IMPACT OF CapX2020 345 kV PROJECTS ON RATEPAYERS

Introduction

This memo is provided in connection with the Certificate of Need Application in MPUC Docket No. ET02, E-002/CN-06-1115 and addresses issues concerning ratepayer impacts arising out of the three 345-kV transmission projects for which Certificates of Need are being sought (Exemption Order Point 9). As set forth in Section 1.10 of the Application, three Project Development Agreements ("PDAs") have been executed by 10 utilities that have reached agreement on how they will share in costs associated with the preliminary stages of development of the three projects. They have not yet committed to their investment or ownership share in the lines. The PDAs provide rights to own up to a certain percentage of the projects. However the PDAs also provide that each sponsoring utility can choose to invest less or not to invest. For the purpose of a discussion of rate impacts we have assumed each utility will elect to invest at the maximum level specified in the PDAs.

The Commission's rules related to a discussion of the rate impact of new infrastructure appear to assume that a single utility proposes to construct, own and operate the proposed facility. Thus, the utility provides an estimate of the impact on its ratepayers by calculating annual revenue requirements and applying a forecast of sales to the revenue requirement as if all of the cost of the new facility would be borne primarily by its retail customers.

However, the model for determining impacts on ratepayers has changed due to implementation of the Midwest ISO's Cost Allocation Policy Filing (FERC Docket No. ER06-18) which now allocates and recovers costs associated with new transmission projects and system upgrades within the Midwest ISO Transmission System on a regional basis, using provisions developed by the Regional Expansion Criteria and Benefits ("RECB") Task Force. In an Order on Technical Conference, Rehearing, Clarification, and Compliance dated November 29, 2006, FERC accepted the Midwest ISO's cost allocation proposal for Baseline Reliability Projects rated at 345 kV and above. Under this approved cost allocation method, 20% of a Baseline Reliability Project's revenue requirement is recovered in a "postage stamp" charge applied to all load under the Midwest ISO Transmission and Energy Markets Tariff ("TEMT") and the remaining 80% is recovered though a "subregional"

allocation based on analysis of line outage distribution factor ("LODF") impacts of the project. Baseline Reliability Projects below 345 kV, but above 100 kV (including lower voltage components of 345 kV projects) are allocated 100% based on the LODF analysis. Projects that are primarily designed to facilitate the interconnection of additional generation are classified by the Midwest ISO as a Generator Interconnection Network Upgrade for cost allocation purposes. For projects that are designated Generator Interconnection Network Upgrades, 50% of the project cost are assigned to the interconnecting generators and the remaining 50% are allocated as shown above according to the FERC approved provisions for Baseline Reliability Projects.

These rules are relatively new and untested at this point. Therefore Applicants' analysis in this document is subject to additional refinement and could change depending upon subsequent events.

Assumed Ownership of the Projects

It is expected that 100% of the Twin Cities – Fargo, and the Twin Cities – Brookings County 345 kV projects will be part of the Midwest ISO Transmission System and subject to these provisions of the Midwest ISO TEMT. Approximately 80% of the Twin Cities – La Crosse 345 kV Project will be part of the Midwest ISO Transmission System. Dairyland Power Cooperative and Rochester Public Utilities, companies that are not transmission-owing members of the Midwest ISO, will own the remaining 20%.

For the portions of these CapX2020 projects that are part of the Midwest ISO Transmission System, the Midwest ISO will collect the projects' annual revenue requirements through Schedule 26 to the TEMT and will distribute the revenue to owners. Each transmission owner serving customers at retail will also be billed using Schedule 26 as part of their Network Integration Transmission Service under the Midwest ISO TEMT. Therefore, it is the charges to each of the transmission owners under Schedule 26, not the annual revenue requirements for the portions of these projects that they own, that will determine the impact of these projects on each owner's ratepayers. The following sections estimate project revenue requirements and estimate charges to each owner's network load through Schedule 26 of the TEMT.

Table 1 below shows the assumed ownership breakdown for each of the three proposed CapX2020 projects. The values represent the ownership percentages if all participants were to elect to invest at maximum specified levels. This table provides the same data as shown in Figure 1-11 of the Application.

Table 1

Expected Ownership Shares of CapX2020 Projects (%)

Transmission Owner	Twin Cities – Fargo 345 kV Project	Twin Cities - Brookings County 345 kV Project	Twin Cities – La Crosse 345 kV Project
Central Minnesota Municipal Power Agency ("CMMPA")		2.2 %	
Dairyland Power Cooperative ("DPC")			11.0 %
Great River Energy ("GRE")	25.0 %	16.5 %	
Minnesota Power ("MP")	14.7 %		
Missouri River Energy Services ("MRES")	11.0 %	5.1 %	
Otter Tail Power Company ("OTP")	13.2 %	4.1 %	
Rochester Public Utilities ("RPU")			9.0 %
Southern Minnesota Municipal Power Agency ("SMMPA")			13.0 %
Wisconsin Public Power, Inc. ("WPPI")			3.0 %
Xcel Energy	36.1 %	72.1 %	64.0 %

Project Revenue Requirements

Based on the midpoints of the project cost estimate ranges shown in Chapter 2 of this Application for each project[1], and using a 20% fixed charge rate to develop an approximate annual revenue requirement for each project, each owner's estimated annual levelized revenue requirement for each of the projects is shown in Table 2.

Table 2

CapX2020 Project Annual Revenue Requirement by Transmission Owner (million $)

Transmission Owner	Twin Cities - Fargo 345 kV Project (million $)	Twin Cities - Brookings County 345 kV Project (million $)	Twin Cities - La Crosse 345 kV Project (million $)	Total Annual Revenue Requirement (million $)
CMMPA	$0.0	$2.8	$0.0	$2.8
DPC	$0.0	$0.0	$7 6	$7.6
GRE	$23.8	$20.9	$0.0	$44 6
MP	$14.0	$0.0	$0.0	$14 0
MRES	$10.5	$6.5	$0.0	$16.9
OTP	$12.5	$5.2	$0.0	$17.7
RPU	$0.0	$0.0	$6.2	$6.2
SMMPA	$0.0	$0.0	$9.0	$9.0
WPPI	$0.0	$0.0	$2.1	$2.1
Xcel Energy	$34.3	$91.2	$44.2	$169.7

Cost Allocation of Projects under Midwest ISO TEMT

As discussed earlier, based on the current assumed ownership structure (assuming all utilities own its development percentage as set forth in the PDAs) Applicants anticipate 100% of the cost of the Twin Cities - Fargo and Twin

[1] Assumptions were $475 million for the Twin Cities - Fargo 345 kV project; $632.5 million for the Twin Cities - Brookings County 345 kV project, and $345 million for the Twin Cities - La Crosse 345 kV project.

Cities - Brookings County projects, and 80% of the cost of the Twin Cities – La Crosse project, will be recovered under the Midwest ISO TEMT, and the costs will be allocated across Midwest ISO pricing zones pursuant to the FERC-approved Midwest ISO cost allocation policy for Baseline Reliability Projects.

The unit charges will vary by pricing zone. Table 3 shows the estimated allocation of project costs to Midwest ISO pricing zones. The pricing zones are largely consistent with each Transmission Owner's Control Area (now called Balancing Authority Area) boundaries. Because of their co-mingled service areas and the historical joint transmission system development by utilities in this area of the Midwest, many transmission owners have facilities and load in more than one pricing zone. For example, Great River Energy has facilities and loads in the Northern States Power Company, Alliant West ("ALTW"), Minnesota Power and Otter Tail Power Company pricing zones, in addition to the Great River Energy pricing zone.

Table 3

Allocation of CapX2020 345 kV Project Costs to Midwest ISO Pricing Zones

Midwest ISO Pricing Zone	Twin Cities - Fargo 345 kV Project (million $)	Twin Cities - Brookings County 345 kV Project (million $)	Twin Cities – La Crosse 345 kV Project (million $)	Total Annual Revenue Requirement (million $)
ALTW	$2.2	$4.9	$9.8	$16.8
Ameren	$2.1	$2.5	$1.3	$5.9
American Transmission Co.	$3.0	$3.5	$5.9	$12.4
Central IL Light Co.	$0.2	$0.3	$0.1	$0.6
Cinergy	$2.2	$2.7	$1.3	$6.2
CWLD (Columbia, MO)	$0.0	$0.1	$0.0	$0.1
CWLP	$0.1	$0.1	$0.0	$0.2

Midwest ISO Pricing Zone	Twin Cities - Fargo 345 kV Project (million $)	Twin Cities - Brookings County 345 kV Project (million $)	Twin Cities – La Crosse 345 kV Project (million $)	Total Annual Revenue Requirement (million $)
(Springfield, IL)				
First Energy	$2.4	$2.9	$1.4	$6.8
GRE	$2.9	$5.4	$0.5	$8.9
Hoosier	$0.1	$0.2	$0.1	$0.4
Illinois Power	$0.8	$0.9	$0 5	$2 2
Indianapolis Power & Light	$0.6	$0 7	$0.3	$1.6
International Transmission Co.	$2.1	$2.5	$1.2	$5.8
Montana Dakota Utilities	$0.9	$0 2	$0.1	$1.2
Michigan Electric Transmission Co.	$1.6	$1.9	$0.9	$4 4
MP	$11.5	$1.0	$0.5	$13 0
Northern Indiana Public Service Co.	$0.6	$0.8	$0.4	$1.8
Northern States Power Co.	$40.8	$87.8	$28.6	$157.2
OTP	$20.3	$6.7	$0.3	$27.4
Southern Illinois Power Coop	$0.1	$0.1	$0.0	$0.2
SMMPA	$0.4	$1.1	$1.9	$3.3
Vectren	$0.2	$0.3	$0.1	$0.6

Note that the estimated charges to the CapX2020 owner pricing zones are about 76% of the total project revenue requirements collected under the MISO

TEMT; the remainder of CapX2020 project costs are allocated to other Midwest ISO pricing zones.

Table 4 below shows the estimated charges to each CapX2020 owner's load in each applicable pricing zone from each of the three CapX2020 projects, and in total.

Table 4

Allocation of Charges to Owners for CapX2020 345 kV Projects

CapX2020 Transmission Owner	MISO Pricing Zone	Twin Cities - Fargo 345 kV Project ($)	Twin Cities - Brookings County 345 kV Project ($)	Twin Cities – La Crosse 345 kV Project ($)	Total Annual Revenue Requirement ($)
GRE	ALTW	$67,760	$150,920	$301,840	$520,520
	GRE	$2,574,040	$4,793,040	$443,800	$7,810,880
	MP	$1,037,300	$90,200	$45,100	$1,172,600
	NSP	$3,472,080	$7,471,780	$2,433,860	$13,377,720
	OTP	$2,200,520	$726,280	$32,520	$2,959,320
MP	MP	$10,128,050	$880,700	$440,350	$11,449,100
Xcel Energy	ALTW	$4,510	$10,045	$20,090	$34,645
	GRE	$197,780	$368,280	$34,100	$600,160
	MP	$4,600	$400	$200	$5,200
	NSP	$35,740,800	$76,912,800	$25,053,600	$137,707,200
	OTP	$5,588,590	$1,844,510	$82,590	$7,515,690
OTP	OTP	$10,373,300	$3,423,700	$153,300	$13,950,300
SMMPA	ALTW	$22,220	$49,490	$98,980	$170,690
	GRE	$127,890	$238,140	$22,050	$388,080
	NSP	$665,040	$1,431,140	$466,180	$2,562,360
	SMMPA	$400,000	$1,100,000	$1,900,000	$3,400,000
CMMPA	ALTW	$18,832	$41,944	$83,888	$144,664
	NSP	$228,888	$492,558	$160,446	$881,892
DPC	ATC	$9,000	$10,500	$17,700	$37,200
	NSP	$707,472	$1,522,452	$495,924	$2,725,848
MRES	ALTW	$37,620	$83,790	$167,580	$288,990

CapX2020 Transmission Owner	MISO Pricing Zone	Twin Cities - Fargo 345 kV Project ($)	Twin Cities - Brookings County 345 kV Project ($)	Twin Cities – La Crosse 345 kV Project ($)	Total Annual Revenue Requirement ($)
	NSP	$681,360	$111,890	$5,010	$798,260
	OTP	$2,131,500	$703,500	$31,500	$2,866,500
WPPI	ATC	$180,000	$210,000	$354,000	$744,000
	NSP	$255,408	$549,628	$179,036	$984,072

Note that the analysis above is only for the portions of the project facilities that are part of the Midwest ISO transmission system. Additional portions of the Twin Cities – La Crosse 345 kV will be paid for by Dairyland Power Cooperative (11%) and Rochester Public Utilities (9%). It is anticipated that DPC and RPU will recover the costs of these facilities primarily from their bundled native load.

Table 5 summarizes the approximate total annual cost impact on each of the proposed transmission owners from the three projects. The owners would further allocate these system-wide costs among their applicable state jurisdictions in cases where an owner has native load in more than one state.

Table 5

Total Annual Charges to Owners for CapX2020 345 kV Projects

CapX2020 Transmission Owner	Twin Cities - Fargo 345 kV Project ($)	Twin Cities - Brookings County 345 kV Project ($)	Twin Cities – La Crosse 345 kV Project ($)	Total Annual Revenue Requirement ($)
CMMPA	$247,720	$534,502	$244,334	$1,026,556
DPC	$716,472	$1,532,952	$8,113,624	$10,363,048
GRE	$9,351,700	$13,232,220	$3,257,120	$25,841,040
MP	$10,128,050	$880,700	$440,350	$11,449,100
MRES	$2,850,480	$899,180	$204,090	$3,953,750

CapX2020 Transmission Owner	Twin Cities - Fargo 345 kV Project ($)	Twin Cities - Brookings County 345 kV Project ($)	Twin Cities – La Crosse 345 kV Project ($)	Total Annual Revenue Requirement ($)
OTP	$10,373,300	$3,423,700	$153,300	$13,950,300
RPU			$6,220,000	$6,220,000
SMMPA	$1,215,150	$2,818,770	$2,487,210	$6,521,130
WPPI	$435,408	$759,628	$533,036	$1,728,072
Xcel Energy	$41,536,280	$79,136,035	$25,190,580	$145,862,895

Note that the analysis in Table 5 assumes that all projects are classified as Baseline Reliability Projects and costs are allocated 80/20% as described above Because the Twin Cities - Brookings County 345 kV project also will facilitate the interconnection of additional wind generation in western Minnesota and eastern South Dakota, there is potential for this project to be classified by the Midwest ISO as a Generator Interconnection Network Upgrade for cost allocation purposes. If this were to occur, 50% of the project cost would be assigned to the interconnecting generators and the remaining 50% would be allocated as shown above according to the FERC approved provisions for baseline reliability projects.

Since it is expected that most interconnecting generators would be selling their output to Minnesota utilities, the charges to the generators would likely be passed through to the CapX2020 members. Under this assumption, 50% less costs from the Twin Cities – Brookings – 345 kV Project would be allocated to non-CapX2020 MISO pricing zones, concurrently increasing the aggregate cost impact on the CapX2020 member utilities by approximately 10%. The specific increases would be borne by the entities purchasing wind energy from the interconnecting generators, in proportion to the amount of capacity being purchased.