**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF WISCONSIN**

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| 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 Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project | ) ) ) ) ) ) ) ) ) | 5-CE-146 |

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# DIRECT TESTIMONY OF KERINIA CUSICK ON BEHALF OF THE DRIFTLESS AREA LAND CONSERVANCY AND WISCONSIN WILDLIFE FEDERATION

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## TESTIMONY SUMMARY

The Applicants have not thoroughly and rigorously evaluated alternatives to the Cardinal Hickory Creek (CHC) transmission line project. The Applicants did propose multiple options in their Application, including a Non-Transmission Alternative (NTA). However, the Applicants did not attempt to design the NTA to fulfill even the Applicants' own stated transmission needs. The Applicants failed to evaluate proven, non-wires based solutions such as power electronics, energy storage, solar, and load control, and energy efficiency and demand response approaches in effective combinations to augment the performance of the existing transmission infrastructure, thereby potentially meeting the transmission need more effectively and efficiently. Therefore, the Commission should reject this application so that the Applicants can conduct a fair analysis to develop a portfolio of solutions—termed by the Federal Energy Regulatory Commission (FERC) as Alternative Transmission Solutions (ATSs)—that may be able to meet the current transmission need. Upon completing this analysis, Applicants should submit the analysis to the

Commission for a determination of which alternative is the highest priority energy option to be selected for Wisconsin, and other parties should be allowed a full and fair opportunity to respond. As described further in the testimony of former FERC Chair Jon Wellinghoff, an Alternative Transmission Solution portfolio should receive the same cost treatment as a wires-based transmission line, both from a cost-allocation and cost-recovery perspective.

**Q: Please state your name, employer, and business address.**

A: My name is Kerinia Cusick. I am the Board President of Center for Renewables Integration. My business address is 107 S. West St. #731, Alexandria, VA 22314.

**Q: Please describe your current position and provide your education and professional experience as it relates to this direct testimony.**

A: I am an engineer, and a solar and energy storage expert. I have worked in renewable energy since 2008. First, at Think Energy, a consulting firm that helped Fortune 100 companies procure clean energy. Then, in a variety of positions at SunEdison, a national solar, wind, and energy storage company, culminating as a Vice President of Energy Storage. Finally, as an independent consultant and co-founder of Center for Renewables Integration ("CRI").

Starting in 2017, CRI teamed with GridPolicy Inc. to research and publish on the topic of regulations that enable or restrict the use of Advanced Transmission Technologies[1] as transmission assets. CRI has also been an active participant in California Independent System Operator's ("CAISO") 2018 Storage as a Transmission Asset ("SATA") stakeholder process, where CAISO is working to develop rules to allow storage assets to provide transmission services and participate in markets. Additionally, CRI was one of the companies engaged by NYSERDA to develop New York's Energy Storage Roadmap.

In 2019, I launched research into the impact of a new write out IEEE? IEEE standard on the ability and cost effectiveness of using distributed assets to provide

[1] Advanced Transmission Technologies is a term defined in the Energy Policy Act of 2005 ("EPAct2005") Section 1223.

transmission and distribution support. This research is not yet published, but I do reference it in my testimony.

While at SunEdison, in 2015, I was a leader on the team that was developing, under a joint development agreement with Advanced Microgrid Solutions, now AMS, one of the energy storage projects that I refer to in my testimony. The AMS energy storage projects were contracted by Southern California Edison in 2014 to provide grid-support services as "virtual power plants" and recently announced 2 GWhr of hours in service.[2]

Also at SunEdison, between 2013 and 2015, I led a team developing stand alone as well as hybrid, solar plus storage systems in CAISO and PJM. In that role, I oversaw business development and storage financeability, and negotiated contracts with strategic suppliers, including battery providers and engineering, procurement and supply ("EPC") companies.

From 2011 to 2013, I led a team comprised of SunEdison electrical, power controls, and transmission and distribution system engineers, as well as General Electric transmission and distribution specialists to understand and analyze the technical challenges associated with transitioning Puerto Rico's grid to a very high percentage of renewable generation, and to develop cost effective solutions.

Prior to entering the renewable energy sector, I was an aerospace engineer with a specialization in the design of aircraft digital flight control systems and systems engineering for large systems such as the United States Department of Defense's National Missile Defense system. This is relevant because I have direct experience

[2] Available at: https://www.greentechmedia.com/articles/read/advanced-microgrid-solutions-breaks-2-gigawatt-hours-in-grid-services#gs.77t4ui

designing large-scale, highly complex systems, and modeling those systems to find optimal solutions.

I have a Master of Science in Systems Management from the University of Southern California, and Bachelor of Science in Mechanical Engineering from Drexel University.

**Q: On whose behalf are you testifying in this proceeding?**

A: I am testifying on behalf of the Driftless Area Land Conservancy and the Wisconsin Wildlife Federation ("DALC/WWF"), who are intervenor parties in this proceeding.

**Q: What is the purpose of your testimony?**

A: The purpose of my engagement with DALC and WWF has been to review the Application, testimony, and exhibits to determine if the Applicants thoroughly and rigorously evaluated alternatives that could have offset or deferred the need for the line, or met the transmission need via another option that has not yet been considered. In this testimony, I will focus on the Applicants' approach for developing the Non-Transmission Alternative ("NTA") option, discussing whether their approach is consistent with what I have seen in other jurisdictions, and whether the Applicants fairly evaluated the capabilities of non-wires based technologies to provide transmission services.

**Q: Did the Applicants provide a complete evaluation of alternatives and fairly evaluate the ability of non-wires based solutions to provide transmission services in a manner consistent with what has been performed in other jurisdictions?**

A: No, they did not. Although they did develop and include a Non-Transmission Alternative option in their Application, they dismissed a priori: the ability of technologies such as solar, storage, and demand response to provide transmission services, particularly when combined with existing transmission infrastructure. In other jurisdictions, I have seen transmission planners, as well as transmission owners and operators, analyzing and including non-wires based solutions in their toolbox of solutions, and in some cases finding these technologies to be more cost effective.

**Q: What is missing in the Application?**

A: The Applicants did not attempt to develop solutions, consistent with Wisconsin's Energy Priorities Law, which places a priority on non-combustible renewables and also fulfills the transmission need. They developed a Non-Transmission Alternative portfolio that cannot fulfill transmission needs, stating up front that the portfolio could not fulfill the transmission need and therefore dismissing technologies like energy storage that have been used successfully in other jurisdictions to fulfill transmission needs. In short, they never considered a real portfolio of Alternative Transmission Solutions.

**Q: What is an Alternative Transmission Solution?**

A: An Alternative Transmission Solution, or ATS, is a term used by FERC in its transmission planning Order 890 to designate potential alternative solutions to identified transmission problems by the utility transmission provider, third party project developer, or planning authority. Those solutions may encompass traditional transmission infrastructure such as wires, towers, and substations. The FERC made clear in Order 890, however, that Alternative Transmission Solutions also encompass another category of transmission assets, Advanced Transmission Technologies ("ATT"). DALC/WWF witness Jon Wellinghoff describes in detail in his testimony the applicable FERC Orders, and their basis in the Energy Policy Act of 2005, that establish ATSs. An ATS portfolio is designed to fulfill a specific transmission need, owned or operated by the transmission owner, and dispatched by the transmission system operator to provide transmission services. In contrast, the limited NTA approach like the approach taken by Applicants here did not use a robust combination of available technologies and only coincidentally reduced load.

**Q: What did Applicants review as part of their alternatives analysis?**

A: The Applicants included four options in their Application: Cardinal Hickory Creek Transmission Project ("CHC" or "Project"), No-Action Alternative ("NA"), Low Voltage Alternative ("LVA"), and Non-Transmission Alternative ("NTA").[3]

The CHC option is a 345 kV transmission line designed to fulfill the transmission needs identified by MISO as part of the 2011 MVP analysis. The LVA option is a 138 kV transmission line designed to mimic the performance of CHC, but is not granted similar cost sharing across MISO states as the CHC. The NTA option was developed to comply with Wisconsin's Energy Priorities Law[4] and includes demand response, solar and energy efficiency. That NTA, as presented, is an odd collection of technologies, excludes some obvious cost-effective options, was developed by engineers who according to their own admission have no experience with the technologies in question, and as such, both estimated the costs incorrectly and implemented them in a manner that did not try to provide transmission services.

**Q: Is an ATS portfolio the same thing as an NTA portfolio?**

A: It is not. DALC/WWF witness Jon Wellinghoff discusses the legal differences between the two in his testimony. Direct-DALC-WWF-Wellinghoff. From an implementation perspective, the difference is how the portfolio is designed, operated, and compensated. An NTA is designed to primarily provide an energy, capacity, or ancillary service

[3] Ex.-ATC-Application-Vol. 2: 37-38.
[4] Ex.-ATC-Application-Vol 2: 61.

solution to the system owner, and is located where the owner chooses. The NTA may also reduce load, thereby reducing transmission need. An NTA is not compensated as a transmission asset. An ATS is designed to first act as a transmission asset, sited where needed to fulfill a transmission need, and is contracted in a manner that ensures its availability. It is operated and compensated as a transmission asset. Both an NTA and ATS can include non-wires solutions such as distributed solar or load control. An ATS specifically includes technologies highlighted by Congress in EPAct2005.

**Q: What do you mean by "transmission" and "transmission services" in the context of an ATS?**

A: FERC Order 888 provided a legal definition of transmission, and described six ancillary services that the order deemed to be a subcategory of transmission services, other than the ability to transport electrons across wires. These are:

- scheduling and dispatching services,
- load following service,
- energy imbalance service,
- system protection service,
- reactive power/voltage control service,

  and
- loss compensation service.[5]

**Q: Did Applicants design the NTA option to meet a transmission need?**

[5] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, p. 199 (1996).

A: No. Applicants designed the NTA option by starting with a cost-cap developed by the Applicants, who calculated a budget to allocate to an NTA portfolio by estimating the cost of the CHC project allocated to Wisconsin ratepayers. They developed a constricted budget of $70.3M in 2018 dollars[6] and worked to fill up the budget by layering in demand response, utility and distributed solar, as well as energy efficiency. Applicants specifically stated that in designing the NTA, they did not attempt to identify a portfolio that could mimic the transmission benefits of the Project.[7]

**Q: Do you know why the Applicants did not design the NTA option to meet a transmission need?:**

A: No, I don't know why they chose to not do so, but, at the very least, it appears that they mistakenly concluded that it would be "incredibly difficult" or "impossible" to do so.[8] In developing the NTA option, the Applicants dismissed the ability of non-wires based technologies to meet a transmission need, and assumed some of these technologies, specifically energy storage, to be cost prohibitive. With regards to the NTA option, the Applicants state:

> By definition, non-transmission alternatives such as energy efficiency, demand response, and renewable or conventional generation would not directly link the high-voltage transmission systems in Iowa and Wisconsin. As a result, these options would have little impact on power transfer capability or transmission congestion, and would do little (if anything) to facilitate the import of low-cost energy into Wisconsin. Moreover, these options would not have the same reliability benefits as the Project; this is because transmission upgrade and maintenance projects that would otherwise be avoided if the Project were constructed would become necessary to maintain system reliability.[9]

[6] *Ibid*. Pg 38.
[7] Planning Analysis Document (revised), Appendix D at 29. PSC REF#363769.
[8] Planning Analysis Document, Appendix D (revised). PSC REF#363769.
[9] *Ibid*. Pg 61.

**Q: Do you agree with Applicants' statement that non-transmission alternatives, *by definition*, could not be designed to provide power transfer capability or reduce transmission congestion?**

A: No, I do not. It is correct that technologies such as solar, energy storage, power flow electronics, load control, and even energy efficiency cannot create a new link between two high voltage transmission systems. However, what is ignored in that statement is that those two transmission systems are already linked by a mesh of lower voltage transmission lines, and possibly at points to the north and south by high-voltage transmission lines. Speaking in broad terms, the transmission system is sized to accommodate a peak, similar to the rest of the electric system. A peak may only occur for a specific number of hours per day, such as from 4 to 6 PM, in certain months of the year (e.g. July through September). Using technologies such as solar, that generate electricity on peak, placed strategically on existing lower voltage transmission lines to reduce congestion where is it occurring, will flatten out the peak. A lower voltage transmission line outfitted with technologies designed to strategically reduce the peak may be able to "keep up" with higher voltage transmission lines that it is connected to. By using technologies in combination to reduce the load locally, the lower voltage transmission line may no longer be a bottleneck. Without bottlenecks, the cheapest generation assets can be dispatched. When bottlenecks occur, congestion charges are added, which constrains the dispatch. In short, bottlenecks can be eliminated by either adding new transmission, reducing load, or adding local generation, which has the same net effect as reducing load. The Applicants already found this to be true even with their NTA option, which provided 250 MW of increased transfer capability.[10]

**Q: Do you agree with Applicants' statement that non-transmission alternatives, *by definition*, could not be designed to provide reliability benefits?**

A: No. The Applicants' conclusion that non-wires technologies cannot address reliability needs is simply wrong and is a major gap in the Application. Technologies such as solar, storage, and demand response can be used to meet a reliability need on the transmission system. Reliability violations occur when thermal or voltage thresholds are exceeded. Thermal thresholds are typically exceeded when transmission lines are asked to carry too much power. Voltage violations occur when voltage deviates outside acceptable thresholds. Reducing the load that the transmission line is required to carry, again by providing local generation, can eliminate thermal violations. Generators, both fossil and inverter-based systems such as solar and wind, as well as energy storage and other technologies can provide voltage support locally, correcting voltage deviations. Reliability violations can be driven by peak load, but transmission planners will also examine a wide array of NERC-required contingency scenarios such as the failure of a substation or generation facility, and model the dynamic response of the transmission system to such events. Fast responding assets, such as energy storage, can also be valuable to correct transients, such as a spike in frequency or voltage caused by a sudden event such as the failure of generator or substation, since their response time is near instantaneous. In short, there are many technologies that can solve reliability problems, and that includes technologies that would be considered ATSs.

[10] Ex.-ATC-Application-Vol 2: 52

**Q: Are you aware of any examples of other utilities implementing Alternative Transmission Solutions that include solar, storage, demand response, and some upgrades to the existing transmission system, to provide transmission services?**

A: Yes, I'm aware of several good examples, both in the United States and overseas. Here are a few:

- In their 2017-2018 transmission plan, CAISO selected an Alternative Transmission Solution offered by PG&E as the most effective and efficient solution to a reliability need located in Oakland, CA created by a retiring generation facility. Transmission lines running to Oakland would have exceeded reliability limits in peak conditions with that retirement. Known as the Oakland Clean Energy Initiative ("OCEI"), the project is designed to fulfill a reliability need and includes a combination of wires and non-wires solutions, specifically:
    1. Upgrades to 230/115 kV transformer bank;
    2. Transmission line rerates on selected 115 kV lines;
    3. A minimum of 10 MW/40 MWhr in-front-of-the-meter Utility Owned Energy Storage within specified substation pockets;
    4. Competitive procurement of an additional 10-24 MW of preferred resources (e.g. solar, energy storage) sited within a specified substation pocket, of which at least 19.2 MW must be load modifying; and
    5. Continued reliance on transferring power from specified locations during peak loading conditions and after an N-1, in preparation for an N-1-1.[11]

[11] CAISO 2017-2018 Transmission Plan, Board Approved. Page 128. Available at: http://www.caiso.com/documents/boardapproved-2017-2018_transmission_plan.pdf

- CAISO, Southern California Edison and San Diego Gas and Electric first implemented local solutions to solve transmission constraints and the need to provide local capacity at specific substations in 2014, where they procured 250 MW of energy storage, some of it located behind the meter, to solve constraints at specific substations that could have also been solved by developing new transmission.[12] The behind-the-meter assets are contracted with the utility to follow a dispatch signal, providing local capacity at the instruction of the utility.
- In a project that started in 2015, Arizona Public Service connected 1,600 rooftop solar systems located on individual homes and concentrated on specific distribution feeders via smart inverters to their control center, controlling the output of those solar systems. APS' primary objective is to better understand how to control voltage fluctuations on feeders with a very high penetration of residential solar, but it demonstrates how the Applicants' residential solar solution included in their NTA option could have been designed as an ATS solution.

**Q: Can Alternative Transmission Solutions solve both economic and reliability-based transmission needs?**

A: Yes. While most of the ATS projects that are in the ground or have been selected by an ISO to date are designed to solve transmission reliability needs, ATS technologies can also be designed to solve economic transmission issues such as economic congestion. For example, PJM evaluated ATS projects as part of their 2018 Market Efficiency (aka economic transmission solution), although no ATS projects were selected in that round.

[12] https://www.greentechmedia.com/articles/read/breaking-sce-announces-winners-of-energy-storage-contracts#gs.7pdr6j

PJM is again evaluating a variety of ATS projects to fulfill an economic need as part of their 2019 Market Efficiency evaluation window. As of April 24, 2019, PJM is still evaluating solutions and has not yet selected an option.

Turning overseas, France is building a "virtual transmission line" using energy storage at both ends of the transmission line to relieve congestion for a project slated to come online in 2020.[13] Germany is currently evaluating 1,300 MW of energy storage to augment existing transmission and to act as virtual transmission lines.[14]

Regardless of whether the ATS portfolio is designed to fulfill an economic or reliability-based transmission need, the technology is identical. While each solution is sized to meet a specific need, a battery solution, for example, will include the same battery control system, battery cells, thermal controls, and inverter, whether it is being used to provide reliability or economic services.

**Q: In the examples you cited, did planners and regulators evaluate Alternative Transmission Solutions against other traditional, wires-based solutions and find the alternative solutions to be more efficient and effective?**

A: Yes. Where these projects have been selected, it is because planners and regulators found them to be more efficient and effective. For example, the Oakland Clean Energy Initiative ("OCEI") in CAISO was evaluated against the three following alternatives:

- 200 MW of new local generation to address the reliability issues,
- 115 kV line alternative,
- 230 kV line alternative.[15]

[13] Available at: https://energystorageforum.com/news/energy-storage/french-utility-rtes-ringo-virtual-power-line-will-come-online-in-2020
[14] Available at: https://www.tennet.eu/news/detail/transmission-system-operators-publish-first-draft-of-grid-development-plan-2030-version-2019/

The projected capital costs for the respective options are summarized below from the CAISO Board Approved 2017-2018 Transmission Plan:

Table 2.5-23: Estimated Cost of Alternatives

| | Estimated Capital Cost (2022 $M) | Total Cost (2022 $M) |
|---|---|---|
| **OCEI** | $56-$73[1] | $102[2] |
| **115 kV** | $193-$217 | $367[3] |
| **230 kV** | $316 | $574[4] |
| **Generation** | $232 | $368[5] |

Notes:
1 Proportion of CAPEX to contract spend will be determined by the most cost effective portfolio determined through the RFO
2 Calculated using unit costs of the expected portfolio, including land and O&M as appropriate
3 Based on the $193 CAPEX estimate assuming 2022 installation date
4 Based on the CAPEX estimate assuming 2022 installation date
5 Based on the CAPEX estimate assuming 2022 installation date

The Alternative Transmission Solution selected, OCEI, has a total projected cost of $102M, as compared to the costliest option which is a 230 kV line with an estimated total cost of $574M.

In some of the other examples listed above, such as the APS 1600 solar rooftop program, the utility sought approval from regulators to proceed as a demonstration program and part of a long-term effort to understand how to best incorporate distributed generation onto the grid.

**Q: Are you aware of other examples where a combination of solar, storage, and demand response have been used in lieu of developing a new transmission or distribution line?**

[15] *Ibid*. Pg 129.

A: Yes, I am. Here are a few examples where non-wires based solutions have led to the cancellation of planned transmission lines:

Bonneville Power Association ("BPA") announced in 2017 that it will not build the planned 500 kV, 80-mile I-5 Corridor transmission line. BPA announced it will instead:

- Implement a two-year pilot of "non-wires" projects to address congestion in the greater Portland-Vancouver area during peak periods of electricity use in summer;
- Identify upgrades to existing transmission infrastructure; and
- Update business and commercial practices.[16]

BPA did not make this decision lightly. In 2011, it commissioned a series of studies to determine initially if it could use "non-wires alternatives" to defer the transmission line,[17] ultimately concluding a few years later that it could cancel the project.

In 2017, CAISO announced it was cancelling $2.6B in previously approved transmission projects. In its press release, CAISO stated, "[t]he changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation."[18]

**Q: Did the Applicants consider whether an Alternative Transmission Solution could meet the transmission needs currently fulfilled by CHC?**

A: They did not. While the Applicants developed and included the NTA option in their Application, they did not consider the ability of some of the constituent technologies to

[16] Available at: https://www.bpa.gov/Projects/Projects/I-5/Pages/default.aspx
[17] E3, I-5 Corridor Reinforcement Phase 2 Non Wires Analysis: Feasibility for Line Deferral
[18] Available at: http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf

operate in a dispatchable manner, under contract with the Applicants, or in combination with the existing infrastructure in order to provide transmission services.

**Q: Please explain what you mean by "dispatchable" in this context?**

A: A dispatchable asset operates under the control of an operations center, turning on and off, or ramping up and down based on commands provided by a transmission or distribution operator. The operations center has some form of secure communications with the asset, and in addition to providing instructions, it can also see how the asset is performing. With the publication of IEEE 1547-2018, the US standard for inverters, now roof-top solar systems can be controlled by an operations center and can be dispatchable. The majority of demand response and load control in the US operates in a dispatchable manner. Power flow control electronics operate dynamically in near real-time to control power flows. Energy storage assets are dispatchable. Utility scale solar can be combined with cost effective, short duration, energy storage to firm intermittency, or combined with long duration storage to operate in a dispatchable manner.

**Q: What is your understanding of the reliability need that the proposed CHC transmission line is designed to fulfill?**

A: Based on a summary provided by MISO, the MTEP11 MVP analysis conducted eight years ago in 2011 found the CHC line will help mitigate reliability violations by reducing loadings on fifty-six (56) highly loaded system elements, including lines and transformers, in and around Wisconsin, when the generation required to meet the renewable energy mandates of the MISO states is included in the model. Based on this analysis, which concluded in 2011, the first projected date of overload conditions is 2021. MISO further clarifies the last analyzed date for these reliability issues is the identification date in 2011.[19] That means the reliability need for CHC is based on load models that pre-date 2011, and since that time, the United States has seen dramatic reductions in projected load growth. Additionally, the renewable energy assumptions in the 2010 era largely ignored the ability of solar to help the MISO states meet renewable energy goals and now 500 MW of Wisconsin-based solar has been approved by PCSW. These are significant changes which have not been reevaluated since 2011, as explained further in the testimony provided by DALC/WWF witness Rao Konidena.

MISO has run reliability analysis with recent load models, most recently the MTEP17 report, which does not show any reliability violations in the area of Wisconsin that will be served by CHC. However, it is difficult to isolate whether that is due to changed conditions (e.g. lower expected peak load in out years). Since the date of Board approval of the project, CHC has been included in MISO's model.

MISO did also provide an interconnection analysis published in 2018. The report evaluated the impact of integrating 4.7 GW of wind generation onto the transmission system and found that without the CHC line in place, voltage constraints and stability issues occurred at only two locations.[20] Additionally, a number of MISO reports have shown how the MVP portfolio as a whole improves system stability and solves other reliability needs, but those analysis look at the whole portfolio and do not isolate the reliability needs solved by CHC. Additionally, since that time, in April 2019, 500 MW of new solar energy projects were approved in Wisconsin and 4,000 or more new MW of solar generation are apparently in the queue.

[19] MISO'S Response to 01-DALC-MISO-02. PSC Ref # 36398101.
[20] Siemens PTI, MISO DPP 2016 February West Area Phase 3 Study. Report Number: R068-18. June 26, 2018, Pages 44 and 80.

Therefore, based on the information I have seen, the reliability need is not justified.

**Q: How would an ATS portfolio fulfill a reliability need?**

A: As mentioned previously in this testimony, reliability violations fall into two categories – thermal and voltage. A variety of technologies (e.g. solar, demand response, energy storage) can reduce load locally, which has the net effect of reducing the amount of power a transmission line must carry, thereby solving thermal violations. Voltage excursions outside of allowed thresholds require an asset to correct the voltage. I am most familiar with using solar and energy storage to correct voltage, where smart inverters are used to inject or absorb either real or reactive power to correct voltage. There are many other technology solutions that are available to address reliability concerns, but these are beyond my area of expertise. In short, a high voltage transmission line is one option to fulfill a reliability need, but not the only one.

**Q: Did the Applicants attempt to account for the reliability benefits of Advanced Transmission Technologies in their NTA option?**

A: No, they did not. The Applicants' benefit-cost model assumes that the NTA provides zero reliability benefits.

**Q: Was it reasonable for Applicants to assume that only the CHC and LVA options could provide reliability benefits?**

A: No. As discussed above, an Alternative Transmission Solutions portfolio, if appropriately designed, can provide reliability benefits. In my opinion, it was not reasonable for Applicants to ignore the potential of Alternative Transmission Solutions to provide reliability benefits.

**Q: Turning from reliability to economic benefits, did the Applicants persuasively demonstrate that non-wires technologies could not provide similar levels of economic savings to Wisconsin customers?**

A: No, they did not. From an economic perspective, as a line in the MVP portfolio, the CHC project contributes to mitigating market congestion issues. Based on the data provided in the Application, the Applicants claim that the NTA option provides between $17.8 and $67.4M in energy cost savings, as compared to the CHC option which provides between $38.9 and $407M in savings, primarily by increasing access to low cost generation.[21] The testimony provided by DALC/WWF witness Mihir Desu questions the accuracy of the economic analysis provided by the Applicants. Setting aside the accuracy of the Applicants' economic analysis for the moment, which is covered by Mr. Desu, and the need for "apples-to-apples" comparison as discussed by DALC/WWF witness Jon Wellinghoff, my testimony explains how Applicants failed to rigorously evaluate whether other technologies could provide similar levels of power transfer, and therefore economic savings, to Wisconsin customers. The Applicants did not attempt to design a solution using ATS that can achieve a similar level of power transfer. Even so, their flawed NTA option did achieve 250 MW of transfer capability. Since the Applicants did not attempt it, we don't know whether an ATS portfolio could achieve a similar level of power transfer as the CHC or LVA. But in the text below, I explain the concerns I have with the

[21] Ex.-ATC-Application-Vol 2: 45

Applicants' approach, and steps they should have taken to attempt to develop an ATS that may be able to provide a similar level of power transfer.

**Q: How do the Applicants estimate the economic benefit of the CHC transmission line?**

A: In their Application, the Applicants summarize the amount of power transfer capability provided by the various options (CHC, LVA, and NTA) using the metric of First Contingency Incremental Transfer Capability ("FCITC"), measured in megawatts ("MW"). FCITC measures the amount of incremental power that can be carried over a transmission network, without exceeding any violations. The economic dispatch model calculates expected savings that may result from this additional power transfer capability, but the megawatts of FCITC measures how much incremental power can be carried as a result of modifications to the transmission system. Therefore, the amount of savings is directly correlated to FCITC.

**Q: Did Applicants model the transfer capability provided by their NTA option in the Application?**

A: Yes. The Applicants calculated that the NTA solution provides an average of 250 MW of FCITC (170 MW during peak and 334 MW during shoulder). [22]

**Q: Did the Applicants calculate the FCITC provided by each element of their NTA option individually?**

A: No. Based upon information provided by the Applicants, they did not calculate the amount of FCITC provided by each element of their NTA solution individually. However, they estimate the majority of FCITC comes from the 30 MW of solar placed at

[22] Ex.-ATC-Application-Vol 2: 52

the Nelson Dewey Substation 128 kV bus, since the Stoneman – Nelson Dewey 161 kV line is the limiting transmission element for the transfer capability between Iowa and WUMS.[23] This is a significant point. Based on their own analysis, 30 MW of solar provides a significant portion of the 250 MW of incremental transfer capability attributed to Applicants' NTA portfolio. Given this result, it is surprising that the Applicants did not try to modify their NTA option to increase the amount of FCITC.

**Q: Did the Applicants include the potential FCITC provided by the recently-approved 500 megawatts of new solar generation in Wisconsin, and what should the Commission do?**

A: No, the Applicants did not. The Commission should take steps to ensure that this is done before reaching its decision in this case. On April 11, 2019, the Public Service Commission approved the new 300 MW Badger Hollow solar project—ten times larger than Applicants' NTA—in Iowa County Wisconsin, which is near the proposed CHC transmission line in Montfort, Wisconsin, and the impact of that large solar facility on FCITC has not been modeled. In addition, on April 10, 2019, a new 50 MW solar project was approved in nearby Richland County, and, on April 11, 2019, the Commission approved the new 150 MW Two Creeks solar project in Manitowoc County. The impacts of those solar facilities on FCITC has not been modeled. Nor have the impacts of the significant additional proposed and planned solar generating facilities been modeled.

**Q: Did the Applicants try to maximize the amount of FCITC that could be provided by an NTA or an ATS solution?**

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[23] Applicants' Responses to 01-DALC-ATC-26. PSC REF# 358984.

A: No, they did not. As further discussed in the testimony of DALC/WWF witness Jon Wellinghoff, the Applicants started with a cost cap, filled the bucket with an assortment of solar, energy efficiency, and demand response technologies until they ran out of money, and then entered the solution into the model to determine how many MW of FCITC they achieved. They did not first seek to design a portfolio that maximized FCITC, or iterate solutions once they saw the factors which had the greatest impact. Given that the majority of the modeled value of the CHC transmission line project comes from the purported economic benefit it creates, the Applicants should have attempted to design Alternative Transmission Solutions that may reach similar levels of FCITC as CHC. By failing to do so, they did not provide an equitable and fair analysis of the alternatives.

**Q: Did the Applicants explore whether energy storage could help enhance the transfer capability of the transmission system?**

A: No, they did not. The Applicants never considered using energy storage to increase the transfer capability of the existing infrastructure or whether they could use storage, or a combination of solar and storage, or solar + storage + other technologies, to mitigate congestion on the Stoneman – Nelson Dewey 161 kV line.[24] The Applicants have stated that 30 MW of solar on the line provided the majority of the 250 MW of FCITC. The peak hours of solar generation during the day may only have a small overlap with the hours of the day that Stoneman – Dewey is congested. Instead of prioritizing technologies based on cost effectiveness, the Applicants should have prioritized technologies based on

[24] Applicants’ Response to 01-DALC-ATC-26. PSC REF#: 358984.

their ability to increase FCITC. Adding a small amount of storage to the solar system may significantly increase FCITC by targeting the hours of congestion.

**Q: Please explain further how Applicants evaluated energy storage in the Application.**

A: The Applicants dismissed energy storage as an option without any serious consideration. With regards to energy storage, the Applicants state:

> Theoretically, a large portfolio of batteries could be designed to provide similar levels of reliability as the Project and to increase transfer capability by charging or discharging energy, depending on the storage location, when additional transfer capability is required. But a very large amount of storage would be required to replace the increased transfer capability that would be provided by the Project. That volume of storage could only be provided by pumped hydro, compressed air, or molten salt, none of which is available in Wisconsin due to Wisconsin's geographic features. Multiple storage installations at a variety of locations would be necessary. 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.[25]

When responding to a data request, the Applicants suggested energy storage would need, "a minimum capacity equal to the highest power flow in the reliability model, which is

- Hickory Creek – Hill Valley 345 kV line = 484 MW
- Hill Valley 345 / 138 kV transformer = 138 MW
- Hill Valley – Cardinal 345 kV line = 338 MW."[26]

This adds up to a total of 960 MW of energy storage, which the Applicants allege would be required to entirely replace the functionality of the CHC transmission line if energy storage was used alone without any other complementary technologies. The Applicants never estimated or even attempted to identify the amount of storage required if it was

[25] *Ibid*. Pg 62.
[26] Applicants' Response to 01-DALC-ATC-24. PSC REF#: 358984.

only used in combination to complement solar generation and other technologies, and/or augment the existing infrastructure in order to maximize FCITC.

**Q: Do you agree with Applicants that "a very large amount of storage would be required" to replace the Project?**

A: No, I do not. In fact, I think they are asking the wrong question. When the Applicants came to the conclusion that "a very large amount of storage would be required," they assumed that energy storage would need to *entirely replace* the functionality of the new CHC line. In my opinion, this was not a reasonable assumption because it failed to explore whether energy storage could be deployed cost effectively, in combination with other resources, to meet some or all of the transmission needs identified by Applicants. For example, as articulated above, the applicants did not examine how much additional FCITC could be achieved by adding storage to solar, which may increase coincidence of the solar generation with the peak. That combination is especially important and vibrant with the 500 MW of new solar energy generation projects recently approved in Wisconsin, and, apparently, many more solar energy generation projects in progress and planned in Wisconsin.

**Q: Do you agree with Applicants' conclusion that the volume of energy storage needed in this case could only be provided by pumped hydro, compressed air, or molten salt, and since Wisconsin geography cannot support those options it should not be considered?**

A: No. First, the statement that 960 MW of energy storage is required is false because the logical and sensible approach would be to use storage judiciously in combination with other technologies and to augment the existing infrastructure. Second, as will be explained later, the cost of battery storage is a function of the number of MWhr of energy storage required, not MW. Third, even if a very large amount of storage was required, the Applicants relied upon one data point to come to the conclusion that energy storage is not cost effective and did not pursue a serious effort to educate themselves on factors that impact cost.

**Q: Are other jurisdictions, or countries, installing large battery storage projects and finding the projects to be cost effective solutions?**

A: Yes, they are. Here are a few examples of large energy storage projects that have been built recently, many in record time:

- Australia: 100 MW / 129 MWhr energy storage project is installed to mitigate peaks and alleviate brown outs. The contract was awarded on July 6, 2018 and went into operation on November 23, 2018.[27]
- Aliso Canyon, California: 70 MW / 280 MWhr of energy storage is installed via 3 projects built by AES (now Fluence), Greensmith and Tesla, with some projects getting commissioned with 88 days of breaking ground. The projects were built in 2017.

Recent announcements or commission approval of projects include:

- In November of 2018, the California Public Utilities Commission approved contracts for the following projects, of which the largest is a 300 MW / 1200 MWhr project expected to be operational in 2020.

[27] Available at: https://www.powermag.com/tesla-bet-and-delivered-100-mw129-mwh-energy-storage-system-within-100-days/

| Developer | Size (MWs) | Grid Domain | Technology | Location | Duration (hours) | Contract Type | Duration (years) | COD |
|---|---|---|---|---|---|---|---|---|
| Dynegy | 300 | T | LiOn battery | Moss Landing | 4 | RA capacity-only | 20 | 12/1/20 |
| Humming bird Energy Storage, LLC | 75 | T | LiOn battery | Morgan Hill | 4 | RA capacity-only | 15 | 12/1/20 |
| mNOC | 10 | C | LiOn battery | Various | 4 | RA capacity-only | 10 | 10/1/19 |
| Tesla (PG&E owned) | 182.5 | T | LiOn battery | Moss Landing | 4 | EPC | N/A | 12/31/20 |

- In March of 2019, Florida Power & Light announced its intent to build a 409 MW / 900 MWhr project co-located with solar, to be operational in 2021.[28]
- In February of 2019, Arizona Public Service announced plans to add an additional 850 MW of energy storage to their grid by 2025.[29]

**Q: Do you agree with Applicants that electric batteries are "still too expensive to be considered as a reasonable alternative to the Project"?**

A: I do not. First, I disagree with the cost information the Applicants reference. Second, the way the Applicants considered using energy storage is the most costly application, and there are more cost effective options for using energy storage.

With regards to cost, it appears the Applicants drew their conclusions from one primary data point, specifically a smaller battery system (2.5 MW / 5 MWh) that ATC is proposing for a reliability application, with an estimated capital cost of approximately $10M.[30] From there, they extrapolated that energy storage would cost billions of

[28] Available at: https://www.powermag.com/fpl-will-build-worlds-largest-battery-storage-system/
[29] Available at: https://www.greentechmedia.com/articles/read/aps-battery-storage-solar-2025#gs.7rm0gn
[30] Ex.-DALC-WWF-Cusick-2, p. 4 of 5.

dollars,[31] which caused Applicants to reject storage as an option before it was even considered in any serious way.

The Applicants may not be aware that the capital cost of energy storage is a function of:

- discharge time, or duration (e.g. number of MWhr per MW);
- colocation with other assets, specifically solar, which may allow storage to receive the Investment Tax Credit ("ITC") and share infrastructure (e.g. inverters, interconnection upgrades); and
- the year when battery storage is installed and anticipated cost declines as manufacturing facilities ramp up around the world.

With regards to the capital costs of energy storage as a function of duration, data from a 2018 U.S. Energy Information Administration ("EIA") report is included in Ex.-DALC/WWF-Cusick-3. Based on EIA's data from various installed projects to date, capital costs for short duration batteries is $1000/kW, versus long duration batteries which have an average cost of $2500/kW. Therefore, if the Applicants could find applications for energy storage that require a short duration battery, costs will be reduced.

The U.S. Department of Treasury has also determined that battery storage assets that are charged more than 75% from solar can receive the solar investment tax credit, which is currently 30%, thereby reducing the cost of energy storage by 30%. In the same report, EIA summarized solar plus storage contracts that have been signed recently, showing how competitive these assets can be when sharing infrastructure, and/or storage is able to benefit from the ITC. The data included in the report is included below:

[31] Ex.-DALC-WWF-Cusick-2, p. 5 of 5.

- In May 2017, SolarCity (a subsidiary of Tesla) partnered with the Kauai Island Utility Cooperative (KIUC) to install a 15 MW solar array paired with an 11 MW battery storage system. The project was financed using a 20-year PPA at a price of $139/MWh.[14]
- In early 2017, KIUC signed a PPA with AES corporation at $110/MWh to finance a 28 MW solar array paired with a 20 MW/100 MWh battery system that is slated to come online by the end of 2018.[15]
- In May 2017, NextEra Energy entered into a 20-year PPA with Tucson Electric Power to finance a 100 MW solar array paired with a 30 MW/120 MWh energy storage system—the agreed-upon price was $45/MWh.[16]
- In December 2017, Xcel Energy's Colorado utility subsidiary announced the results of a recent solicitation where the median bid price for solar-plus-storage projects was $36/MWh and the median bid price for wind-plus-storage projects was $21/MWh.[17]

It isn't commonly known that stationary storage used for grid applications is frequently the exact same technology used for electric vehicles ("EVs"). As sales of EVs ramp up around the world, increased competition and manufacturing capability is rapidly driving significant cost declines. There are a variety of data sources for projected battery storage costs, of which I have included one, Bloomberg New Energy Finance in Ex.-DALC/WWF-Cusick-4. If this information from Bloomberg is correct, the projected installed cost for energy storage in 2023 may be around $100/MWhr.

In summary, the Applicants concluded that energy storage would cost billions of dollars is based on one data point, which is a misunderstanding of the cost factors and a false assumption that storage would be used on its own, not complementing other technologies. If used correctly, the Applicants may find they are able to achieve a very significant increase in FCTIC by adding energy storage, and the Commission should so explore and determine. Using Bloomberg's future cost estimates to make the cost tangible, if for example, the Applicants concluded that layering in 100 MW / 100 MWhr of energy storage in addition to other solutions, the capital cost for storage in 2023 may be as low as $10M, which is certainly much less than billions. The Applicants' conclusion that energy storage is “still too expensive” isn’t supported by the record and the market experience in the United States and around the world.

**Q: Have you identified any other flaws in the Applicants’ consideration of non-transmission alternatives.**

A: Yes. Even setting aside the fundamental flaws in the design of the NTA portfolio described at length above, the Applicants’ assumptions for the costs of the other technologies in the NTA portfolio are not accurate.

**Q: Do you agree with their cost estimates for utility solar included in the Application?**

A: I do not. With regards to utility scale solar, their estimates appear to be high, based on an examination of the same data the Applicants used as the basis for their analysis. Additionally, for residential solar, the Applicants are incorrectly assuming the entire cost of the system is borne by the Applicants instead of shared under contract with the hosts of the systems.

The Applicants stated they used National Renewable Energy Laboratory’s Annual Technology Baseline report as the basis to determine costs estimates for utility and residential solar in the NTA option. Ex.-DALC-WWF-Cusick-5 includes: (1) a summary of Applicants’ assumed NTA costs, as included in the Application; (2) data provided by NREL in their 2018 Annual Technology Baseline; (3) the Applicants’ data, extracted from a spreadsheet provided in response to Data Request 01-DALC-ATC-14 and 4) NREL’s current cost benchmarks for utility, commercial and residential solar.

Table 1 of Ex.-DALC/WWF-Cusick-5 shows the Applicants’ estimate of utility solar to cost approximately $64M in 2023, and for that facility to provide a maximum peak load mitigation of 30 MW, or a cost of $2.1/W. The Applicants’ projected solar costs are not consistent with NREL's current Annual Technology Baseline report, which projects future costs for various technologies, as well as NREL's 2018 cost benchmark summary. Based on data provided by NREL in their cost benchmark report, in 2018, the average cost for utility solar is $1.06/W for a fixed tilt system and $1.13/W for a system that is mounted on a single-axis tracker and designed to rotate and track the sun from sunrise to sunset. That means, based on NREL's data, utility solar already costs approximately 50% less than what the Applicants budgeted. This does not account for ongoing cost declines in solar, which will further reduce the costs of solar in 2023.

NREL's cost benchmark averages actual costs seen across the U.S. and does not project future cost declines. The latter is included in NREL's Annual Technology Baseline report. Ex.-DALC/WWF-Cusick-5 shows NREL's projection for a utility PV solar system in 2023. I have selected Chicago to use as an average for MISO, which is $881/kW (highlighted), or $0.88/W. Based on that information, the Applicants used cost information that is approximately 2.4x higher than what NREL projects.

Table 1 of Ex.-DALC/WFF-Cusick-5 shows the Applicants' input data used to calculate the cost of utility solar. It is probable the Applicants used data published by NREL in a previous year, possibly 2014. However, their data shows a projected cost of $1,213/kW ($1.2/W) versus the 2018 projection of $881/kW. It appears the Applicants may have misunderstood NREL's data and incorrectly adjusted for inflation. They ultimately used $1,899/kW as a nominal value to calculate the system cost. Finally, to reach a total cost of $2,100/kW, as shown in the application, the Applicants included 28 years of O&M costs in their 2023 investment calculations. Given that the Applicants are using upfront capital costs for CHC, and have not included O&M costs, it is not an apples-to-apples comparison.

Therefore, using current NREL data, not inflating it, and removing 28 years of O&M costs, the capital cost for a 30 MW peak solar system in 2023 should be $26M ($0.88/W), not $64M ($2.1/W). In comparing the NREL cost estimate to real solar projects that have been approved recently by the PSCW, they are slightly aggressive, but consistent. The PSCW recently approved contracts for 300 MW of solar with a cost of $389M ($1.29/W) to be built by 2022.[32]

**Q: Do you agree with the Applicants' cost estimates for residential solar included in the Application?**

A: No, I do not. Similar to the utility solar cost calculations, the Applicants used a nominal cost for residential solar that is significantly above NREL's estimated cost in 2023. NREL estimates a capital cost of $1,946/kW for residential solar in Chicago in 2023. The Applicants used a baseline of $3,041 in 2023, and similarly folded in 28 years of maintenance costs into the $6.5M estimate included in the Application. Therefore, using NREL's data, 2 MW of residential solar should cost $3.9M, not $6.5M, as shown in the Application.

Additionally, the Applicants should not include 100% of the cost of residential solar in their Application. If the Applicants were to decide to move forward with residential solar as part of an NTA solution, then possibly only a small incentive may be required to encourage Wisconsin homeowners to install solar on their own homes. The homeowner receives the primary benefit of installing the solar system and the Applicants

[32] PSCW Docket No. 5-BS-228, *Order and Final Decision* (April, 18, 2019) (PSC REF#: 364436).

don't need to pay for 100% of the system, and provide O&M for the life of the system. Incentives would motivate Wisconsin homeowners to install solar, and it would cost less than the $6.5M included in the Application.

Alternatively, if the Applicants chose to include residential storage as part of an ATS portfolio, which implies the solar would be installed on the distribution system fed by substations that require peak to be reduced in order to mitigate reliability or economic-driven congestion, then it is probable a higher incentive may be required to ensure residents supplied by that specific substation install solar. Additionally, in order to ensure these residential solar assets meet the criteria outlined in MISO's tariff, the Applicants may want to own the solar system and receive a lease payment from homeowners, or other similar contractual structure.

**Q: Finally, did the Applicants utilize experts in developing their NTA portfolio that have the appropriate experience, skills, and knowledge to develop a portfolio of solutions that can meet the transmission need?**

A: No, they did not. The Applicants relied upon ATC's experts Thomas Dagenais and Erik Winsand to develop their NTA portfolio and did not work with consultants to develop solutions or perform a peer review of their proposal. Mr. Dagenais and Mr. Winsand have substantial experience designing traditional wires-based transmission lines during their careers at ATC. However, as was stated in the deposition of Thomas Dagenais, these gentlemen do not have experience and do not consider themselves experts in the use of solar, storage, demand response, and other alternative technologies to provide transmission services. They stated that they relied upon publications from third parties, such as the National Renewable Energy Laboratories ("NREL"), FERC's Smart Grid

Report, and Wisconsin's Focus on Energy report to draw the conclusion that non-wires based solutions are not cost-effective.[33]

**Q: What is your overall conclusion based on your full review of the record?**

A: I do not believe that the Applicants have persuasively demonstrated that the CHC project is the highest priority energy option that is cost effective and technically feasible. The Applicants rejected without consideration a number of solutions based on Applicants' mistaken belief that the component technologies are not cost effective and not technically feasible despite the fact that such technologies have been successfully implemented as transmission solutions in other jurisdictions. The Applicants based their decision to ignore these technologies on fundamentally incorrect assumptions. They assumed that nearly 1 GW of energy storage would be required and it would cost billions of dollars, so they never considered it. In fact, they never considered using energy storage judiciously to augment the existing infrastructure, and deploy it in ways that would be cost effective. They also assumed that non-wires based solutions categorically cannot provide power transfer capability, when in fact their own analysis shows that it can. In sum, the Applicants, by their own admission, never tried to design a portfolio of non-wires based solutions that may be able to augment the existing infrastructure and provide a similar level of performance as the CHC project. In my opinion, the Application is fundamentally flawed and does not meet the Applicants' burden to demonstrate that the CHC project is the highest priority energy option that is cost effective and technologically feasible.

[33] Ex.-DALC/WWF-Cusick-2, p. 1-2 of 5.

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

A: Yes.