BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Dairyland Power Cooperative, Northern States Power Company-Wisconsin, and Wisconsin Public Power, Inc., for Authority to Construct and Place in Service 345kV Electric Transmission Lines and Electric Substation Facilities for the CapX Hampton-Rochester-La Crosse Project, Located in Buffalo, Trempealeau, and La Crosse Counties, Wisconsin

PSC Docket No. 05-CE-136

CITIZENS ENERGY TASK FORCE (CETF) AND SAVE OUR UNIQUE LANDS (SOUL) REQUEST TO REOPEN THE CAPX2020 DOCKET BASED ON NEW INFORMATION

The Wisconsin Public Service Commission (hereinafter "Commission") has broad discretion, and the authority, to reopen a case at any time:

> The commission at any time, upon notice to the public utility and after opportunity to be heard, may rescind, alter or amend any order fixing rates, tolls, charges or schedules, or any other order made by the commission, and may reopen any case following the issuance of an order in the case, for any reason.

Wis. Stt. § 196.39(1). Only the Commission may decide to reopen a docket. Wis. PSC Code 2.04(2)(c). Recognizing that a request to reopen should not be made lightly, Petitioners acknowledge the spirit of Wisconsin law, which states that rehearing requires new information -- a material error of law, fact, and/or discovery of new evidence sufficiently strong to reverse or modify the order, and which could not have been previously discovered by due diligence. Wis. Stt. §227.49(3)(c).

Furthermore, the Commission may refuse to certify a project **if it appears** that the project will do **any** of the following:

1. Substantially impair the efficiency of the service of the public utility.
2. **Provide facilities unreasonably in excess of the probable future requirements**.

> 3. When placed in operation, add to the cost of service without proportionately increasing the value or available quantity of service (**value** or available quantity of service the facilities provide **must be proportionate to their cost**)

Wis. Stat. § 196.49(3)(b)(emphasis added); Wis. Stat. §196.491(3)(d), (3)(t). The Commission may also require that a public utility submit specific details, plans and specifications "which the commission finds will materially affect the public interest." Wis. Stat. § 196.49(3)(a).

New information calls into question the scale, proportionate value, and very need for the CapX2020 Hampton-La Crosse transmission line (hereinafter CapX2020). New information includes continued depression in electrical demand, studies and actions influencing capabilities of demand response, energy efficiency and distributed generation, changes in La Crosse area electrical resources, a court ruling regarding land-owner compensation, and the recently filed Badger Coulee transmission line application PSC Docket 05-CE-142 (hereinafter Badger Coulee).

Much of the information requested by the Commission in deeming the Badger Coulee application incomplete is relevant to CapX2020.[1] New demand forecasts, allocation of costs and benefits, and enhanced analysis of alternatives requested by the Commission will impact need, benefits and value of both projects. Furthermore, CapX2020 need and benefits depend on the uncertain existence of Badger Coulee -- a reopening of CapX2020 is timely and prudent.

Petitioner Citizens Energy Task Force is an interested party and intervenor in the above-captioned CapX2020 case with full party status. Save Our Unique Lands (SOUL) has an interest due to its past experience intervening in the Arrowhead transmission project docket and its more than two year involvement in the recently applied for Badger Coulee transmission line.

[1] See ERF 193819, Completeness Letter and List, 11/21/2013.

As interested parties in both projects, with responsibility to raise these issues, we ask the Commission to exercise its discretion to reopen the CapX2020 docket and add the new information to the record. The Commission has jurisdiction to do so and, if appropriate, to modify or reverse its decision based on Wis. Stat. §§ 196.39 and 227.49(3)(c). The physical, electrical, and policy connections between the CapX2020 and Badger-Coulee projects, together with Applicant work on project plans and profiles and the imminent Mississippi River crossing, create urgency for the Commission to do so.

I. BACKGROUND

On May 30, 2012 the Commission approved the Certificate of Public Convenience and Necessity (CPCN) for the Wisconsin portion of the CapX2020 Hampton-La Crosse high-voltage power line (hereinafter "Order"), marking the first transmission line approved by the Commission in large part to increase regional power transfer.

Utility applicants have long planned for an interconnected line of transmission extending from North and South Dakota, through Minnesota, and crossing the Mississippi River near Alma and extending to Madison. See Rebuttal of Daniel Kline[2]; CapX2020 Technical Update, October 5, 2005[3]; Western Wisconsin Transmission Reliability Study, Final Report, September 20, 2010[4]. Once connected to Madison, the electricity can readily be moved and marketed to other states. Id., see also Badger Coulee Application, Appendix D, Exhibit 1, §2.2, p. 15-16[5]. This transmission overlay, stretching from the Dakotas to Madison to import electrons

[2] PSC ERF 16000, Rebuttal of Kline, p. 5-9; 12-13; see also 16002, Kline Ex. 2, MTEP 11 (selected).
[3] PSC ERF# 160027
[4] PSC ERF# 160026
[5] PSC ERF#191920

via regional transmission, alters Wisconsin energy policy and statutory decision-making criteria. See Wis. Stat. §§196.491; 196.49(3)(b), 1.11; 1.12(6); 196.025; Wis. Code chs. PSC 4 and 111.

Amongst other criteria, the Commission must find that a 345 kilovolt high-voltage transmission line provides usage, service or increased regional reliability benefits to the wholesale and retail customers or members in Wisconsin and that benefits be reasonable in relation to the cost. The May 30, 2012 Order ignored the key concept of regional reliability benefits by instead focusing its finding on an economic definition of "regional benefits" that failed to address reliability, costs beyond production and power flow, and with no comparison of state ratepayer benefits versus the costs to state ratepayers.

> The Hampton-Rochester-La Crosse project will serve the following purposes:
>
> - Local reliability – to serve increasing electric demand in La Crosse, Wisconsin and Winona and Rochester, Minnesota areas.
> - Regional reliability – to maintain the reliability of the regional electrical system.
> - Generation support – to provide a means for getting local electric generation output onto the electric grid.
> - Regional benefits – to enhance power transfers from states located west of the Mississippi River, access to more economical generation, and access to sources of renewable generation.
>
> The primary basis of the need for the Wisconsin portion of the proposed project is local reliability and regional benefits.

PSC Order, p. 8-9, May 30, 2013.[6]

After the May 30, 2012 Order, citizens and citizen groups, following the statutorily prescribed Commission process, asked the Commission to review its decision, citing significant legal and financial issues including flawed and incomplete analysis of need, costs, benefits and

[6] PSC ERF 165332.

alternatives. The Commission denied the Requests for Rehearing. Judicial review was then requested, but denied on a procedural issue. And the public's questions remain unanswered.

Although Petitioners have no right to have a hearing reopened, new information has arisen that directly affects need, costs and benefits for the CapX2020 project. Petitioners request the Commission to exercise its discretion and consider the impact of the new information upon ongoing issues regarding the application and approval of CapX2020.

II. NEW INFORMATION RENDERS PRIOR ANALYSIS INADEQUATE

New information on demand, potential for demand response, energy efficiency and distributed generation, La Crosse area electrical resources, land-owner compensation rights, and the recently filed Badger Coulee transmission line application are sufficiently strong to alter the analysis and conclusions that serve as the basis for the CapX2020 approval.

A. APPLICANTS' DEMAND IS CONSISTENTLY LOWER THAN FORECAST AND ABILITY TO REDUCE DEMAND IS CONSISTENTLY INCREASING.

The "final" application for CapX2020 submitted in December, 2010, accepted as complete in June, 2011 used outdated 2004-2005 utility forecasts predicting a demand growth of 2.49% per year. See CapX Technical Update, p. 1, p. 6, NoCapX/CETF Item 5, ERF 160027; Kline, Tr., Vol. 2, p. 154-155. During the hearing, projections for average load growth in the La Crosse area were lower ranging from Commission expert Dr. Sirohi's +0.78% per year and MTEP11's +1.28%. PSC Order, p. 14-15. The Order approving CapX2020 ultimately relied on Applicant revised forecasts that were higher than both Sirohi and MTEP11:

> Using these individual load growth estimates, the applicants arrived at estimated average annual load growth rates of 1.46 percent for the period 2011 to 2020, and 1.24 percent for the period after 2020.

PSC Order, p. 12, May 30, 2012. New information from Applicants and Commission staff shows demand growth forecasts to be grossly overstated.

1. Applicant Utilities are Experiencing Reductions in Forecasted Demand

Rather than 1.46% average annual demand growth, Dairyland Power experienced a 9.4% 2-year decline, and Xcel Energy forecasts continuing declines in Minnesota and Wisconsin along with an increased confidence in Xcel forecasting abilities:

> **Teresa Madden** – Xcel Energy Chief Financial Officer & Senior Vice President
> Well, sure, Kit. Let's start with the 2013 by the states. Minnesota, we're still projecting a decline of about 1.2%. In NSP-Wisconsin, just a slight decline. … And then the other 2 jurisdiction, PSCo slightly up and SPS at about 1.2% range. But all of it netting to within the -- up to 0.5%. When we look to the future, we're looking at about, as we indicated in our guidance up to 0.5%, those are narrowing, not such a great degree in terms of the decline in NSP-Minnesota. In terms of the various classes of customers, it does vary by jurisdiction. I will say that C&I, we see the most growth in Texas with the oil and gas industry boom.
>
> **Benjamin Fowke** - Xcel Energy Chairman, Chief Executive Officer & President
> Kit, I would just add that our forecasting abilities for sales have really been very, very accurate this year, and we believe heading into next year too. I think we really got our arms around what's happening with the economy and how that relates to our sales growth.

Xcel Energy Q3 2013 Results – Earnings Call, p. 15.

As stated above, Xcel Energy isn't only Applicant reporting decreased demand. Dairyland Power at its June 2012 Annual Meeting[7] and in its 2011 Annual Report announced an 8% decrease in 2011 total energy sales and flat demand from Class A members.

2011 year-end results are positive:

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[7] Dairyland Power sees margin rise on decreased power sales, La Crosse Tribune, June 7, 2012, online at http://lacrossetribune.com/news/local/dairyland-power-sees-margin-rise-on-decreased-power-sales/article_6148a1c0-b051-11e1-ba91-001a4bcf887a.html

> Dairyland experienced a moderate decline in electric sales in 2011 due to the continued economic recession and very mild seasonal temperatures. System-wide, Dairyland energy sales decreased to 5.9 billion kilowatt-hours (kWh) in 2011—compared to 2010 sales of 6.4 billion kWh. However, sales to Class A members remained stable at about 4.5 billion kWh. Total operating revenues were steady at $411.4 million in 2011, as compared to $415.5 million in 2010.
>
> Despite the decrease in overall sales, Dairyland's year-end results were positive with an increase in margins, strengthening Dairyland's overall financial position. For 2011, margins increased to $18.2 million over 2010 margins of $13.2 million.

Dairyland Annual Report, p. 13, 2011[8].

Dairyland energy demand again decreased in 2012 down 1.7% from 5.9 billion kWh in 2011 to 5.8 billion kWh in 2012. Dairyland Power 2012 Annual Report, p. 10. Together this is a 9.4% decline in demand from 6.4 billion kWh to 5.8 kWh over the last two reported years.

Decreases in Applicant demand are consistent with trends reported by the DOE's Energy Information Administration (EIA) on electrical consumption, which is dominated by decreases in demand nationally and in CapX2020 relevant regions.

% Growth: Total Electric Sales (Units) Versus Same Period a Year Ago

	2011	2012	2013 through Sept/Q3
Total US: All Sectors	-0.12%	-1.45%	-0.87%
Wisconsin: All Sectors	-0.20%	0.30%	-1.35%
Minnesota: All Sectors	1.08%	-0.79%	-1.42%

See *Short-Term Energy Outlook,* U.S. Energy Information Administration, December 11, 2013[9].

Consistent with Xcel Energy's recent projection for soft demand, EIA forecasts 2014 demand will remain 1.5% below that of 2011 despite annual growth of 0.3%.

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[8] Full Dairyland Power 2011 Annual Report online at http://www.dairynet.com/who_we_are/2011_annual_report.pdf

[9] Figures gleaned from Appendices, available online at http://www.eia.gov/forecasts/steo/report/electricity.cfm%20?src=Electricity-f1
Electric sales information at : http://www.eia.gov/forecasts/steo/tables/pdf/7btab.pdf

Retail Electric Sales (billion kWh per day)

	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast
Residential Sector	3.90	3.76	3.78	3.78
Commercial Sector	3.64	3.63	3.65	3.64
Industrial Sector	2.72	2.69	2.63	2.68
Total Retail Sales	10.27	10.10	10.09	10.12

New information provided by Applicants and the EIA renders the forecasts relied upon to analyze and approve CapX2020 invalid. Actual and forecasted demand growth are consistently and significantly below the +1.24 to +1.46% forecasted growth used by the Commission. Overstated growth projections and an inflationary method in calculating peak demand are ongoing issues that result in overstated need, benefits and project value, and increase costs to Wisconsin ratepayers. For these reasons, the Commission should reopen the CapX2020 docket.

2. **Demand Response, Efficiency and Distributed Generation have unrealized potential, and have increased beyond expected subscription level, despite slashed budgets and the forwarding of regional transfer capacity initiatives.**

Demand and project need are intentionally further reduced by interruptible service, conservation and efficiency measures and distributed generation. New information demonstrates a growing desire and trend to implement these measures to defer or negate the need for new "mega" infrastructure -- in this case the CapX2020 Hampton-La Crosse and Badger Coulee transmission lines.

A "peak demand" issue in La Crosse drove the "local reliability need" for CapX2020. Requests for Rehearing following the approval presented new information showing significant opportunity to reduce energy spikes through demand side management and to use this as a planning tool including an 8% growth in Xcel/NSPW's ability to reduce summer "peak load" between 2011 and 2012. Decreased demand potential was also identified by the Eastern Interconnection States Planning Council (EISPC).

In deliberating and denying the initial Requests for Rehearing, the Commissioners expressed uncertainty if the energy-saving opportunity identified in the EISPC study was relevant to CapX2020 Hampton-Lacrosse areas and did not consider this information, believing it inapplicable. The *Assessment of Demand Side Resources within EISPC* study has since become publicly available. The new information demonstrates potential for increased Wisconsin and Minnesota demand side energy and peak load impacts, as follows:

Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)

	2012	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
WI	3,818	4,535	5,250	5,975	8,532	10,815	12,141
vs. 2012		717	1,432	2,157	4,714	6,997	8,323
%		19%	38%	56%	123%	183%	218%
MN	2,563	2,698	2,829	2,965	3,885	4,921	6,042
vs. 2012		135	266	402	1,322	2,358	3,479
%		5%	10%	16%	52%	92%	136%
Total	6,381	7,233	8,079	8,940	12,417	15,736	18,183
vs. 2012		852	1,698	2,559	6,036	9,355	11,802
%		13%	27%	40%	95%	147%	185%

Projected Demand-Side Resource Peak Load Impact (MW/year)

	2012	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
WI	1,325	1,340	1,334	1,365	1,442	1,539	1,644
vs. 2012		15	9	40	117	214	319
%		1%	1%	3%	9%	16%	24%
MN	2,526	2,673	2,863	2,988	3,316	3,686	4,068
vs. 2012		147	337	462	790	1,160	1,542
%		6%	13%	18%	31%	46%	61%
Total	3,851	4,013	4,197	4,353	4,758	5,225	5,712
vs. 2012		162	346	502	907	1,374	1,861
%		4%	9%	13%	24%	36%	48%

Id., see Minnesota §A-18, p. A-52-54; Wisconsin §A-40, p. A-118-120.

While the increase in NSPW 2012 summer load control capacity was not acknowledged by the Commission, new information provided by Xcel Energy acknowledges further potential to reduce total and peak demand. That reduction, when combined with slower than forecasted growth, could negate the local reliability need for CapX2020. Xcel Energy offered many options in its Integrated Resource Plan, adopted by the Minnesota Public Utilities Commission on March 5, 2013, including:

- Continuing to use demand-side management programs such as offering discounts to customers that permit Xcel to interrupt electric service during time of peak demand, estimated to reduce the demand on Xcel's system during periods of peak demand by approximately 1000 MW.

- Continuing to use demand-side management to reduce energy sales by 1.3 percent, and working with stakeholders to achieve even greater savings.

Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket, Minnesota Public Utilities Commission, March 5, 2013[10]. The order goes on to require additional consideration of demand response, reasoning:

> Xcel commissioned a study that suggests that Xcel could avoid the need for an additional 300 MW if Xcel could harness the full potential for demand response in its service area. Xcel argues, however, that the study is too general to be relied upon. For its next resource plan, therefore, the Commission will direct Xcel to analyze the capacity for demand response in its service area – and to conduct the study with sufficient rigor that the Commission may rely on the results for evaluating how demand response will influence Xcel's forecasted need for additional resources.

Id., p. 7.

The Wisconsin Order states that Applicants claimed "[l]oad growth would need to remain stagnant until 2020, which would require a 98 MW load reduction based on the

[10] P. 3, see also p. 7-8, Document ID **20133-84447-01** , MPUC Docket 10-825.

applicants' load forecast." The Order also notes that for critical local load forecasts, "[e]ven at the most conservative estimate of annual load growth (0.7 percent), line loadings and voltage will be out of tolerance within the five-to ten year planning horizon without the proposed project."

Not only is demand overstated in these conclusions, but the 1,000 MW reduction of demand by just one of the Applicant utilities as offered in the Minnesota planning docket would obviate the claimed need for this transmission project. However, when Commission staff reviewed alternatives higher on the State's energy priorities, the conclusion was:

> This level of load reduction is substantially higher than the annual potential identified in the August 2009 *Energy-Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin Study* conducted by the Energy Center of Wisconsin. It is also substantially higher than the annual savings goals established by various Midwestern states which range from 1.0 to 2.0 percent.
>
> The Commission finds that energy efficiency and conservation and other sources of electric supply are not technically feasible, cost-effective alternatives to the project.

PSC Order, p. 18.

New information shows substantive local demand shaving potential that, when combined with unrealized demand growth, would defer or negate the need for CapX2020. The November 2013 Commission staff letter deeming the Badger Coulee application incomplete until demand side management measures are more thoroughly addressed serves as new information that opens the door for the Commission to require the same for CapX2020. And, while the Commission can't assume ratepayers will take advantage of demand response, efficiency or local renewables, repeated cuts to the successful and oversubscribed Focus on Energy program make it harder or impossible for ratepayers to participate.

For Example, on April 26, 2012, the Commission issued an Order in docket 5-GF-191 requiring the annual renewable energy incentive level for 2012, 2013, and 2014 not exceed $10 million in a given year, and that for program years 2013 and 2014 75% of total incentives be allocated to Group 1 technologies (biomass, biogas, geothermal) and 25% to "less cost-effective" Group 2 technologies (solar photovoltaic, solar thermal, wind). On September 26, 2013 the Commission issued an Order related to the above cited docket 5-GF-191 and Commissioner Calisto provided dissenting opinions on multiple points. These Orders serve as new information and evidence that budget cuts and policy changes are impeding the adoption of high-priority energy options that could increase grid reliability through reduced demand and in-state renewables.

> I dissent from those portions of the Commission's Order that necessitate the unplanned stoppage of Focus funding for solar and wind energy technologies. This is the second time in just more than two years that Focus funding for renewable energy projects has been suspended. The last time we stopped funding – a suspension that lasted nearly a year – we had a good reason: there was substantial program overspending that potentially threatened the overall cost-effectiveness of the full Focus portfolio. No similar situation exists today. The Commission's decision creates uncertainty in the renewables marketplace and penalizes entire classes of technologies without any compelling justification.

See Dissent of Callisto, p. 2, attached to Order, Quadrennial Planning Process, 5-GF-191, Sept. 26, 2013.

Commissioner Callisto's dissent addresses both the effectiveness and need for stability in policy and funding of the state's renewables program;

> The Commission's decision to cut off Group 2 funding also has nothing to do with program cost-effectiveness. Compare, for example, today's renewables funding stoppage with when it was last suspended in 2011. Here's what happened then: in the first six months of 2011, the renewables program had spent more than $10 million in incentives, more than 22 percent of the Focus program's overall incentive spending for that year, an amount that surpassed any previous year's

> 12-month spending total, all the while producing just 3 percent of the program's overall energy savings. The situation led at least one commissioner to conclude that the renewable over-commitments from 2011 "jeopardized the cost-effectiveness of the entire Focus program," which ultimately justified a "temporary suspension" of programs.[5]
>
> Today, we have a very different situation. The program administrator just recently projected an overall benefit-cost ratio of 2.98 for the full Focus portfolio, assuming 2013 renewables funding continues as planned. And the Commission's Order of April 26, 2012, only required that Focus not dip below a benefit-cost of 2.3 program-wide. So even without halting Group 2 renewables funding in 2013, the program is on track to best the ommission's ordered cost-effectiveness benchmark by nearly 30 percent. Moreover, the renewables share of total Focus incentives in 2013 will likely be about 3 percent, a fraction of any previous year's share since the program began and nowhere near the 22 percent figure that was reached halfway through 2011.

Id. Wisconsin's pattern has been to cut efficiency resources rather than expand them:

> Consequently, Wisconsin is backsliding, and it has not gone unnoticed. In the American Council for an Energy-Efficient Economy's most recent "energy efficiency scorecard," released late last year, Wisconsin was one of only seven states that actually had a lower total score in 2011 than the previous year, and indication of the national trend to do more, not less, on energy efficiency. That trend is apparent here in the Midwest. Minnesota, Illinois, Iowa, Indiana, and Michigan all have energy efficiency resource standards and four out of five of them have energy reduction goals of either 1.5 or 2 percent per year. Our neighboring states obviously get it: with such markedly positive benefit/cost ratios, investing more in energy efficiency makes good, economic sense.

Quadrennial Planning Process, Callisto Dissent, p. 1, January 13, 2012[11].

Focus on Energy was established to support Wisconsin Energy Priority Law. Wisconsin Energy Priority Law also requires the Commission to evaluate conservation, efficiency and renewable options, individually and in combination, and must reject all or part of the project if it does not utilize the statutory energy hierarchy:

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[11] PSC ERF 158228, Docket 05-GF-191.

- Energy conservation and efficiency
- Noncombustible renewable energy resources
- Combustible renewable energy resources
- Nonrenewable combustible energy resources
    - Natural Gas
    - Oil or coal with a sulfur content of less than one percent
    - All other carbon-based fuels

Wis. Stat. § 1.12(4); see also Wis. Stat. §196.025(1)(b)(1).

In CapX2020 Hampton-La Crosse, rather than analyze, separately or in combination, the impact of an equal investment in non-transmission alternatives or speculate whether ratepayers would take advantage of the programs if made available, the Commission fails to appropriately recognize demand reduction potential -- the highest priority energy solution.

Fossil fuels, the lowest priority, have been shown to be the primary benefactor of enhanced power transfers from states located west of the Mississippi River via the transmission build-out. See ICF, Independent Assessment of MISO Operational Benefits, February 27, 2007[12] CapX2020 was approved on its ability "to enhance power transfers from states located west of the Mississippi River, access to more economical generation, and access to sources of renewable generation," P. 9 of Order, May 30, 2012.

New and continued Focus on Energy program cuts show a pattern of stifling established policies that would reduce demand while at the same time following a policy that forwards fossil fuels and regional power transfers through high-voltage regional transmission.

The new information demonstrating increased Applicant ability and potential to reduce overall and peak demand alone justifies the Commission's reopening of the CapX2020

[12] PSC ERF # 160024; see p. 15 & 83: RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation, and better use of import potential.

Hampton-La Crosse docket. New and continued cuts in Focus on Energy that reduce the potential for demand response, energy efficiency, and distributed renewable generation to address congestion and reliability reinforce the need to do so. New and requested information regarding Badger Coulee, which is the second line forwarded in the State in large part to increase regional power transfer, further make reopening the CapX2020 Hampton-La Crosse transmission line docket timely and prudent.

B. NEW INFORMATION REGARDING SUPPLY DRAWS PRIOR ANALYSIS OF NEED AND ROUTE INTO QUESTION

To the extent that the Order relied on the unavailability of French Island Unit 3 generation and the existence of Dairyland Alma generation as justification for transmission into La Crosse, new information regarding supply draws the Commission's prior analysis of need and route into question. French Island Unit #3 will reopen, lessening need for additional transmission into La Crosse, and Dairyland's Alma plant will be closed, also lessening need for additional transmission between Alma and La Crosse. Furthermore, in June 2013 Dairyland announced the completion of an upgrade of its Q1 line from Genoa north to La Crosse, increasing the efficiency of the line by 40% and further lessening concerns regarding peak demand.

1. French Island Unit #3 is reopening per Xcel Energy's Minnesota IRP.

New information that Xcel Energy's French Island Unit #3 will be available to serve La Crosse load should be considered by the Commission, because the May 2012 Order presumed that the French Island Unit 3 would not be operational:

Table 1 Power plants serving the La Crosse local area

Plant	Capacity (MW)	Fuel Type	Distance from La Crosse (miles)
John P. Madgett	395	Coal	40
Alma Units 1-5	208	Coal	40
Genoa Unit 3	377	Coal	20
French Island Units 1 and 2	26	Refuse	Within the city of La Crosse
French Island Unit 4	70	Oil	Within the city of La Crosse
French Island Unit 3	70	Oil	Currently not operational

PSC Order, p. 9, May 30, 2012.

The Order also found that reopening French Island Unit 3 was a viable means to address critical load limit concerns in the La Cross area:

> The applicants did not consider French Island Units 3 and 4 as available resources in the critical load limit analysis. Although NSPW has allocated $1.9 million for the repair of the mothballed French Island Unit 3 in order to make it operational, this repair is neither scheduled nor planned with certainty. French Island Unit 4 has numerous operational problems which result in its reduced availability. **If French Island Unit 3 is included, the critical load limit could increase to 500 MW calculated consistent with NERC standards.**

PSC Order, p. 12, May 30, 2012, emphasis added (French Island Unit 4 was also not considered as a resource and it remains unknown the cost and impact of addressing its operational issues.)

The Order also acknowledged ongoing disagreement regarding demand growth forecast and how lower growth would push the need for the project back in time, but the impact of demand softness and declines in excess of the lower growth projection are not apparent:

> The Commission acknowledges that the applicants, intervenors and Commission staff differ in their estimates of the local area critical load level. Even at the most conservative estimate of annual load growth (0.7 percent), line loadings and voltages will be out of tolerance within the five- to ten-year planning horizon without the proposed project.

Id.

The Order further noted NSPW's allocation of "$1.9 million for the repair of the mothballed French Island Unit 3, $1.9 million, in comparison to the $211 million cost of the

Wisconsin portion of CapX2020 Hampton-La Crosse transmission, is a reasonable investment." Id. Since then, the Minnesota Public Utilities Commission Ordered, at Xcel Energy's initiative, reopening of the La Crosse French Island Unit 3 demonstrating that this $1.9 million alternate solution is indeed available and planned, providing the certainty of resource availability not present on May 30, 2012:

> Continuing the operation of the Key City generator in Mankato (43 MW) and Granite City generator near St. Cloud (54 MW) until 2016, and bringing the French Island Unit 3 generator (57 MW) back into service.

PUC Order, Xcel IRP, p. 3, March 5, 2013.

To the extent that uncertainty prevented the Commission from considering French Island Unit 3 peaking capacity in determining need for the CapX2020 line, the Commission's conclusion is invalid.

2. Dairyland announces closing of Alma Units 4 and 5.

The Commission's Order approving the CPCN for the CapX 2020 project relied on generation serving the local area that included Dairyland's Alma Units 1-5:

Table 1 **Power plants serving the La Crosse local area**

Plant	Capacity (MW)	Fuel Type	Distance from La Crosse (miles)
John P. Madgett	395	Coal	40
Alma Units 1-5	208	Coal	40
Genoa Unit 3	377	Coal	20
French Island Units 1 and 2	26	Refuse	Within the city of La Crosse
French Island Unit 4	70	Oil	Within the city of La Crosse
French Island Unit 3	70	Oil	Currently not operational

PSC Order, p. 9, May 30, 2012.

Plans to close Alma Units 1-3 in June 2012 had previously been announced and new information arose on October 21, 2013, when Dairyland Power announced it would be closing units 4 and 5 at the Alma coal generating plant[13] The Order is flawed to the extent it relied on Alma Units 1-5 to justify need or route. And, to the extent recent closings are related to decreases in demand, the availability of in-state generation capacity to address local and state demand is also substantiated.

The Commission ordered construction using the Q-1 Galesville Route, and a rebuild of the 161 kV Q-1 line from Alma generating plant south to North La Crosse. The Alma closings bring into question the purpose, convenience and necessity of rebuilding the 161 kV Q1 transmission line from Alma to La Crosse. But for using the Q-1 route as a corridor, and but for this closing of the plant, the Commission may have chosen a more northerly route as was requested by ATC, thereby avoiding issues of DOT easement, Van Loon wetlands, running next to school buildings, and duplicate costs of building transmission down to La Crosse and then back up again to the Blair area back to the interstate corridor.

Need and route for the CapX2020 transmission line should be reconsidered based on new information regarding closing of Dairyland's Alma generation.

3. Dairyland announces upgrading of Q-1 line from Genoa to La Crosse.

The Commission did not address or consider the impact of the reconstruction of the southern Q-1 line, from Genoa north to La Crosse, which was announced by applicant Dairyland Power as finished in June 2013. Dairyland deemed this section of the Q-1 transmission line to be "the primary source of power delivery to the La Crosse area" whose reconstruction was reported "to increase capacity and therefore delivery efficiency by over 40%" to La Crosse[14].

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[13] See attached Exhibit D, newspaper articles regarding closure of the Alma generating plant.

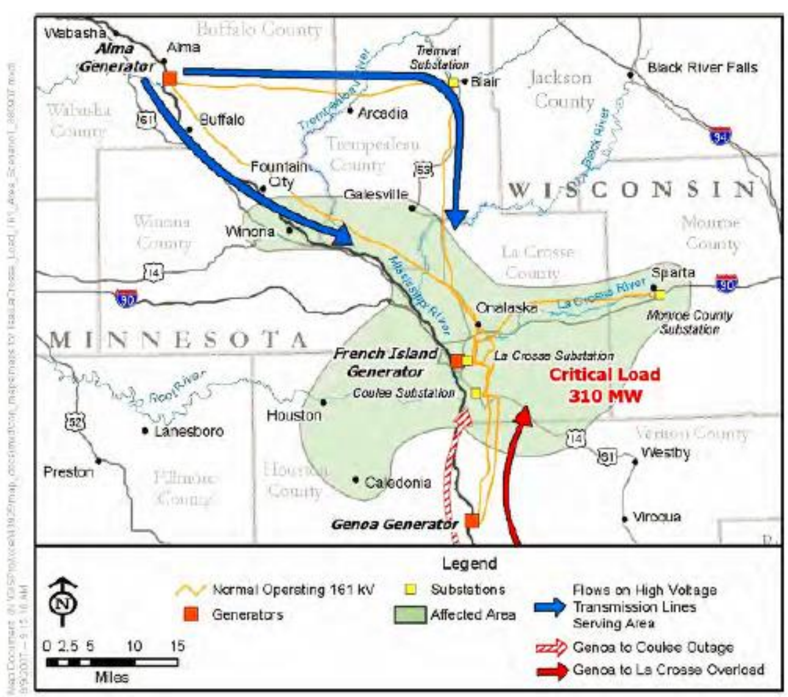
[14] Dairyland Power Genoa to La Crosse Transmission Project Fact Sheet

This new information about the Q-1 transmission upgrade, resulting in increased capacity of 40%, demonstrates increased availability of electricity in La Crosse from the south from “the primary source of power delivery to the La Crosse area,” which would address peak demand issues in the La Crosse area.

The modeling for the CapX2020 line also uses a contingency of this Genoa-La Crosse 161 kV line, <u>added to a highly unlikely multiple outage scenario</u>, as justification of need, with two generators off line and two transmission lines out of commission, an apparent n-4 situation:

> The system capacity is similarly limited if the John P. Madgett generator is off-line, French Island peaking generation is off-line, and the Genoa – Coulee 161 kV transmission line is lost. In this scenario, the Genoa – La Crosse 161 kV transmission line overloads and the electrical system can reliably serve only 310 MW. Figure 6-4 illustrates this contingency scenario.

Figure 6-4
La Crosse/Winona Area, John P. Madgett Off-line, Genoa – Coulee 161 kV Line Contingency



Technical Studies Summary Report, p. 16-17, CapX 2020 Application, Appendix E.

A 40% increase in efficiency of Q-1 line likewise increases availability of electricity. The use of a Genoa-La Crosse 161kV contingency, on top of multiple outage scenario, as a basis for CapX2020 need isn't credible and requires reworking based on new information.

When all these factors regarding supply of electricity to La Crosse are taken into account, the Commission's findings and arguments are not reasonable justification for this project, even without consideration of the new information on decreased demand and increased ability to further lower demand. For these reasons, the Commission should reopen the CapX 2020 Hampton-La Crosse transmission line docket.

C. RECENT CONDEMNATION RULING BY WISCONSIN SUPREME COURT WILL INCREASE PROJECT COST

A July 16, 2013 Wisconsin Supreme Court order provides new information regarding land acquisition, relocation and court costs associated with condemnation of land for electrical transmission that should be considered in a timely manner. The Court, in Waller v American Transmission Company, directed ATC to acquire not only the transmission right-of-way but also an "uneconomic remnant" left after a condemnation-taking. The definition of an uneconomic remnant is whatever property remains after a partial taking that is of little value or of "substantially impaired economic viability." Wis. Stat. § 32.06(3m), and the Court held that:

> The easements themselves not only restricted the Wallers' activity in the easement area but also substantially diminished the desirability, practicality, and value of the Wallers' property for either a residential or industrial user.

Waller v American Transmission Company.[15]

[15] Online at Supreme Court site: Scott N. Waller and Lynnea S. Waller, Plaintiffs-Respondents, v. American Transmission Company, LLC, Defendant-Appellant, Case No. 2012AP805 & 2012 AP840, July 16, 2013.

According to the Court, “when a partial taking changes a property’s highest and best use, the change provides a basis for determining that the property has become an uneconomic remnant.” Waller, 2013 WI 77, ¶ 97. In this case, the Waller property was residential and included space for raising small livestock. After the transmission lines were installed, the highest and best use of the property was deemed to be a vacant industrial lot. This change in use and a projected loss in value of 57 to 88% led the Court to determine that the property was an uneconomic remnant. Id., ¶ 96.

The Court also interpreted Wis. Stat. § 32.19(2)(e)1a, which defines a displaced person as “any person who moves. . . as a direct result of” a condemnation proceeding, determining that the statute “contains no explicit requirement that a person’s move must be ‘forced’ or involuntary in order to render that person ‘displaced.’” Waller, 2013 WI 77, ¶ 116. Since the Wallers moved due to installation of transmission lines, they were displaced persons entitled to relocation expenses. The Court also interpreted Wis. Stat. § 32.06(3m) reasoning that if the utility fails to include an uneconomic remnant in its offer, “the condemnee must have some recourse to assert and prove the uneconomic remnant claim.” Waller, 2013 WI 77, ¶ 77.

On December 9, 2013 new information by ATC conveyed that the $35.9 million projected cost for the Pleasant Prairie-Zion Energy Center line is expected to increase 13.7% due to “final transmission line design, extended right-of-way easement acquisition activities, and associated transmission line construction activities…”[16]

As has already been seen in the Pleasant Prairie-Zion Energy line, it is prudent to assume that the court decision will impact costs associated with land acquisition, including purchase

[16] See Milwaukee Journal Sentinal: http://www.jsonline.com/blogs/business/235107061.html

price and costs for relocation and court expenses. However, the Commission's Order of May 30, 2012 is approving a project at a specific cost:

> This authorization is for the specific project as described in this Final Decision at the stated cost. Should the scope, design, or location of the project change significantly, or if it is discovered or identified that the project cost, including force majeure costs, may exceed the estimated cost by more than 10 percent, the applicants shall promptly notify the Commission as soon as they become aware of the possible change or cost increase.

PSC Order, p. 50, May 30, 2012[17].

For these reasons, the Commission should reopen the CapX2020 docket to consider the impacts of this new information while construction is in the early stages.

D. BADGER-COULEE APPLICATION HAS BEEN SUBMITTED, BUILDING ON THE CAPX2020 TRANSMISSION LINE, BUT DENYING THE CONNECTION.

We applaud the Commission's request for extensive information prior to deeming the Badger Coulee application complete. Commission staff issued eight pages of single-spaced questions requesting more information regarding alternatives to and "need" for the project. See PSC Completeness Letter and List, November 21, 2013, Requests 01.87 – 01.153[18]. We ask the Commission for similar due diligence regarding the continued flow of new information by reopening the May 2012 CapX2020 Order.

As above, the Commission's approval of CapX2020 was based in large part on the regional transfer capacity benefits, which are realized with the addition of Badger Coulee:

> The primary basis of the need for the Wisconsin portion of the proposed project is local reliability and **regional benefits**.

[17] Project costs as presented in the Application were $393 million, $258 million in Minnesota (some of which is allocated to Wisconsin ratepayers),and $135 for the Wisconsin Portion. However, costs listed on the Order are $211 million for Wisconsin only, a $76 million dollar increase compared to the Applicants forecast of $135 million.
[18] PSC ERF **193819**.

PSC Order, p. 9, May 30, 2012 (emphasis added)

In its Order the Commission acknowledges the dependent interconnections of the projects and found that:

> The Hampton-Rochester-La Crosse project, in turn, is part of the CapX2020 Transmission Expansion Initiative (CapX 2020), which will serve the state of Minnesota and parts of Iowa, the Dakotas, and Wisconsin.

PSC Order, p. 8, May 30, 2012.

> The proposed project will provide significant reliability and service benefits to Wisconsin customers and a continuous 345 kV interconnection for potential future projects such as the possible Badger-Coulee 345 kV project.
>
> The increased transfer capability has a positive impact that will facilitate commerce and not adversely affect competition in the wholesale electric market. The transfer capability and design of the project match long range plans for the area and are not in excess of probable future requirements.

PSC Order, p. 16, May 30, 2012.

The Badger Coulee transmission project application became available in October 2013 and, although the project relies on CapX2020 electrically, physically and in policy, Applicants inexplicably state that it is not connected:

The Project is not contingent upon or part of a project under another docket number.

Badger Coulee Application, p. 8 of 137[19]. Emphasis added.

Clearly, if CapX 2020 did not exist, there would be no connection available in the La Crosse, or any other area, for interconnection of the Badger Coulee project. Evidence in the CapX2020 docket, relied on in the Order for approval, conveys the inter-connection, as does the Badger Coulee Application. See Application, Regional Economic, Reliability and Public Policy

[19] PSC ERF#192166

Benefits, Badger Coulee Application, App. D, p. 88-95; Badger Coulee Integration with Future Transmission Facilities, App. D, p. 97.[20]

The purpose of the Upper Midwest Transmission Development Initiative is to connect generation in the Dakotas to points east. Badger Coulee project application maps show this initiative extending to Canton, in eastern Ohio. Badger Coulee Application, App. D, p. 90-92. The Eastern Interconnect States Planning Collaboration (EISPC)[21] promotes the same web of transmission from the Midwest to the Mid-Atlantic, with expansion plans that have yet to integrate the demand side management potential identified by EISPC's March 2012 research.

An ATC FERC filing also serves as new information demonstrating how utilities planning and applying for the lines recognize the interdependence of the lines:

> As Xcel Energy further explained, the Twin Cities-La Crosse segment "was not developed or proposed in isolation. It was studied extensively along with other region-enhancing transmission line projects as one aspect of a long-range, phased, program to deploy transmission assets throughout the Upper Midwest region to enhance regional reliability and facilitate the transfer of energy to major regional load centers." Id. at 5. The studies showed that construction of the Twin Cities-La Crosse segment in conjunction with the La Crosse-Madison segment "would enhance the reliability and energy delivery benefits created by the Twin Cities-La Crosse Line." Id. **In other words, as Xcel Energy itself acknowledges, the studies show that the benefits to be derived depend upon a new transmission line between the NSPM and ATC systems that runs all the way from Minneapolis, Minnesota, to Madison, Wisconsin.**

ATC Answer to Xcel[22], pages 8-9(emphasis added).

> Importantly, as acknowledged by Xcel Energy, the WWTRS report characterized the La Crosse–Madison segment as "extending" the Twin Cities–La Crosse segment and also "connecting" to the Twin Cities–La Crosse segment. The report further concluded that the La Crosse–Madison segment was to be an extension

[20] The Badger Coulee Application has been filed with the PSC, Docket 05-CD-142, and deemed incomplete.
[21] EIPC at www.eipconline.com/
[22] Online at: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14056224

> of the CapX2020 Twin Cities–La Crosse segment. Xcel Energy confirmed that the "final scope" of the project analyzed in this report was to interconnect the endpoint of the Twin Cities-La Crosse segment with a line into ATC's North Madison Substation; i.e., the La Crosse-Madison segment.

Id., page 14.

> Perhaps even more significantly, Xcel Energy asserted that "MISO's MVP studies identified the benefits of extending the Twin Cities–La Crosse Project into the Madison, Wisconsin area as a main driver for the MVP designation of the La Crosse–Madison Line. Therefore, the La Crosse-Madison Line, to maintain its status as an MVP, must have its western terminus at a point electrically identical to the eastern terminus of the Twin Cities-La Crosse Project.

Id., page15.

The foregoing discussion, based primarily on new information provided by ATC and Xcel Energy, demonstrates that the regional reliability and economic benefits projected to result from the Twin Cities-La Crosse segment are inextricably linked to and interdependent upon the La Crosse-Madison segment that was at issue in the Xcel Order. Id.

This new information acknowledges Badger Coulee to be a continuation of CapX2020, whose Order forwards regional economic benefits as a driving force in Wisconsin energy planning. This policy has yet to be fully vetted and can contradict and be inconsistent with Wisconsin statutory criteria for project approval. Furthermore, when projects are so integral that need and benefits for one project are dependent on another being constructed, total cost should be used in the analysis. The October 2013 Badger Coulee application shows costs of between $514 -$552 million that were not considered in approving CapX2020 as a foundational line to enable Badger Coulee. The segmentation of these lines was an issue in challenging the approval of CapX, and previous concerns regarding incomplete cost and environmental analysis are substantiated by the new information.

The Commission further makes the presumption, through acceptance and acknowledgement of MISO planning, that if a project is MISO approved it exists and is inserted into modeling assumptions:

> Implementation of a project approved in an MTEP is assumed in modeling for subsequent planning cycles. Therefore, each successive MTEP builds upon the transmission system assumed and approved in previous MTEPs.

See Xcel Motion for Leave to Answer and Answer of Xcel Energy Services, et al., p. 9 (quoting Complaint, Affidavit of Xcel's Daniel P. Kline, p. 52).

Orders made under these presumptions pre-empt the legal authority of each State to determine need and route for power lines. Furthermore, by not requiring MISO to incorporate established energy priorities during its strategic planning, the Commission further minimizes existing state statutes.

The above stated reasons and issues, backed by relevant new information herein, provide ample reason for the Commission to conclude that the Order approving the CapX2020 Hampton-La Crosse transmission line relied upon inadequate information.

III. PETITIONERS REQUEST THAT THE COMMISSION REOPEN THE DOCKET

Ratepayers deserve a sound and documented basis for the Order and a thorough discussion of a significant policy that would require Wisconsin to both pay for and host through-state transmission based on "regional transfer capacity." We are aware of over 100 resolutions submitted by municipalities asking for more comprehensive analysis regarding CapX2020 and/or Badger Coulee transmission lines, and over 3,000 individuals have signed petitions expressing their concern, most, if not all, eFiled in the Commission's project dockets.

Though Petitioners have no right to have a hearing reopened, the Commission has the authority to reopen a case for any reason, at any time, including after the Commission has made an initial decision. Wis. Stt. § 196.39(1). Based upon the following new information, the Commission should reopen this docket:

- Applicants demand is consistently lower than forecast and ability to reduce demand is consistently increasing;

- Demand Response, Efficiency and Distributed Generation have unrealized potential, and have increased beyond expected subscription level, despite slashed budgets and the forwarding of regional transfer capacity initiatives;

- Supply in La Crosse is increased with reopening of French Island Unit #3~~;~~

- Supply in La Crosse is increased with rebuilding of Dairyland's southern Q-1transmission line;

- Dairyland announces closing of Alma Units 4 & 5 closing;

- Recent condemnation ruling by Wisconsin Supreme Court will increase project cost;

- Badger Coulee application has been submitted, building on CapX 2020 yet denying the connection.

This new information creates essential and pertinent questions regarding the "need" for CapX2020, and places into question the benefits claimed by the applicants. Moreover, since the original application was based on data that has been shown to be inaccurate, with an increasing magnitude of inaccuracy, the integrity of the CPCN process demands the attention of the Commission. Therefore, Petitioners ask that the Commission exercise its discretion to reopen this docket to consider the impact of the new information and how it builds upon ongoing issues in the CapX2020 and Badger Coulee transmission permitting.

Respectfully submitted on this 9th day of January, 2014,

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