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Xcel Energy

Docket No.: E002, ET2/CN-06-1115

Response To: Hwikwon Ham Information Request No. 47
MN Department of Commerce

Date Received: March 3, 2008

Question:

- A. Please provide the Figure 4-3, 4-8, 4-13, 4-16, and 4-19 in Chapter 4 in a Microsoft Excel spreadsheet.
- B. Please provide Appendix C-1 to C-5 of the petition in a Microsoft Excel spreadsheet.
- C. Please provide detailed information supporting substation level forecasting in Appendix C-1 to C-5.
- D. If any area mentioned in Chapter 4 Section 1 is currently (or will be) violating NERC N-1 contingency, please confirm the conclusion with MRO and provide MRO's letter/ or email confirming applicants' conclusion.

If any (or all) of the above information has already been provided in this docket or in response to an earlier OES information request, please identify the specific cite or OES information request number.

Please provide any and all the definition of the acronyms and abbreviations used.

Response:

- A. See attached CD, bates number CapX2020 0000011.
- B. See attached CD, bates number CapX2020 0000011.
- C. The substation level forecasting that is depicted in Appendix C-1 to C-5 of the Application was compiled by the planning engineers for the various utilities serving these specific geographic areas.

Appendix C-1 (Rochester Area)

Appendix C-1 provides substation forecasting for the Rochester area. Appendix C-1 was compiled by using substation forecasts provided by Rochester Public Utilities (“RPU”) and Dairyland Power Cooperative (“Dairyland”) and its distribution cooperative for this area, Peoples Cooperative Services. Attached is an updated version of Appendix C-1. (CD CapX2020 0000011.) The updated version is being provided to correct several errors in the tables regarding RPU’s substation loads. The updated data is highlighted in blue. None of these updates affect the need for the facilities in the Rochester area.

Rochester Public Utilities

RPU used load forecasting data provided by the Southern Minnesota Municipal Power Agency (“SMMPA”) that forecast RPU’s total system peak load demand for the years 2007-2020 when constructing the substation forecasts for Appendix C-1. RPU relies on SMMPA’s load forecasting because SMMPA supplies the first 216 MW of generation for RPU’s load and RPU generates power to meet any demand above the 216 MW level. The SMMPA forecasting methodology is entitled “Load Forecast Methodology Booklet,” which is attached (as CapX2020 0000012-0000061) and also is available in SMMPA’s 2006 Integrated Resource Plan supplied to the Department of Commerce at Attachment V-1. The SMMPA forecast was assigned only to RPU’s load serving buses in Appendix C-1, which are:

1. Bamber Valley
2. Cascade Creek
3. IBM
4. Crosstown
5. Northern Hills
6. Silver Lake
7. Willow Creek
8. Zumbro

Metering data was examined from the previous year (2006 for the data provided in Appendix C-1) and a calculation was performed to determine the percentage of the system peak demand load being served by each individual RPU load serving bus. This demand percentage was used as the basis for assigning a load forecast for 2007-2020 at each bus, using the SMMPA total system peak load forecast for the RPU system.

As a result, RPU allocated the total load among the substations based on SMMPA data which identifies the peak load for each bus. The percentage of the total load forecast assigned to each substation is as follows:

1. Bamber Valley: 10 percent
2. Cascade Creek: 19 percent
3. IBM: 6 percent
4. Crosstown: 10 percent
5. Northern Hills: 8 percent
6. Silver Lake: 19 percent
7. Willow Creek: 13 percent
8. Zumbro: 15 percent

As the forecast years extended beyond 2009, the demand percentage at each bus was adjusted to account for the historical growth pattern for RPU where the RPU system has been growing faster, such as, on the western, northwestern, and southwestern portion of the RPU system, due to higher housing, commercial, and light industrial load developments in these regions, as compared to downtown, northeastern, eastern, and southeastern portions of the RPU load. Therefore, the demand percentage was scaled up for RPU's Bamber Valley, Cascade Creek, and Northern Hills substations over the 2009-2020 forecast. Conversely, the demand percentages at RPU's IBM, Crosstown, Silver Lake, Willow Creek, and Zumbro substations was scaled down or held constant to accommodate this historical growth pattern for the 2009-2020 timeframe.

SMMPA's growth rate was applied across RPU's system as a whole and allocated based on percentage of the total load forecast assigned to each substation. The rates were not compounded.¹

Dairyland Power Cooperative

Dairyland forecasts its load by distributive cooperative rather than by substation. To calculate the substation load forecasts contained in the Application, the actual summer peak loads were used for 2002-2006. For 2007, the average of the 2002 to 2006 peak load was calculated and the particular distributive cooperative growth rate was applied to each substation. For 2008 to 2020, the particular distribution cooperative growth rate was compounded. Dairyland's distributive cooperative for the Rochester area is

¹ Note that the Application references a 3.46 percent growth rate. This is RPU's historical growth rate from 1979. This rate was used in the Rochester/La Crosse Study to compare options. It was not used for the substation forecast.

Peoples Cooperative Services (“Peoples”). Peoples’ growth rate of 1.6% was assigned to its load serving buses in Appendix C-1, which are:

1. Airport
2. Canisteo
3. Chester
4. Genoa
5. Kalmar
6. Marion
7. Marvale
8. Oronoco
9. Pleasant Grove
10. Pleasant Valley
11. Ringe
12. Rock Dell

Dairyland’s forecasting process occurs biannually with an annual review to assess any observations related to the comparison between actual and forecasted load. This process is consistent with the Rural Utilities Service (“RUS”) requirements for Load Forecast Studies (“LFS”).

The residential consumer forecast is the dominant growth factor for Dairyland and its member cooperatives. Residential consumer projections rely mostly on county-level projections of population and households. Econometric modeling using composites of end-use variables as independent variables is used to forecast residential energy use per customer for both Dairyland and individual member cooperative load forecasts. The variables considered for econometric modeling include, for instance, household income, weather, and appliance efficiency.

Small commercial and industrial customers’ consumer forecasts were developed using demographic and economic data at the individual cooperative level. As data for small commercial and industrial customers can often be erratic and contaminated by reclassification, where econometric models could not be fit to historic data for individual cooperatives, judgmental forecasts were used.

Large commercial and industrial forecasts were developed using econometric models and judgmental forecasts. For individual cooperative forecasts, large load customers were interviewed to determine their specific future needs. Member cooperatives were also asked to assess the prospects for the addition of new named and unnamed large loads to their system and the significant expansion of existing loads.

For the remaining class of customers, including seasonal, irrigation, and street and highway lighting, econometric modeling combined with the historic methods of trending and judgmental forecasts were continued with verification of the results by the individual systems.

Appendix C-2 (La Crosse/Winona)

Appendix C-2 provides substation forecasting for the La Crosse/Winona area. Appendix C-2 was compiled by using substation forecasts provided by Xcel Energy and Dairyland's distribution cooperatives that serve the La Crosse/ Winona Area.

Xcel Energy

Each year, Xcel Energy distribution planning engineers update the load forecasts for each substation from which Xcel Energy serves load. This process is completed separately from transmission planning. The values are then reported to transmission planning engineers who incorporate these load forecasts into models developed via regional model-building processes.

Xcel Energy's service territory is divided into areas for which various distribution planning engineers are responsible. Each year, the distribution planning engineer assigned to a particular area examines the annual peak loads going back five years. The average load growth is then calculated. This load growth rate is one piece of information used in forecasting future loads.

After determining the load growth rate, the distribution planning engineers meet with area distribution engineers responsible for various areas. Area distribution engineers are responsible for an even smaller territory and deal much more closely with individual customers and cities. These engineers have a good understanding for the trends, growth potential, and development opportunities in their communities. These engineers provide the distribution planning engineers with general information about trends in each community. For instance, area distribution engineers will be more aware of the potential for large shifts in growth, such as new residential developments or industrial parks. This information is then combined with the previously calculated growth rate to determine the final growth rate that will be applied.

Finally, the distribution planning engineers and area engineers discuss any large customer loads that may come online during the planning period. When a potential future load is identified as needing to be included in future load forecasts, its total load is added separately from the load growth. As a result, the growth rate for each individual substation is based on the particular local realities affecting the load growth at each substation.

Dairyland Power Cooperative

Dairyland's substation level forecasting is described above. The particular growth rates applied to the Dairyland's distributive cooperatives that serve the La Crosse area are described in the following. Oakdale Electric Cooperative's growth rate is 2.8 percent and was applied to its Sparta substation. Riverland Energy Cooperative's growth rate is 1.7 percent and was applied to its substations: Brice, Centerville, Krause, New Amsterdam, and Sand Lake Coulee. Tri-County Electric Cooperative's growth rate is 1.8 percent and was applied to its substations: Caledonia City, Houston, Mound Prairie, Pine Creek, and Wild Turkey. Note that Tri-Electric Cooperative was inadvertently omitted from the Application at 4-14. Vernon Electric Cooperative's growth rate is 3.4 percent and was applied to its substations: Grand Dad Bluff, Greenfield, and Mount La Crosse.

Appendix C-3 (Southern Red River Valley)

Appendix C-3 provides substation forecasting for the southern Red River Valley area. Appendix C-3 was compiled by using substation forecasts provided by Xcel Energy, Great River Energy, Basin Electric Power Cooperative,² Minnkota Power Cooperative, Minnesota Power, Missouri River Energy Services ("MRES"), Otter Tail Power Company, and Western Area Power Administration ("WAPA"). Xcel Energy's methodology for calculating substation forecasting is discussed above.

Great River Energy

Great River Energy used loadflow bus loads derived from 110 metering points to determine the forecast for each load bus. This load is served by Great River Energy's distribution cooperatives including substations from Agrilite Electric Cooperative, Connexus Energy, Crow Wing Power, East Central Energy, Meeker Cooperative, Stearns Electric Association, and Runestone Electric Association.

Seasonal maximum values (non-coincident) for each of the metering points were compiled for the period from May 2002 to February 2007. In addition to this data, hourly data for both kilowatt ("kW") and kilovolt-amperes reactive ("kVar") values for the entire period were also gathered for each of the metering points to evaluate various load data metrics for purposes of developing the delivery point load projections.

² Basin Electric Cooperative's winter load was 4 MW and details regarding its forecasting are not provided here.

To develop a relationship of the area non-coincident peak totals, a seasonal coincident peak value was calculated for the Summer 2002 through Winter 2006 period. The ratio of the seasonal coincident peak total to the non-coincident peak was evaluated to determine if there was a consistent relationship. The historic winter ratio was in the range of 93 percent and summer ratios dropped from over 90 percent to 87 percent in 2006. The summer ratio of 87 percent and the winter ratio of 92.5 percent were used to develop the non-coincident delivery point projection.

To reflect a consistent snapshot of the system loading with the most recent data available, data from the most recent season was used as the base values to project future loads. Specifically, individual non-coincident peaks from the summer 2006 and winter 2006 seasons were used as a base for the seasonal delivery point load forecasts.

Member cooperative load forecasts were available for each of the Great River Energy cooperatives that serve load in this area. These forecasts are deemed the most relevant information in terms of developing a forecast for model delivery points. These forecasts were developed as coincident system forecast for the Great River Energy system.

Seasonal demand growth rates from the 2004 member Long Range Load Forecasts were used as a basis for forecasting loads for each delivery point. Growth rates varied for each distributive cooperative.

A seasonal demand growth rate was derived using cooperative load forecasts and historic data from the most recent season. Specifically, historic data from each cooperative was used to determine the contribution to the total peak area, and the weighted value of each cooperative was used to create an area forecast rate.

Area seasonal demand growth rates were applied to each metering point to project the future coincident seasonal demand values. These growth rates were not compounded. The area coincident season peak values were converted to non-coincident seasonal peak using the historic non-coincident/coincident ratio. The non-coincident seasonal peak was allocated to each delivery point based on the historic contribution to the non-coincident peak. Reactive loading was determined using historic power factor for each delivery point.

Minnkota Power Cooperative

Information regarding substation level forecasting by Minnkota Power Cooperative is being collected and will be provided in a supplemental response.

Minnesota Power

To develop a 2007-2020 forecast, Minnesota Power grew the 2006 substation loads by the expected growth rate in system peak demand for winter and summer based on the Minnesota Power 2006 Annual Electric Utility Forecast Report (“AFR 2006”) submitted to the Department of Commerce. As a result, the projected growth rates were not based on a specific area load forecast.

Missouri River Energy Services

Information regarding substation level forecasting by MRES is being collected and will be provided in a supplemental response.

Otter Tail Power Company

Information regarding substation level forecasting by Otter Tail Power Company is being collected and will be provided in a supplemental response.

Western Area Power Administration

WAPA’s load is capped at a contractual level, as a result, all of its load growth is handled by other entities, *i.e.*, either Basin Electric Power Cooperative or MRES depending on the location.

Appendix C-4 (Alexandria Area)

Appendix C-4 provides substation forecasting for the Alexandria area. Appendix C-4 was compiled by using substation forecasts provided by Xcel Energy, Great River Energy, MRES, and Otter Tail Power Company. Xcel Energy and Great River Energy’s methodology for calculating substation forecasting is discussed above. Information regarding substation level forecasting by MRES and Otter Tail Power Company is being collected and will be provided in a supplemental response

Appendix C-5 (St. Cloud Area)

Appendix C-5 provides substation forecasting for the St. Cloud area. Appendix C-5 was compiled by using substation forecasts provided by Xcel Energy and Great River Energy. Xcel Energy’s and Great River Energy’s methodology for calculating substation forecasting are discussed above.

D. None of the areas is currently experiencing a Category B (N-1) NERC planning criteria violation.

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