BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission	)	
Company, ITC Midwest LLC, and Dairyland	)	
Power Cooperative, for Authority to Construct	)	
And Operate a New 345 kV Transmission Line	)	
From the Existing Hickory Creek Substation in	)	5-CE-146
Dubuque County, Iowa, to the Existing	)	
Cardinal Substation in Dane County,	)	
Wisconsin, to be Known as the Cardinal-	)	
Hickory Creek Project	)	

DIRECT TESTIMONY OF MIHIR DESU ON BEHALF OF THE DRIFTLESS AREA LAND CONSERVANCY AND WISCONSIN WILDLIFE FEDERATION

EXECUTIVE SUMMARY

The Applicants' benefit-cost assessment for the Cardinal-Hickory Creek ("CHC") transmission line project is flawed in several respects and does not support the Applicants' conclusion that the CHC transmission line is needed to provide Wisconsin customers with more reliable energy, more affordable energy, and more renewable energy.[1]

First, the economic benefits predicted by Applicants are highly contingent on the modeling methodology and their decision to use only a production cost model. The Applicants' model simulates the operations of an electric system that is optimized for the CHC transmission line. The Applicants fail to produce a realistic simulation of the system if the CHC line is not constructed, as they do not allow their model the flexibility to

[1] Direct-Applicants-Dagenais-6

include the construction of additional in-state resources. This methodological flaw increases the modeled energy savings for the CHC transmission line and suppresses the modeled energy savings for its alternatives.

Second, the results from the Applicants' production cost model are highly sensitive to slight changes in the input assumptions. As such, I find that the magnitude of the purported benefits is not high enough to guarantee that the CHC transmission line will have positive net benefits if the assumptions used in the model are slightly violated (i.e. the reality unfolds somewhat differently than the assumed futures and parameters used in the model). I believe the risk of committing to a capital-intensive investment under this uncertainty is not worth the significant loss of flexibility that could enable smaller, more prudent investments in the electric system that can adapt to future changes and leverage the rapidly decreasing costs of renewables, energy storage, and other emergent energy technologies.

Finally, the Applicants' data does not support their claim that the CHC transmission line will necessarily lead to more renewable energy for Wisconsin customers. My analysis of the generation schedules under the different alternative interventions modeled by the Applicants reveals that the CHC transmission line will carry a significant amount of fossil fuel generated MWh, and not just renewable energy.

Overall, I believe the Applicants' benefit-cost assessment is unreliable and does not persuasively support the Applicants' claim that the CHC transmission line project would result in benefits to Wisconsin. I recommend that the PSCW direct the Applicants to remodel the CHC project alternatives in the manner that is suggested in my testimony.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Mihir Desu. I am a Director in Strategen's consulting practice. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please provide detail on the scope of your company, Strategen.

A. Strategen is a mission-driven professional services company focused on market development for a decarbonized electrical system. Strategen has three business lines that include Association Management, Events, and Consulting. The Association Management team manages the California Energy Storage Alliance (CESA), which is a membership-based organization that is composed of storage companies from across the industry. The Events team manages an annual grid-connected energy storage conference called Energy Storage North America (ESNA), which brings industry leaders from across the world to share knowledge. The Consulting team works with utilities, regulatory policy stakeholders, and corporate entities ranging from startups to Fortune 500 companies to assist in implementing clean energy strategies.

Q. Please explain how Strategen's expertise is relevant to this proceeding.

A. Through CESA, ESNA, and various consulting projects, Strategen has a strong pulse on the energy storage industry and a wealth of knowledge and expertise on the technological advancements related to the development of clean electricity systems. Strategen specializes in shaping and adapting policy and planning for the electrical system to value these technological advancements in isolation and relative to traditional infrastructure solutions. A key area of focus for this work is with respect to alternative transmission solutions (ATS), also known as non-wires alternatives, non-wires solutions, and non-transmission alternatives. Some relevant projects include:

- On behalf of Puget Sound Energy (PSE), Strategen developed a methodology to evaluate energy storage as a non-wire solution for a transmission capacity deficit. The evaluation was conducted as part of an alternatives assessment for a large 230kV upgrade in an urban area.[2]
- On behalf of the Australian Energy Market Operator (AEMO), which operates Australia's National Energy Market, Strategen conducted a survey of global best practices for coordination between Transmission System Operators and Distribution System Operators and system architecture for enabling an electric system with a high penetration of distributed energy resources (DER).[3]
- On behalf of the CESA, Strategen has provided comments throughout the stakeholder process for the Storage as Transmission Asset ("SATA") Initiative issued by California Independent System Operator ("CAISO").[4]

Q. Please summarize your professional and educational background and its relevance to this proceeding.

A. As a Director in Strategen's consulting practice, I oversee the development of strategies to advance clean energy for corporate, utility, and government clients across the U.S. and internationally. My projects cover topics such as rate design, integrated resource

[2] Strategen Consulting, Eastside System Energy Storage Alternatives Assessment Report Update, 2018. Available at:https://development.bellevuewa.gov/UserFiles/Servers/Server_4779004/File/pdf/Development%20Services/EnergizeEastside/PSE-EE-Eastside-System-Energy-Storage-Alternatives-Assessment.pdf
[3] Newport Consortium, Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design, 2018.
[4] California Energy Storage Alliance ("CESA"), Storage as a Transmission Asset ("SATA") Straw Proposal, 2018. Available at: caiso.com/Documents/CESAComments-Storageas-TransmissionAssetStrawProposal.pdf

planning, infrastructure planning for transportation electrification, energy storage policy, energy storage project development, non-wires solutions, and wholesale market design with the intent of accurately valuing and compensating distributed energy resources (“DER”) for the benefit of all ratepayers.

Prior to joining Strategen, I worked for Portland General Electric, an investor-owned electrical utility in Oregon, where I supported regulatory policy strategy related to DER and developed models to value energy storage, qualifying facilities, demand response, and electric vehicles. I have also worked as a consultant for The Cadmus Group evaluating demand-side management programs for utilities and government entities. I started my career analyzing wholesale electricity markets for energy traders and developers with EnergyGPS. I hold a Bachelor of Arts degree in Mathematics from Binghamton University. My full resume is included as Ex.-DALC/WWF-Desu-1.

Q. Please further detail your experience with benefit-cost assessments of electric infrastructure projects.

A. Since the start of my career, I have worked on projects related to benefit-cost assessments and cost-effectiveness evaluations. At The Cadmus Group, I conducted numerous cost-effectiveness evaluations of demand-side management (“DSM”) programs across the United States and became intimately familiar with the California Standard Practice Manual,[5] which is the foundational resource for benefit-cost assessments of investments in emergent energy technologies such as DER and ATS. At Portland General Electric, I worked on benefit-cost assessments for a number of customer-side resource programs

[5] California Governor’s Office of Planning and Research, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, 2002. Available at: http://www.calmac.org/events/SPM_9_20_02.pdf

such as demand response, electric vehicles, energy storage, and distributed solar. Most recently, on behalf of the respective consumer advocates in Massachusetts and Maryland, I have conducted evaluations of benefit-cost assessments for utility EV infrastructure programs in each state.

Q. Please further detail your experience with alternative transmission solutions.

A. I have worked on issues related to non-wires solutions and alternative transmission solutions for a number of years. Some recent highlights include:

- On behalf of the Environment Law and Policy Center, I wrote testimony on the development of a framework to evaluate Duke Energy Ohio's non-wires solution project proposals.[6]
- Rocky Mountain Institute ("RMI") invited me to present on the topic during a recent webinar on the Opportunities and Challenges for Non-Wires Solutions[7] after previously contributing to their recent report called the Non-Wire Solutions Implementation Playbook.[8]
- On behalf of the 25x'25 Alliance, I wrote comments on best practices for a rule proposed by the Mississippi Public Service Commission to require regulated electric utilities in state to develop Integrated Resource Plans (IRP). This included best practices on procurement of non-traditional resources such as ATS.[9]

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[6] Environmental Law and Policy Center, Direct Testimony of Mark Higgins on Behalf of Environmental Law and Policy Center, 2018. Available at: https://dis.puc.state.oh.us/TiffToPDf/A1001001A18F27B70708E06358.pdf

[7] Rocky Mountain Institute, *Non-Wires Solutions: Opportunities and Challenges for Scaling the Market*, 2019 April 4. Available at: http://rmi.org/wp-content/uploads/2019/04/2019.4.4-RMI_NWS-Webinar-Deck-FINAL.pdf

[8] Rocky Mountain Institute, *The Non-Wires Solutions Implementation Playbook: A Practical Guide for Regulators, Utilities, and Developers*, 2018. Available at: https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf

[9] 25x'25 Alliance, *Best Practices for the Development of an Integrated Resource Planning Rule for Mississippi*, 2018 August 1. Available at:

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Driftless Area Land Conservancy ("DALC") and the Wisconsin Wildlife Federation ("WWF"). The mission of DALC is to maintain and enhance the health, diversity and beauty of Southwest Wisconsin's natural and agricultural landscape through permanent land protection and restoration, and improve people's lives by connecting them to the land and to each other.

Q. What is the purpose of your testimony?

A. My testimony will review and evaluate the need for the Cardinal-Hickory Creek ("CHC") transmission line as proposed in the Certificate of Public Convenience and Necessity ("CPCN") application of American Transmission Company LLC, ITC Midwest LLC, and Dairyland Power Cooperative (collectively the "Applicants") and the testimony of the Applicants' witnesses, particularly Mr. Tom Dagenais. More specifically, my testimony will evaluate the Applicants' benefit-cost assessments of the CHC transmission line and its alternatives.

Q. Have you ever testified before the Public Service Commission of Wisconsin or other state or federal regulatory bodies?

A. No, I have not. However, I have written testimony for sponsored witnesses in numerous proceedings, most recently before the Public Utility Commission of Ohio on the evaluation of Duke Energy Ohio's non-wires solution pilot project. I have also written testimony and/or comments in proceedings before the Arizona Corporation Commission, the Maryland Public Service Commission, the Massachusetts Department of Public

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http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=554462

Utilities, the Mississippi Public Service Commission, and the Oregon Public Utility Commission. In addition to these written testimony and comments, I have delivered in-person comments at a technical conference before the Federal Energy Regulatory Commission (FERC) and presented results of a study for Focus on Energy before the Public Service Commission of Wisconsin ("PSCW" or "Commission").

Q. How is your testimony organized?

A. My testimony is presented in four sections:

1. Section 1 is an executive summary of the key points of my testimony.
2. Section 2 is an introduction to my testimony, including my company's expertise, my own credentials, and the purpose of my testimony.
3. Section 3 provides the market context within which the application for the CHC transmission line falls.
4. Section 4 provides a summary of the Applicants' CPCN application as it relates to my testimony.
5. Section 5 details my evaluation of the Applicants' methodology for their analysis.
6. Section 6 details my evaluation and analysis of the Applicants' benefit-cost assessment of the CHC transmission line and its alternatives.

MARKET CONTEXT OF THE APPLICANTS' CPCN APPLICATION

Q. Please describe any electricity market drivers that the Commission should consider for context.

A. Due to major technological innovations in the electricity sector the dynamics of energy markets across the world are changing incredibly fast. As the cost curves of emergent technologies decline at a rapid rate, the risk of stranding 20- to 40-year capital-intensive traditional infrastructure investments increases at a similar rate. Below are some trends, which are not hypothetical, indicating how these market dynamics are unfolding across the United States:

- Coal plants that are still on PacifiCorp's balance sheet (and in its rate base) are operating uneconomically, i.e., losing the utility money.[10] Replacing most of those plants with new wind power purchase agreements would be cheaper for the utility, even without taking the plants out of its rate base.[11]
- Commissions across the country are rejecting utility plans to build new gas plants because smaller and cleaner alternatives could be cheaper.
    - The Arizona Corporation Commission instituted a moratorium on new gas plants after rejecting the IRP filed by the state's investor-owned utilities.[12]
    - The Oregon Public Utility Commission rejected Portland General Electric's ("PGE") initial IRP indicating a need to possibly build one or

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[10] PacifiCorp, *2019 Integrated Resource Plan Public Input Meeting*, 2018 December 3-4. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_December_3-4_2018_PIM.pdf

[11] Energy Strategies, *PacifiCorp Coal Unit Valuation Study: A Unit-by-Unit Cost Analysis of PacifiCorp's Coal-Fired Generation Fleet*, 2018 June 20. Available at: https://www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf

[12] Utility Dive, *Arizona Regulators Move to Place Gas Plant Moratorium on Utilities*, 2018 March 15. Available at: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/

two new gas plants. PGE found the gas plants could be avoided with small-scale solar qualifying facilities and a renewed hydro contract.[13]

  - The Indiana Utility Regulatory Commission rejected an 850 MW gas plant proposed by the investor-owned utility, Vectren, and directed the utility to evaluate alternatives to large, centralized resources.[14]

- Utility-scale solar-paired energy storage resources are "solidly competitive" with natural gas combined cycle plants in MISO.[15]
- Wind-paired with energy storage could reduce congestion in high-wind penetration areas similar to a transmission line. In addition, since independent developers would likely be building the energy storage, the capital costs would not be borne by electric customers as the CHC transmission line would require.
- Portfolios of emergent technologies such as energy storage, renewables, and other distributed energy resources like energy efficiency and demand response coupled with upgrading existing transmission and distribution ("T&D") infrastructure are proving capable of meeting electric system needs more cost-effectively than the construction of new traditional T&D infrastructure. As detailed in a recent report by the Rocky Mountain Institute,[16] non-wires solutions or as referred to

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[13] Portland Business Journal, *PUC gives Portland General Electric another chance on new renewables*, 2017 August 8. Available at: https://www.bizjournals.com/portland/news/2017/08/08/puc-gives-portland-general-electric-another-chance.html

[14] Utility Dive, *Indiana regulators reject Vectren gas plant over stranded asset concerns*, 2019 April 25. Available at: https://www.utilitydive.com/news/indiana-regulators-reject-vectren-gas-plant-over-stranded-asset-concerns/553456/

[15] Fluence, *Beyond Peaker Replacement: Solar+Storage Finds a New Job*, 2019 April 18. Available at: https://blog.fluenceenergy.com/fluence-energy-storage-solar-storage-mid-merit-utility-scale-asset

[16] Rocky Mountain Institute, *The Non-Wires Solutions Implementation Playbook: A Practical Guide for Regulators, Utilities, and Developers*, 2018. Available at: https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf

henceforth, alternative transmission solutions ("ATS"), require evaluation processes that are able to accurately value the full benefit of the new technologies.

Q. Can you provide examples of where Alternative Transmission Solutions have been the most cost-effective solution to an electric system need?

A. Yes. In a recent presentation on "Non-Wires Solutions,"[17] Wood Mackenzie detailed that there were almost 100 projects in the United States that used "non-wires" alternatives to traditional "poles and wires" projects in 2018.[18] I would like to highlight two specific projects, detailed in a SEPA report[19], that have been identified to fulfill a need on the transmission system:

- Bonneville Power Administration's South of Allston project was procured to relieve a transmission constraint related to summer peak power flows. The solution was 100 MW of redispatched generation and procurement of demand response.[20]
- Con Edison's Brooklyn Queens Demand Management project was procured[21] to relieve a sub-transmission constraint at a substation. The solution consisted of approximately 52 MW of energy efficiency, demand response, distributed solar, and energy storage.[22]

[17] Rocky Mountain Institute, *Non-Wires Solutions: Opportunities and Challenges for Scaling the Market*, 2019 April 4. Available at: http://rmi.org/wp-content/uploads/2019/04/2019.4.4-RMI_NWS-Webinar-Deck-FINAL.pdf
[18] *Id.* Please see slide 7.
[19] SEPA, *Non-Wires Alternatives: Intervention Studies from Leading U.S. Projects*, 2018 September. Available at: https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/
[20] *Id. See* pages 45-48.
[21] *Id. See* pages 52-55. Note that Con Edison has received an extension to procure additional load-reducing resources.
[22] *Id. See* pages 52-55.

The Long Island Power Authority has also considered using an ATS to defer transmission grid investment.[23] DALC/WWF witness Kerinia Cusick describes several additional examples of Alternative Transmission Solutions in her direct testimony.

Q. Please describe the benefit of evaluating Alternative Transmission Solutions.

A. The primary benefits of considering technologies that can provide alternative transmission solutions are twofold:

1. The cost curves of the emergent technologies comprising ATS are declining at a rapid rate, and
2. The emergent technologies comprising ATS can be deployed in a modular manner, which avoids the need for overbuilding (i.e., building a "gold-plated" solution for the electric system need). This mitigates the risk of cost-overruns and delays that have plagued the development and construction of traditional infrastructure.

Q. Are there other transmission market developments that the Commission should be aware of?

A. The Applicants' CHC transmission line is not the only transmission project proposing to increase the transfer capacity between Northeast Iowa to Southeast Wisconsin. The SOO Green Renewable Rail ("SOO Green") is a proposal for a 2.1 GW, high-voltage direct current transmission line. The project seeks to bypass permitting issues faced by above-ground transmission lines like CHC through "burying the transmission line along an

[23] Greentech Media, *A Snapshot of the US Gigawatt-Scale Non-Wires Alternatives Market*, 2017 August 22. Available at: https://www.greentechmedia.com/articles/read/gtm-research-non-wires-alternatives-market#gs.79vtsz

existing railroad and boring under ecologically sensitive areas" and proposes to become operational by 2024.[24]

Q. Why is the SOO Green Renewable Rail notable?

A. The SOO Green project is notable because the developer is independent and thus cannot fund it through a utility rate base.[25] This indicates that developers could be willing to take the risk of such a project without the certainty of a regulated rate of return. This also adds evidence that the CHC transmission line may not be needed. The Applicants' benefit-cost assessment does not consider the impact on the cost-effectiveness of the CHC transmission line or its alternatives assuming that the SOO Green project or other similar merchant transmission lines are eventually built.

Q. Can you provide evidence of the declining cost trajectories of the emergent technologies described above?

A. There are many sources that document the price trends for energy storage, photovoltaic solar, and other emergent technologies that can comprise an ATS. DALC/WWF witness Kerinia Cusick describes the declining cost trajectories of ATS technologies in her direct testimony in this case. Costs for these technologies have declined exponentially and are expected to continue a similar trajectory into the future.

Q. What evidence do you have that illustrates the risk of cost overruns and delays for traditional transmission infrastructure?

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[24] Utility Dive, *Independent developer proposes $2.5B underground transmission line, to bring Iowa wind to PJM, MISO*, 2019 March 13. Available at: https://www.utilitydive.com/news/independent-developer-proposes-25b-underground-transmission-line-adding/550399/

[25] *Id.*

A. Energy researcher Benjamin Sovacool and colleagues published two studies[26,27] examining the cost overruns of over 400 electric infrastructure projects, including 50 electric transmission lines. The average cost overrun for a transmission project examined was eight percent with a standard deviation of over 40 percent,[28] meaning certain transmission projects could have cost overruns significantly more than eight percent. In addition, the transmission projects examined were delayed for almost four years on average.[29]

Given that this testimony is evaluating the CHC transmission line, which is categorized as a MISO multi-value project ("MVP"), a more specific piece of evidence is that some MVP projects experienced cost overruns as high as 45 percent.[30]

Q. Can you detail how these emergent technologies are less financially risky relative to traditional transmission projects?

A. The studies also examined 39 solar projects and found average cost overruns of only 1.3 percent,[31] meaning they are significantly less financially risky than transmission lines. While the studies did not examine other emergent technologies that could serve within an

[26] B.K. Sovacool et al., *Risk, innovation, electricity infrastructure and construction cost overruns: Testing six hypotheses*, Energy 74 (2014) 906-917
[27] B.K. Sovacool et al., *An international comparative assessment of construction cost overruns for electricity infrastructure*, Energy Research & Social Science 3 (2014) 152–160
[28] *Id.* See Table 1, page 154.
[29] *Id.*
[30] Minnesota Department of Commerce, *Minnesota's Electric Transmission System Annual Adequacy Report*, 2019 January 15 at 13. Available at: https://www.leg.state.mn.us/docs/2019/mandated/190253.pdf.
[31] B.K. Sovacool et al., *An international comparative assessment of construction cost overruns for electricity infrastructure*, Energy Research & Social Science 3 (2014) 152–160. *See* Table 1, page 154.

ATS portfolio like energy storage, they validated the following hypotheses regarding cost overruns[32]:

- Bigger transmission projects are more susceptible to cost overruns.
- Longer transmission lines are more susceptible to cost overruns.
- Solar projects see fewer cost overruns with economies of scale but on a normalized basis per-MW of capacity, smaller projects actually have lower cost overruns than larger projects.
- Decentralized and modular projects experience few and small cost overruns.

The validated hypotheses for solar could be applied to other small, decentralized, and modular technologies like energy storage.

<u>SUMMARY OF THE APPLICANTS' CPCN APPLICATION</u>

Q. What is the "need" that the Applicants propose to meet with the construction of the CHC transmission line?

A. The Applicants claim that the CHC transmission line is "needed" to provide Wisconsin customers with more reliable energy, more affordable energy, and more renewable energy. The Applicants' witness, Mr. Dagenais, states that "the Cardinal-Hickory Creek Project, if approved, will provide Wisconsin electric customers with more reliable energy, more affordable energy, and more renewable energy; but for Wisconsin customers to realize these benefits, the Cardinal-Hickory Creek Project needs to be constructed."[33]

[32] B.K. Sovacool et al., *Risk, innovation, electricity infrastructure and construction cost overruns: Testing six hypotheses*, Energy 74 (2014) 906-917.
[33] Direct-Applicants-Dagenais-6

Q. How do the Applicants support their conclusion that the CHC transmission line is needed?

A. The Applicants primarily support the purported "need" for the line through a quantitative benefit-cost assessment.[34] The Applicants cite additional qualitative benefits as well although it is not clear whether Mr. Dagenais relies on these qualitative factors to support his claim that the line is "needed."

Q. Please summarize the Applicants' benefit-cost assessment.

A. The Applicants quantify five different benefit metrics for each of four different alternatives, or "interventions." These benefit metrics capture the different avoided costs (or savings) of meeting electricity demand ("load") in Wisconsin due to each of the three action interventions relative to the No Action intervention ("NA"). The Applicants then estimate the capital cost of each intervention and calculate the net benefit for Wisconsin as the difference between the benefits and costs. The four interventions are finally compared to each other based on their estimated net benefits. The net benefit is the criterion upon which the Applicants' conclude that the CHC transmission line should be built.

Q. What are the different interventions examined by the Applicants in their benefit-cost assessment?

A. The Applicants examine the CHC transmission line and three alternatives, which I detail below per their application:

[34] Ex.-ATC-Application-Vol. 2:37. (PSC REF#:352698)

1. Under the No Action intervention, no new transmission infrastructure is built other than reliability upgrades to the existing system necessary to maintain safety and reliability. This intervention is the baseline or reference intervention used by the Applicants to determine avoided costs/savings of each of the other three action interventions.
2. Under the Cardinal-Hickory Creek intervention, the Applicants' proposed transmission line is built.
3. Under the Low-Voltage Alternative ("LVA") intervention, a low-voltage transmission line is built instead of the CHC transmission line.
4. Under the Non-Transmission Alternative ("NTA") intervention, a portfolio of distributed energy resources, energy-efficiency, and demand response is developed instead of the CHC transmission line.

Each one of these interventions assume that capital improvements are needed to maintain an adequate and reliable transmission system.[35]

Q. What are the different futures examined by the Applicants in their benefit cost assessment?

A. The Applicants initially assessed the energy savings benefits of each of the aforementioned interventions in five different futures, which were based on MISO's 2017 Transmission Expansion Plan ("MTEP17"). To derive these futures, MISO and its stakeholders identified key variables affecting the future delivered price of electricity, which include load and energy forecasts, fuel prices, different levels and types of generation capacity retirements and expansions, and the design and makeup of the

[35] Ex-ATC-Application-Vol. 2: 48. (PSC REF#:352698)

regional transmission system. A plausible range of values was assigned to each of these drivers. Select values for each of these drivers were then assigned to the following three MISO futures:

- Existing Fleet ("EF"),
- Policy Regulations ("PR"), and
- Accelerated Alternative Technologies ("AAT").

The Applicants modeled the four interventions under all three MISO futures and two additional futures, both of which are variations on the MISO PR future:

- PR future with low demand/energy in MISO ("PRLE"), and
- PR future with the development of the Foxconn facility in Mount Pleasant, WI ("PRFoxconn").

Commission Staff later asked the Applicants to update some assumptions to include actual or likely changes that have become known since the initial futures were created. After making the changes requested by Commission staff and incorporating the Foxconn development, the Applicants re-calculated the energy savings of each intervention for the initial three futures:

- EF future with Foxconn and the PSCW changes ("EFPSCW");
- PR future with Foxconn and the PSCW changes ("PRPSCW"); and
- AAT future with Foxconn and the PSCW changes ("AATPSCW").

Thus, in total, the Applicants examined the four interventions under eight different futures.

Q. What are the benefits that the Applicants evaluate in their benefit-cost assessment?

A. The Applicants identify and quantify five different metrics in their benefit-cost assessment:

- Energy Cost Savings,[36] which represent the ability of each action intervention (CHC, LVA, NTA) to lower overall electricity costs for WI customers relative to the NA intervention.
- Capacity Loss Savings,[37] which result from the reduction of capacity costs for each action intervention relative to the NA intervention.
- Insurance Value,[38] which is the reduction in the economic impact of severe generation or transmission outages under each intervention relative to the NA intervention.
- Avoided Reliability Project Benefits,[39] which are the savings that result from avoiding the need to construct future reliability projects under each action intervention relative to the NA intervention.
- Asset Renewal Benefits,[40] which are the savings associated with avoiding the need to renew and replace existing transmission lines under each action intervention relative to the NA intervention.

To determine the net benefits of the various alternatives, the Applicants used the following equation:[41]

[36] Table 4, Direct-Applicants-Dagenais-34
[37] Table 6, Direct-Applicants-Dagenais-36
[38] Table 7, Direct-Applicants-Dagenais-37
[39] Table 9, Direct-Applicants-Dagenais-41
[40] Table 10, Direct-Applicants-Dagenais-42
[41] Direct-Applicants-Dagenais-43

Equation 1: Net Benefit of Each Intervention

$$\begin{gathered}Net\\Benefit\end{gathered} = Max\begin{bmatrix}Energy\ Cost\ Savings + Insurance\ Value\\ or\\ Avoided\ Reliability + \ Asset\ Renewal\ Benefits\end{bmatrix} + \begin{gathered}Capacity\ Loss\\Savings\end{gathered}$$

$$- \begin{gathered}Costs\ to\\WI\ Customers\end{gathered}$$

Q. What are the costs that the Applicants evaluate in their benefit-cost assessment?

A. The Applicants estimate the costs of each of the four interventions in the following manner:

- For the CHC and LVA interventions, the cost is calculated as the present value of revenue requirements charged to Wisconsin customers.
- For the NTA intervention, the cost is calculated as the present value of the cumulative capital and O&M costs of the measures included in the NTA portfolio. Unlike CHC and LVA interventions, no determination is made of the total revenue requirement charged to Wisconsin customers.

In the net benefits calculation, the Applicants heavily discount the cost of the CHC intervention based on their interpretation of the MISO MVP tariff, which allows cost allocation of approved MVP projects to the entire MISO region. According to the Applicants, only the CHC intervention is subject to the favorable cost allocation provisions of the MISO MVP tariff. Thus, in the net benefits calculation, only a small portion of the cost for the CHC intervention is accounted for compared to the full cost of the LVA and NTA interventions. This results in skewing the benefit-cost assessment in favor of the Applicants' preferred CHC intervention. DALC/WWF witness Jon Wellinghoff details in his direct testimony how an Alternative Transmission Solution ("ATS") portfolio, appropriately designed to meet transmission needs, would also be eligible for similar regional cost sharing as the CHC project. However, Mr. Wellinghoff concludes that the Applicants did not design their NTA intervention in a manner that would allow cost allocation as an ATS under the relevant FERC Orders.

Q. How do the Applicants determine the value of the energy savings benefit metric for the interventions?

A. The Applicants calculate the value of the energy savings benefit following these steps:

1. The Applicants first simulate the operational cost of serving the WI load under the NA intervention.
2. The Applicants then simulate the operational cost of serving the WI load under each of the other interventions. In each of the three interventions (CHC, LVA, NTA) this cost is lower due to the addition of transmission or generation resources in the system.
3. The Applicants then take the operational cost difference between each of the three action interventions (CHC, LVA, NTA) and the NA intervention. The result of step 3 is the value of the energy savings benefit for each action intervention on an annual basis.
4. The Applicants then calculate the energy savings benefit on a project lifetime basis by extrapolating for all other years, assuming a 40-year lifetime for each intervention.

Q. How do the Applicants simulate the cost of serving Wisconsin load in Steps 1 and 2 above?

A. The Applicants used Ventyx's PROMOD software package to simulate the cost of serving Wisconsin load in years 2021, 2026, and 2031 and for each of the futures described above. PROMOD is a production cost model that simulates operation of the power system by minimizing the operational costs (e.g. fuel, O&M) of serving a projected load with a given generation fleet and transmission system.

Q. Please state the benefits and costs of each intervention as determined by the Applicants.

A. Below is a summary of the purported benefits of each of the four interventions as calculated by the Applicants.[42] I break out the benefits for each intervention by the eight futures analyzed. The benefits are reported in millions of 2018 dollars ($M-2018 PV).

Table 1: Summary of Benefits for Each Intervention

		NA	CHC	LVA	NTA
Energy Savings	EF	0	38.9	35.5	32.3
	EFPSCW	0	33.6	25.3	30.5
	PRLE	0	214.6	195.2	41.4
	PR	0	164	166.1	31.7
	PRFoxconn	0	187.7	198.5	17.8
	PRPSCW	0	153.3	170.5	31.9
	AAT	0	407.8	484.2	67.4
	AATPSCW	0	383.6	434.1	58.9
Capacity Loss Savings		0	2.5	1	27.1
Insurance Benefit		0	6	5.8	1.2
Avoided Reliability Benefit		0	42.2	44.9	0
Avoided Renewal Benefit - Preferred Route		0	45	45	0

Table 2, shown below, is the summary of the total purported benefits as calculated based on the different benefit categories outlined in Table 1 and Equation 1.[43]

[42] Tables 4, 6, 7, 9, and 10, Direct-Applicants-Dagenais

Table 2: Summary of Total Benefits and Costs of Each Intervention

		NA	CHC	LVA	NTA
Total Benefits	EF	0	89.7	90.9	60.6
	EFPSCW	0	89.7	90.9	58.8
	PRLE	0	223.1	202	69.7
	PR	0	172.5	172.9	60
	PRFoxconn	0	196.2	205.3	46.1
	PRPSCW	0	161.8	177.3	60.2
	AAT	0	416.3	491	95.7
	AATPSCW	0	392.1	440.9	87.2
Cost		0	492	220.6	66
Cost to WI customers		0	67	220.6	66

EVALUATION OF THE APPLICANTS’ ANALYTICAL APPROACH

Q. Have you identified any flaws in the methodology of the Applicants’ benefit-cost assessment?

A. Yes. The first and most significant flaw is that the Applicants rely entirely on a production cost model to model the energy savings of the different interventions. The production cost model takes a snapshot of the electric system and simulates the operation of generators to serve system load in the least cost manner. However, given that the time horizon of the four interventions is very long, the Applicants’ should have used a capacity expansion model to reflect not only the operational cost of existing generation units but also the investment cost of new generation units. A capacity expansion model simulates investments in an electric system and operations of that system in the least cost manner over time.

[43] Total benefit of LVA differs from the one reported in testimony of the Applicants’ witness Mr. Dagenais, which seems to account for reliability savings of 42.2 instead of 44.9 as reported in Table 2.1-8 of the Application.

The Applicants' production cost model held the capacity expansion plan for each of the MTEP17 futures constant under all four interventions. This rigid approach does not reflect the dynamic changes in energy markets that are occurring today, which reduces the accuracy of the model. It would be more accurate to use a capacity expansion model in order to allow for new generation units to be built during the study horizon. The decisions regarding when and where to build those units would depend, in part, on whether the CHC transmission line exists to transfer electricity to load. In sum, the Applicants' choice to rely exclusively on a production cost model affects the results in two ways:

1. First, the energy savings of the CHC intervention are significantly overestimated.
2. Second, the analysis does not account for the capital cost of serving Wisconsin load in a consistent way across the different interventions.

Q. Please explain why using a capacity expansion model would be more appropriate than relying solely on a production cost model.

A. Let me start with an example. Climate change can significantly affect agricultural yield. Let's assume that a farmer grows crop A which is very sensitive to temperature changes. Let's also assume that if the temperature increases and the farmer continues to grow crop A, the farmer will lose the entire yield of the crop. However, if the farmer also has the option of growing crop B, which has a lower sales price but is less sensitive to changes in climate, the farmer will likely move to growing crop B to at least generate some revenue. In climate economics, when evaluating the damage that farmers may suffer from temperature increases, a crucial assumption is that farmers will adapt. Thus, the farmer's damage is calculated as the difference between the revenue of a successful yield of crop

A and a successful yield of crop B (since A is not feasible anymore due to temperature increases). The farmer can avoid losing all revenue by not blindly sticking to a decision which was only optimal under historic circumstances. This is possible because the farmer can adapt. Human systems are adaptive. Simulating how systems adapt is of crucial importance when evaluating the impact of any intervention in economics.

Going back to the MISO system, assuming that generating units will only develop in one way independent of whether the CHC transmission line is constructed or not is an extremely restrictive view that ignores the electric system's ability to adapt. Using a production cost model with a fixed capacity expansion plan is analogous to limiting the farmer to growing crop A even after the temperature increases. A capacity expansion model would instead allow for the flexibility of the electric system to adapt to changing circumstances.

Q. How is this limitation reflected in the Applicants' analysis?

A. The capacity expansion plan (i.e. the generating units) used in the analysis for each future is based on MISO's 2017 Transmission Expansion Plan ("MTEP17"). The Applicants simulate the operations of the *same* units under each intervention, with a specific change conditional to the specific intervention examined (i.e., LVA intervention replaces the CHC transmission line with an LVA line, leaving all else equal).

The major flaw is that the single capacity expansion plan that is used for each future was developed *assuming that the CHC transmission line is built*. Given that scenario, the capacity expansion plan in each future includes a lot of wind resources outside of Wisconsin and almost no construction of wind or other renewables within Wisconsin. However, the pattern of capacity development in MISO's footprint is very likely to change if the CHC transmission line is not built. In that case, there would likely be more local renewable resources built in Wisconsin.

Fixing the generating units to one capacity plan for each future under all interventions has the result of overestimating the operational cost under the NA, LVA, and NTA interventions. This is analogous to overestimating the damages to the farmer due to temperature increases if we restricted the farmer's ability to adapt to the climate. As humans can always choose what is optimal under changing circumstances, electric system investors can also choose how to develop generating units under different interventions. Restricting this ability leads to preferencing the CHC intervention while suppressing the benefits of the alternative interventions.

Q. Can you provide another example to illustrate why Applicants' assumption to use the same capacity expansion plan to simulate the production cost of each intervention is unrealistic?

A. Yes. Let's assume that New York City's ("NYC") Metropolitan Transportation Authority decides to add a new subway stop at the far East border of Queens. If the subway stop in Queens was built in 2021, housing development in NYC in 2031 would likely concentrate near the new subway stop as commute times into Manhattan may be only marginally longer with commuters living further away. However, if the subway stop was not built, housing development in that same area in Queens might look very different in 2031 as commute times into Manhattan from that area would likely increase without the new subway stop.

In their analysis, the Applicants are evaluating the operational cost of the MISO system under consideration in the No Action intervention assuming a generation and transmission fleet in 2031 derived based on the existence of the CHC transmission line. This is analogous to estimating the total commute time of commuters in NYC in 2031 using the housing developments that were built near a hypothetical subway stop in Queens even though the subway stop may never be completed. This preferences the alternative that includes the subway stop against alternatives that don't.

This example helps to illustrate how the Applicants' modeling choice to use a fixed capacity expansion plan across all futures inflates the energy savings benefits of the CHC intervention. The Applicants' assumption that the capacity expansion of the MISO system in future years would be the same with and without the CHC transmission line is unreasonable and preferences the CHC transmission line as compared to its alternatives.

Q. How does the Applicants' decision to use the same capacity expansion plan across all future scenarios in their model significantly overestimate the benefits of the CHC intervention?

A. By using a capacity expansion plan that is optimized for the CHC intervention, the Applicants' can claim congestion benefits that may not materialize in reality. Just like the subway example above, the assumption that the CHC transmission line exists will lead to generation capacity development patterns that rely on the line. This includes wind resources in the MEC and ALTW zone that can transfer electricity to Wisconsin via the CHC transmission line. The table below contains information on the assumed new wind capacity added each year ("MW") under the Applicants' future assumptions.[44]

[44] Data provided in Att. 1 to 01-DALC-ATC-38

[redacted]

[redacted]

As discussed above, the Applicants use the same capacity expansion plan to examine the NA, LVA, and NTA alternative scenarios even though the alternative scenarios *do not* include the CHC transmission line. Similar to the subway example discussed above, the generation capacity expansion plan developed based on the existence of the CHC transmission line leads to significant congestion and artificially inflated costs when the CHC transmission line is removed. When Applicants model the CHC intervention, the artificially created congestion costs in the reference case (i.e., NA intervention) are reduced and thus significant benefits accrue to the CHC intervention as compared to the alternative interventions. The Applicants' model does not allow consideration of more in-state renewable resources being built in Wisconsin even though it better reflects what is actually happening in Wisconsin today, as discussed further below.

Q. How does the capacity expansion plan in the analysis compare with what is currently happening in Wisconsin?

A. The MTEP17 capacity expansion plan includes no solar additions in the ATC zone for 2018, 2019, and 2020. This does not reflect what is actually happening in Wisconsin today. The Public Service Commission recently approved 450 MW of new solar projects in Wisconsin, including 300 MW located near the footprint of the CHC transmission line project. Dairyland Power Cooperative recently announced another 149 MW project in Jefferson County, called Badger State Solar, that will likely seek a CPCN in the near future.[45] Other smaller solar farms are in development throughout the state with much

[45] Journal Sentinal, *Solar power project planned for Jefferson County*, 2019 March 19. Available at: https://eu.jsonline.com/story/money/business/energy/2019/03/19/large-solar-power-project-jefferson-county/3206379002/

more likely on the way. The MISO generation interconnection queue for the ATC zone includes 4,612 MW of Solar PV.[46]

Q. Why does this matter?

A. It is further evidence that the fixed capacity expansion plan selected by Applicants does not reflect reality on the ground and is therefore unreliable.

Q. You mentioned that not using a capacity expansion model results in inconsistent accounting of the cost to serve Wisconsin load. Why?

A. A production cost model simulates the operation of the electric system in the least cost manner. The results reflect only the operational costs of generating energy. Within the model, generating units exist and their capital cost is not accounted for. This capital cost never shows up in the Applicants' calculations and the units are essentially free to build. Their only cost is operational. However, when evaluating the NTA intervention, the Applicants account for the capital and operating costs of the units. They partially refund this capital cost through the Capacity Loss Savings value, but this value is not high enough to cover all of the capital cost, while resources included in the capacity expansion plan are still free to build. The way the Applicants have set up the NTA analysis, they compare the operations of a fleet of free generators outside of Wisconsin versus the costs of constructing and operating resources in Wisconsin that would have to be built. Furthermore, the model ignores the significant fleet of renewable resources that are *actually* being constructed in Wisconsin today and likely into the future.

[46] MISO generation interconnection queue, accessed April 8, 2019. Available at: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

Q. Can you suggest a correct approach to modeling the system and evaluating the energy savings of the interventions?

A. The Commission should require Applicants to remodel the CHC project and its alternatives using a method that includes both investment and operational costs. The No Action intervention should be based on a system that is not premised on the existence of the CHC transmission line and an optimal expansion of the electric system given that the line does not exist. The cost of serving load for that intervention should include both the investment and operational cost. The CHC intervention should be based on a system that is premised on the existence of the line and an optimal expansion of the electric system given the line. Modeling the interventions would result in different developments of generation units on the system. Comparing the cost of the two different interventions would better reflect the actual potential savings of the line, which I believe would be very different than the energy savings purported by the Applicants using their flawed modeling approach in this case.

Q. In light of the methodological flaw discussed above, what is your opinion of the final recommendation to construct the line?

A. Although I cannot quantify the error introduced by following a flawed methodology without fully recreating the analysis, I am confident that the identified flaws have significantly impacted the purported benefits and the latter are not reliable. The CHC intervention’s energy savings are artificially inflated due to using the fixed capacity expansion plan. The NTA costs are artificially inflated by accounting for the capital cost of providing electricity, while this is not present in the CHC intervention analysis.

Q. You are claiming that the methodology used by the Applicants is incorrect. Besides the aforementioned flaw, what is your opinion of the recommendation made based on the numerical results?

A. The methodology is significantly flawed. However, even putting aside the methodological flaws and relying on the Applicants' results as presented, I find:

- the results to be sensitive to specific assumptions, and
- the recommendation to be based on a very thin margin of error.

Both findings decrease my confidence in the recommendation even if we assume the Applicants' methodology to be correct.

Q. What do you mean by the increased sensitivity of results?

A. Modeling is an inexact science with high levels of uncertainty. Determining the energy savings of the CHC intervention is characterized by the significant uncertainty of each input used in the model. Furthermore, any error in the assumptions gets propagated when the modeled footprint and time horizon are so large. Let me give a specific example: in Appendix D-5: Detailed Description of ATC's Customer Benefit Metric, the Applicants state that "based on discussions with our customers, ATC assumes that FTRs provide an 85 percent hedge against internal congestion costs, with annual FTR revenues equal to 85 percent of the calculated annual congestion cost." Changing this assumption to 90 percent for the PR future changes the CHC savings from $164M to $105M. So, an almost 5% change in the assumption made by the modeler changes the calculated benefits by 30%. This example is provided only to illustrate the sensitivity of the results to some of the parameters and assumptions.

Q. What do you mean by a "thin margin of error"?

A. It is important to put the magnitude of projected savings for the CHC intervention in perspective relative to its cost. For example, in the EF future the CHC intervention results in total benefits of $89.7M with a cost of $67M, even after taking into account the favorable MVP cost allocation. If the energy savings are overestimated or there are cost overruns as discussed above, the net benefits could very possibly be negative, in which case, I would conclude that the construction of the CHC intervention should not occur.

An intervention that would deliver benefits multiple times its cost would be a much more reliable recommendation even in the presence of uncertainty. But given the numbers presented within the Applicants' analysis, the net benefits of the line could possibly turn out to be negative if one or more of their assumptions are slightly different.

Q. In light of this sensitivity, do you consider the Applicants' projected energy savings due to the CHC line to be reliable? Do you agree with the final recommendation to construct the line?

A. No, to both questions. As discussed above, the Applicants' results are sensitive to specific assumptions. In other words, small changes in assumptions could drive large changes in results. Furthermore, the modeled energy savings of the CHC intervention are small in comparison to the simulated system energy cost.

A robust recommendation remains the same even if the assumptions in the analysis are somewhat violated. If an intervention resulted in significant savings that are multiple times higher than its cost, then even if those savings were only partially realized due to a change in the way reality unfolds compared to the model, the recommendation would remain the same. This is not true in this analysis.

Because the CHC transmission line under investigation is of such scale and of such long time-horizon, and is characterized by significant uncertainty, such a sensitive recommendation is not reliable and is risky. Making smaller additions to the system through an appropriately designed ATS portfolio as described in the testimony of DALC/WWF witness Kerinia Cusick would provide Wisconsin with much more flexibility to adapt, rather than committing to what may turn into a huge sunk cost that might fail to deliver the promised benefits.

Q. Mr. Dagenais claims that "[t]he Project would also improve the flexibility of the transmission grid in the face of changes to the regional generation portfolio."[47] Do you agree?

A. No. The CHC line requires a huge upfront capital investment. As described above, in the presence of significant uncertainty about future fuel prices, technology costs, and policy changes, the CHC line is a huge commitment. On the other hand, modular additions to the system have an optionality value, i.e. there is the potential of a high upside if renewable and storage costs decline rapidly and investment in such technologies becomes even more profitable, while there is a smaller downside as there is no stranded cost and locked capital. I believe that not committing to such large infrastructure provides the system with more flexibility to react and adapt to future changes.

[47] Direct-Applicants-Dagenais-13

EVALUATION OF THE APPLICANTS' ANALYSIS AND BENEFIT-COST ASSESSMENT

A. Evaluating the Need for the Applicants' CHC Intervention and its Alternatives

Q. Have the Applicants demonstrated that CHC transmission line is "needed" by the electric customers in Wisconsin?

A. No, I do not believe so. In planning for electric infrastructure, it is prudent to conduct a needs assessment prior to a benefit-cost assessment as the latter is only possible if a need is established and multiple interventions to meet that need exist. Based on my review of the Applicants' application and witnesses' testimonies, I am not aware of the Applicants performing a needs assessment that is specific to the CHC transmission line in order to establish a need that the CHC transmission line would meet.

Q. Can you provide an example to illustrate the sequence of the needs assessment and subsequent benefit-cost assessment?

A. Yes. A prime example of a needs assessment leading to a benefit-cost assessment is the process for developing an Integrated Resource Plan ("IRP"). The IRP process differs by state but based on best practices.[48] An IRP will assess a utility's needs (e.g., resource adequacy/capacity shortfalls, energy deficiency/sufficiency, local capacity needs/T&D constraints, etc.) based on many factors (e.g., load forecasts, generation mix, peak

[48] 25x'25 Alliance, *Best Practices for the Development of an Integrated Resource Planning Rule for Mississippi*, 2018 August 1. Available at: http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=554462

demand forecasts, etc.). Following the IRP, the utility may have a need to procure generation capacity to meet peak demand.

Based on this need for generation capacity, the utility may conduct an open procurement to solicit generation resources that meet the specified generation capacity need. Following such a solicitation, the utility will now have multiple options to choose from to meet their generation capacity need. In order to choose the best resource to meet the need, the utility will then conduct a benefit-cost assessment to compare the resource options from the solicitation.

Q. Have the Applicants conducted a similar process to establish a need prior to their benefit-cost assessment?

A. No. Based on the Applicants' Application and testimonies, I am not aware of the Applicants conducting a needs assessment that is specific to the CHC transmission line that would establish a time-dependent capacity need, reliability need, energy need, or any other need for the development of the CHC transmission line.

Q. What is your understanding of the need for the CHC transmission line?

A. My understanding is that the purported need for the CHC transmission line stems from MISO's analysis of the full portfolio of MVP transmission projects that were identified in 2011. The CHC transmission line is included as one part of the MISO MVP portfolio.

Q. Please provide further detail of the MISO MVP portfolio and the CHC transmission line.

A. The MISO MVP portfolio was developed over a multi-year planning process prior to 2011 to find regional transmission solutions to meet local energy and reliability needs.

However, while the portfolio as a whole was developed to meet specific needs, each individual transmission line was not. The CHC transmission line is the last project in the MISO MVP portfolio. As such, during the time between when the portfolio was developed prior to 2011 and now, many market changes have occurred. DALC/WWF witness Rao Konidena provides further detail on why the Applicants cannot rely on the needs assessment from the 2011 MISO analysis of the MVP portfolio as justification of the current need for the individual CHC transmission line.

Q. In light of the prior discussion, do you believe that Applicants have provided persuasive evidence to support their claim that the CHC transmission line is "needed"?

A. No, I do not.

B. <u>Evaluating the Applicants' claim that the CHC Transmission Line will provide more reliable energy to WI customers</u>

Q. Does the Applicants' benefit-cost assessment indicate that the CHC transmission line is needed to preserve system reliability?

A. No. It is my understanding that DALC/WWF witness Rao Konidena concludes in his direct testimony that the CHC transmission line is not needed to meet a near-term reliability need. Furthermore, the reliability needs of the system are successfully met in all four interventions. As such, the CHC intervention is not "more reliable" than the other interventions. The difference between the four interventions in meeting the reliability needs is only the avoided cost, which is reflected and accounted for in the final net benefit calculation for each intervention.

Q. Does the Applicants' benefit-cost assessment indicate whether one intervention is better than the others at preserving system reliability?

A. No. The Applicants' benefit-cost model indicates that all of the interventions under consideration maintain an adequate and reliable system. For example, according to the Applicants, even the NA intervention is a feasible alternative to the CHC intervention. Although the NA intervention is presented as the one with lowest net benefits, it still successfully addresses all reliability concerns through a set of upgrades and new projects identified in section 2.1.2.2 of the Application: "the Applicants compared the capital improvements needed to maintain an adequate and reliable system under the No-Action alternative to the capital improvements that would be needed under each of the other alternatives."[49] Thus, an adequate and reliable system is successfully maintained in the NA intervention. Similarly, reliability concerns are addressed for all interventions considered.

C. <u>Evaluating the Applicants' claim that the CHC Transmission Line will provide more affordable energy to WI customers</u>

Q. Does the Applicants' benefit-cost assessment indicate that the CHC transmission line is needed to provide WI electric customers with more affordable energy?

A. No. As described at length above, the Applicants' conclusion that the CHC intervention will provide net economic benefits is based on a significantly flawed methodology. The methodological flaws have resulted in the overestimation of the net benefits of the CHC intervention and the underestimation of the net benefits of the other interventions.

[49] Ex.-ATC-Application-Vol. 2: 48. (PSC REF#:352698)

Q. What is driving the majority of energy savings in the Applicants' benefit-cost analysis?

A. It appears from the Applicants' benefit-cost assessment that the majority of the energy savings come from relieving congestion. The Applicants used two different methods for determining the energy saving benefits associated with the various utility zones. For NSPW and Dairyland customers, the Applicants used the Adjusted Production Cost method of identifying potential savings. Adjusted Production Cost ("APC") savings measure the actual production costs of the power plants used to generate energy for a footprint, adjusted for imports and exports:

$$\begin{aligned} &\mathit{Cost\ of\ Generation\ Supply} \\ &\quad = \mathit{Production\ Cost\ of\ ATC\ Utility\ Generation} \\ &\quad + \mathit{Revenue\ to\ Utilities\ of\ IPP\ Contracts} + \mathit{Cost\ of\ Imports} \\ &\quad + \mathit{Revenue\ from\ Exports} \end{aligned}$$

However, for ATC, the Applicants use the Customer Benefit Metric ("CBM"), which differs from the APC method in that it has additional adjustments for congestion, financial transmission rights, and losses**:**

$$\begin{aligned} &\mathit{Total\ Customer\ Cost} \\ &= \mathit{Cost\ of\ Generation\ Supply} + \mathit{Congestion} + \mathit{Financial\ Transmission\ Rights} \\ &+ \mathit{Loss\ Charges} \\ &+ \mathit{Loss\ Refund\ and\ "Credit"\ for\ Losses\ Already\ Captured\ in\ Production\ Cost.} \end{aligned}$$

The Applicants refer to the CBM metric as only "slightly different" than the APC method.[50] However, the results of the two metrics differ significantly. As an example, below is a summary of the calculated savings for the CHC line in 2031:

Table 5: Calculated Savings for DPC WI, NSPW, and ATC in 2031

	(DPC WI and NSPW) APC Method	(ATC) APC Method	(ATC) Customer Benefit Metric
EF	$ 154,190	$ (3,250,124)	$ 2,913,722
PRLE	$ (76,173)	$ 8,156,092	$ 19,593,719
PR	$ 391,330	$ (6,099,850)	$ 13,944,244
PRFoxconn	$ 277,577	$ (4,345,330)	$ 16,426,517
AAT	$ 876,197	$ (4,451,969)	$ 33,711,033

The difference in the two metrics indicates that energy savings do not stem from the generation of lower cost energy (which would be reflected in the APC savings), but from adjusting for financial transmission rights and congestion. However, as already explained, this congestion could be artificially inflated due to the assumed capacity expansion plan in the Applicants' analysis. The CHC line cannot deliver benefits by solving a problem that might not exist.

Q. In light of the flaws discussed above, what is your opinion of Mr. Dagenais' claim that the CHC intervention is needed to provide Wisconsin electricity customers with more affordable energy?

A. I do not think the record supports Mr. Dagenais' conclusion. The Applicants simulate the operation of an electric system that has been developed conditional on the existence of the CHC transmission line. Consequently, the system includes significant wind capacity in Zone 3 and very few renewable resources built in Wisconsin. The Applicants then

[50] Ex.-ATC-Application-Vol. 2:45. (PSC REF#:352698)

remove the CHC transmission line and simulate the same system. As expected, there is no low-cost energy generated in Wisconsin, but this is not due to the absence of the CHC transmission line, but because the system does not include in-state renewable resources. It is unreasonable to expect that in-state resources will not be built absent the CHC transmission line. Furthermore, the CHC line provides relief from a congestion problem that might not be there (were the appropriate modeling method used).

D. Evaluating the Applicants' claim that the CHC Transmission Line will provide more renewable energy to WI customers

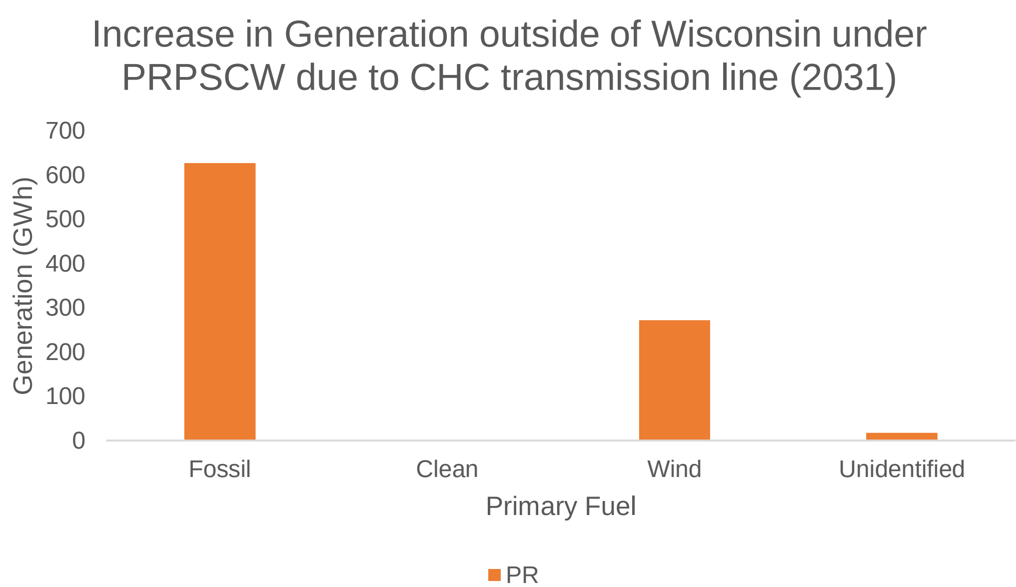
Q. Does the Applicants' benefit-cost assessment indicate that the CHC transmission line is needed to provide WI electric customers with more renewable energy?

A. The Applicants' conclusion that the CHC line will provide more renewable energy is again based on a significantly flawed methodology. The methodological flaw identified previously results in a fixed set of generating units in and out of Wisconsin. This set includes small numbers of renewable capacity in Wisconsin. This results in low renewable generation in Wisconsin in the NA intervention. However, this is not realistic. It is purely an outcome of the Applicants' decision to not allow renewable resources to develop in Wisconsin by using a fixed capacity expansion plan. The argument is dictated by the Applicants and does not reflect a realistic development nor the current actual experience in Wisconsin.

Q. Based on the Applicants' analysis, what is the fuel content of the imports made possible by the CHC line?

A. The Applicants have repeatedly failed to produce any evidence as to the fuel content of the CHC imports. At any given time, electricity enters into the electric system as different units operate. As such, I am not able to follow the origin of electrons and attribute any specific features such as the fuel content to any MWh. However, studying the generation schedules of the units outside of Wisconsin under the different alternatives reveals that the CHC line enables more fossil fuel generated MWh, and not just renewable energy. For example, below is a graph summarizing the increase in generation from units in Zones 1 and 3 in 2031 in the PRPSCW future when the CHC line is constructed. Although wind generation increases, so does fossil fuel generation.

Figure 1: Increase in Generation outside of Wisconsin under PRPSCW due to the CHC line in 2031



This information, as well as the differences in generation under the AATPSCW and EFPSCW futures are included in the following table.[51] For each scenario, the reduction in

[51] The table was created from data in spreadsheets provided as Att. 1 to 3-CUB-RFP-2. Primary fuel of each generator was identified based on Att. 1 to 1-DALC-ATC-38. The primary fuel of a few of the generators contained in Att. 1 to 3-CUB-RFP-2 was not identified and remains in the table as unidentified.

generation from units in zones ATC, DPC, and NSP, as well as the increase in generation in zones GRE, MDU, MP, ALTW, MEC, MPW is presented for year 2031 in GWh.

Table 6: Changes in Generation (GWh) due to the CHC line in 2031

		Difference in Generation in 2031 due to the CHC line relative to the NA case (GWh)			
Future	Pricing Zones	Fossil	Clean	Wind	Unidentified
AAT	ATC, DPC, NSP	-3109	3	-186	-22
	GRE, MDU, MP, ALTW, MEC, MPW	688	6	2109	36
EF	ATC, DPC, NSP	-517	-2	3	4
	GRE, MDU, MP, ALTW, MEC, MPW	342	0	3	12
PR	ATC, DPC, NSP	-1242	-4	38	-2
	GRE, MDU, MP, ALTW, MEC, MPW	627	0	272	18

In sum, the actual data presented by Applicants does not support their statement that the CHC will primarily carry wind generated electricity to Wisconsin. In fact, the data suggests that the line may provide a lifeline for fossil resources to reach Wisconsin. The line enables renewable generation, but at the same time displaces in-state fossil fuel electricity with out-of-state fossil fuel electricity.

Q. Please explain why the CHC line will carry more fossil generation than wind, under the scenarios described above in the Applicants' model.

A. As already mentioned, tracking the fuel content of the imports is not possible. However, we know that adding the CHC transmission line reduces generation in Wisconsin and increases generation out of Wisconsin. This is due to the increased imports. By looking how the generation changes when the CHC transmission line is introduced, I can gain some insight into what generation is enabled by the line. This generation includes wind but also a significant amount of fossil.

The fossil group includes: CT Oil, ST Gas, ST Coal, IC Oil, CT Gas, CC, ST Other, IC Gas, CT Other. The clean energy group contains the following: Conventional Hydro, Nuclear, Geothermal, Interruptible Loads, ST Renewable, Solar PV, IC Renewable. Wind is reported separately.

Q. Isn't it true that under the AAT future, there is more wind imported to Wisconsin?

A. That is correct, but this does not mean that more renewable energy is consumed in Wisconsin than would have been without the CHC intervention. If the CHC transmission line is not constructed, then it is reasonable to assume that more in-state resources such as wind and solar will be constructed and generation from those resources would occur within state rather than be imported. The reason this does not show up in the Applicants' analysis lies entirely with the modelers' decision of taking the same capacity expansion plan for all futures and not allowing the model to consider other resources built within the state of Wisconsin.

The system is simulated with the same generation capacity resources with or without the line. The Applicants' model does not allow for more in-state resources to be built even if developing the resources made economic sense. The Applicants' model only allows for the given resources to operate optimally within each future and under each case. So, there is no clear picture of what would really happen if the CHC transmission line were not constructed. However, I would expect that more renewable resources would be built within Wisconsin and more wind and solar energy would be generated in Wisconsin if the CHC line was not constructed.

Q. Isn't it true that the Applicants have provided unit specific generation data for only three future scenarios?

A. That is correct, the Applicants provided the generation schedules of all units in Zones 1, 2, and 3 in futures PRPSCW, EFPSCW, and AATPSCW. Although these futures contain edits to the original PR, EF, and AAT futures, I believe that the overarching conclusions are the same. If the Applicants provide data for all 8 futures, I will provide analysis to supplement the testimony.

Q. In light of the flaws discussed above, what is your opinion of Mr. Dagenais' claim that the CHC transmission line is needed to provide Wisconsin electricity customers with more renewable energy?

A. I do not believe the record supports Mr. Dagenais claim. Although it is impossible to follow the origin of any given MWh delivered to WI, we can draw conclusions by looking at the generation that is enabled by the presence of the CHC transmission line. For the area outside of Wisconsin, this generation is composed of not only wind but significant amounts of fossil fuel derived electricity. On the other hand, the methodological flaws discussed throughout my testimony result in a flawed reference case. Mr. Dagenais claims that the CHC transmission line will provide Wisconsin electric customers with more renewable energy, but fails to address the reference case against which this comparison refers to. The reference case presented in this analysis includes less renewable generation, but this is only so because the Applicants constrained the model in such a manner.

CONCLUSION AND RECOMMENDATION

Q. What is your overall conclusion based on your review of the record in this case?

A. I conclude that the Applicants' benefit-cost assessment for the CHC transmission line project is flawed in several respects and does not support the Applicants' conclusion that the CHC transmission line is needed to provide Wisconsin customers with "more reliable energy, more affordable energy, and more renewable energy." The claim that the CHC intervention delivers more reliable energy is not substantiated. The methodology used to derive the net benefits of the CHC intervention is flawed and leads to an inflated figure. And, finally, the Applicants have failed to persuasively demonstrate that the CHC intervention will bring in more renewable energy as compared to other possible alternatives.

Q. What is your recommendation?

A. I recommend that the PSCW direct the Applicants to remodel the CHC project and its alternatives in the manner that is suggested in my testimony.

Q. Does this complete your testimony?

A. Yes, it does.