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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC and Dairyland Power Cooperative - Wisconsin, as Electric Public Utilities, for Certificate of Public Convenience and Necessity and WDNR Utility Permit Cardinal-Hickory Creek 345 kV Transmission Line Project	Docket No: 05-CE 146

DIRECT TESTIMONY OF WILLIAM E. POWERS, P.E.
ON BEHALF OF S.O.U.L. OF WISCONSIN, INC.
APRIL 26, 2019

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I. Introduction

Q. Mr. Powers, please state your name, position and business address.

A. William E. Powers, P.E., principal of Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of S.O.U.L. of Wisconsin, Inc ("SOUL")[1].

Q. Mr. Powers, please summarize your educational background and recent work experience.

A. I am a consulting energy and environmental engineer with over 35 years of experience in the fields of power plant operations and environmental engineering. I have permitted numerous peaking gas turbine, microturbine, and engine cogeneration plants, and am involved in siting of distributed solar PV projects. I began my career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. I wrote "San Diego Smart Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012). Both of these strategic energy plans prioritize energy efficiency, local solar power, and combined heat and power systems as a more cost-effective and efficient pathway to large reductions in greenhouse gas emissions from power generation compared to conventional utility procurement strategies. I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from the UNC – Chapel Hill, and am a registered professional engineer in California and Missouri. My complete resume is provided as Exhibit 2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the Applicant's proposed Cardinal-Hickory Creek (CHC) 345 kV transmission line.

II. Summary and Conclusions

Q. What documents have you reviewed as part of your investigation?

A. The principal documents I have reviewed include: the Applicants Application for a Certificate of Public Convenience and Necessity and WDNR Utility Permit for the 345 kV Cardinal-Hickory Creek Transmission Line Project, PSCW Docket No. 5-CE-146 September 2018 (PSC REF#:352698); Revised Appendix D, Exhibit 1 Planning Analysis Document, (PSC REF#:363769); Revised Appendix D, Exhibit Planning Analysis Document Appendices. (PSC REF#:363773); Public Service Commission of Wisconsin Final Strategic Energy Assessment, 2018-2024, Docket 5−ES−109 (PSC REF#348358); MTEP17 Appendix E2, MTEP17 Futures Assumptions Document; Focus on Energy

[1] Ex.-SOUL-Powers-1.

2016 Evaluation Report Volume I, (May 19, 2017); Focus on Energy 2016 Evaluation Report Volume II, (May 19, 2017); 2017 State of the Market Report for the MISO Electricity Market, (June, 2018, Potomac Economics); The 2018 State Energy Efficiency Scorecard, (October, 2018) American Council for an Energy-Efficient Economy; Public Service Commission Of Wisconsin Draft Report on the Access Study Initiative, (October, 2005), Docket 137-EI-100, (PSC REF#: 44916) and other documents on the case dockets and MISO library,

Q. Please summarize your findings and conclusions.

A. The analysis I present evaluates: 1) the justifications provided by the Applicants for CHC, specifically future load growth and the need to import wind power into Wisconsin from the west, 2) whether the Applicant accounted for all the costs to Wisconsin ratepayers to make CHC fully deliverable, and 3) whether the Applicant fully accounted for the net economic benefits in the Non-Transmission Alternative ("NTA") it evaluated. Finally, I present an optimized NTA as an alternative to the Applicants' NTA. The optimized NTA presented in this testimony:

- Greatly reduces the number of people who will be adversely affected by the environmental and visual impacts of new transmission facilities by relying on rooftop and community-scale solar arrays, battery storage, and energy efficiency measures.
- Greatly reduces environmental impacts by eliminating new large-scale energy infrastructure.
- Provides greater value for Wisconsin ratepayers than projected for CHC.
- Provides a more robust and resilient solution than a single large 345 kV transmission line.
- Provides greater reliability enhancements to the grid that Wisconsin ratepayers actually rely on.
- Demonstrates that the cost of the transmission line is unreasonable when greater benefits can be provided at lower cost with an optimized NTA.
- The optimized NTA maximizes greenhouse gas reduction relative to the proposed CHC transmission line.

III. Legal Framework

Q. Why do you believe that a focus on non-transmission alternatives is legally relevant to these proceedings?

A. Applicants have included a NTA in the application materials for CHC.[2] Also, Wisconsin law states an unequivocal preference for energy efficiency and clean alternatives to conventional power generation to meet the state's electric power needs:[3]

> (2) CONSERVATION POLICY. A state agency or local governmental unit shall investigate and consider the maximum conservation of energy resources as an important factor when making any major decision that would significantly affect energy usage.

[2] UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project, 5.3 Non-Transmission Alternative, pdf p.37.

[3] 2011−12 WISCONSIN STATUTES & ANNOTATIONS: Updated through 2013 Wisconsin Act 380, SS1.12 State energy policy.

(3) GOALS.

(a) Energy efficiency. It is the goal of the state to reduce the ratio of energy consumption to economic activity in the state.

4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost–effective and technically feasible, options be considered based on the following priorities, in the order listed:

(a) Energy conservation and efficiency.
(b) Noncombustible renewable energy resources.
(c) Combustible renewable energy resources.
(cm) Advanced nuclear energy using a reactor design or amended reactor design approved after December 31, 2010, by the U.S. Nuclear Regulatory Commission.
(d) Nonrenewable combustible energy resources, in the order listed:
1. Natural gas.
2. Oil or coal with a sulphur content of less than 1%.
3. All other carbon–based fuels.

(5) MEETING ENERGY DEMANDS. (a) In designing all new and replacement energy projects, a state agency or local governmental unit shall rely to the greatest extent feasible on energy efficiency improvements and renewable energy resources, if the energy efficiency improvements and renewable energy resources are cost–effective and technically feasible and do not have unacceptable environmental impacts.

IV. Applicants Provide No Evidence That Upper Midwest Wind Power That Would Flow Over CHC Is Substantially Lower Cost Than Other Wind or Solar Power Alternatives Available to Wisconsin Utilities

Q. Does the Applicants presume wind power generated west of Wisconsin is substantially less costly than Wisconsin wind power or Illinois wind power?

A. Yes. The Applicants state "*the Project will provide a key transmission connection between Wisconsin and Iowa allowing the transfer of low-cost wind energy between the two states...*"[4]

Q. Do Applicants provide any evidence to support this low-cost wind power contention?

A. No.

Q. Are Wisconsin utilities preferentially contracting with wind power projects located to the west of Wisconsin?

A. No. Of the 296 MW of recent wind power contracts signed by Wisconsin utilities, 230 MW of the capacity is located in Illinois and Wisconsin.[5] Only 66 MW is located west of

[4] *Application for PSCW Certificate of Public Convenience and Necessity and WDNR Utility Permit Cardinal-Hickory Creek Transmission Line Project* PSCW Docket No. 5-CE-146, September 2018, p. 36.

the state in Iowa.[6] Less than 25 percent of the wind capacity contracted for by Wisconsin utilities in the most recent data published in the PSC's 2018 Strategic Energy Assessment 2018-2024 is located west of Wisconsin.

Q. Is wind power generated west of Wisconsin presumptively less costly than Wisconsin solar power?

A. No. EIA forecasts the average levelized cost of energy (LCOE) of wind power at $36.6/MWh in 2023, while its levelized avoided cost of energy (LACE) is $33.7/MWh.[7] LACE is a measure of the market value of the power at the time it is generated.[8] EIA forecasts the average LCOE of solar power at $37.6/MWh in 2023, while its LACE is $40.3/MWh.[9,10] Based on the EIA numbers, it would make more economic sense in 2023 to generate solar power in Wisconsin and transmit it to Iowa than build transmission to move Iowa wind power to Wisconsin and other points east of the state.

Q. Did solar projects dominate the MISO interconnection queue in 2018?

A. Yes. Figure 1 shows the resource capacity and composition added to the MISO interconnection queue over the last five years. Solar capacity dominated new additions to the MISO interconnection queue in 2018.

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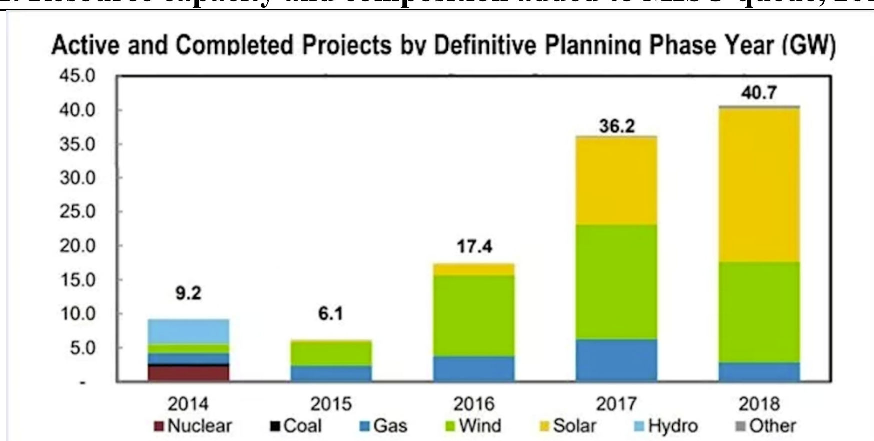
Figure 1. Resource capacity and composition added to MISO queue, 2014-2018[11]



Q. What is the capacity of solar and wind projects among the current MISO generation interconnection requests in Southwestern and South-Central Wisconsin?

A. There is 924 MW of solar capacity and 729 MW of wind capacity currently in the interconnection queue.[12]

Q. Is the solar resource stronger in Iowa than in Wisconsin?

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[5] Ex.-SOUL-Powers-3, Public Service Commission of Wisconsin, *Strategic Energy Assessment - Energy 2018-2024*, Docket 5-ES−109, July 2018, pp. 71-72. DPC, 98 MW Quilt Block Wind Farm, Platteville, Wisconsin; WPPI Energy, 132 MW Bishop Hill III Wind Energy facility, Illinois. Madison General Electric.

[6] Ibid, p. 71. Madison Gas and Electric, 66 MW Saratoga Wind Farm.

[7] Ex.-SOUL-Powers-4, EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019*, February 2019, Table 4a, p. 12.

[8] Ibid, p. 3.

[9] Ibid, Table 4a, p. 12.

[10] The National Renewable Energy Laboratory ("NREL") defines "utility-scale" as 1 MW and up. See: NREL, *2016 Renewable Energy Grid Integration Data Book*, June 2018, p. 16. ". . utility-scale generation with project capacity of 1 MW or larger . . ."

[11] Ex.-SOUL-5, RTO Insider, *MISO Proposal Aims to Speed Up Queue Process*, May 16, 2018.

A. No. Not significantly. The solar resource strength in Iowa and Wisconsin is about the same.[13]

Q. Then there is no productivity justification for preferentially locating solar in Iowa instead of Wisconsin?

A. No.

V. The Number of Wind Projects in the MISO Queue Is No Indication of the Demand for that Wind Power Capacity

Q. Applicants imply that amount of wind power with MISO interconnection requests represents the amount of wind power that will be built if sufficient transmission is available. Is this a realistic perspective on the MISO interconnection request process?

A. No. Applicants erroneously states that:[14] *A large amount of new, primarily low-cost wind generation is being developed in the upper Midwest that is contingent upon the development of the Project.* This is an inaccurate statement, as it implies these wind projects are under construction and awaiting the CHC transmission line to connect them to the regional grid. Projects in the MISO queue are under consideration for development, not being developed. Submitting an interconnection queue request is a first step for a project developer. It does not mean the project will be built, whether or not CHC is built.

Q. Does the CEO of MISO acknowledge that many projects in the MISO queue will not be constructed?

A. Yes. MISO CEO John Bear stated "*There's a lot of capacity in the queue, and a lot of it won't come online . . .*" in September 2017.[15] In the first two months of 2019, over 50 projects were withdrawn from the MISO interconnection queue.[16]

Q. What percentage of the total capacity in MISO interconnection requests have historically resulted in operational capacity?

A. About 11 percent.[17]

VI. There Is No Peak Load or Retail Electric Sales Growth Occurring in Wisconsin

Q. Do utilities in Applicants service territory forecast no growth through 2020?

A. Yes. Based on the actual summer Applicants peak load in the 2007-2017 period shown in Figure 2, the maximum coincident summer peak load, primarily occurring in July, has

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[12] Ex.-SOUL-6, USDA-Rural Utilities Service, *Draft Environmental Impact Statement, Cardinal– Hickory Creek 345–kV Transmission Line Project, Volume 1: Chapter 1-3,* November 2018, Table 1.4.1.2 Enable Generation in Southwestern and South-Central Wisconsin, pp. 14-15.

[13] Ex.-SOUL-7, NREL, *A Consumer's Guide - Get Your Power from the Sun*, 2003, p. 9.

[14] Application, p. 56.

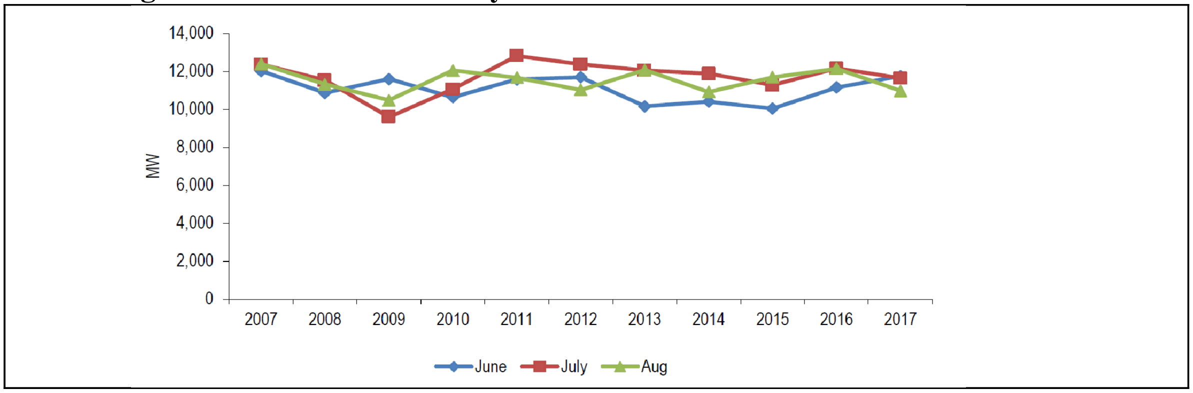
[15] Ex.-SOUL-Powers-8, RTO Insider, *MISO Works to Address Unprecedented Queue Volume*, October 1, 2017.

[16] Ex.-SOUL-Powers-9, MISO, Generator Interconnection Queue webpage, New and Withdrawn GI Projects - 2019, accessed April 22, 2019.

[17] Ex.-SOUL-Powers-10, MISO, *Interconnection Queue Reforms – Fact Sheet*, November 11, 2013, p. 2. Since the beginning of the queue process in 1995, MISO and its Transmission Owners have received approximately 1300 interconnection requests, 256,000 MW. Among them, 28,236 MW obtained commercial operation (11.0%).

been in modest decline over the last decade (see red line).[18] The winter peak is about 80 to 90 percent of the summer peak for Wisconsin utilities,[19] or 2,000 to 4,000 MW.[20]

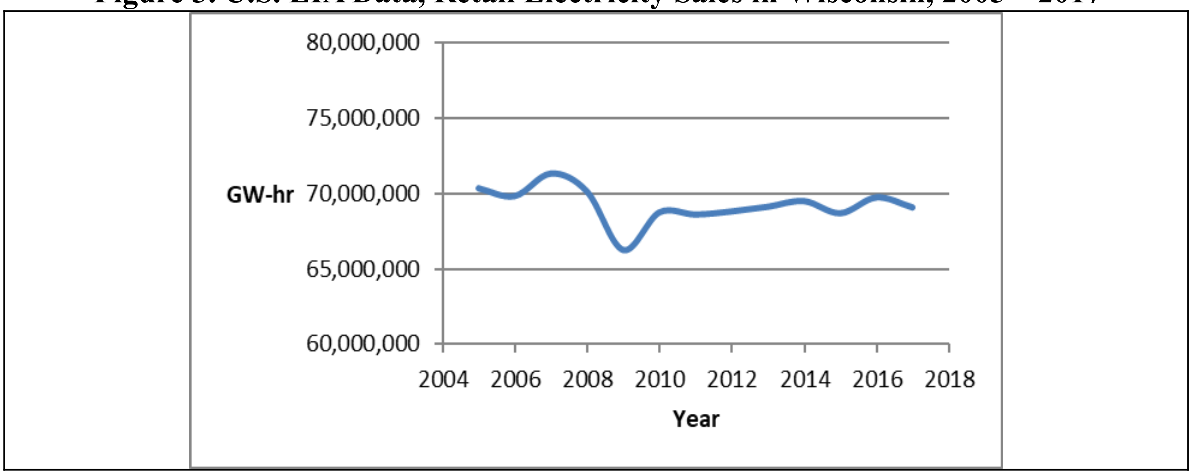
Figure 2. 2007-2017 Monthly Summer Coincident Peak Demand – ATC



Q. What is the historic trend in retail electricity sales in Wisconsin?

A. The actual historic trend in electricity sales in Wisconsin is no growth. The Wisconsin retail sales data reported by the U.S. Energy Information Administration from 2005 through 2017 is shown in Figure 3.[21] Retail electricity sales in 2017 were significantly less than retail sales in 2007.

Figure 3. U.S. EIA Data, Retail Electricity Sales in Wisconsin, 2005 – 2017



The logical business-as-usual default forecast used in the Futures scenarios would be no growth based on this actual trend.

Q. Can you point to examples of where Applicants and Wisconsin utilities have asserted that the actual historical load growth trend is the appropriate metric to use to forecast future load growth?

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[18] Ex.-SOUL-Powers-3, Figure 5, p.18.

[19] Ibid, p. 18.

[20] Ibid, Figure 7, p. 20.

[21] Ex.-SOUL-Powers-11, EIA, *Wisconsin Electricity Profile 2017*, January 9, 2019, Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2017.

A. Yes. Applicants witness Mark Williamson testified in support of Applicants' Rockdale to West Middleton 345 kV transmission line application in 2009 that "*prudent planning suggests that the past is a good predictor of the future, as long as known and foreseeable changes are taken into account.*"[22]

Q. Are the load growth projections in the Applicants Futures Scenarios consistent with the "no peak load growth" forecasts for Wisconsin load by Wisconsin utilities?

A. No. The three primary Futures Scenarios analyzed in MTEP 17 modeling assume varying degrees of peak demand growth and retail sales growth over the study period.[23] Three primary Futures Scenarios are examined: Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT). The lowest peak demand growth examined is 0.4 percent per year through 2027 in the Existing Fleet Scenario. The PR Scenario assumes a peak load growth of 0.5 percent per year. The AAT Scenario assumes a peak demand growth rate of 0.6 percent per year.[24]

Q. Are the NERC violations described in the Application due to projected shoulder peak wind power flows?

A. Yes. The NERC violations on the existing transmission system, that would partially be addressed by CHC or completely addressed by the "Low Voltage - LV" alternative to CHC,[25] are caused by this projected west-to-east shoulder peak wind power flows assumed by the Applicants in 2027. Any level of load growth in the Applicants Futures Scenarios contradicts the forecasts of Wisconsin utilities of no peak load growth, relative to earlier actual peaks in 2007 or 2012, through 2024.[26]

Q. What is the driver for the forecast loads leading to modeled 2027 NERC violations on the LV segments?

A. Wind power transfers from west to east. The entirety of the potential LV NERC violations identified in 2027 in the MTEP17 modeling is exclusively the result of shoulder peak overloads caused by wind power transiting through Wisconsin to serve loads in the

[22] Ex.-SOUL-Powers-12, Application of American Transmission Company, as an Electric Public Utility, to Construct a New 345 kV Line from the Rockdale Substation to the West Middleton Substation, Dane County, Wisconsin, Docket No. 137-CE-147, *Rebuttal Testimony of Mark Williamson on Behalf of American Transmission Company LLC and Applicants Management Inc*., March 13, 2009, p. 13.

[23] Application, p. 34. Two sensitivities based on the PR Scenario are also included: 1) PR with Low Energy, and 2) PR with Foxconn.

[24] Ex.-SOUL-Powers-13, *MTEP 17 Futures Assumptions Document: Futures Development, Model building, Resource Forecasting and Siting,* p. 35.

[25] *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* 6.2.2 Energy Cost Saving Benefits with Future Constraints Resolved, pdf p. 54. CHC requires the construction of a 138 kV transmission line to resolve the Eden Substation outlet constraint to be fully deliverable. This constraint does not need to be resolved for either the LV alternative or the NTA alternative.

[26] It is important to distinguish between an increase in peak load from year-to-year, which may occur, with the absolute value of that peak load and whether is higher than the historic peak load in 2007.

southeast part of the state (Milwaukee area) and Chicago.[27,28,29] There would be no modeled LV system NERC violations in 2027 if only Wisconsin load growth is considered at its actual historic growth rate over the last 15 years, which is negative compared to historic peaks.[30]

Q. Applicants imply that CHC would enable 1,300 MW of wind power transfer capacity. Is this accurate?

A. No. Applicants' statement in its Application is misleading when it states *"(CHC will) increase the transfer capability of the electric system between Iowa and southwest and southcentral Wisconsin by approximately 1,300 MW, thereby easing congestion, increasing competition and allowing the transfer of additional low-cost wind energy into the state*."[31] The implication is that 1,300 MW of wind power will be transferred from Iowa. Applicants was careful to parse the amount of wind power transfer capacity in testimony, stating that "*in combination with another MVP, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability.*"[32] Assuming an even split between CHC and the Oak Grove – Galesburg – Fargo 345 kV line, CHC wind power transfer capacity would be 550 MW, not 1,300 MW. Under this scenario, the majority of CHC's total transfer capacity of 1,300 MW would consist of dispatchable fossil power, either coal or natural gas.

Q. What increase in transfer capacity is achieved with Applicants' NTA?

A. A transfer capacity increase of 334 MW as stated in Applicant's revised Planning Analysis Document,[33] achieved with an investment of $67 million.[34]

Q. **What increase in transfer capacity is achieved with CHC, the proposed project?**

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27 Direct-Applicants-Dagenais-18. "The 345 kV line from Dubuque to Spring Green to Cardinal creates a tie between the 345 kV network in Iowa to the 345 kV network in southcentral Wisconsin. This expansion creates an additional wind outlet path across the state; bringing power from Iowa into southern Wisconsin, where it can then go east into Milwaukee or south toward Chicago providing access to less expensive wind power in two major load centers. In combination with another MVP, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability."

28 Application, p. 1. "[MISO approved package of seventeen MVP projects are] designed to create an interstate backbone system to reliably and cost-effectively deliver renewable energy, primarily from high wind resource areas in the west and Midwest, to population centers to the east"; p. 30. "[CHC would] allow low-cost wind energy that is trapped in areas to the west of Wisconsin to be released to the system by allowing more than a dozen new low-cost wind facilities to fully interconnect to the electric system and deliver their full output."

29 Application, p. 48. "Even moderate additional wind capacity to the west of Wisconsin would further stress this already constrained system. The transmission system in this geographic area is comprised mainly of 69 kV facilities with some 138 kV and 161 kV facilities intended for local load serving purposes. In addition, much of the existing infrastructure is aging and expected to be replaced in the next 30 years."

30 Ex.-SOUL-Powers-3, Public Service Commission of Wisconsin, *Strategic Energy Assessment - Energy 2018-2024*, Docket 5-ES−109, July 2018, Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW, Table 4, p.15.

31 Application, p. 1.

32 Direct-Applicants-Dagenais-18.

33 *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* Table 47: Other Benefits, pdf p. 98.

34 Ibid, pdf p. 12.

A. A transfer capacity increase of 1,231 MW achieved with an investment of $492 million (without considering the cost of the Eden Extension 138 kV transmission line).[35]

Q. The NTA produces a greater increase in transfer capacity on a unit basis than CHC?

A. Yes. The NTA increases transfer capacity 1 MW for every $200,000 invested. CHC increases transfer capacity 1 MW for every $400,000 invested.[36] The NTA is twice as economically efficient at increasing transfer capacity.

VII. Future Grid Reliability Violations Described in Applicants Application Are Driven Exclusively by Erroneous Presumption that Substantial New Wind Power Flows Will Occur from West-to-East Into Wisconsin

Q. What is the source of the future transmission congestion that Applicants proposes to rectify with CHC?

A. Wind power flowing from Iowa and other Upper Midwest states flowing into Wisconsin from west-to-east. Applicants indicates that "moderate" growth in wind power flows from the west would stress the existing transmission system.[37]

Q. Wouldn't CHC create congestion under certain conditions?

A. Yes. As Applicants states in its planning analysis, "under certain conditions, the Project allowed too much power to flow into the southcentral Wisconsin system, and under some outages, this could lead to congestion on the system east of the Eden Substation."[38]

Q. Did Applicants include the cost of resolving the congestion east of the Eden Substation caused by CHC in the proposed project?

A. No. Applicants indicate that are, "...not seeking approval to build the necessary facilities to resolve these potential constraints at this time and are not including the costs of doing so as part of the CPCN application."[39]

Q. What is the cost and infrastructure necessary to resolve the "east of Eden Substation" constraint?

A. About $110 million.[40]

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[35] Ibid, p. 12 and p. 98.

[36] NTA: $67 million ÷ 334 MW = $200,599/MW. CHC: $492 million ÷ 1,231 MW = $399,675/MW.

[37] Application, p. 48. "Even moderate additional wind capacity to the west of Wisconsin would further stress this already constrained system. The transmission system in this geographic area is comprised mainly of 69 kV facilities with some 138 kV and 161 kV facilities intended for local load serving purposes." Powers Engineering note: The term "moderate additional wind capacity" is not defined in the Application.

[38] *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* 6.2.2 Energy Cost Saving Benefits with Future Constraints Resolved, p. 54.

[39] Ibid, p. 54

[40] Ex.-SOUL-Powers-14, Applicants' Responses to Intervenor S.O.U.L. of Wisconsin's Third Set of Document and Data Requests to the Joint Applicants, April 8, 2019, Response to Request No.124, p. 71. Wisconsin – Eden and Eden – Cardinal 138 kV double-circuit transmission lines, 94 miles length, $198.8 million. Estimated length, by Powers Engineering, of East of Eden Substation 138 kV double circuit transmission line, between Montfort, WI and

Q. **If that is the case, what is the appropriate Wisconsin budget for Wisconsin-only alternatives to CHC?**

A. $177 million. This is Wisconsin's share of CHC, $67 million, and the cost to Wisconsin ratepayers to resolve the congestion east of the Eden Substation, $110 million.

VIII. Alternatives to CHC Evaluated in Application

Q. **What alternatives to CHC are included in the Application?**

A. The 1) Low Voltage (LV) alternative, the 2) Non-Transmission Alternative (NTA), and the 3) No Action alternative.

Q. **What is the total estimated cost of CHC?**

A. $492 million.[41]

Q. **How much of the $492 million would be borne by Wisconsin ratepayers?**

A. Approximately 14 percent.[42] MISO allocates the cost of MVP projects across the MISO region.[43] The Wisconsin share of CHC is estimated at $67 million.[44] As result the alternatives in Wisconsin to CHC are compared to the $67 million Wisconsin share of CHC by Applicants, not to the total $492 million cost of CHC.

Q: **Does CHC create NERC violations that must be resolved with an additional project that is not accounted for by Applicants?**

A. Yes. The presence of CHC would result in excessive power flows in southwest Wisconsin under certain grid conditions.[45] To mitigate the resultant violation would the construction of a new 138 kV line (Eden Extension) that would be fully paid for by Wisconsin ratepayers. As noted, the estimated cost of this line is $110 million.

Q. **Does the LV Alternative require the Eden Extension 138 kV project?**

A. No. The LV Alternatives does not have the potential to create the excess power flows caused by CHC.[46]

Q. **Given the Eden Extension will have to be built if CHC is built, is the "all-in" cost to Wisconsin ratepayers $67 million + $110 million = $177 million?**

A. Yes. The total capital cost to make the capacity of CHC fully deliverable is $177 million.

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the Cardinal Substation in Middleton, WI, is ~50 to 55 miles depending on route. Therefore, cost of East of Eden Substation transmission line = (52.5 miles) x ($198.8 million ÷ 94 miles) = $111.0 million.

[41] *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* 1.2 Benefits and Costs for the MISO Region. pdf p. 12.

[42] Ibid, pdf p. 12.

[43] Application, p. 34. "The revenue requirements associated with the project are subject to MVP cost allocation across the MISO region. The allocation of the MVP revenue requirement for the preferred route to Wisconsin customers is estimated to be 13.9%."

[44] UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project, Table 1: Monetized Range of Net Benefits of Alternatives to Wisconsin, pdf p.15.

[45] *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* pdf p. 54.

[46] Ibid, p. 54. "These [Eden outlet] constraints did not need to be resolved in the LVA or the NTA alternative because they only appeared with CHC."

Q. What are the components of NTA included in the Application?

A. The components of the NTA are shown in Table 1.

Table 1. Components of NTA included in Application[47]

Element	On-Peak Capacity (MW)
Energy Efficiency	2.6
Demand Response	31.5
Utility-Scale Solar	30
Distributed Solar	2
Total:	**66.1**

Q. The NTA does not include battery storage. What rationale did Applicants provide for excluding battery storage?

A. High cost. The Applicants state that "*Widespread utility-scale energy storage projects by means of electric batteries are still too expensive to be considered as a reasonable alternative to the Project.*"[48]

Q. Is the assertion by the Applicants that battery storage "*is still too expensive*" supported by any evidence?

A. No.

Q. Is there evidence that battery storage is cost-effective?

A. Yes. A precipitous decline in the cost of lithium batteries has made battery storage an economically viable non-wires alternative in recent years. Lithium battery costs declined from about $900 per kilowatt-hour (kWh) of storage in 2011, the year MTEP 2011 was published,[49] to about $180/kWh in 2018.[50] This is an 80 percent decline in lithium battery cost in only seven years. See Figure 4.

Figure 4. Decline in Lithium Battery Cost, 2010-2018[51]

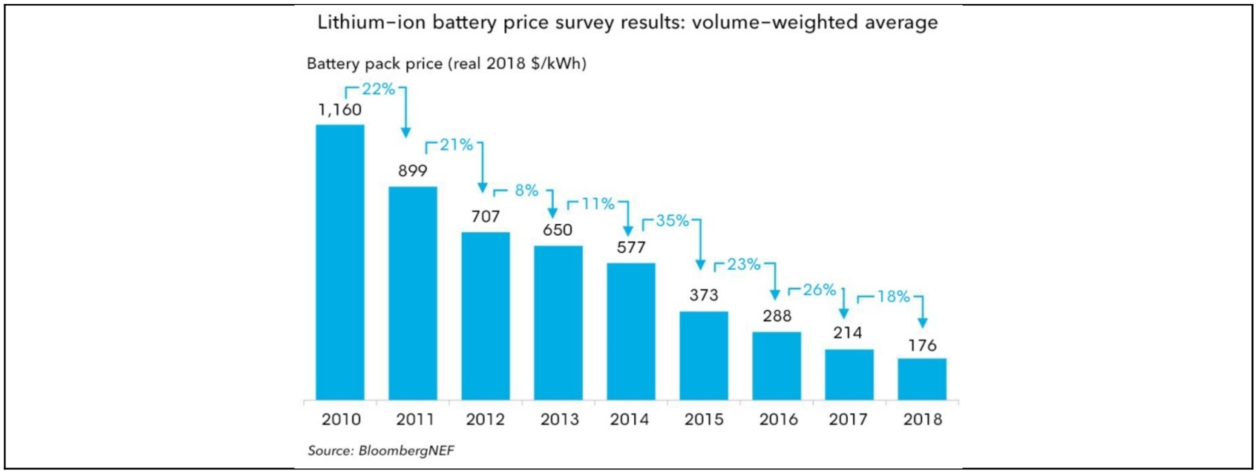
[47] Application, Table 2.1-2, p. 39.

[48] Application, p. 62.

[49] *Revised Appendix D, Exhibit Planning Analysis Document Appendices,* April 9, 2019, MISO Transmission Expansion Plan 2011, pdf p. 50.

[50] Ex.-SOUL-Powers-15, Bloomberg New Energy Finance (BNEF), *A Behind the Scenes Take on Lithium-ion Battery Prices*, March 5, 2019.

[51] Ibid.



Utility-scale battery installations at substations have become common. A battery facility with 100 MW of design output and 400 MW-hour (MWh) of usable storage is being developed by AES under contract to Southern California Edison (SCE) in Long Beach, California and will be operational in 2019.[52] Tesla completed a 100 MW battery installation in Australia in less than 100 days in late 2017.[53] The San Diego Gas & Electric 30 MW/120 MWh battery installation at a substation in Escondido, California won Utility Dive's 2017 project-of-the-year award.[54] This project went from conception to operation in about six months.[55]

Florida Power & Light (FPL) announced in late March 2019 that it will construct a 409 MW, 900 MWh battery storage facility in Florida, the Manatee Energy Storage Center, that will be online by late 2021.[56] FPL states the Manatee Energy Storage Center will be more cost-effective than running fossil fuel-powered plants during periods of high demand and (as a result) will save customers $100 million.[57] FPL is demonstrating with its action that Applicants' position that "widespread utility-scale energy storage projects by means of electric batteries are still too expensive to be considered as a reasonable alternative to the Project" is out-of-date.

The $492 million cost of CHC would purchase about 600 MW of battery capacity, with approximately 2,400 MWh of usable storage, at a 2018 installed utility-scale battery cost of $200/kWh.[58,59]

Q. Did Applicants include distributed solar with battery storage in NTA?

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[52] Ex.-SOUL-Powers-16, California Energy Commission, Storage - Tracking Progress, p. 24.

[53] Ex.-SOUL-Powers-17, Los Angeles Times, *Tesla builds world's largest battery in Australian outback*, December 1, 2017

[54] Ex.-SOUL-Powers-18, Utility Dive, *Project of the Year: SDG&E's Escondido energy storage project*, December 4, 2017.

[55] Ibid.

[56] Ex.-SOUL-Powers-19, Power Magazine, *FPL Will Build World's Largest Battery Storage System*, April 3, 2019, "FPL, a subsidiary of NextEra Energy Inc., said using energy from batteries during periods of high demand for electricity is more cost-effective than running fossil fuel-powered plants, and would also help the utility reduce emissions, with estimated savings to ratepayers of $100 million."

[57] Ibid.

[58] $200/kWh × 1,000 kWh/MWh × 2,400 MWh = $480,000,000.

[59] *UPDATED Planning Analysis for Cardinal – Hickory Creek Transmission Line Project,* pdf p. 12, p. 98.

A. No. Applicants includes a small amount of customer-owned solar, 2 MW, without battery storage.

Q. What is the reason Applicants gives for the small amount of customer-owned solar?

A. None. Presumably Applicants assumes customer solar would be higher cost than utility-scale under utility ownership and would also be selling into the wholesale market. However, customer solar is almost always owned by the customer, and thereby imposes no cost on the utility or other non-solar ratepayers. Customer solar is also located behind the customer's electric meter and offsets retail electric rates, not wholesale rates. The average residential retail rate in Wisconsin in 2017 was \$0.1435/kWh.[60] The average commercial retail rate in 2017 was \$0.1087/kWh.[61] These are the electricity rates that customer solar is offsetting, not wholesale market prices.

Q. How can many small residential and commercial building solar and battery systems compete economically against utility-scale systems?

A. Behind-the-meter (BTM) residential and commercial building solar and battery systems have the price advantage of offsetting retail electricity prices, not the wholesale prices that utility-scale systems are compared against. As noted, the average residential retail rate in Wisconsin in 2017 was \$0.1435/kWh, while the average commercial retail rate was \$0.1087/kWh. When the output of these individual systems are aggregated, they can be dispatched in much the same manner as single utility-scale facilities.

Q. **Are some utilities now aggregating building batteries and dispatching their collective output as virtual power plants?**

A. Yes. The first large-scale BTM commercial building battery storage VPP is the Southern California Edison 85 MW VPP in Southern California. See **Attachment A** for a description of this project. The output of more than 100 battery storage systems commercial buildings is automatically dispatched to offset grid congestion during periods of peak demand. This project is an operational success, as summarized by SCE: Stem (system operator) dispatched its fleet of distributed storage systems more than two dozen times throughout 2017, often during hours when the sun had set and solar PV systems could not be leveraged to generate electricity to offset increasing evening loads. This NWA capacity contributed to meeting critical peak capacity during 2017's unprecedented summer and fall heat waves. The VPP's performance demonstrates that distributed storage assets are consistently reliable, fatigueless, fast-dispatch assets year-round on both a day-ahead and "day of" call basis. That stands in contrast to the performance of typical DR assets. VPPs can also be sited to serve precise local congestion issues and manage the variability associated with high penetrations of wholesale and distributed renewable energy.

Q. **Are some utilities and third-party market participants aggregating 100s or 1,000s of behind-the-meter residential batteries and dispatching their collective output as virtual power plants?**

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[60] Ex.-SOUL-Powers-11, *EIA, Wisconsin Electricity Profile 2017*, January 9, 2019, Tab/Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2017*,* Average 2017 residential retail price = \$0.1435/kWh; Average 2017 commercial retail price = \$0.1087/kWh.

[61] Ibid.

A. Yes. Green Mountain Power (GMP), an investor-owned utility in Vermont, began offering retail customers 14 kWh battery storage units for $15 per month in 2017.[62] The project at full build-out will consist of 2,000 residential units. GMP aggregates the output of these battery storage systems to serve as a virtual peaking power plant.

GMP saved $500,000 during a July 2018 heat wave by dispatching 500 of these Tesla Powerwall™ batteries as a virtual peaker plant.[63] Tesla introduced a software update in 2018 that allows the Powerwall™ to be optimized for charging and discharging on time-of-use rates.

In February 2019 Independent System Operator-New England, MISO's equivalent in New England, became the first regional market to accept an aggregated residential "solar with battery storage" bid.[64] Sunrun, a major residential solar and battery integrator, was awarded 20 MW of distributed grid capacity to be online in 2022. The system will include battery systems in 5,000 homes, each dispatching approximately 4 kW. An advantage of the residential distributed model is that the battery storage system provides direct backup power to residential customers.

Q. Has DPC become a leader in distributed and community solar in Wisconsin?

A. Yes. DPC added eighteen new solar arrays at member rural cooperatives from 2016 through 2018 with a total capacity of 25 MW.[65] Most of these solar arrays are located in Wisconsin. The capacity of these solar arrays varies from 0.5 to 2 MW. A portion of each of these solar arrays is allocated as community solar capacity for the resident rural cooperative. Rural cooperative customers purchase the output from a set number of panels and are credited at the retail rate for the output of the panels.[66] DPC also has about 700 individual net-metered solar customers in its service territrory.

Q. Are solar and battery packages being operated cost-effectively at distribution substations?

A. Yes. Minster is a small Ohio town of about 2,800 people with a municipal utility that receives its electric power primarily from American Municipal Power, the wholesale power provider for municipal utilities in Ohio.[67] The first Minster solar with battery storage system, a 4.2 MW solar array and a 3 MWh battery storage system with 7 MW of peak output, came online in April 2016 under a power purchase agreement (PPA) with Half Moon Ventures.[68] The PPA sets the price for solar electricity at $0.07 per kWh. The

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[62] Ex.-SOUL-Powers-20, *Tesla Powerwall Grid Transformation Innovative Pilot,* application to Vermont PUC, July 31, 2017. The customer owns the Powerwall™ after 10 years of payments. The customer also has the option to make a one-time $1,500 payment to purchase the unit.

[63] Ex.-SOUL-Powers-21, Utility Dive, "Tesla batteries save $500k for Green Mountain Power through hot-weather peak shaving," July 23, 2018. Tesla is in the process of completing the 2,000-unit Powerwall™ deployment.

[64] Ex.-SOUL-Powers-22, Utility Dive, *Residential solar+storage breaks new ground as Sunrun wins ISO-NE capacity contract*, February 8, 2019.

[65] Ex.-SOUL-Powers-23, DPCW, *Solar at Dairyland Power - United We Shine* (webpage), accessed April 20, 2019:

[66] Ex.-SOUL-Powers-24, Richland Electric Cooperative, *Transition Energy (community solar) Frequently Asked Questions*, 2016. "How much will I be paid for the energy my panel(s) subscriptions produce? Energy produced in the current month will be multiplied by the energy rate you are paying for energy you buy from Richland Electric Cooperative. For example, if your energy bill shows you are paying 12.95 cents per kilowatt hour and your panel produces 40 kilowatt hours, your bill will be credited .1295 x 40 or $5.18."

[67] Ex.-SOUL-Powers-25, Utility Dive, *Inside the first municipal solar-plus-storage project in the US*, July 5, 2016.

[68] Ibid.

all-in PPA price with storage is $0.095 per kWh. This matches the Minster utility's average retail rate.

This system provides Minster with multiple revenue streams, including integration of frequency and voltage regulation, demand response and transmission services.[69] Minster has cut its peak capacity and demand charges by approximately $180,000 per year.[70] The town also avoided a $350,000 cost to buy capacitors, that otherwise would have been needed to improve power quality, by installing the battery system.[71] Minster's total upfront investment in the project was about $200,000.[72]

Minster is in the process of adding another 4.2 MW of solar and 7 MW of storage – Phase 2 – to the existing installation. The solar price under the Phase 2 contract will be about $0.05 per kWh.[73]

Finally, Minster also has in its project pipeline a Phase 3 that would add 19 MW of battery storage. The goal of Phase 3 is to create a local microgrid to ensure power and improve reliability for critical facilities and local businesses in the event of a grid outage.[74]

Q. **Can you provide another example of a solar and battery package being operated cost-effectively at distribution substation?**

A. Yes. Sterling Municipal Light Department in Massachusetts serves 3,700 residential, commercial, municipal and industrial customers. Sterling had the most solar watts per customer in the country in 2013, with PV power accounting for approximately 30 percent of the utility's peak load. The costs of capacity and transmission services purchased from the grid operator rose from $500,000 in 2010 to $1.2 million in 2017. The high solar penetration was also causing some power quality issues.[75]

To address these issues, a 2 MW, 3.9 MWh lithium battery storage system was installed in October 2016. The system is designed to "island" from the grid during a power outage. It is supported by 2 MW of existing solar generation. The substation where the battery storage is located, the 2 MW of solar and the police department are all on the same electrical feeder, which can be isolated to form an islanded microgrid in the event of a grid outage. This package can provide 12 days or more of backup power to the Sterling police station and dispatch center when it is operating as an islanded microgrid.

Battery storage was chosen over the gas turbine alternative initially considered. The project is expected to save at least $400,000 per year over the project's lifespan. This

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[69] Ex.-SOUL-Powers-26, NREL Blog, "Community Energy Storage: A New Revenue Stream for Utilities and Communities?", September 24, 2018,

[70] Ex.-SOUL-Powers-37, D. Harrod, Village Administrator – Minster, Ohio, *Village of Minster Solar and Energy Storage Project*, PowerPoint presented at North Carolina Clean Path 2025 workshop, Chapel Hill, NC, November 17, 2018, p. 13.

[71] Ibid.

[72] Ex.-SOUL-Powers-36, E-mail communication between B. Powers, Powers Engineering, and D. Harrod, Village Administrator – Village of Minster, April 22, 2019.

[73] Ibid.

[74] Ibid.

[75] Ex.-SOUL-Powers-27, "Sterling Municipal Light Department - Energy Storage System," *Home Power*, August 2018, pp. 25-26.

is a significant savings for the Sterling municipal utility, which has an annual budget of $8.2 million. The battery storage also allows Sterling to increase solar penetration while maintaining good power quality.

IX. The Economic Benefits That Applicants Asserts for CHC Are Insignificant

Q. What is the impact of the 40-year economic benefit the Applicants assert for CHC on the monthly bills of residential ratepayers in Wisconsin?

A. The average monthly residential bill will decrease about 4 cents per month Wisconsin. See Table 2 for the conversion of the Applicants 40-year net benefits forecasts into monthly customer bill impacts.

Table 2. Applicants 40-year economic benefits for CHC converted into monthly customer bill impacts[76,77,78]

[76] *Revised Appendix D, Exhibit Planning Analysis Document Appendices,* April 9, 2019, Monetized Range of Net Benefits of Alternatives to Wisconsin, Table 1, pdf p.15

[77] EIA. Number of Retail Customers by State by Sector, Wisconsin, 2017 (EIA-861).

[78] EIA, Retail Sales of Electricity by State by Sector by Provider, Wisconsin, 2017 (EIA-861).

Economic Futures	Wisconsin 40 Year Net Benefits ($million, 2018 dollars)	Wisconsin Average Annual Benefits ($ per year)	Wisconsin Residential Customer Average Monthly Share (31%)	Wisconsin Commercial Customer Average Monthly Share (34%)	Wisconsin Industrial Customer Average Monthly Share (35%)
Existing Fleet (EF)	22.7	$567,500	$0.005	$0.05	$2.92
Policy Regulations with Low Energy (PRLE)	156.1	$3,902,500	$0.04	$0.32	$20.11
Policy Regulations (PR)	105.5	$2,637,500	$0.03	$0.21	$13.59
Policy Regulations with Foxconn (PRFoxconn)	129.2	$3,230,000	$0.03	$0.26	$16.65
Accelerated Alternative Technologies (AAT)	249.3	$6,232,500	$0.06	$0.51	$32.12
Number 2017 WI Customers			2,681,341	351,707	5,666
2017 Usage (kWh)			21,233,154,000	23,641,127,000	24,204,631,000
2017 Percentage Usage			30.7%	34.2%	35.0%

Q. Were ratepayer level impacts evaluated in past transmission line applications?

A. Yes. In his testimony in support of the Rockdale - West Middleton 345 kV transmission line, ATC witness Hodgson computed the cost impacts of the transmission line on an average electric bill and described the process he used.[79]

X. Applicants Did Not Fully Account for the Economic Benefits of NTA

Q. What level of economic benefits did Applicants determine for CHC and the NTA?

A. The economic benefits calculated by Applicants for the three primary Futures scenarios are shown in Table 3.

[79] Ex.-SOUL-Powers-28, Direct Testimony of on Behalf of American Transmission Company LLC and ATC Management Inc, February10, 2009, p.270, "What were the results of the rate impact analysis? The rate impact analysis showed that end-use customer rates would approximately increase on average in the peak cost year of 2014 by between 0.29% and 0.32% for the Rockdale-Beltline Route (with an average of 0.31%) and between 0.34% and 0.38% for the Albion-Fitch Beltline Route (with an average of 0.36%), depending on the LDC. For MGE customers, the peak increase on the average customer bill will be approximately 0.29% for the Rockdale-Beltline Route and 0.32% for the Albion-Fitch Beltline Route in 2014. The average rate increase due to the Project for the period 2009-2014 will be 0.17% for all LDC's and 0.16% for MGE specifically for the Rockdale-Beltline Route, and 0.20% for all LDC's and 0.19% for MGE specifically for the Albion-Fitch Beltline Route. If the increased costs to the LDC are distributed equally accros its customer classes, a retail customer with a $75 monthly electric bill would see an increase in 2014 of $0.23 per month attributable to the Rockdale-Beltline Route and $0.27 per month attributable to the Albion-Fitch Beltline route. The year 2014 is the peak revenue requirement year because that is the first full year with the Project completed. After 2014, the rate impact will decrease due to accumulated depreciation reducing the rate base impact of the Project. The results of the retail rate impact anlaysis are presented in Exhibit 29."

Table 3. Net Benefits of Evaluated Alternatives, Millions (2018 present value)[80]

Future Scenario	CHC	NTA
Existing Fleet	23.5	(9.7)
Policy Regulation	106.3	(10.3)
Accelerated Alternative Technology	350.1	25.3

Q. **What is the value of the benefits that Applicants calculated for its NTA?**

A. Depending on Futures scenario, the NTA benefits calculated by Applicants ranged for -$5 million to $25 million.

Q. **Do you concur with Applicants' calculation of the benefits of the NTA?**

A. No. Applicants failed to accurately account for the energy savings economic benefits of the energy efficiency, utility-scale solar, and residential solar components of the NTA.

Q. **What are the energy savings economic benefits of the NTA?**

A. $132.1 million. The calculations supporting this revised NTA economic benefits value is shown in Table 4.

Table 4. Revised NTA energy savings economic benefits calculations

Applicants' NTA Component	Description	# Units	Avoided or Produced (kWh-year)	Current Rate /Sales Value (kWh)	Lifespan (years)	Average rate lifetime, 2.5% per year inflation, starting in 2023	Additional Savings	Benefit to Cost Ratio
Energy Efficiency Residential LED Bulbs	Household 9.5W LED bulbs, $1M, 15,000 hrs/ 2 hrs day	117,786	37.00	$0.14350	20	$0.2154	**$18,775,995**	**18.8**
Energy Efficiency Commercial LED Bulbs	Applicants' BR30 LED bulbs@$1M / 960 kWh lifecycle	92,530	48.00	$0.14350	20	$0.2154	**$19,135,127**	**9.6**
Residential Solar Arrays	2 MW Total – 5kW (ac) ea. @ 1,577 kWh/kW/year production; $2.50/W; $5M investment	400	7,789	$0.14350	30	$0.2469	**$23,079,631**	**4.6**
30 MW Solar Array	As utility-scale @ 1,577 kWh/kW/year solar production; $39M investment	1	46,731,000	$0.02946	30	$0.0507	**$71,072,396**	**1.8**
						Total	**$132,063,149**	

Q. **What is the range of overall economic benefits for Applicants NTA when the revised energy savings values are utilized?**

A. $126.3 million to $153.3 million, depending on the Future Scenario. See Table 5. The Applicants definition of "Energy Cost Savings" is congestion relief savings, not credit for avoided energy costs in the case of energy efficiency or for solar energy production. When the avoided electricity production (energy efficiency) and solar energy production in the NTA are included as economic benefits, the resultant NTA net economic benefits are much higher than indicated by the Applicants.

[80] Application, Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin, p. 34.

Table 5. Revised NTA total economic benefits for each Futures scenario[81,82]

40 YEAR NET ECONOMIC SAVINGS FROM APPLICANTS' NTA - BY FUTURE	Existing Fleet Future .4% Growth	Policy Regulations 5% Growth	Accelerated Tech .6% Growth	Policy Reg LE . 4% Growth	Policy Regulations 5% Growth	Policy Regulations Foxconn. 5% Growth	Policy Regulations 0% Growth Used PRLE - Applicants did not evaluate	Policy Regulations -0.43% Growth Used PRLE - Applicants did not evaluate
Energy Cost Savings	32.3	31.9	58.9	41.4	31.9	31.9	41.4	41.4
Capacity Loss Savings	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1
Insurance Benefit	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Subtotal	60.6	60.2	87.2	69.7	60.2	60.2	69.7	69.7
Discounted Cost of NTA for WI Ratepayers	-66	-66	-66	-66	-66	-66	-66	-66
Net NTA Benefits (Millions)	-$5.4	-$5.8	$21.2	$3.7	-$5.8	-$5.8	$3.7	$3.7
Applicants did not include Economic Benefits From Consumer Energy Savings or Produced Energy from Utility Scale SolarIn Their NTA								
Energy Efficiency Savings (20 Years)	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9
Residential Solar Energy Savings (30 Years)	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
Utility-Scale Solar Wholesale Power (30 yr)	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
Total Benefits Applicants Excluded	*$132.1*	*$132.1*	*$132.1*	*$132.1*	*$132.1*	*$132.1*	*$132.1*	*$132.1*
Adjusted Net Estimated Benefits (Millions)	$126.7	$126.3	$153.3	$135.8	$126.3	$126.3	$135.8	$135.8

Q. What are the economic benefits of the NTA if the $110 million for the Eden Extension 138 kV transmission line is added to the base $67 million NTA budget to bring it to $177 million?

A. The economic benefit of the NTA would increase from a minimum of $126.3 million to $333.7 million, assuming a linear scale-up of the net economic benefits.[83]

Q. What would be the increase in the transfer capacity of the adjusted NTA with budgets of $67 million and $177 million, respectively?

A. As noted, the NTA developed by the Applicants increases transfer capacity 1 MW for every $200,000 invested. Using this metric, the NTA transfer capacity would increase from 334 MW with a $67 million budget to approximately 885 MW with a $177 million budget.[84]

XI. Existing Demand Response Programs Are Underutilized

Q. What are demand response (DR) programs?

A. There are two DR mechanisms, also known as "load management," utilized by Wisconsin electricity providers for managing peak demand. These are: 1) curtailment by direct load control, and 2) tariffs that establish interruptible load. As explained in the PSC's *Strategic Energy Assessment - Energy 2018-2024*:[85]

> Direct load control gives electricity providers the ability to turn off specific equipment at certain times, such as residential air conditioners, at certain times to

[81] Revised Appendix D, Exhibit Planning Analysis Document Appendices, Table D-13-1 to Table D-13-3, pdf p. 440-441.
[82] Revised Appendix D, Exhibit Planning Analysis Document, 6.7 Net Economic Benefits - Summary of Alternatives, Tables 37-41: Net Economic Benefits Calculations, pdf p.79.
[83] $126.3 × ($177 million ÷ $67 million) = $333.7 million.
[84] $177 million ÷ $200,000/MW = 885 MW.
[85] Ex.-SOUL-Powers-3, p. 16.

> reduce load on the system. When electricity providers implement direct load control, affected customers who volunteered to participate in the program receive a credit on their bill. An industrial customer choosing an interruptible load tariff receives a lower electric energy rate in cents per kilowatt-hour (kWh) by agreeing to allow the electricity provider to interrupt load during periods of peak demand on the system.

These are existing programs under existing tariffs that do not require additional action or investment to be realized.

Q. Do Wisconsin utilities forecast an increase in DR capacity over time?

A. Yes and no. Total available DR capacity is forecast to rise from 798 MW in 2017 to approximately 924 MW in 2020 and hold at 924 MW through 2024.[86] The contribution of direct load control is forecast to decline from a peak of 282 MW in 2006 to 54 MW in 2020.[87] In contrast, interruptible load DR capacity is forecast to increase from 667 MW in 2017 to 869 MW in 2020, and hold at 870 MW from 2021 through 2024.[88]

Q. What amount of load has been interrupted in recent years relative to the fully subscribed potential of ATC-Wisconsin member utilities and DPC-Wisconsin?

A. The amount of load actually interrupted was a small fraction of the fully subscribed available DR capacity for the most recent year (2017) for which actual DR deployment data is available, 44 MW of 798 MW, on the order of 5 percent of available DR capacity.[89]

Q. So in 2017 over 750 MW of DR capacity available for dispatch by Wisconsin utilities was not utilized to address peak load conditions?

A. That is correct.

Q. Does the Applicant address the potential of DR to reduce peak load, and thereby increase transfer capacity on the existing LV transmission grid during peak load conditions, in its application to construct CHC?

A. No. The Application for CHC simply states:[90]

> It is difficult to determine how much energy efficiency and demand response would be necessary to reduce, alter, or otherwise eliminate the need for the Project. This is because the Project generates economic, transfer capability, reliability, and public policy benefits for Wisconsin customers that energy efficiency and *demand response either cannot provide at all or cannot provide in amounts that are comparable to the Project*.

Q. Do you agree that existing DR programs *either cannot provide at all or cannot provide in amounts that are comparable* the economic, transfer capability, reliability, and public policy benefits of the Project?

A. No. The wind transfer capability of CHC, by itself, could be in the range of only about 550 MW based on the testimony of Applicants witness Dagenais.[91] Wisconsin utilities left approximately 750 MW of available DR underutilized in 2017. This 750 MW of

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[86] Ibid, Table 5, Available Amounts of Programs and Tariff to Control Peak Load, MW, p. 17.

[87] Ibid.

[88] Ibid.

[89] Ibid.

[90] Applicants Application, September 2018, p. 63.

underutilized DR capacity requires no new investment to employ, as this capacity is already subscribed under existing Wisconsin utility DR tariffs. It simply needs to be dispatched when it is needed. Wisconsin customers are already paying for the DR programs, so there is no additional economic commitment necessary. Reducing load on existing transmission lines to reduce congestion at times of peak demand is an excellent tool for assuring grid reliability.

Q. What is the dollar value of the reliability and asset renewal costs that Applicants claim would be avoided if CHC is built?

A. $87.2 million.

Q. Would the dispatch of up to 750 MW of available DR on an as-needed basis likely eliminate the need for the $87.2 million in reliability and asset renewal costs that Applicants claims are avoided by constructing CHC?

A. Potentially.

XII. Wisconsin Can Cost-Effectively Increase Electricity Savings Programs

Q. Can Wisconsin increase the rate of incremental electricity savings if it chooses to do so?

A. Yes. Wisconsin ranks 26th out of 50 states in incremental electricity savings in 2017.[92] Wisconsin achieved an incremental electricity efficiency savings of 0.66 percent in 2017.[93] The top state, Vermont, achieved annual incremental electricity savings of over 3 percent per year.[94] The Energy Center of Wisconsin has identified annual energy savings potential equivalent to 1.6 percent of both total electricity sales and peak demand, and 1.0 percent of natural gas sales.[95]

XIII. The Optimized NTA

Q. Describe your optimized NTA proposal. , based on $67 million and $177 million budgets.

A. The principal elements of the optimized NTA, relative to the Applicants' NTA, are: 1) a doubling of electricity savings, 2) leveraging of Focus on Energy ("FoE") net-metered solar incentives to accelerate net-metered solar adoption, 3) emphasis on community solar arrays to complement net-metered systems and supply power to structures, due to

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[91] Direct-Applicants-Dagenais-18 "In combination with another MVP, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability." Powers Engineering assumes that the transfer capacity of each 345 kV transmission line separately is approximately one-half of 1,100 MW combined transfer capacity stated by witness Dagenais, or 550 MW.

[92] Ex.-SOUL-Powers-29, American Council for an Energy-Efficient Economy, *The 2018 State Energy Efficiency Scorecard*, October 2018, Table 8, p. 28.

[93] Ibid.

[94] Ibid.

[95] Ex.-SOUL-Powers-31, Energy Center of Wisconsin, *Energy Efficiency and Customer-Sited Renewables Potential in Wisconsin for the Years 2012 and 2018*, prepared for PSC of Wisconsin, July 2009, Abstract, pdf p. 7.

shading or other limitations, that are not suitable for solar arrays, and 4) include point-of-use behind-the-meter ("BTM") battery storage systems in customer structures, whether or not those structures also incorporate solar arrays, to take full advantage of the back-up power resilience gained by locating the battery storage in structures. The cost of the battery systems associated with the community solar array, would be covered under a PPA between the project developer and the utility or cooperative. The battery storage output will be aggregated as a virtual power plant to maximize the value of storage to the grid and to individual customers.

Q. So the only component of the net-metered residential or commercial BTM solar systems included in your optimized NTA budget is the FoE incentive payment?

A. That is correct. The customer pays for the net-metered system and owns it. The cost of the battery system in a net-metered residential or commercial building configuration would also be supported by FoE incentive payments.

Q. Would there be substantial upfront costs associated with the community solar and battery storage systems?

A. No. The community solar and battery systems would be financed using a PPA model similar to that used to finance the Village of Minster 4 MW solar and 3 MWh battery storage system. The Village of Minster invested $200,000 in the project, and agreed to a solar and storage payment schedule, $0.095/kWh with a 2.0 percent escalator. Even though the Minster project began operation in 2016, this same PPA contract pricing is applied in the optimized NTA in this testimony to calculate economic benefits. The one operational difference is that the batteries in the optimized NTA are located on customer premises and aggregated into a virtual large battery system. At Minster, the 3 MWh battery system is located at one site by adjacent to a substation.

Q. What is the role of DR in the optimized NTA?

A. The optimized NTA alternative(s) include the same assumption used by the Applicants for DR in the Applicants' NTA. The Applicants' NTA allocates of approximately $20 million capital investment to produce 31.5 MW of new DR capacity. However, this is done only to eliminate DR capacity in the NTA as a point of controversy in comparing NTA alternatives. There is no need to purchase new DR when Wisconsin utilities are not using the DR they already have under contract. As noted, Wisconsin utilities had 750 MW of DR that was not deployed in 2017. All NTA alternatives should assume this available DR is actually utilized to increase transfer capacity by decreasing congestion under peak load conditions.

Q. How did you calculate the economic benefit of the various components of the optimized NTA over their operational lifetimes?

A. The optimized NTA economic benefit calculation assumes that retail tariffs increase 2.5 percent per year, which is the inflation rate used by the Applicants.[96] This inflation rate assumption is conservative relative to the actual rate-of-increase of residential and commercial retail electricity tariffs in Wisconsin from 2005 to 2017.[97] Retail residential

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[96] Revised Appendix D, Exhibit Planning Analysis Document, 6.2 Energy Cost Saving Benefits for Wisconsin Customers, pdf p.53. "inflation was assumed to be 2.5 percent per year."

[97] Ex-SOUL-Powers-11, *Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2017*. 2005 retail residential = $0.0966/kWh; 2017 retail residential = $0.1435/kWh. 2005 retail commercial = $0.0767/kWh;

rates increased by an average of 3.35 percent per year during this period.[98] Retail commercial rates increased by an average of 2.95 percent per year during this period.[99] Also, the initial year for economic benefit calculation purposes is assumed to be 2023, the year the Applicants project as the start date for CHC.[100]

Q. Do the economic benefits of any of the optimized NTA components escalate at less than 2.5 percent per year?

A. Yes. The Village of Minster PPA includes a 2 percent per year escalator. For this reason, I apply an escalator of 0.5 percent, the difference between the Applicants' assumed inflation rate of 2.5 percent per year and the Minster PPA escalator of 2.0 percent per year, to the community solar and battery storage component of the optimized NTA.

Q. What are the net economic and capacity benefits of the $67 million version of your optimized NTA?

A. The economic benefit of the optimized NTA with just under a $67 million budget is $1,632.5 million. The capacity benefit is 246.7 MW. The contribution of each optimized NTA component to these economic and capacity benefits is shown in Table 6. I assume the capacity benefit of each element of optimized NTA is equivalent to the capacity cost assigned by the Applicants to DR.[101]

Table 6. Net economic and capacity benefits of $67 million optimized NTA[102]

Component	Units	Capacity (kW)	Capital cost ($)	Term (years)	Net economic benefit ($)	Capacity benefit (MW)	Capacity economic benefit ($)
DR	$/kW	31,500	20,002,500	30	20,002,500	31.5	20,002,500
EE	$/blub	5,200	3,571,166	20	43,489,984	5.2	3,571,166
BTM PV	$/kW FoE incentive	60,000	16,020,000	30	228,507,300	see BTM storage	see BTM storage
BTM storage	$/kWh FoE incentive	60,000 [not additive]	18,000,000	30	270,000,000	60	18,000,000
Community PV	$, upfront PPA cost	150,000	3,750,000	30	502,432,200	See community storage	See community storage
Community storage	$, upfront PPA cost	150,000 [not additive]	4,950,000	30	497,587,500	150	95,250,000
Totals:			66,293,666		1,562,019,484	246.7	136,823,666
Total net economic benefit:					1,632,549,484		

2017 retail commercial = $0.1087/kWh.

[98] Retail residential rate-of increase, 2005-2017: $0.1435/kWh = $0.0966/kWh × $(1 + x)^{12}$, x = escalation rate.

[99] Retail commercial escalation rate, 2005-2017: $0.1087/kWh = $0.0767/kWh × $(1 + x)^{12}$, x = escalation rate.

[100] Revised Appendix D, Exhibit Planning Analysis Document, pdf p.52.

[101] This assumption is based on DR providing at least a 1:1 cost-to-benefit ratio.

[102] Ex.-SOUL-Powers-31, $67 million optimized NTA economic and capacity benefits.

Q. What are the net economic and capacity benefits of the $177 million version of your optimized NTA?

A. The economic benefit of the optimized NTA with a $177 million budget is $4.5 billion. The capacity benefit is 621.7 MW. The contribution of each optimized NTA component to these economic and capacity benefits is shown in Table 7.

Table 7. Net economic and capacity benefits of $177 million optimized NTA[103]

Component	Units	Capacity (kW)	Capital cost ($)	Term (years)	Net economic benefit ($)	Capacity benefit (MW)	Capacity economic benefit ($)
DR	$/kW	31,500	20,002,500	30	20,002,500	31.5	20,002,500
EE	$/blub	5,200	3,571,166	20	43,489,984	5.2	3,571,166
BTM PV	$/kW FoE incentive	235,000	62,745,000	30	894,986,925	see BTM storage	see BTM storage
BTM storage	$/kWh FoE incentive	235,000 [not additive]	70,500,000	30	1,057,500,000	235	70,500,000
Community PV	$, upfront PPA cost	350,000	8,750,000	30	1,172,341,800	See community storage	See community storage
Community storage	$, upfront PPA cost	350,000 [not additive]	11,550,000	30	1,161,037,500	350	222,250,000
Totals:			177,118,666		4,349,358,709	621.7	316,323,666
Total net economic benefit:					4,488,563,709		

Q. Would it be feasible to locate components of the optimized NTA, such as a community solar and battery system similar to the Minster, Ohio project, to defer the need for investments in renewal assets?

A. Applicants model distributed solar in the Mount Horeb/Cross Plains area to remove load from the older low voltage lines in the area. In Section 5.3 of the Applicants' description of their NTA in the Revised Planning Analysis Document, Applicants state:[104]

> The residential solar facilities were modeled as offsetting load in Mount Horeb and Cross Plains. These locations were selected as a general proxy for southwest and southcentral Wisconsin but also because the location could reduce the thermal loading of the West Middleton – Timberlane Tap – Stagecoach 69 kV line in various planning models.

The Optimized NTA, if located in the CHC project study area, would have a similar capability to reduce loading on existing transmission facilities. The Inter-Municipal Energy Planning Committee ("IMEPC") comprised of nine Wisconsin municipal Governments, has been studying possible applications of NTAs for several years.[105]

[103] Ex.-SOUL-Powers-32, $177 million optimized NTA economic and capacity benefits.
[104] Revised PAD, pdf p. 54.
[105] Ex.-SOUL-Powers-39, IMEPC planning draft, IMEPC & Commission Staff Grid Modernization Meeting, February 20, 2018.

The Town of Vermont in Dane County, a member of IMEPC, is located in the project area with residents receiving power from Black Earth Municipal Utility, Mount Horeb Municipal Utility and Alliant (WP&L). The Town of Vermont is near substations associated with two of the Applicants potential asset renewal projects: Stagecoach – West Middleton 69 kV (6927) and Wally Road –Stagecoach 69 kV (Y-128). The Applicants have identified as much as $19.3 million in foreseeable line/substation costs associated with these facilities.[106] Locating community solar array(s) similar to the Minster, Ohio solar and storage system at or near the substation in Black Earth, which serves the majority of electric customers in the Town of Vermont, could defer the need for investments in the Stagecoach – West Middleton 69 kV (6927) and Wally Road – Stagecoach 69 kV (Y-128) renewal projects.[107]

IXV. Environmental Advantages of the Proposed NTA

Q. The CHC DEIS describes numerous temporary and permanent impacts to the environmental that would be caused by construction of CHC, including impacts to forests and wetlands, wildlife habitat loss, and visual quality and aesthetics.[108] How would the use of the NTA you propose compare to the proposed CHC transmission line regarding such impacts?

A. Energy efficiency measures would have no environmental impacts. Rooftop and small-scale community solar with onsite storage would have no significant air, water, or land impacts. The environmental advantages of rooftop solar relative to remote utility-scale renewable energy and associated transmission lines were recognized by the California Public Utilities Commission at the time of its approval of a 500 MW urban warehouse rooftop PV project:[109]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

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[106] Revised PAD, Table 34, pdf p. 77.
[107] Ex.-SOUL-Powers-39, possible location of a solar/storage facility, Black Earth Municipal Utility territory, serving residents of the Town of Vermont.
[108] Ex.-SOUL-Powers-33**,** U.S. Department of Agriculture – Rural Utilities Services, *Cardinal– Hickory Creek 345–kV Transmission Line Project Draft Environmental Impact Statement, Volume I Chapters 1–3*, December 2018, Table ES-5: Comparison Summary for Action Alternatives, p. ES-17 to p. ES-19.
[109] Ex.-SOUL-Powers-34, CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

Q. **What are the forecast CO_2 emissions from CHC compared to CO_2 emissions from the optimized NTA?**

A. The Applicants examine three basic Futures scenarios, EF, PR, and AAT. The AAT Future is an unrealistic scenario due to the very high 0.9 percent growth rate assumed. For this reason, greenhouse gas reductions projected for the ATT Future are excluded from the greenhouse gas emissions reduction comparison. The average greenhouse gas reduction of the EF and PR Futures scenarios is approximately 27 million metric tons over 40 years.[110]

Q. **What are the CO_2 reductions associated with the optimized NTA?**

A. 33.1 million metric tons of greenhouse gas reductions are achieved with the optimized NTA over 40 years.[111] The greenhouse gas reductions associated with the optimized NTA are significantly greater than the average greenhouse gas reductions projected by the Applicants for the EF and PR Futures scenarios.

XV. Conclusion

Q. **Does this conclude your testimony?**

A. Yes.

A. Yes.

[110] Ex.-SOUL-Powers-35, Response to S.O.U.L. OF Wisconsin, Inc.'s First Document and Data Requests, January 16, 2019, RESPONSE TO REQUEST 12G, p. 32, Applicants' EF CO_2 reductions = 20 million tons. PR CO_2 reductions = 40 million tons. Average = 30 million tons. 0.9072 tons = 1 metric ton. Therefore, 30 million tons × 0.9072 metric ton/ton = 27.2 million metric tons.

[111] Ex.-SOUL-Powers-32.