – Sioux City 230 kV~~
SU 70 BR 50% - 50% - MISO	2~~64~~569.6~~8~~	Cayler – Wisdom 161 kV~~Twin Church – Sioux City 230 kV~~
SU 70 BR 75% - 25% - MISO	1989.7	Cayler – Wisdom 161 kV
SUM BR 25% - 75% - MN	2559.0	Webster – Wright 161 kV
SUM BR 50% - 50% - MN	3272.9	Twin Church – Sioux City 230 kV
SUM BR 75% - 25% - MN	2841.1	Brookings – White 115 kV
SUM BR 25% - 75% - MISO	1883.5	Twin Church – Sioux City 230 kV
SUM BR 50% - 50% - MISO	2019.4	Twin Church – Sioux City 230 kV
SUM BR 75% - 25% - MISO	1945.6	Triboji – Dickinson Co. 161 kV

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: December 18, 2013

Requested From: David Grover, Mgr. Regulatory Strategy Response Due: January 6, 2013

Analyst Requesting Information: Steve Rakow

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
27	Regarding the *ITC Midwest LLC Multi-Value Project #3 Planning Study* (Appendix J) please explain why the 2,366.1 amount listed in Appendix 51 (Table 5 on page 53) does not match the amounts listed in Appendix 41. **Response:** The wrong table was inserted in appendix 41. Attached is the correct table.

Response by: Joe Berry

Title: Senior Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

Appendix 41: SUM MVP 3 and 4 Buffalo Ridge 50%N / 50%S Gen – MISO East Scenario

AC FCITC	Limiting Constrain	Contingency	PreShift	PostShift	Ratin	AC TD
2366.1	L:640386 TWIN CH4	230 652565 SIOUXCY4 230 1	188.2	320.0	320.0	0.05572
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
2366.1	L:640386 TWIN CH4	230 652565 SIOUXCY4 230 1	188.2	320.0	320.0	0.05572
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
3383.6	L:631079 BNE JCT5	161 636020 FT.DODG5 161 1	32.6	147.0	147.0	0.03381
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3383.6	L:631079 BNE JCT5	161 636020 FT.DODG5 161 1	32.6	147.0	147.0	0.03381
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3502.4	L:635201 RAUN 5	161 640377 TEKAMAH5 161 1	53.7	217.2	217.0	0.04669
		C:MEC-C528				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
3502.4	L:635201 RAUN 5	161 640377 TEKAMAH5 161 1	53.7	217.2	217.0	0.04669
		C:C2-RAUN-0270				
		Open 635200 RAUN 3 345 645451 S3451 3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
3588.9	L:640386 TWIN CH4	230 652565 SIOUXCY4 230 1	185.1	320.1	320.0	0.03760
		C:635200 RAUN 3 345 640226 HOSKINS3 345 1				
		Open 635200 RAUN 3 345 640226 HOSKINS3 345 1				
3959.5	L:601043 NLAX 5	161 681531 LAC TAP5 161 1	70.6	178.5	178.0	0.02726
		C:601043 NLAX 5 161 602026 MAYFAIR5 161 1				
		Open 601043 NLAX 5 161 602026 MAYFAIR5 161 1				
3587.0	L:636001 WEBSTER5	161 636050 WRIGHT 5 161 1	78.3	212.1	212.0	0.03729
		C:MEC-C522				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				
3587.0	L:636001 WEBSTER5	161 636050 WRIGHT 5 161 1	78.3	212.1	212.0	0.03729
		C:GRIMES-B904				
		Open 635590 FALLOW 3 345 635600 GRIMES 3 345 1				
		Open 635600 GRIMES 3 345 636010 LEHIGH 3 345 1				

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February 17, 2014

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lagrimonti@briggs.com

VIA E-MAIL

Sharon Ferguson
Minnesota Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed is ITC Midwest LLC's Response to Information Request 28 from the Department of Commerce, Division of Energy Resources.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email): Julia Anderson
Steve Rakow

Briggs and Morgan, Professional Association
Minneapolis | St. Paul | www.briggs.com
Member - Lex Mundi, a Global Association of Independent Law Firms

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docker Number: ET6675/CN-12-1053 Date of Request: February 6, 2014

Requested From: David Grover, Manager Regulatory Strategy Response Due: February 18, 2014

Analyst Requesting Information: Steve Rakow

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	

28 The Petition at page 89, regarding the Lakefield Junction—Rutland alternative, states that "the termination of the 345 kV line at Rutland resulted in constraints farther east on the 161 kV system, increasing loading on the 161 kV line between Rutland and Winnebago Junction." However, MTEP09 addressed this concern:

> One concern raised by the TRG [technical review group] was the potential overload of the Rutland - Winnebago 161 kV line, with the 345 kV upgrade ending at the Rutland substation. Additional economic sensitivity analysis was performed with the Rutland - Winnebago 161 kV included in the list of monitored elements. The economic benefit results are provided in Table 8.3-11. Compared to the original case the total benefits go down slightly as expected; however, the project still exceeds the 2.0 B/C ratio threshold and is qualified for Appendix B consideration.

Please provide further screening analysis explaining why the Lakefield Junction—Rutland alternative does not merit detailed analysis. Otherwise, please provide a detailed economic and engineering analysis of the Lakefield Junction—Rutland alternative.

Response: The Department is correct that MISO performed additional economic sensitivity analysis to account for additional congestion created on the Rutland-Winnebago 161 kV line by the 345 kV project, and found that while the 345 kV project's potential benefits were reduced, the project still qualified for further consideration. For this reason, MISO listed the Lakefield Junction-Rutland 345 kV project in MTEP 09 Appendix C (see MISO's response to IR #20), noting in the MTEP 09 report that:

Additional sensitivities are required to determine what effects this plan has on the surrounding system's low voltage line flows. Those sensitivities along with reliability analysis must be performed prior to Appendix A recommendation.

As further discussed in the MISO responses to IRs #21 and #22, additional analysis of the Lakefield Junction – Rutland 345 kV alternative was not performed in MTEP 10 or MTEP 11 because the Lakefield Junction – Rutland 345 kV facilities were included within options being studied to address a broader set of needs, including public policy requirements, generator interconnection and reliability needs in addition to congestion. This more comprehensive analysis in later MTEP cycles ultimately resulted in the 17-Project MVP portfolio being approved in MTEP 11 Appendix A, which included the Minnesota-Iowa 345 kV Project facilities as part of MVP 3.

The Lakefield Junction-Rutland 345 kV alternative does not merit additional detailed analysis because its facilities alone would not meet the broader set of needs being addressed by the MVP 3. However, because the Lakefield Junction – Rutland 345 kV facilities are part of the Minnesota-Iowa 345 kV project, the potential congestion relief benefits examined in MTEP 09 will be achieved as part of the Minnesota-Iowa 345 kV project.

5983144

Response by: Joe Berry

Title: Senior Engineer

Department: Transmission Planning

Telephone: (563) 585-3641

List sources of information:

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February 17, 2014

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<u>VIA E-MAIL</u>

Sharon Ferguson
Minnesota Department of Commerce
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St. Paul, MN 55101-2198

Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed is ITC Midwest LLC's Response to Information Request 29 from the Department of Commerce, Division of Energy Resources.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email): Julia Anderson
Steve Rakow

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State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: February 10, 2014

Requested From: Todd Schatzki, Joseph Berry Response Due: February 21, 2014

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
29	Please provide, Table 1 of Appendix N (for 2021 only), assuming the 161 kV Rebuild alternative replaces the MVP 3 project.

Response:

Table 1 of Appendix N provides estimates of the Minnesota Avg LMP impacts of two cases: MVP 3 and MVP 4 combined, and MVP 3 with MVP 4 not in service. The information request asks for similar impact estimates under the assumption that the 161kW Rebuild alternative is developed in place of MVP 3 – that is, one case with the 161 kV Rebuild alternative and MVP 4 combined, and another case with the 161 kV Rebuild alternative in service, but MVP 4 not in service.

In the response to Department of Commerce's Information Request No. 13 provided on November 27, 2013, Table 5 of Attachment 11-1 provides estimates of the impact on Minnesota Avg LMPs from the 161 kV Rebuild based on a comparison of a study case with the 161 kV Rebuild, but not MVP 4, in service to a base case without MVPs 3 and 4 in service. Thus, Table 5 provides estimates of the Minnesota Avg LMP impact of the 161 kV Rebuild for the case with the 161 kV Rebuild alternative in service, but MVP 4 not in service.

However, it is not reasonable to provide an alternative 161 kV Rebuild impact estimate under the assumption that both the 161 kV Rebuild alternative and MVP 4 are in service. As explained in footnote 9 of Appendix N, MVP 4 would not be developed without MVP 3. Thus, in Appendix N, the impact of MVP 3 alone is not evaluated assuming that MVP 4 is in service. Just as MVP 4 would not be developed without MVP 3, MVP 4 would not be developed if the 161 kV Rebuild alternative were constructed in place of MVP 3. Consequently, we did not evaluate the impact of the 161 kV Rebuild alternative under the assumption that MVP 4 is in service.

Response by:	Todd Schatzki; Joseph Berry	List sources of information:
Title:	Vice President; Engineer	
Department:	N/A; Transmission Planning	
Telephone:	(617) 425-8250; (563) 585-3641	

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November 27, 2013

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VIA E-MAIL

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Re: In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties
MPUC Docket No. ET6675/CN-12-1053

Dear Ms. Ferguson:

Enclosed are ITC Midwest LLC's supplemental responses to the Department of Commerce, Division of Energy Resources' Information Requests 11 and 13, with attachments.

Please contact me with any questions.

Sincerely,

/s/ Lisa M. Agrimonti

Lisa M. Agrimonti

LMA/rlr
Enclosures
Cc (via email) : Julia Anderson
Adam Heinen

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 | Date of Request: August 13, 2013

Requested From: ITC-Midwest | Response Due: August 23, 2013
Extension granted to Nov. 31, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[X] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
11	**Subject: Forecasting** **Please provide, at a high level, what impact failure to construct MVP4, MVP5, and both projects, would have on Minnesota LMPs, and the cost and benefits associated with MVP3.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	The Certificate of Need Application, Appendices M and N provide information regarding the Minnesota LMP impact if MVP 3 and 4 were constructed and if MVP 3 were constructed, but not MVP 4. ITC Midwest has not prepared an analysis of how the Minnesota LMP would be affected if MVP 5 or any other MVP were not constructed. Additional studies to examine the impact on Minnesota LMPs if MVP 5 is not constructed or both MVP 4 and MVP 5 are not constructed will be performed and a response detailing those impacts will be submitted after these studies are completed. ITC Midwest estimates it can provide this information by November 1, 2013.
Supplemental Answer	Data responsive to this request is provided in the LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis, **Attachment 11-1**.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis

Rodney Frame
Todd Schatzki

Analysis Group

November 2013

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis

Rodney Frame
Todd Schatzki

Executive Summary

ITC Midwest LLC (ITC Midwest) is proposing to develop the Minnesota – Iowa 345 kV Transmission Project (the Project). The Project involves construction of new 345 kV transmission lines and associated facilities in Minnesota and Iowa with the purpose of providing economic, policy and reliability benefits. The Project is part of MVP 3, one of the 17 projects that make up the Midcontinent Independent System Operator, Inc.'s (MISO) Multi-Value Project (MVP) Portfolio.

Using the PROMOD market simulation model, the analyses herein estimate the change in locational marginal prices (LMPs) in Minnesota and production costs (in MISO) from implementing the Project (and other components of MVPs 3 and 4) and a 161 kV Rebuild alternative. Analyses are performed with and without MVP 5, which includes new transmission lines and associated facilities in south western Wisconsin. Impacts are evaluated under two future electricity demand scenarios: Business as Usual: Low Demand (hereafter, Low Demand) and Business as Usual: High Demand (hereafter, High Demand). These analyses are performed in response to Utility Information Requests made by the Department of Commerce, Division of Energy Resources (DER). The analyses have been performed using wind curtailment estimates developed by ITC Midwest.

The development of MVPs 3 and 4 lowers average LMPs for Minnesota by $0.48 per MWh (1.7%) in 2021 and $0.68 per MWh (2.1%) in 2026 under the Low Demand scenario. Price reductions are similar under the High Demand scenario: $0.52 per MWh (1.5%) in 2021 and $0.55 per MWh (1.2%) in 2026. These LMP changes result in annual reductions in wholesale energy payments for Minnesota load that range from $36.1 million (2021 Low Demand) to $52.4 million (2026 Low Demand).

The development of MVP 3 alone, without the development of MVP 4, results in smaller LMP reductions. In 2021, LMPs fall by $0.06 per MWh (0.2%) under both Low Demand and High Demand scenarios. In 2026, LMPs are effectively unchanged with the development of MVP 3 alone without MVP 4. These LMP changes result in annual reductions in wholesale energy payments for Minnesota load that range from $0.9 million (2026 High Demand) to $4.6 million (2021 Low Demand).

LMP reductions from the implementation of MVPs 3 and 4 are widespread across the eight individual load-serving entities (LSEs) in Minnesota included in the PROMOD analysis. Average LMPs decline for all eight LSEs in 2021 and for seven of the eight LSEs in 2026. LMP reductions from the implementation of MVP 3 alone, without MVP 4, are varied, with LMPs rising in some areas and falling in others.

Development of MVPs 3 and 4 also lowers production costs for the entire MISO footprint. Reductions in production costs range from $114.9 million to $185.6 million across scenarios and years when both MVPs 3 and 4 are developed, and range from $35.2 million to $49.5 million when only MVP 3 is developed.

Results are sensitive to the development of MVP 5, which is assumed to take place for the results reported above. If MVP 5 is not developed, LMP reductions from development of MVP 3 and 4 (together, or MVP 3 alone) are smaller than they otherwise would be. For example, the LMP reductions from development of both MVP 3 and 4 would be 7% to 43% lower if MVP 5 were not developed in comparison to the case where it is developed. Production cost reductions from development of both MVP 3 and 4 are similar whether or not MVP 5 is developed, ranging from $95.3 to $185.6 million. However, production cost reductions from development of MVP 3 alone, which range from $35.2 million to $82.4 million across demand scenarios and years, are greater if MVP 5 is not developed.

Development of the 161 kV Rebuild alternative (without MVPs 3 and 4) reduces LMPs by $0.17 per MWh (0.6%) in 2021 and $0.32 per MWh (1.0%) in 2026 under the Low Demand scenario if MVP 5 is constructed. Price reductions are similar under the High Demand scenario: $0.35 per MWh (1.0%) in 2021 and $0.32 per MWh (0.7%) in 2026. However, if MVP 5 is not constructed, these price reductions are lower, ranging from $0.06 per MWh (0.1%) to $0.15 per MWh (0.4%). Reductions in production costs range from $16.3 million to $23.7 million if MVP 5 is developed. If MVP 5 is not developed, the 161 kV Rebuild results in higher production costs in three of four scenario/study year combinations evaluated.

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis

Rodney Frame
Todd Schatzki

1. BACKGROUND ON THE MINNESOTA-IOWA PROJECT

ITC Midwest LLC (ITC Midwest) is proposing to construct new 345 kV transmission lines and associated facilities with the purpose of providing economic, policy and reliability benefits. These facilities include the Minnesota – Iowa 345 kV Transmission Project (the Project), which is being developed as part of the Midcontinent Independent System Operator, Inc.'s (MISO) 17 Multi-Value Project (MVP) portfolio. MVPs are transmission projects in the MISO footprint that have been "determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones."[1] The costs of MVPs are recovered from all load within and exports from MISO via a per MWh charge.[2]

Among other things, the portfolio of MVPs is intended to help enable the reliable delivery of renewable energy, including wind power, within the MISO footprint, allow for a more efficient dispatch of generation resources, open markets to further competition and spread the benefits of low-cost

[1] 133 FERC ¶ 61,221(2010), at P 1. See also the listing of the three MVP criteria in Section II.C.2 of Attachment FF of the MISO Tariff, as follows:

Criterion 1. A Multi Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

Criterion 2. A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher ….

Criterion 3. A Multi Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs ….

[2] See MISO Tariff, Schedule 26A, Multi-Value Project Usage Rate, and Attachment MM, Multi-Value Project Charge.

generation. The Federal Energy Regulatory Commission (FERC) approved the methodology used by MISO to identify the MVP portfolio as "an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads."[3]

MISO's *Multi Value Project Portfolio, Results and Analysis*, January 10, 2012 (MISO MVP Report)[4] provides a comprehensive assessment of the complete 17 MVP portfolio and recommends that each of the 17 projects be approved by MISO's Board of Directors for inclusion in Appendix A of the MISO Transmission Expansion Plan. On December 8, 2011, the MISO Board approved this recommendation.

The Project consists of a 345 kV transmission line and associated facilities located in Jackson, Martin, and Faribault counties in Minnesota, and Kossuth County in Iowa.[5] The Project, together with other facilities being proposed by MidAmerican Energy Company (MidAmerican) to be constructed in Iowa [6] comprises what is referred to as MVP 3 in MISO's MVP portfolio. The development of MVP 3 is closely tied to MVP 4, which is also being proposed by ITC Midwest and MidAmerican.[7] Together, MVPs 3 and 4 provide new pathways to help power flow from western Minnesota and Iowa, connecting to major 345 kV hubs in eastern Iowa, along with providing reliability and congestion relief benefits.

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[3] Midwest Independent Transmission System Operator, Inc., 133 FERC ¶ 61,221(2010), p. 3 (Dec. 16, 2010 Order).

[4] https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf

[5] In Minnesota, ITC Midwest's existing Lakefield Junction Substation will be expanded for a new 345 kV line to be constructed between the substation and a new Huntley Substation, proposed to be located south of the existing Winnebago Junction Substation. The Winnebago Junction Substation will be removed and the four existing 161 kV lines connecting to Winnebago Junction will be re-connected to the Huntley Substation. From Huntley, the 345 kV transmission line will run south to cross the Minnesota/Iowa border and connect first to a new ITC Midwest Ledyard Substation, and then to a new Kossuth County Substation owned by MidAmerican, both of which will be in Kossuth County, Iowa. The expected total cost of the Project is approximately $271 to $283 million (plus or minus 30 percent.) Details on these expected costs, the route taken by the Project, and new and modified changes to substations and transformers, are provided in Chapter 2 of: ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Minnesota-Iowa 345 kV Transmission Project in Jackson, Martin and Faribault Counties, Docket No. ET6675/CN-12-1053, March 22, 2013.

[6] As a part of MVP 3, MidAmerican is proposing to construct (1) a 345 kV transmission line that runs from the Kossuth County Substation south to its existing Webster Substation, near Fort Dodge, Iowa, and (2) a 345 kV transmission line running west from the Kossuth County Substation to its new O'Brien Substation, near Sanborn, Iowa.

[7] MVP 4 includes new transmission infrastructure that runs across Iowa through the Winco, Lime Creek, Emery, Blackhawk and Hazleton Substations.

This report supplements previous analyses that have been developed and responds to Utility Information requests of the Department of Commerce, Division of Energy Resources (DER).[8] These requests include:

1. Information on the impacts of the failure to construct MVP 4, MVP 5 and both projects; and
2. Information on the economic impacts of alternatives identified in the MVP Planning Study.

The MVP Planning Study,[9] performed by ITC Midwest and included in its application for a Certificate of Need for the Project, evaluates the reliability impacts of transmission alternatives on ITC Midwest's system in Minnesota. In this study, ITC Midwest considered a transmission alternative, referred to herein as the 161 kV Rebuild, that is evaluated in the current report.[10] With the 161 kV Rebuild, the existing transmission line from Fox Lake-Rutland-Winnebago Junction, that has been a main constraint on the electrical system in the region, would be rebuilt. This rebuild would include new structures and lines, and would increase the line's rating from 168 MVA to 446 MVA. As requested by the DER, the analyses described herein include evaluations of the 161 kV Rebuild, in addition to analyses of MVP 3 and 4.

This Second Supplemental Report differs from prior analyses we have prepared (referred to as the March 2013 Analysis and the April 2013 Analysis)[11] in the following two ways: (i) the Second Supplemental Report develops price impacts and changes in production costs for the 161 kV Alternative, which was not considered in either earlier analysis; and (2) the Second Supplemental Report considers the impacts of alternative transmission infrastructure for Minnesota when MVP 5 is not in service, whereas both earlier analyses assumed that MVP 5 was in service in all cases evaluated.

2. METHODOLOGY

The analyses described herein use the PROMOD IV (PROMOD) market simulation model to estimate both wholesale electricity price and annual production cost changes resulting from MVPs 3 and 4, and the 161 kV Rebuild. PROMOD, which is marketed by Ventyx, simulates the operation of the regional generation and transmission system, in so doing reflecting a variety of generator operating characteristics and constraints, and transmission system topology and limits. Among other things,

[8] Department of Commerce, Division of Energy Resources, Utility Information Requests No. 11 and 13, August 13, 2013.

[9] Jeff Eddy and Joseph Berry, "ITC Midwest LLC, Multi-Value Project #3 Planning Study," Appendix J, Application of ITC Midwest for a Certificate of Need for the Minnesota-Iowa 345 k V Transmission Project, March 22, 2013.

[10] This study also considered a "No Build" alternative, under which no new transmission is built. This alternative is the same as our Base Case, and therefore serves as the baseline against which other cases are compared.

[11] Frame, Rodney, Todd Schatzki, Pavel Darling, "LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis," April 2013; Frame, Rodney, Todd Schatzki, Pavel Darling, "LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project," March 2013.

PROMOD allows the estimation of time-varying locational marginal energy prices (LMPs)[12] under different sets of operating conditions and infrastructure development. PROMOD also allows the estimation of generator-by-generator variable production costs. The PROMOD analysis and the data set employed are described more fully in Appendix A. The PROMOD market simulation model and the data set employed largely are identical to those used by MISO in the MISO MVP Report.

The hour-by-hour LMP values produced by the PROMOD analysis were used, along with the amount of load served from each of the pricing nodes, to develop load-weighted average wholesale energy prices (referred to as "average LMPs"). These average LMPs were determined both for Minnesota taken as a whole (sometimes hereafter referred to as the "Minnesota Avg LMP") and for each of the eight individual Minnesota load-serving entities (LSEs) that are represented in the PROMOD database.[13] Appendix A provides further detail on these computations.

The PROMOD analysis uses two alternative "base cases". In one base case (Base Case), all 17 projects in the MVP portfolio except MVPs 3 and 4 are assumed to be in service. In the second base case (No MVP 5 Base Case), all 17 projects in the MVP portfolio except MVPs 3, 4 *and 5* are assumed to be in service. Changes in average LMPs and the Minnesota Avg LMP – together or separately sometimes referred to as "LMP impacts" – are calculated between each base case and three "study cases". A summary of these base and study cases is provided in Table 1.

In Study Case 1, all 17 MVPs are assumed to be in service. The difference between the average LMPs without MVPs 3 and 4 in service (Base Case) and the average LMPs with MVPs 3 and 4 in service (Study Case 1) then represents the LMP impact from implementing both MVPs 3 and 4. If this difference is negative, as turns out generally to be the case, then this is an indication that MVPs 3 and 4 will lower average wholesale electric energy prices in Minnesota. The annual change in total wholesale market energy payments for Minnesota load is calculated by multiplying these differences by total Minnesota load.

In Study Case 2, MVP 3 is assumed to be placed in service, but MVP 4 is not. The LMP impacts in this case provide one measure of the incremental impact of MVP 3.[14] For example, the difference

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[12] In MISO, electric energy prices are developed for individual "nodes" on the system. These location-specific "nodal" prices commonly are referred to as locational marginal prices or LMPs. Differences in LMPs from location to location occur because of differences in marginal losses as well as the presence of congestion. When congestion is present, it is not possible fully to exploit differences in marginal generating costs at different locations and LMPs in transmission-constrained areas will rise above LMPs outside those transmission-constrained areas.

[13] These eight Minnesota LSEs are Alliant West—Interstate Power & Light, Dairyland Power Cooperative (Dairyland), Great River Energy, Minnesota Power and Light Company, Minnkota Power Cooperative, Northern States Power Company, Otter Tail Power Company and Southern Minnesota Municipal Power Agency (SMMPA). All but three of these entities also have retail load in states other than Minnesota, requiring the development of a means to unbundle the Minnesota portion of the LMP effects.

[14] Hypothetically, an alternative approach to measure the incremental impact of just MVP 3 would be to compare a case with all 17 MVPs except MVP 3 to a case in which all 17 MVPs are developed. Such an analysis implicitly assumes that, in the absence of MVP 3, MVP 4 in fact still would be constructed. However, we understand that MVP 4 would not be developed without MVP 3. Thus, we have not analyzed PROMOD cases that assume the construction of MVP 4 but not MVP 3.

between the average LMP without MVPs 3 and 4 (Base Case) and the average LMP with MVP 3, but not MVP 4 (Study Case 2) represents the LMP impact from implementing MVP 3 alone, as compared to the Base Case without both MVPs 3 and 4.

Study Case 3 assumes that the 161 kV Rebuild is placed in service instead of MVP 3, and also that MVP 4 is not in service. The difference in average LMPs between the Base Case and Study Case 3 represents the impact of the 161 kV Rebuild.

Table 1

Base Cases and Study Cases Considered

With MVP 5 In Service **Base Case** • MVP 3 & 4 Not In Service (Base Case) **Study Cases** • MVP 3 & 4 In Service (Study Case 1) • MVP 3 In Service, MVP 4 Not in Service (Study Case 2) • 161 kV Rebuild, MVP 3 and 4 Not In Service (Study Case 3)
With MVP 5 Not In Service **Base Case** • MVP 3, 4 & 5 Not In Service (No MVP 5 Base Case) **Study Cases** • MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4) • MVP 3 In Service, MVP 4 & 5 Not in Service (Study Case 5) • 161 kV Rebuild, MVP 3, 4 & 5 Not In Service (Study Case 6)

Note: MVPs 1, 2 and 6-17 are assumed to be in service in all base cases and study cases.

The LMP impacts and changes in wholesale market energy payments calculated relative to the Base Case assume that MVP 5 is in service. We also calculate the impacts of these transmission projects under the assumption that MVP 5 is not in service. These estimates are calculated by comparing a Base Case with MVPs 3, 4 and 5 not in service – which is referred to as the No MVP 5 Base Case – to study cases with the relevant project elements in service. For example, the LMP impact of MVPs 3 and 4 without MVP 5 in service is based on the difference between the load-weighted average electric energy prices in No MVP 5 Base Case and the load-weighted average electric energy prices with MVPs 3 and 4 in service, but MVP 5 not in service (Study Case 4). Analogous calculations are performed to estimate the impacts of MVP 3 alone (Study Case 5), and the 161 kV Rebuild (Study Case 6).

The PROMOD analysis quantifies the lower wholesale electric *energy* prices that will result from MVPs 3 and 4 and the 161 kV Rebuild, but it does not quantify other potential wholesale electricity price benefits such as lower operating reserve costs and lower capacity requirements and prices. Consequently, focusing solely on the change in wholesale electric energy prices from the PROMOD analysis potentially will understate the full range of price benefits that can be expected from MVPs 3 and 4 or the 161 kV Rebuild.

In addition to the LMP comparisons, the PROMOD analysis that we have conducted also estimates the production costs of meeting MISO load (referred to herein as MISO Production Costs), and develops similar comparisons between cases as those described above for the LMP comparisons. What we refer to as MISO Production Costs are the fuel, variable operations and maintenance, emissions and start-up costs associated with supplying MISO load, adjusted for net imports or exports of power with pools outside MISO.

The PROMOD analyses were run for two future study years, 2021 and 2026, using two different load growth scenarios for each year. These scenarios, which were also used in the MISO MVP Report, are as follows:

(i) Business as Usual: Low Demand ("Low Demand") scenario – assumes the continuation of current energy policies and continuing "recession-level" demand and energy growth; and
(ii) Business as Usual: High Demand ("High Demand") scenario – assumes the continuation of current energy policies and a return to pre-recession demand and energy growth levels.

These two scenarios are described more completely in Appendix A.

The geographic region covered by the PROMOD analysis includes a large portion of the Eastern Interconnection,[15] including all of MISO and the footprint of the adjacent PJM Interconnection and other directly and indirectly interconnected systems.

The PROMOD analysis relies largely on the same data used by MISO in its economic analysis of the MVP portfolio. The assumptions regarding customer demand and energy growth, transmission infrastructure, forecasted fuel prices, and existing and new generation resources are the same as employed by MISO. New renewable resources are added so that each state in the MISO region can comply with its state Renewable Portfolio Standards. Aside from the changes to transmission (*i.e.*, MVPs 3, 4 and 5, and the 161 kV Rebuild), the only difference between the study cases and the base case is the quantity of wind power assumed. The quantity of wind power resources is reduced from the base case based because fewer wind resources can be reliably supported without elements of the MVP portfolio, as proposed. As discussed more fully in Appendix A, estimates of the quantity of wind power that can be reliably supported under different transmission configurations have been developed by ITC using the same methodology that MISO used in the MISO MVP Report.

[15] The Eastern Interconnection includes roughly the eastern two-thirds of the "lower 48" (with the exception of portions of Texas) plus Canadian provinces to the east of Alberta.

3. RESULTS

A. LOCATIONAL MARGINAL PRICE

I. MVPS 3 AND 4

The LMP impacts arising from MVPs 3 and 4 are reported in Tables 2 to 4. Table 2 shows the Minnesota Avg LMPs for each of the cases and scenarios evaluated. Tables 3 (Low Demand) and 4 (High Demand) then provide the results for the individual Minnesota LSEs. The weighted average prices shown reflect each of the eight Minnesota LSEs represented in PROMOD, with weightings in turn reflecting the portion of each company's load that is in Minnesota.

We first consider results when MVP 5 is in service. These are the comparisons between the Base Case as defined above, and Study Cases 1, 2 and 3. In 2021, under the Low Demand scenario, the Minnesota Avg LMP is $28.44 without MVPs 3 and 4 in service (*i.e.*, the Base Case) and $27.96 with both MVPs 3 and 4 in service (*i.e.*, Study Case 1). The results indicate a Minnesota Avg LMP reduction of $0.48 per MWh from the implementation of both MVPs 3 and 4, or 1.7%. Under the High Demand scenario, the Minnesota Avg LMP in 2021 is reduced by $0.52 per MWh from the implementation of both MVPs 3 and 4, or 1.5%. When the Minnesota Avg LMP reductions are multiplied by Minnesota load levels, the resulting decreases in annual wholesale energy payments for those Minnesota loads range from $36.1 million in 2021 under Low Demand to $52.5 million in 2026 under Low Demand.

Development of MVP 3 alone without MVP 4 (Study Case 2) results in smaller LMP reductions, as shown in columns [F] and [G] of Table 2. In 2021, under Low Demand, the Minnesota Avg LMP is $28.38 per MWh in Study Case 2 as compared to $28.44 per MWh in the Base Case. Thus, the Minnesota Avg LMP falls by $0.06 per MWh (0.2%) with the introduction of MVP 3 but not MVP 4. With High Demand in 2021, the price reduction from development of MVP 3 is $0.06 (0.2%). The resulting decrease in annual wholesale energy payments in 2021 is $4.6 million under Low Demand and $4.3 million under High Demand.

The lower panel of Table 2, along with Tables 3B and 4B, report LMP impacts when it is assumed that MVP 5 is not developed. Across the scenarios and years evaluated, Minnesota Avg LMPs are higher when MVP 5 is in service compared to when it is not in service. For example, under Low Demand in 2021, the Minnesota Avg LMP increases from $27.96 per MWh with all MVPs in service (Study Case 1) to $28.85 per MWh with all MVPs except MVP 5 in service (Study Case 4).

The LMP reductions from MVPs 3 and 4 together, and MVP 3 alone, are lower when MVP 5 is not developed. For example, with MVP 5 not in service, development of MVP 3 and 4 results in change in Minnesota Avg LMP of $0.36 per MWh (Low Demand in 2021), while with MVP 5 in service, the impact of MVP 3 and 4 is $0.48 per MWh.

Table 3 reports, for the Low Demand scenario, the load weighted average LMPs for each Minnesota LSE with and without MVPs 3 and 4. Table 4 reports similar figures for the High Demand scenario. The LMP impacts vary across companies but generally show significant price decreases for all LSEs across study years and demand scenarios after the inclusion of both MVPs 3 and 4. The principal exception is Dairyland, which has about 12 percent of its load in Minnesota. Dairyland experiences a price increase in both scenarios in 2026, but not in 2021. With MVP 5 in service, the largest (beneficial) price impacts are for SMMPA, where the average LMP is $26.55 with MVPs 3 and 4 in service, and $27.54 without MVPs 3 and 4 in service. Thus, the effect of MVPs 3 and 4 is to lower SMMPA's average LMP by $0.99, or 3.6%, in 2021. (The effects are similar for the High Demand scenario shown in Table 4.) The smallest price impacts are for Dairyland. For Dairyland, in 2021 under Low Demand, the effect of implementing MVPs 3 and 4 is to lower Dairyland's average LMP by $0.19, or 0.6%.

When developing only MVP 3, compared to a case in which neither MVP 3 nor 4 are developed, LMP impacts vary widely across Minnesota LSEs, with LMPs falling in some LSEs and rising in others. When MVP 5 is not in service, LMP impacts (reductions) for individual LSEs in most instances are larger compared to when MVP 5 is in service.

II. 161 KV REBUILD

The LMP impacts arising from the 161 kV Rebuild are reported in Tables 5 to 7. Table 5 shows the LMP impacts in each of the study years for Minnesota taken as a whole. Table 6 reports the LMP impacts for each Minnesota LSE for the Low Demand scenario, while Table 7 reports similar figures for the High Demand scenario.

In 2021 under Low Demand, the Minnesota Avg LMP is $28.27 per MWh with the 161 kV Rebuild (but not MVP 4) (Study Case 3) as compared to $28.44 per MWh without both MVPs 3 and 4 (Base Case). Thus, the Minnesota Avg LMP falls by $0.17 per MWh (0.6%) with the introduction of the 161 kV Rebuild (and without MVPs 3 and 4). The price reduction from the 161 kV Rebuild in 2021 under High Demand is $0.35 (1.0%). The resulting decrease in annual wholesale energy payments for 2021 is $12.5 million under Low Demand and $27.6 million under High Demand.

The price effects vary across LSEs. With MVP 5 in service, the addition of the 161 kV Rebuild generally reduces price for all LSEs across study years and demand scenarios. As shown in Table 6, the largest (beneficial) price impacts are for SMMPA, while the smallest price impacts are for Alliant West. When MVP 5 is not in service, LMP impacts (reductions) from the 161 kV Rebuild are generally smaller for individual LSEs compared to LMP impacts when MVP 5 is in service.

B. PRODUCTION COSTS

I. MVPS 3 AND 4

The estimated changes in MISO Production Costs resulting from MVPs 3 and 4 are provided in Table 8 and 9. Table 8 reports the change in total annual MISO Production Costs, while Table 9 reports the average change in production costs per MWh of load. With MVP 5 in service, in 2021 under a Low Demand scenario, annual MISO Production Costs are $13,217 million with both MVPs 3 and 4 (Study Case 1) and $13,332 without MVPs 3 and 4 (Base Case). Thus, the development of MVPs 3 and 4 reduces annual MISO Production Costs by $114.9 million, or 0.9%. In 2026, the analogous reduction is $136.9 million or 0.9%. Decreases in production costs arising from development of both MVPs 3 and 4 under the High Demand scenario are somewhat higher: $132.2 million (0.8%) in 2021 and $185.6 million (0.9%) in 2026.

With MVP 5 not developed, MISO Production Costs are higher across all years and demand scenarios compared to when MVP 5 is developed. The reductions in MISO Production Costs, based on the different study case-base-case comparisons, are similar whether or not MVP 5 is developed. Except for the Low Demand scenario in 2021, MISO Production Cost impacts are within $10 million annually with and without MVP 5.

The reductions in MISO Production Costs from developing MVP 3, but not MVP 4, are reported in columns [F] and [G] of Table 9. With MVP 5 in service, under the Low Demand scenario, the development of MVP 3 without MVP 4 reduces annual MISO Production Costs by $42.9 million in 2021 (0.3% of total production costs), and $35.2 million (0.2%) in 2026. Reductions in MISO Production Costs from introducing MVP 3 without MVP 4 are higher when MVP 5 is not in service – for example, under Low Demand, MISO Productions Costs fall by $65.4 million (0.5%) with MVP 5 not in service, as compared to $42.9 million with MVP 5 in service, a difference of 52%.

II. 161 KV REBUILD ALTERNATIVE

The estimated changes in MISO Production Costs resulting from the 161 kV Rebuild are provided in Tables 10 and 11. Table 10 reports the change in annual MISO Production Costs, while Table 11 reports the average change in MISO Production Costs per MWh. With MVP 5 in service, reductions in MISO Production Costs range from $16.3 to $23.7 million (0.1% of total production costs) across the study years and demand scenarios considered. With MVP 5 not in service, changes MISO Production Costs range from a decrease of $7.5 million to an increase in $10.2 million.

Table 2
LMP Changes From MVPs 3 and 4
Minnesota Avg LMP

With MVP 5

		Load Weighted Average LMP ($ per MWh)			Average LMP Change			
	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$27.96	$28.38	$28.44	-$0.48	-1.7%	-$0.06	-0.2%
Low Demand	2026	$31.17	$31.84	$31.85	-$0.68	-2.1%	-$0.01	0.0%
Business as Usual:	2021	$34.50	$34.96	$35.02	-$0.52	-1.5%	-$0.06	-0.2%
High Demand	2026	$45.09	$45.62	$45.64	-$0.55	-1.2%	-$0.02	-0.1%

Without MVP 5

		Load Weighted Average LMP ($ per MWh)			Average LMP Change			
	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$28.85	$29.18	$29.21	-$0.36	-1.2%	-$0.02	-0.1%
Low Demand	2026	$32.10	$32.63	$32.58	-$0.48	-1.5%	$0.06	0.2%
Business as Usual:	2021	$35.26	$35.70	$35.74	-$0.48	-1.3%	-$0.04	-0.1%
High Demand	2026	$46.26	$46.69	$46.57	-$0.31	-0.7%	$0.11	0.2%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A.

Table 3A
LMP Changes From MVPs 3 and 4
Business as Usual: Low Demand

			With MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$29.08	$29.65	$29.43	-$0.35	-1.2%	$0.22	0.8%
		2026	$33.07	$33.49	$33.28	-$0.21	-0.6%	$0.22	0.7%
Dairyland Power Cooperative	11.5%	2021	$30.97	$32.72	$31.16	-$0.19	-0.6%	$1.56	5.0%
		2026	$35.54	$37.57	$35.31	$0.23	0.6%	$2.26	6.4%
Great River Energy	99.6%	2021	$27.47	$27.71	$28.00	-$0.53	-1.9%	-$0.29	-1.0%
		2026	$29.84	$30.29	$30.58	-$0.74	-2.4%	-$0.29	-1.0%
Minnesota Power and Light Company	100.0%	2021	$28.23	$28.50	$28.63	-$0.40	-1.4%	-$0.13	-0.4%
		2026	$31.43	$31.88	$32.02	-$0.58	-1.8%	-$0.14	-0.4%
Minnkota Power Coop	45.1%	2021	$30.22	$30.41	$30.65	-$0.43	-1.4%	-$0.24	-0.8%
		2026	$34.47	$34.75	$35.18	-$0.72	-2.0%	-$0.44	-1.2%
Northern States Power Company	74.8%	2021	$27.92	$28.32	$28.39	-$0.47	-1.7%	-$0.06	-0.2%
		2026	$31.47	$32.14	$32.16	-$0.69	-2.2%	-$0.02	-0.1%
Otter Tail Power Company	48.4%	2021	$28.54	$28.62	$28.95	-$0.41	-1.4%	-$0.33	-1.1%
		2026	$31.04	$31.20	$31.65	-$0.61	-1.9%	-$0.45	-1.4%
Southern Minnesota Municipal Power Agency	100.0%	2021	$26.55	$28.67	$27.54	-$0.99	-3.6%	$1.13	4.1%
		2026	$28.64	$31.57	$29.58	-$0.94	-3.2%	$1.99	6.7%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 3B
LMP Changes From MVPs 3 and 4
Business as Usual: Low Demand

			Without MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$29.32	$30.29	$30.17	-$0.85	-2.8%	$0.11	0.4%
		2026	$33.25	$34.43	$34.00	-$0.75	-2.2%	$0.43	1.3%
Dairyland Power Cooperative	11.5%	2021	$31.25	$33.25	$31.62	-$0.37	-1.2%	$1.63	5.1%
		2026	$35.83	$37.93	$35.58	$0.25	0.7%	$2.35	6.6%
Great River Energy	99.6%	2021	$28.51	$28.59	$28.85	-$0.34	-1.2%	-$0.26	-0.9%
		2026	$30.92	$31.19	$31.44	-$0.52	-1.7%	-$0.25	-0.8%
Minnesota Power and Light Company	100.0%	2021	$29.01	$29.18	$29.31	-$0.31	-1.1%	-$0.13	-0.5%
		2026	$32.24	$32.61	$32.72	-$0.47	-1.4%	-$0.10	-0.3%
Minnkota Power Coop	45.1%	2021	$30.97	$30.97	$31.27	-$0.30	-1.0%	-$0.29	-0.9%
		2026	$35.40	$35.57	$36.07	-$0.67	-1.9%	-$0.50	-1.4%
Northern States Power Company	74.8%	2021	$28.75	$29.08	$29.10	-$0.35	-1.2%	-$0.02	-0.1%
		2026	$32.30	$32.83	$32.76	-$0.46	-1.4%	$0.07	0.2%
Otter Tail Power Company	48.4%	2021	$29.63	$29.51	$29.88	-$0.25	-0.8%	-$0.37	-1.2%
		2026	$32.06	$32.09	$32.62	-$0.56	-1.7%	-$0.53	-1.6%
Southern Minnesota Municipal Power Agency	100.0%	2021	$28.21	$30.46	$28.98	-$0.77	-2.7%	$1.48	5.1%
		2026	$30.84	$33.42	$31.31	-$0.47	-1.5%	$2.11	6.8%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 4A
LMP Changes From MVPs 3 and 4
Business as Usual: High Demand

			With MVP 5							
			Load Weighted Average LMP ($ per MWh)			Average LMP Change				
Area	Percent of Sales in Minnesota	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$32.39	$33.39	$33.24	-$0.84	-2.5%	$0.15	0.5%
		2026	$39.44	$40.85	$40.45	-$1.01	-2.5%	$0.40	1.0%
Dairyland Power Cooperative	11.5%	2021	$36.06	$38.16	$36.39	-$0.34	-0.9%	$1.77	4.9%
		2026	$44.69	$47.07	$44.18	$0.51	1.2%	$2.90	6.6%
Great River Energy	99.6%	2021	$33.60	$33.84	$34.21	-$0.61	-1.8%	-$0.37	-1.1%
		2026	$42.34	$42.70	$42.99	-$0.64	-1.5%	-$0.29	-0.7%
Minnesota Power and Light Company	100.0%	2021	$33.77	$34.13	$34.28	-$0.51	-1.5%	-$0.16	-0.5%
		2026	$41.95	$42.39	$42.37	-$0.42	-1.0%	$0.02	0.1%
Minnkota Power Coop	45.1%	2021	$36.01	$36.15	$36.57	-$0.56	-1.5%	-$0.41	-1.1%
		2026	$44.71	$44.95	$45.43	-$0.72	-1.6%	-$0.48	-1.1%
Northern States Power Company	74.8%	2021	$35.24	$35.65	$35.66	-$0.42	-1.2%	$0.00	0.0%
		2026	$47.94	$48.33	$48.46	-$0.53	-1.1%	-$0.14	-0.3%
Otter Tail Power Company	48.4%	2021	$33.97	$34.04	$34.53	-$0.56	-1.6%	-$0.49	-1.4%
		2026	$40.87	$41.03	$41.48	-$0.61	-1.5%	-$0.45	-1.1%
Southern Minnesota Municipal Power Agency	100.0%	2021	$31.58	$34.11	$32.86	-$1.28	-3.9%	$1.25	3.8%
		2026	$38.59	$41.75	$39.39	-$0.80	-2.0%	$2.36	6.0%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 4B
LMP Changes From MVPs 3 and 4
Business as Usual: High Demand

			Without MVP 5						
			Load Weighted Average LMP ($ per MWh)			Average LMP Change			
Area	Percent of Sales in Minnesota	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	LMP Change Due to MVPs 3 and 4	Percent Difference	LMP Change Due to MVP 3 only	Percent Difference
			[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Alliant West - Interstate Power & Light	5.5%	2021	$32.11	$33.46	$33.57	-$1.46	-4.4%	-$0.12	-0.3%
		2026	$39.31	$41.36	$41.16	-$1.84	-4.5%	$0.20	0.5%
Dairyland Power Cooperative	11.5%	2021	$36.24	$38.56	$36.93	-$0.69	-1.9%	$1.64	4.4%
		2026	$45.45	$47.56	$45.15	$0.30	0.7%	$2.41	5.3%
Great River Energy	99.6%	2021	$34.54	$34.71	$35.02	-$0.47	-1.4%	-$0.31	-0.9%
		2026	$43.64	$43.76	$44.00	-$0.37	-0.8%	-$0.24	-0.5%
Minnesota Power and Light Company	100.0%	2021	$34.56	$34.83	$34.95	-$0.38	-1.1%	-$0.11	-0.3%
		2026	$43.23	$43.51	$43.50	-$0.27	-0.6%	$0.01	0.0%
Minnkota Power Coop	45.1%	2021	$36.78	$36.84	$37.23	-$0.45	-1.2%	-$0.39	-1.0%
		2026	$46.09	$46.21	$46.66	-$0.57	-1.2%	-$0.45	-1.0%
Northern States Power Company	74.8%	2021	$35.90	$36.32	$36.33	-$0.44	-1.2%	-$0.02	0.0%
		2026	$48.97	$49.35	$49.22	-$0.25	-0.5%	$0.13	0.3%
Otter Tail Power Company	48.4%	2021	$35.05	$35.04	$35.45	-$0.40	-1.1%	-$0.41	-1.2%
		2026	$42.38	$42.40	$42.87	-$0.49	-1.2%	-$0.47	-1.1%
Southern Minnesota Municipal Power Agency	100.0%	2021	$33.03	$35.53	$34.14	-$1.12	-3.3%	$1.39	4.1%
		2026	$40.82	$43.31	$41.00	-$0.18	-0.5%	$2.31	5.6%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 5
LMP Changes From the 161 kV Rebuild
Minnesota Avg LMP

With MVP 5

	Year	Load Weighted Average LMP ($ per MWh): Study Case 3: With 161kV Rebuild, Without MVPs 3 & 4	Load Weighted Average LMP ($ per MWh): Base Case: Without MVPs 3 & 4	Average LMP Change: LMP Change Due to 161kV Rebuild	Average LMP Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$28.27	$28.44	-$0.17	-0.6%
Low Demand	2026	$31.53	$31.85	-$0.32	-1.0%
Business as Usual:	2021	$34.67	$35.02	-$0.35	-1.0%
High Demand	2026	$45.32	$45.64	-$0.32	-0.7%

Without MVP 5

	Year	Load Weighted Average LMP ($ per MWh): Study Case 6: With 161kV Rebuild Without MVPs 3, 4 & 5	Load Weighted Average LMP ($ per MWh): No MVP 5 Base Case: Without MVPs 3, 4 & 5	Average LMP Change: LMP Change Due to 161kV Rebuild	Average LMP Change: Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$29.11	$29.21	-$0.10	-0.4%
Low Demand	2026	$32.45	$32.58	-$0.13	-0.4%
Business as Usual:	2021	$35.59	$35.74	-$0.15	-0.4%
High Demand	2026	$46.51	$46.57	-$0.06	-0.1%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.
[2] Minnesota Avg LMP is the load weighted average LMP for Minnesota, calculated as described in Appendix A.

Table 6A
LMP Changes From the 161 kV Rebuild
Business as Usual: Low Demand

			With MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	**Percent of Sales in Minnesota**	**Year**	**Study Case 3: Without MVPs 3 and 4, 161kV Rebuild**	**Base Case: Without MVPs 3 and 4**	**LMP Change Due to 161kV Rebuild**	**Percent Difference**
			[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Alliant West - Interstate Power & Light	5.5%	2021	$29.47	$29.43	$0.04	0.1%
		2026	$33.22	$33.28	-$0.06	-0.2%
Dairyland Power Cooperative	11.5%	2021	$31.02	$31.16	-$0.14	-0.5%
		2026	$34.98	$35.31	-$0.33	-0.9%
Great River Energy	99.6%	2021	$27.79	$28.00	-$0.21	-0.7%
		2026	$30.25	$30.58	-$0.33	-1.1%
Minnesota Power and Light Company	100.0%	2021	$28.52	$28.63	-$0.12	-0.4%
		2026	$31.83	$32.02	-$0.18	-0.6%
Minnkota Power Coop	45.1%	2021	$30.54	$30.65	-$0.11	-0.4%
		2026	$35.01	$35.18	-$0.17	-0.5%
Northern States Power Company	74.8%	2021	$28.22	$28.39	-$0.16	-0.6%
		2026	$31.82	$32.16	-$0.35	-1.1%
Otter Tail Power Company	48.4%	2021	$28.82	$28.95	-$0.13	-0.5%
		2026	$31.48	$31.65	-$0.16	-0.5%
Southern Minnesota Municipal Power Agency	100.0%	2021	$27.17	$27.54	-$0.37	-1.3%
		2026	$28.83	$29.58	-$0.75	-2.5%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 6B
LMP Changes From the 161 kV Rebuild
Business as Usual: Low Demand

			Without MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	Percent of Sales in Minnesota	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	LMP Change Due to 161kV Rebuild	Percent Difference
			[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Alliant West - Interstate Power & Light	5.5%	2021	$30.41	$30.17	$0.24	0.8%
		2026	$34.39	$34.00	$0.39	1.2%
Dairyland Power Cooperative	11.5%	2021	$31.74	$31.62	$0.12	0.4%
		2026	$35.69	$35.58	$0.11	0.3%
Great River Energy	99.6%	2021	$28.69	$28.85	-$0.16	-0.6%
		2026	$31.27	$31.44	-$0.17	-0.6%
Minnesota Power and Light Company	100.0%	2021	$29.21	$29.31	-$0.10	-0.3%
		2026	$32.66	$32.72	-$0.05	-0.2%
Minnkota Power Coop	45.1%	2021	$31.13	$31.27	-$0.14	-0.4%
		2026	$35.93	$36.07	-$0.14	-0.4%
Northern States Power Company	74.8%	2021	$29.00	$29.10	-$0.10	-0.4%
		2026	$32.60	$32.76	-$0.16	-0.5%
Otter Tail Power Company	48.4%	2021	$29.79	$29.88	-$0.09	-0.3%
		2026	$32.52	$32.62	-$0.09	-0.3%
Southern Minnesota Municipal Power Agency	100.0%	2021	$28.99	$28.98	$0.01	0.0%
		2026	$31.20	$31.31	-$0.11	-0.3%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 7A
LMP Changes From the 161 kV Rebuild
Business as Usual: High Demand

			With MVP 5			
			Load Weighted Average LMP ($ per MWh)		Average LMP Change	
Area	**Percent of Sales in Minnesota**	**Year**	**Study Case 3: Without MVPs 3 and 4, 161kV Rebuild**	**Base Case: Without MVPs 3 and 4**	**LMP Change Due to 161kV Rebuild**	**Percent Difference**
			[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Alliant West - Interstate Power & Light	5.5%	2021	$33.26	$33.24	$0.03	0.1%
		2026	$40.58	$40.45	$0.13	0.3%
Dairyland Power Cooperative	11.5%	2021	$36.00	$36.39	-$0.40	-1.1%
		2026	$43.75	$44.18	-$0.43	-1.0%
Great River Energy	99.6%	2021	$33.83	$34.21	-$0.38	-1.1%
		2026	$42.66	$42.99	-$0.32	-0.7%
Minnesota Power and Light Company	100.0%	2021	$34.02	$34.28	-$0.26	-0.8%
		2026	$42.27	$42.37	-$0.10	-0.2%
Minnkota Power Coop	45.1%	2021	$36.39	$36.57	-$0.18	-0.5%
		2026	$45.38	$45.43	-$0.04	-0.1%
Northern States Power Company	74.8%	2021	$35.30	$35.66	-$0.35	-1.0%
		2026	$48.07	$48.46	-$0.39	-0.8%
Otter Tail Power Company	48.4%	2021	$34.25	$34.53	-$0.28	-0.8%
		2026	$41.42	$41.48	-$0.07	-0.2%
Southern Minnesota Municipal Power Agency	100.0%	2021	$32.11	$32.86	-$0.75	-2.3%
		2026	$38.57	$39.39	-$0.81	-2.1%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 7B
LMP Changes From the 161 kV Rebuild
Business as Usual: High Demand

Area	Percent of Sales in Minnesota	Year	Without MVP 5 – Load Weighted Average LMP ($ per MWh): Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	Without MVP 5 – Load Weighted Average LMP ($ per MWh): No MVP 5 Base Case: Without MVPs 3, 4, and 5	Without MVP 5 – Average LMP Change: LMP Change Due to 161kV Rebuild	Without MVP 5 – Average LMP Change: Percent Difference
			[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Alliant West - Interstate Power & Light	5.5%	2021	$33.88	$33.57	$0.30	0.9%
		2026	$41.54	$41.16	$0.38	0.9%
Dairyland Power Cooperative	11.5%	2021	$36.98	$36.93	$0.05	0.1%
		2026	$44.83	$45.15	-$0.32	-0.7%
Great River Energy	99.6%	2021	$34.82	$35.02	-$0.20	-0.6%
		2026	$43.79	$44.00	-$0.21	-0.5%
Minnesota Power and Light Company	100.0%	2021	$34.84	$34.95	-$0.11	-0.3%
		2026	$43.35	$43.50	-$0.15	-0.3%
Minnkota Power Coop	45.1%	2021	$37.06	$37.23	-$0.16	-0.4%
		2026	$46.44	$46.66	-$0.22	-0.5%
Northern States Power Company	74.8%	2021	$36.17	$36.33	-$0.16	-0.5%
		2026	$49.27	$49.22	$0.05	0.1%
Otter Tail Power Company	48.4%	2021	$35.34	$35.45	-$0.11	-0.3%
		2026	$42.64	$42.87	-$0.23	-0.5%
Southern Minnesota Municipal Power Agency	100.0%	2021	$33.97	$34.14	-$0.17	-0.5%
		2026	$40.80	$41.00	-$0.20	-0.5%

Notes:
[1] Percent of sales in MN is calculated using data from 2011 Form EIA-861.
[2] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 8
MISO Production Cost Changes From MVPs 3 and 4

With MVP 5

	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		MISO Production Cost ($ Millions)			MISO Production Cost Change			
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$13,217	$13,289	$13,332	-$114.9	-0.9%	-$42.9	-0.3%
Low Demand	2026	$15,474	$15,576	$15,611	-$136.9	-0.9%	-$35.2	-0.2%
Business as Usual:	2021	$15,821	$15,903	$15,953	-$132.2	-0.8%	-$49.5	-0.3%
High Demand	2026	$20,308	$20,451	$20,494	-$185.6	-0.9%	-$43.5	-0.2%

Without MVP 5

	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		MISO Production Cost ($ Millions)			MISO Production Cost Change			
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$13,461	$13,491	$13,556	-$95.3	-0.7%	-$65.4	-0.5%
Low Demand	2026	$15,704	$15,782	$15,843	-$138.7	-0.9%	-$60.4	-0.4%
Business as Usual:	2021	$16,081	$16,121	$16,204	-$122.3	-0.8%	-$82.4	-0.5%
High Demand	2026	$20,587	$20,694	$20,769	-$181.8	-0.9%	-$75.4	-0.4%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 9
MISO Production Cost per MWh Load Changes From MVPs 3 and 4

With MVP 5

		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
	Year	Study Case 1: With MVPs 3 & 4	Study Case 2: With MVP 3 Only (No MVP 4)	Base Case: Without MVPs 3 & 4	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$22.82	$22.95	$23.02	-$0.20	-0.9%	-$0.07	-0.3%
Low Demand	2026	$25.65	$25.82	$25.88	-$0.23	-0.9%	-$0.06	-0.2%
Business as Usual:	2021	$25.67	$25.80	$25.88	-$0.21	-0.8%	-$0.08	-0.3%
High Demand	2026	$30.66	$30.87	$30.94	-$0.28	-0.9%	-$0.07	-0.2%

Without MVP 5

		MISO Production Cost per MWh Load ($/MWh)			MISO Production Cost per MWh Change			
	Year	Study Case 4: With MVPs 3 & 4 (No MVP 5)	Study Case 5: With MVP 3 Only (No MVP 4 & 5)	No MVP 5 Base Case: Without MVPs 3, 4 & 5	Cost Change Due to MVPs 3 and 4	Percent Difference	Cost Change Due to MVP 3 only	Percent Difference
		[A]	[B]	[C]	[D] = [A] - [C]	[E] = [D]/[C]	[F] = [B] - [C]	[G] = [F]/[C]
Business as Usual:	2021	$23.24	$23.29	$23.41	-$0.16	-0.7%	-$0.11	-0.5%
Low Demand	2026	$26.03	$26.16	$26.26	-$0.23	-0.9%	-$0.10	-0.4%
Business as Usual:	2021	$26.09	$26.15	$26.29	-$0.20	-0.8%	-$0.13	-0.5%
High Demand	2026	$31.08	$31.24	$31.36	-$0.27	-0.9%	-$0.11	-0.4%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 10
MISO Production Cost Changes From the 161 kV Rebuild

		With MVP 5			
		MISO Production Cost ($ Millions)		MISO Production Cost Change	
	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,315	$13,332	-$17.4	-0.1%
Low Demand	2026	$15,595	$15,611	-$16.3	-0.1%
Business as Usual:	2021	$15,933	$15,953	-$19.3	-0.1%
High Demand	2026	$20,470	$20,494	-$23.7	-0.1%

		Without MVP 5			
		MISO Production Cost ($ Millions)		MISO Production Cost Change	
	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$13,557	$13,556	$1.4	0.0%
Low Demand	2026	$15,852	$15,843	$9.6	0.1%
Business as Usual:	2021	$16,196	$16,204	-$7.5	0.0%
High Demand	2026	$20,779	$20,769	$10.2	0.0%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Table 11
MISO Production Cost per MWh Load Changes From the 161 kV Rebuild

		With MVP 5			
		MISO Production Cost per MWh Load ($/MWh)		MISO Production Cost per MWh Change	
	Year	Study Case 3: Without MVPs 3 and 4, 161kV Rebuild	Base Case: Without MVPs 3 and 4	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$22.99	$23.02	-$0.03	-0.1%
Low Demand	2026	$25.85	$25.88	-$0.03	-0.1%
Business as Usual:	2021	$25.85	$25.88	-$0.03	-0.1%
High Demand	2026	$30.90	$30.94	-$0.04	-0.1%

		Without MVP 5			
		MISO Production Cost per MWh Load ($/MWh)		MISO Production Cost per MWh Change	
	Year	Study Case 6: Without MVPs 3 and 4, 161kV Rebuild	No MVP 5 Base Case: Without MVPs 3, 4, and 5	Cost Change Due to 161kV Rebuild	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual:	2021	$23.41	$23.41	$0.00	0.0%
Low Demand	2026	$26.28	$26.26	$0.02	0.1%
Business as Usual:	2021	$26.27	$26.29	-$0.01	0.0%
High Demand	2026	$31.37	$31.36	$0.02	0.0%

Notes:
[1] All cases include all other projects in the MVP portfolio -- that is MVPs 1, 2 and 6-17.

Appendix A

PROMOD Modeling and Data

This appendix provides a summary of the PROMOD IV (PROMOD) model, data and assumptions used in analyzing MVPs 3 and 4 and the 161 kV Rebuild, and the methodology for estimating the effect of MVPs 3 and 4 and the 161 kV Rebuild on wholesale electric energy prices in Minnesota and annual production costs within the footprint of the Midwest Independent Transmission System Operator, Inc. (MISO).

1. THE PROMOD MODEL

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices (LMPs) at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generator output. It can also perform and support various reliability analyses, including calculation of loss-of-load probability, expected unserved energy, and effective capacity support.

2. DATA AND ASSUMPTIONS

The analysis relies largely on data developed by MISO in its Multi Value Project (MVP) process. A detailed description of MISO's MVP process and data analysis is provided in the MVP Report.[16] As described by MISO, the principal purposes of the MVPs are "to meet one or more of three goals: reliably and economically enable regional public policy needs; provide multiple types of economic value; and provide a combination of regional reliability and economic value."[17] To identify these transmission projects, MISO has performed detailed economic and engineering analyses of many alternative transmission projects and portfolios using PROMOD.

The data and assumptions used by MISO in its MVP analysis are based on Ventyx-provided data, and have been modified as needed by MISO. These data include:

1. load forecasts provided by individual utilities within MISO,[18]

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[16] MISO, Multi Value Project Portfolio: Results and Analyses, January 10, 2012 (hereafter "MVP Report").

[17] MISO website, available at https://www.midwestiso.org/Planning/Pages/MVPAnalysis.aspx, accessed November 6, 2012.

[18] Demand and energy growth rates for each region are provided in: MISO, *MISO Transmission Expansion Plan 2011: PROMOD Case Assumptions Document*, p 23 ("MTEP PROMOD Assumptions" hereafter).

2. transmission line data from transmission operators,[19]
3. unit specifications for existing generation resources,[20]
4. new generation resources based on units planned and under construction,[21]
5. future generation resource additions developed by a capacity expansion model,[22]
6. retirement of generation facilities based on currently announced retirements, but not in response to economic or regulatory factors, including EPA regulation,[23]
7. "hurdle rates" for transactions between NERC regions,[24] and
8. fuel and emission price forecasts.

The system modeled includes individual generator data and much of the transmission information for the Eastern Interconnection,[25] at the bus[26] level.

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[19] Transmission constraints are based on the most recent Book of Flowgates from MISO and North American Electric Reliability Corporation (NERC), updated to include rating and configuration changes from studies performed during the MTEP 11 process. Transmission line data includes items such as the voltage rating of the line and the buses that each line runs between.

[20] Individual unit specifications include maximum operating capacity; fuel type; variable costs; no-load and startup costs; minimum run times; emission rates; and heat rate curves.

[21] Detailed information on the existing, under construction and planned units in each region is provided in MTEP PROMOD Assumptions, p 17.

[22] MISO relies upon the Electric Generation Expansion Analysis System (EGEAS) model developed by the Electric Power Research Institute. EGEAS is designed to find the optimized capacity expansion plan to meet forecast demand (load plus planning reserve margin target minus losses) through a least cost-mix of supply-side and demand-side resources. Planning reserve margins are identified in MTEP PROMOD Assumptions, pp. 23-24.

[23] As part of MTEP 2011, MISO performed an EPA Regulation Impact Analysis that identifies planning needs arising from the retirement of coal-fired generation facilities due to EPA regulations and other market factors (*e.g.*, competition from natural gas-fired generation). Aside from those already announced, MISO's MVP analysis does not incorporate any retirements of coal-fired generation.

[24] PROMOD allows power to flow between regions based on economic transactions (subject to security constraints and congestion) such that prices must exceed generator costs in a neighboring region by a dollar per MWh "hurdle rate" in order for power to flow across regions.

[25] The Eastern Interconnection comprises roughly the eastern two-thirds of the "lower 48" (excluding portions of Texas), including the Canadian provinces east of Alberta and the following NERC regions: Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), SERC Reliability Corporation (SERC), Florida Reliability Coordinating Council (FRCC), Reliability*First* Corporation (RFC), and Northeast Power Coordinating Council (NPCC). MISO's PROMOD modeling excludes Peninsular Florida, New England, and Eastern Canada, but accounts for aggregate regional flows to and from these areas through the use of fixed transactions. For more detail, see MTEP PROMOD Assumptions, p 24.

[26] A bus is the specific geographical point that a generator is located at or that a transmission line connects to.

The quantity and location of future renewable resources, including wind and solar, are determined by MISO both to meet state RPS requirements and reduce the combined cost of renewable and transmission resources.[27] Based on these requirements, MISO's analysis assumes that, with its full 17 MVP project portfolio[28] in service, 8,765 MW of new wind resources will be added in 2021, and an additional 2,272 MW of new wind resources will be added by 2026.[29]

MVPs 3, 4 and 5 represent three projects within the MVP portfolio.[30] These projects are listed in Table A1, and are shown geographically in Figure A1. The 161 kV Rebuild is a project identified in the "Multi-Value Project Planning Study" included in ITC's Certificate of Need Filing for Minnesota—Iowa 345 kV Transmission Project.[31] This Alternative would rebuild the existing Fox Lake – Rutland – Winnebago Jct. 161 kV transmission line to increase the transfer capability.

Table A1

Project Elements

MVP Element	Project	Voltage	In-Service Year
3	Lakefield Jct.–Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	345	2016
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	345	2015
5	N. LaCrosse – N. Madison – Cardinal & Dubuque Co. – Spring Green – Cardinal	345	2018/2020

Source: MISO MVP Report.

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[27] MISO determined the amount of wind enabled by the MVP portfolio by first determining the amount of wind needed to meet RPS targets, and then determining what amount of wind would not be supported but for the MVP portfolio. This process is detailed by MISO in the MVP Report, pp. 17-20 and 48-49.

[28] The full 17 MVP portfolio is identified in Table 1.1 of the MVP Report.

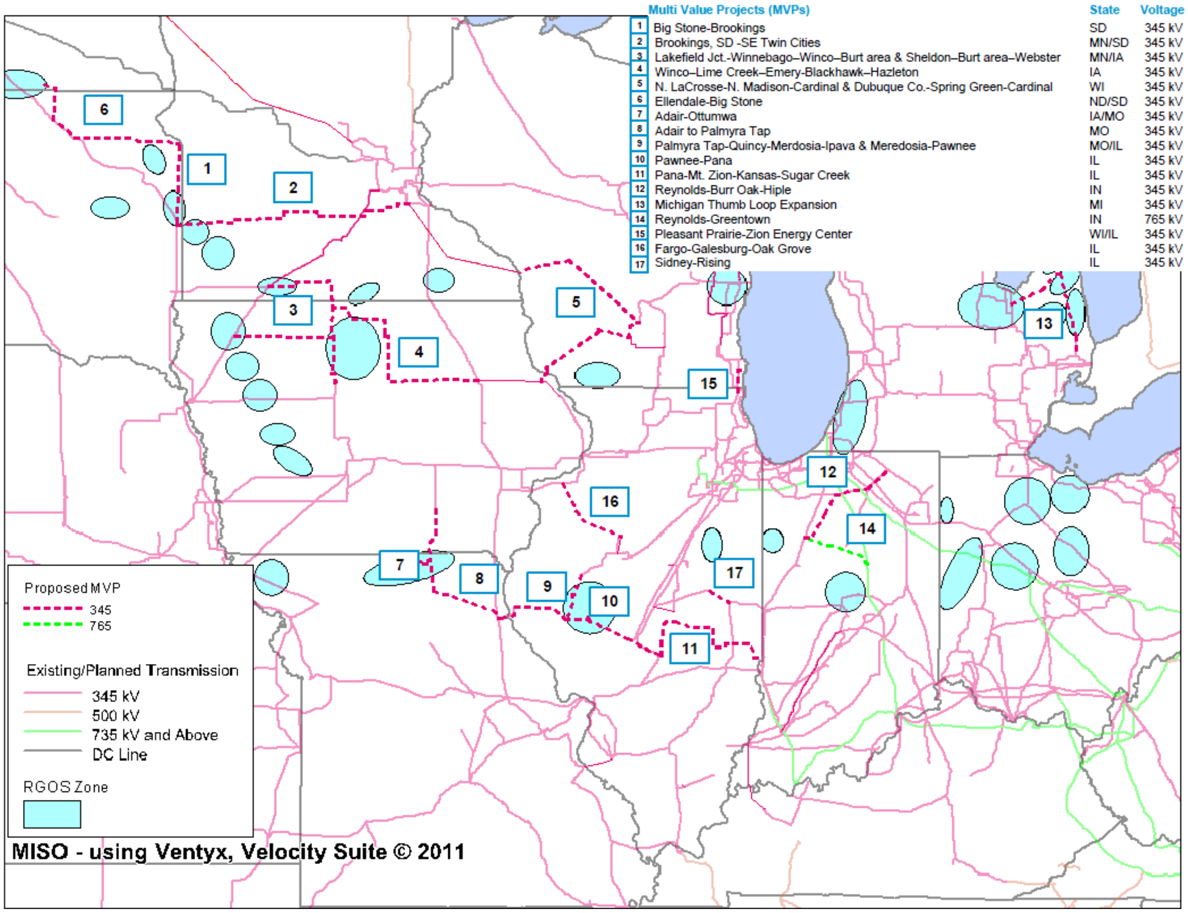
[29] Table 4.2, MVP Report. MISO also finds that the MVP portfolio can support an additional 2,230 MW of wind power from the wind zones without incurring additional reliability constraints. MVP Report, pp. 48-49.

[30] These two are: (1) Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster and (2) Winco–Lime Creek–Emery–Black Hawk–Hazleton.

[31] Jeff Eddy and Joseph Berry, "ITC Midwest LLC, Multi-Value Project #3 Planning Study," Appendix J, Application of ITC Midwest for a Certificate of Need for the Minnesota-Iowa 345 k V Transmission Project, March 22, 2013.

Figure A1

Map of MVP Portfolio



Source: MISO MVP Report.

The analyses herein estimate the impact of three alternative project configurations – MVPs 3 and 4, MVP 3 without MVP 4, and the 161 kV Rebuild without either MVP 3 or MVP 4 – against two different baseline transmission systems – with and without MVP 5. Impacts are estimated through comparisons of the Study Cases and Base Cases identified in Table A1.

Consider comparisons that assume MVP 5 is in service, which use the Base Case with all 17 of MVP projects except MVPs 3 and 4 (Base Case 1). The first comparison is between a study case that includes all 17 MVP projects in MISO's portfolio (Study Case 1) and a base case (Base Case) that includes only 15 of these MVP projects (all except MVPs 3 and 4). This comparison provides an indication of the impacts of developing both MVPs 3 and 4. The second comparison is between a case that includes all 17 MVP projects in MISO's portfolio except MVP 4 (Study Case 2) and the same Base Case 1 (i.e., a base case that includes all 17 of these MVP projects except MVPs 3 and 4). This comparison provides an indication of the impacts of developing MVP 3 in the absence of MVP 4. The third comparison is between the case that includes the 161 kV Rebuild along with 15 MVP projects in MISO's portfolio (again, all except MVPs 3 and 4), referred to as Study Case 2 and the same Base Case.

Estimates of project impacts without MVP 5 are performed in an analogous fashion, except the Base Case has14 of the MVP projects (all except MVPs 3, 4 and 5). For example, in this case, the first comparison is between a study case that includes all projects in the MVP portfolio other than MVP 5 (referred to as Study Case 4) and a base case that includes only 14 of these MVP projects (all except MVPs 3, 4 and 5). This comparison provides an indication of the impacts of developing both MVPs 3 and 4 when MVP 5 is not in service. The impacts of MVP 3 alone and the 161 kV Rebuild are estimated in the same manner as above, but with MVP 5 not in service in both the Study and Base Cases.

Table A2

Base Cases and Study Cases Considered

<u>With MVP 5 In Service</u>

Base Case

- MVP 3 & 4 Not In Service (Base Case 1)

Study Cases

- MVP 3 & 4 In Service (Study Case 1)
- MVP 3 In Service, MVP 4 Not in Service (Study Case 2)
- 161 kV Rebuild, MVP 3 and 4 Not In Service (Study Case 3)

<u>With MVP 5 Not In Service</u>

Base Case

- MVP 3, 4 & 5 Not In Service (Base Case 2)

Study Cases

- MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4)
- MVP3 In Service, MVP 4 & 5 Not in Service (Study Case 5)
- 161 kV Rebuild, MVP 3, 4 & 5 Not In Service (Study Case 6)

Note: All other MVP's are assumed to be in service in all base cases and study cases.

All six study cases include each of the 14 MVPs other than MVPs 3, 4 and 5. Apart from differences in which other projects (MVPs 3, 4 and 5 and the 161 kV Rebuild) are included in each case, the only other differences among the cases relates to the quantity of new wind generation resources assumed to be in service. In cases that do not include all 17 MVPs, the quantity of new wind resources has been reduced from the level in the case with all 17 MVPs because of the diminished ability of the transmission system to support that wind capacity without the additional MVPs. Unless new wind additions are reduced in this fashion, power flows may exceed line capacities under certain contingencies. To determine the quantity of wind capacity that can be supported in cases in which some MVPs are not in service, ITC performed an analysis to identify the minimum quantity of wind capacity curtailments that would still allow line loadings to be kept within limits. In performing this analysis, ITC utilized the same general methodology as MISO when it developed the wind curtailments values for its MVP Report and for our April 2013 Analysis. The quantity of wind curtailments compared to the case in which all 17 MVPs are in service is provided in Table A3.

Table A3

Wind Curtailment, by Case

Description	Wind Curtailment (MW)
With MVP 5 In Service	
MVP 3 and 4 In Service (Study Case 1)	0
MVP3 In Service, MVP 4 Not in Service (Study Case 2)	689
161 kV Rebuild, MVP 4 Not In Service (Study Case 3)	872
MVP 3 & 4 Not In Service (Base Case)	1,130
With MVP 5 Not In Service	
MVP 3 & 4 In Service, MVP 5 Not In Service (Study Case 4)	2,779
MVP 3 In Service, MVP 4 & 5 Not in Service (Study Case 5)	2,958
161 kV Rebuild, MVP 4 & 5 Not In Service (Study Case 6)	3,562
MVP 3, 4 & 5 Not In Service (No MVP 5 Base Case)	3,644

3. ANALYTICAL METHOD

The analysis herein provides estimates of changes in (load-weighted average) wholesale energy prices, measured through LMPs, and annual production costs, as a result of implementing MVP 3 (with and without also implementing MVP 4). We also provide estimates of changes in annual wholesale energy payments for Minnesota resulting from the LMP changes.

The computation of wholesale energy prices and annual payments is based on two outputs from the PROMOD model: area LMPs and area loads. A "Minnesota area" as used below refers to a PROMOD area that includes some portion of Minnesota. The process used to develop changes in wholesale energy prices is as follows:

1. Hourly area LMPs are calculated by PROMOD and reflect the load-weighted LMP of all nodes within the area.
2. Minnesota Area LMPs are calculated, which reflects the annual average of the hourly area LMP, weighted by the hourly area load.[32] Area load is based on the PROMOD inputs

[32] Hours in which the LMP for a Minnesota area is less than -$10/MWh are dropped across all base and study cases for that study year/demand scenario for purposes of calculating an annual load-weighted average LMP. Hours in

developed by MISO, and reflects hour-by-hour load forecasts for individual areas within MISO.[33] For areas that include portions of both Minnesota and one or more neighboring states, the Minnesota area LMPs are assumed to equal the prices across the entire area.

3. A Minnesota load-weighted LMP (referred to as the "Minnesota Avg LMP") is calculated, which reflects each Minnesota area's weighted average LMP and each Minnesota area's load. Because some Minnesota areas include portions of both Minnesota and one or more neighboring states, an adjustment must be made to the MISO area loads to estimate the quantity of load inside Minnesota. To make this adjustment, the percent of each area's load that is in Minnesota is calculated. These percentages, which are reported in Tables 3 of the main body of this report, are developed using data from the Energy Information Administration.[34] To calculate the Minnesota area load, each area's total load is multiplied by the percent of that area's load that is in Minnesota. To calculate the load-weighted LMP for Minnesota, each Minnesota area's LMP, calculated as described above in #2, is weighted by the estimated load for each Minnesota area, as described above.

4. The change in annual wholesale energy payments for Minnesota is calculated by multiplying the total Minnesota load, based on the calculations noted in #3 above, and the change in LMP between relevant Study Case and Base Case.

The analysis also estimates changes in production costs across the entire MISO region. We refer to these as MISO Production Costs. Production costs include fuel, variable operations and maintenance, emissions and start-up costs for all units operating in the MISO market. These production costs are then adjusted to account for net imports or exports of power between MISO and other regions operating in the Eastern Interconnection. Net transfers between pools are priced at the hourly weighted average LMP for MISO, consistent with the methodology used by MISO when it estimates production costs in its planning studies, such as the MVP Report. Average LMPs are weighted by generation output when net flows with other regions are positive, and are weighted by load when net flows with other regions are negative. Changes in annual production costs between scenarios are calculated in the manner described in item #4, above.

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which the LMP for a Minnesota area is greater than $1,000/MWh are capped at $1,000/MWh. As a result of these two corrections, there may be slight LMP differences for some cases/scenarios from the figures reported in the April 2013 LMP Analysis.

[33] These loads reflect forecasts for annual peak load and annual energy shaped over 8,760 hours.

[34] See Form EIA-861 data files, available at http://www.eia.gov/electricity/data/eia861/index.html, accessed September 20, 2012.

4. SCENARIOS

The results presented in the body of this report reflect two scenarios, which are detailed below and in Table A2. Each scenario was designed by MISO in its MVP portfolio analysis, and no additional changes have been made. The definitions are provided by MISO in its MVP portfolio analysis report.[35]

- **Business As Usual: Low Demand** – assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.[36]
- **Business As Usual: High Demand** – assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.[37]

Table A2

Scenario Assumptions[38]

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
Business As Usual: Low Demand	State RPS	0.78 percent	0.79 percent	BAU	None
Business As Usual: High Demand	State RPS	1.28 percent	1.42 percent	BAU	None

[35] MVP Report, p 52.

[36] Note that the MVP Report titles this case "Business As Usual with Continued Low Demand and Energy Growth (BAULDE)."

[37] Note that the MVP Report titles this case "Business As Usual with Historic Demand and Energy Growth (BAUHDE)."

[38] Table A2 is based on Table 8.1 from the MVP Report.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: ET6675/CN-12-1053 Date of Request: August 13, 2013

Requested From: ITC-Midwest Response Due: August 23, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:			
	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[X] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
12	**Subject: Forecasting** **Reference: Appendix I, Section 6.1** **At the beginning of this section, the Applicant references MTEP11 Reliability Analyses that are included in Appendix D2-D8. While reviewing the application, it is unclear if these information are in the application (only D1 and D2 appear present). As such, please provide Appendices D2-D8.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	Appendix I is a report prepared by MISO for MTEP 11. On Page 121 of the report, MISO notes that Appendices D2 through D8 to MTEP 11 are confidential and only available on the MISO MTEP 11 FTP site. ITC Midwest has contacted MISO to obtain the documents for production to the Department. MISO has advised that the documents contain non-public Critical Energy Infrastructure Information, and there are confidentiality concerns that must be addressed before the documents can be produced, specifically, how the documents will be protected from public disclosure by governmental entities both during the proceeding and after the proceeding concludes. ITC Midwest will continue to work with MISO and the Department to clarify the scope of the data requested and the protections necessary to protect that data from public disclosure.

ITC Midwest also notes that the information in MISO's MTEP 11 document is unrelated to the information in Appendix D of the Certificate of Need Application, which shows technical drawings of transmission structures proposed for the Project.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	

State of Minnesota
Department of Commerce
Division of Energy Resources

Utility Information Request

Docket Number: ET6675/CN-12-1053 — Date of Request: August 13, 2013

Requested From: ITC-Midwest — Response Due: August 23, 2013
Extension granted to Nov. 31, 2013

Analyst Requesting Information: Adam J. Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[X] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
13	**Subject: Forecasting** **Reference: MVP3 Planning Study** **The Applicant provides significant discussion regarding alternatives in the above reference. The majority of the analysis is focused on engineering studies, but there is some discussion of costs. Focusing on economic cost, please provide the following:** **a) The projected impact to LMP costs, in 5-year intervals, for each alternative discussed in the above reference;** **b) The total construction cost for each alternative; and** **c) Total lifetime operating cost, in Net Present Value, for each alternative.** **If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific testimony cite(s) or DOC information request number(s).**
Answer	ITC Midwest has not conducted this analysis and does not have the requested data. Additional studies to examine the impact on Minnesota LMPs from the 161 kV rebuild alternative will be performed and a response detailing those impacts will be submitted after these studies are completed. The response will include analysis of the additional impacts on Minnesota LMPs if MVPs 4 and 5, or both are not constructed. The study will examine years 2021 and 2026, consistent with the LMP cost impacts discussed in the Application. ITC Midwest estimates it can provide this information by November 1, 2013.

Supplemental Answer	The Multi-Value Project #3 Planning Study in Appendix J of the Certificate of Need Application evaluated one alternative to the Minnesota-Iowa 345 kV Project, the 161 kV Rebuild Alternative. The responses below to parts a-c of this information request relate to this alternative.

a. Data responsive to this request is provided in the LMP and Production Cost Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Second Supplemental Analysis, **Attachment 11-1**.

b. The total construction cost of $52 million for the 161 kV Alternative was provided in Appendix J, p. 21 of the Application. In response to DOC IR No. 7, ITC Midwest explained that this estimate was in nominal 2012 dollars.

c. The total lifetime operating cost of this alternative would include O&M expenditures and property taxes. In response to DOC IR No. 5, ITC Midwest reported that average 2012 O&M expense for 161 kV transmission lines on its system was approximately $1250 per mile. Therefore, based on the 32 mile length of the existing 161 kV line from Fox Lake to Rutland to Winnebago Junction, average annual O&M expense is estimated to be $40,000. Property taxes on the incremental investment are estimated to be an additional $1.02 million annually, for a total cost in 2012 dollars of $1.06 million. Assuming a 2017 in-service date, 2.5% annual cost escalation and using a discount rate equal to ITC Midwest's 2012 after-tax weighted cost of capital (8.61%), the NPV in 2017, assuming a nominal 60 year life, would be approximately $19 million.

Response by:	David Grover	List sources of information:
Title:	Manager	
Department:	Regulatory Strategy	
Telephone:	(651) 222-1000, Ext. 2308	