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) REPLY TO APPLICANT NORTHERN STATES POWER COMPANY AND DAIRYLAND POWER COOPERATIVE AND WPPI ENERGY'S RESPONSE TO CETF AND SOUL PETITION TO REOPEN THE CAPX2020 DOCKET BASED ON NEW INFORMATION

Citizens Energy Task Force and SOUL of Wisconsin have brought a request to the Public Service Commission to reopen the CPCN Decision in the above-captioned docket.

> 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).

Applicants cast aspersions on our terminology and claim we've conflated peak demand, demand, energy, capacity, but we have clearly labeled and cited each reference – we do understand and we are not confused. Applicants, however, again offer old and misleading information about non-coincident peak demand that is a clear effort at conflation, while also choosing to not address relevant new information that would eliminate or defer the need for the line, and call into question the value of the project for Wisconsin ratepayers.

I. APPLICANTS CONTINUE TO USE "NON-COINCIDENT" PEAK, RATHER THAN COINCIDENT PEAK, WHICH GIVES A MISLEADINGLY HIGH PEAK DEMAND.

In the initial case, Applicants inappropriately relied on non-coincident peak, not coincident peak. Applicants continue to use this inappropriate method, which overstates need, in its response in its chart of "Actual Peak Demand":

Year	2002	2006	2008	2010	2011	2012	2013
La Crosse/Winona Area Actual Peak Demand (MW)	425.1	464.6	435.4	451.4	465.0	481.0	490.4

This "red flag" of statistical misrepresentation is not new, as was aptly noted by CUB's witness Hahn.

> Non-coincident peak loads are the maximum load at each individual substation regardless of the hour in which that maximum occurred. .. Coincident peak load, by contrast, is the maximum aggregate load across all substations with the study area at any given hour. By definition, the coincident peak load can be no higher, and is often significantly lower, than the non-coincident peak load.

CUB Initial Brief, p. 5. Hahn calculated the difference in Applicants' claims and Coincident peak:

Figure 6
Load Adjustment for Coincident Peak

Substation Owner	Claimed Peak Load[6] (MW)	Coincident peak (MW)	Difference (%)
2010			
DPC	50.0	50.0	0.0
NSPW	401.5	369.5	-8.0%
La Crosse Total	**451.4**	**419.5**	**-7.1%**
2011			
DPC	53.9	53.9	0.0
NSPW	411.1	388.5	-5.5%
La Crosse Total	**465.0**	**442.4**	**-4.9%**

Correcting for the overstatement of "non-coincident" peak used by Applicant's in their response reduces 2010 peak by ~32 MW (7.1%) and reduces 2011 peak by ~23 MW (-4.9%). Using the average adjustment of -6 % would bring the 2012 and 2013 figures down by ~29 MW each year. This is not an insignificant misstatement or correction.

Doing calculations based on both the 7.1% and 4.9% decrease for the difference Hahn demonstrated (see Hahn chart above), the Applicants chart, but showing coincident peak demand at 7.1% and 4.9% of non-coincident peak demand, looks like this:

Year	2002	2006	2008 (2009?)	2010	2011	2012	2013
La Crosse/Winona Area Actual Peak Demand (MW)	425.1 N-C 394.9 7.1% 404.3 4.9%	464.6 N-C 431.6 7.1% 441.8 4.9%	435.4 N-C 404.5 7.1% 414.1 4.9%	451.4 N-C **419.4** 7.1% 429.3 4.9%	465.0 N-C 432.0 7.1% **442.4** 4.9%	481.0 N-C 448.8 7.1% 457.4 4.9%	490.4 N-C 455.6 7.1% 466.4 4.9&

The EIS calculations, based on a range of scenarios, showed a similarly lower expectation:

Table 2.5-2 Comparison of peak load projections (in MW)

Year	Applicants' Revised Forecast	Forecast based on MISO Growth Rate of 0.78%	Forecast based on MISO Growth Rate of 1.28%
2015	492.43	469.29	481.05
2020	529.92	487.88	512.63
2025	561.7	507.21	546.29
2030	595	527.30	582.16

CapX EIS, p. 20, ERF 158958.

Noting the disparity in the methodologies used by Applicants and suggested by expert testimony, CUB sought clarification through information requests:

I have reviewed the values for expected peak load in 2015 and 2020 that were provided as Ex. Applicants-King-6, and I have reviewed the general description of the Applicants' methods in direct testimony and the August 2011 Supplemental Need Study ("SNS") (PSC REF #:152526). I have not seen sufficient quantification that shows their methodology. In response to discovery requesting quantification of assumptions about Demand Side Management ("DSM"), temperature, population and economic growth in the load forecast, the Applicants stated that they did not have specific quantification for such assumptions. The Applicants also produced no documents in response to discovery requesting work papers and studies used to generate the load forecast in the Application as well as all subsequently revised load forecasts.

Hahn, Direct at 12, l. 1-10. From Mr. Hahn's description, and with failure of Applicants to provide any substantive methodology or quantification of assumptions, why would these "values for expected peak load in 2015 and 2020" be regarded as anything but fiction and wishful thinking on the part of the Applicants?

One would think that use of non-coincident peak figures would instantly draw attention and scrutiny. Instead, **non-coincident** peak demand figures are again provided by Applicants to justify need in the Badger Coulee application, Appendix D:

Figure 3: Historical La Crosse/Winona Area Non-Coincident Substation Loads

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual Loads					
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2011	Load MW 2012
Bangor	4.08	4.17	3.46	3.30	3.10	4.43
Brice	5.12	6.93	6.36	3.50	3.52	3.52
Caledonia City	3.42	3.90	3.51	3.65	3.38	4.37
Cedar Creek	3.54	5.17	4.93	5.00	4.73	5.90
Centerville	2.79	3.34	4.20	3.05	4.73	5.57
Coon Valley	4.29	5.22	3.96	3.99	4.00	5.00
Coulee	53.50	60.30	52.91	54.60	56.00	55.80
East Winona	8.92	9.47	11.09	7.00	7.64	7.38
French Island	19.50	29.04	24.06	29.00	29.00	28.80
Galesville	6.91	6.89	5.50	5.79	6.00	6.92
Goodview	31.78	35.33	33.61	31.67	37.30	39.80
Grand Dad Bluff	1.67	1.91	1.63	1.68	1.75	1.97
Greenfield	2.85	3.43	3.06	2.93	3.62	3.76
Holland	-	-	-	4.74	4.78	5.33
Holmen	14.97	13.16	14.91	13.30	14.10	11.51
Houston	3.61	3.78	3.38	3.75	3.89	4.27
Krause	4.12	4.48	4.54	5.02	5.25	5.49
La Crosse	58.43	50.33	46.98	47.63	49.00	50.65
Mayfair	43.90	46.58	45.39	56.45	49.00	45.10
Mound Prairie	2.18	2.02	2.39	2.24	2.38	2.76
Mount La Crosse	1.64	2.00	2.09	2.15	2.29	2.44
New Amsterdam	3.88	4.66	4.46	3.47	3.84	4.84
Onalaska	11.73	12.93	10.48	13.77	13.50	14.32
Pine Creek	2.03	2.36	1.84	1.93	2.06	2.33
Rockland	4.18	4.14	3.10	3.66	3.70	3.11
Sand Lake Coulee	2.99	2.84	2.59	3.01	3.84	3.13
Sparta	29.65	32.47	31.74	30.90	33.00	34.80
Sparta (Dairyland)	1.15	1.36	1.16	1.14	1.15	1.38
Swift Creek	17.10	24.80	21.83	23.75	24.00	22.10
Trempealeau	4.43	3.94	3.68	2.68	3.20	3.55
West Salem	23.30	24.52	23.97	22.80	24.00	28.13
Wild Turkey	1.17	1.20	1.35	2.69	2.71	3.54
Winona	46.30	51.91	51.19	51.17	54.54	59.00
Total Load MW:	425.13	464.58	435.35	451.41	465.00	481.00

Applicants further continue to use **non-coincident** peak demand in response to PSC questions regarding completeness:

REQUEST NO. 01.131:

(Application Appendix D, pp. 87, 101 of 263, AFR Section 2.3.) Appendix D states that the proposed project will provide added reliability to the La Crosse area because there will be a second 345 kV line into the Briggs Road Substation. Explain if this added reliability is necessary to address a potential NERC violation.

RESPONSE TO REQUEST NO. 01.131:

Yes. When the local load in the La Crosse/Winona area reaches 750 MW, an additional line and a second Briggs Road 345 kV/161 kV transformer will be necessary to address NERC Category C contingencies, specifically, TPL-003, loss of a generator in the area and the CapX2020 345 kV line into Briggs Road Substation. This peak demand level is expected to be reached in the area between 2025 and 2040 depending on how load develops in the area. Applicants note that peak demand in the La Crosse/Winona area has increased each year since 2009:

La Crosse/Winona Area Non-Coincident Peak Loads
2009-2013

Year	Load (MW)	Percentage Increase
2009	435.35	----
2010	451.41	3.68
2011	465	3.00
2012	481	3.44
2013	490.4	1.95

Badger Coulee Applicant Response to 01.131, January 24, 2014.

The PSC should address this inflationary method of calculating and presenting peak demand by requiring Applicant utilities to use the more accurate coincident peak levels. As above, CUB's witness Hahn calculated the difference between the non-coincident peak favored by Applicants with coincident peak, which favors reality, and found differences that reduced peak demand ranging from 4.9 – 7.1%. Using non-coincident peak to justify a second 345 kV line into Briggs Road and estimating when local load might reach 750 MW is beyond a stretch, and without a doubt beyond the transmission planning time frame and this writer's lifetime.

Correcting Applicant calculation of peak demands, as above, to reflect coincident peak presents a very different perspective on the "necessity" for a 345 kV line. When other aspects of new information are further applied to this correction, it is evident that the need for CapX2020 is eliminated or deferred, and the benefits and value are substantially overstated.

II. FRENCH ISLAND Unit #3 WAS REGARDED AS UNCERTAIN, AND THE UNCERTAINTY MADE IT A DETERMINATIVE FACTOR FOR THE COMMISSION – BUT REOPENING OF FRENCH ISLAND #3 IS NOW PRESUMED IN XCEL'S RESOURCE PLANNING REMOVING UNCERTAINTY AND MAKING THIS A VIABLE ATERNATE SOLUION.

As noted in the original Request to Reopen filing, French Island Unit #3 will be available to serve La Crosse load, and this resource must be taken into account by the Commission.

> 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, yet staff found it provided increased capability:

> **2.6.1. N-1 contingency**
>
> The applicants identified an N-1 critical contingency that limited load serving capability to 460 MW with the operation of all generating units at Alma and Genoa. With additions of two 60 megavolt amperes reactive (MVAR) capacitor banks to the La Crosse area 161 kV system, the load serving capability increased by 10 MW to 470 MW. With operation of the 70 MW peaking French Island Peaking Unit 4 generation, the load serving capability could be increased to about 540 MW.
>
> Commission staff estimates that reactivating the French Island Unit 3 generator could further increase the load serving capability to 610 MW.

2.6.2. N-2 contingency

> The applicants identified an N-2 critical contingency that limited load serving capability up to 430 MW. The applicants consider that additional electrical infrastructure is needed to provide load serving capability for customer loads greater than 430 MW.
>
> Commission staff considers that operation of French Island Unit 4 could increase the load serving capability to 500 MW53 and that reactivating French Island Unit 3 could increase it to 570 MW.

EIS Chapter 2, p. 21, ERF 158958.

The use of French Island 3 and 4 individually or in combination is relevant and substantive. The ability to apply these less costly and denigrating solutions should be considered in the context of coincident peak and demonstrated Applicant ability and potential to shave peak demand.

III. LOAD MANAGEMENT IS AN UNRECOGNIZED RESOURCE DESERVING OF CONSIDERATION

In Commission staff Stemrich's testimony before the commission, as Xcel points out, Stemrich's analysis indicated that an approximately eight percent reduction in peak load is needed immediately, in addition to the approximate 0.5 percent annual reduction already reflected in the demand forecasts, to alleviate the need for the Project. In the end, Stemrich concluded, and the Commission rightly agreed, that "it is unlikely that this level of load reduction can be achieved through energy efficiency and conservation."

However, key omissions and new information show this conclusion to be inadequate and incorrect First, the required load reduction was based upon the inflated peak demand using non-coincident peak. The impact of this has already been demonstrated above. Next,

Commission testimony admits that the impact of increased load management was not considered in Ms. Stemrich's analysis.

> Direct, p. 1, l. 11 et seq
>
> You state, "The purpose of my testimony is to address the feasibility of alleviating the need for this project through energy efficiency." Please explain why you mention "energy efficiency" but not "load management."
>
> Response:
>
> Load management was not included in Ms. Stemrich's analysis for several reasons. First, the Energy Priorities Law, referenced in DR 01-05, does not include load management in the list of priorities for meeting energy needs. Second, Wisconsin utilities have a long history of providing load management programs, the impacts of which are already reflected in their forecasts.

Stemrich Testimony, Exhibit 1, PSC ERF 160502.

Cooperatives, such as Applicant Dairyland, are allowed to count load management towards their "self-directed" energy efficiency requirements. As a co-applicant, Dairyland's ability to use load management as an energy efficiency tool makes the measure relevant in consideration as higher energy priority and the impact of its ability to offset the need for CapX2020 must be considered. If it applies to one applicant, it applies to the project.

Furthermore, arguing that increased load management was not considered since it not identified in the Energy Priorities Law does not negate the need to consider the impact of increasing use of it. As a technologically proven and viable non-transmission alternative, it should have been considered, as should the new information presented on increased Applicant ability and potential to shave peak demand.

That utilities do not utilize demand reduction until it reaches the point of load shedding and that it is not considered amongst the State's energy efficiency and conservation measures

are policy issues that should be corrected. Policy corrections aside, the impact of increased load management activities remains relevant and viable to the case at hand, especially when considered in tandem with other higher energy priorities and with the peak load calculations and relief previously discussed.

IV. THE MAJOR TRANSMISSION LINE SERVICE LA CROSSE HAS BEEN UPGRADED, WITH 40% INCREASE IN CAPACITY. MODELING MUST BE CORRECTED TO REFLECT THIS INCREASED CAPACITY RESOURCE.

The Commission failed to consider Dairyland's 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[1]. An increase of capacity of this magnitude alters the need of the area. Modeling assumptions must be corrected to reflect this and power-flow modeling re-performed to properly consider the impact and capability of the line's increased reliability and capacity.

V. DECREASE IN PEAK DEMAND ALONE SHOULD CAPTURE THE COMMISSION'S ATTENTION

More than any other issue, the conflicts between the Applicants' statements in the public arena and in the CapX 2020 docket should grab the Commission's attention and trigger reopening of this docket.

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

Applicants admit overall demand is down, far below that level chosen by the Commission to support "need" for this transmission project. Despite this, Applicants criticize the data used as new information. Applicants also recognize that the sales figures presented for Wisconsin, Minnesota and the US are utility neutral, such that they indeed convey reduced demand.

% 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[2].

Furthermore, these levels of demand decline call into question the need, benefits and value of the regional transfer capacity benefits for which the line was largely approved.

The new information presented in the Request to Reopen 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. Petitioners again request the Commission to exercise its discretion to reopen this docket to consider the impact of the new information on the "need", value and benefits for CapX 2020 Hampton-La Crosse transmission.

Respectfully submitted on this 30th day of January, 2014,

[2] 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

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