UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Implementation of Dynamic Line Ratings	)	**AD-22-5-000**
	)	

COMMENTS OF THE WATT COALITION, AMERICAN CLEAN POWER ASSOCIATION, ADVANCED ENERGY ECONOMY AND SOLAR ENERGY INDUSTRIES ASSOCIATION

April 25, 2022

Working for Advanced Transmission Technologies ("WATT Coalition"), the American Clean Power Association ("ACP"), Advanced Energy Economy ("AEE") and the Solar Energy Industries Association ("SEIA") [collectively "Clean Energy Entities"] appreciates the opportunity to provide information about dynamic line ratings technology and applications on the US transmission network. With Order No. 881, the Federal Energy Regulatory Commission created a new paradigm for transmission line ratings in the United States. The Clean Energy Entities strongly support the Commission's continuing work to ensure that line rating methodologies support just and reasonable rates. The Clean Energy Entities appreciates the Commission's finding in Order No. 881 that the "use of DLRs generally allow for greater power flows than would otherwise be allowed, and its use can also detect situations where power flows should be reduced to maintain safe and reliable operation and avoid unnecessary wear on transmission equipment."[1]

The Commission's requirement that transmission providers use ambient-adjusted ratings (AAR) will significantly increase transmission capacity and prevent customers from bearing unnecessary costs from phantom congestion. However, dynamic line ratings (DLR) can go further to ensure that congestion costs are only incurred with lines that are truly at capacity. DLR will also help interconnect cheaper and cleaner generating resources and allow grid infrastructure to adapt and better serve changing load and generation profiles. Prior comments of Clean Energy Entities in RM20-16-000[2] have been incorporated into this docket, so we do not restate those positions here. Where appropriate, some values have been updated in the responses below to reflect impacts of Order No. 881 or updated research and modeling.

Clean Energy Entities have previously suggested criteria for the Commission to use when requiring DLR. The intent was to provide a framework to identify lines where DLR would create system benefit, far beyond the cost of the installation, as an initial phase of operational DLR deployment in the U.S. We note that the Independent Market Monitor for PJM and the market

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[1] *Managing Transmission Line Ratings*, 177 FERC ¶ 61,179, P 253, December 16, 2021.

[2] *Comments of the WATT Coalition*, Docket No. RM20-16, March 22, 2022.

monitoring unit in Southwest Power Pool (referenced in FERC's NOI)[3] support broader deployment of DLR. A statement from the PJM market monitor in the 2021 State of the Market Report is unequivocal:

> The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.[4]

Clean Energy Entities believe that in addition to the contributions of DLR to reduce congestion costs for just and reasonable rates, DLR's benefits to reliability and the facilitation of new resource interconnection merit greater deployment than our initial criteria would achieve and supports FERC encouraging transmission owners to deploy DLR well beyond the minimum criteria. A similar recommendation was made in 2006 by the U.S. Canada Power System Outage Task Force:

> Develop enforceable standards for transmission line ratings. NERC should develop clear, unambiguous requirements for the calculation of transmission line ratings (including dynamic ratings), and require that all lines of 115 kV or higher be re-rated according to these requirements by June 30, 2005[5]

The Commission could take several approaches to facilitate greater deployment of DLR beyond the minimum criteria, including ensuring that jurisdictional transmission providers consider DLR in their transmission planning processes and when determining Network Upgrades necessary to interconnect new generation resources.[6] We note that the Commission's Notice of Proposed Rulemaking issued April 21, 2022 in RM21-17-000 did propose consideration of DLR in planning.[7] The Commission should also act in this docket on DLR requirements for transmission providers outside of the planning context.

In April 2022, the Department of Energy released *Grid Enhancing Technologies: A Case Study on Ratepayer Impact.* The study found that using DLR on just 16 transmission line segments would reduce New York's wholesale electricity cost by $1.8 million per year and reduce the gigawatt hours of renewable generation curtailed in the area by 9% overall.[8] In addition, the report finds that DLR provides proactive asset health monitoring and improves situational awareness, supporting grid reliability.[9]

In our response to Question 3, we suggest criteria that the Commission can use to direct transmission owners to unlock these consumer benefits. The recommendations are updated from

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[3] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110, at 6, February 17, 2022.

[4] Monitoring Analytics, LLC, *State of the Market Report for PJM*, March 20, 2022.

[5] U.S. - Canada Power System Outage Task Force, *Final Report on the Implementation of Task Force Recommendations*, at 54, June 16, 2006.

[6] *See Comments of Advanced Energy Economy*, Docket No. RM21-17, October 12, 2021; *Comments of the American Clean Power Association and the U.S. Energy Storage Association on Advance Notice of Proposed Rulemaking*, Docket No. RM21-17, October 12, 2021.

[7] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028, April 21, 2022

[8] Department of Energy, *Grid Enhancing Technologies, A Case Study on Ratepayer Impact*, at 41-44, April 20, 2022

[9] Department of Energy, *Grid Enhancing Technologies, A Case Study on Ratepayer Impact*, at 58, April 20, 2022

the WATT Coalition's recommendations submitted to the Commission on March 22, 2021,[10] to reflect the impacts of Order No. 881 and to ensure that entities outside of RTOs will also use DLR.

The Clean Energy Entities strongly support FERC's continued efforts to develop clear and effective policies for the use of DLR to ensure just and reasonable rates.

I. About the Clean Energy Entities

a. WATT Coalition

The WATT Coalition started in 2017 and is made up of technology providers who support greater deployment and use of Grid-Enhancing Technologies (GETs) such as dynamic line ratings, power flow control, and topology optimization. WATT members are listed at www.watt-transmission.org.

Grid Strategies LLC serves as the convener of the WATT Coalition.

b. American Clean Power Association

ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this document do not necessarily reflect the official position of each individual member of ACP.

c. Advanced Energy Economy

AEE is a national association of businesses that are making the energy we use secure, clean, and affordable. AEE is the only industry association in the United States that represents the full range of advanced energy technologies and services, both grid-scale and distributed. Advanced energy includes energy efficiency, demand response, energy storage, wind, solar, hydro, nuclear, electric vehicles, and more.

d. Solar Energy Industries Association

SEIA is the national trade association of the solar energy industry. As the voice of the industry, SEIA works to support solar as it becomes a mainstream and significant energy source by expanding markets, reducing costs, increasing reliability, removing market barriers, and providing education on the benefits of solar energy.

II. Questions on the Need for DLR Requirements

1. *As a threshold matter, even for transmission lines that incorporate AARs, is there a need to further increase the accuracy of transmission lines ratings through the implementation of DLRs to ensure just and reasonable wholesale rates? Why or why not? If yes, please explain whether a requirement by the Commission to adopt DLRs is needed.*

Yes – There are 3 primary ways that DLR will help ensure more just and reasonable rates:

[10] "Comments of the WATT Coalition," Managing Line Ratings, Docket No. RM20-16-000, March 22, 2021

1) **Reducing congestion costs:** In one study, DLR was found to increase transmission capacity by over 16% on average above AAR.[11] If this capacity is not accounted for, customers may pay congestion charges when a line could still have safely and reliably delivered more power. The 2020 State of the Market Report for MISO noted $51.9 million in savings possible in 2020 if emergency ratings were used, showing significant additional benefit beyond AAR.[12] A European modeling study found that deployment of DLR could result in a 50% reduction in the EU equivalent of congestion (redispatch costs).[13] Just and reasonable transmission service rates therefore require accurate line ratings.
2) **Enabling interconnection:** Transmission upgrade costs assigned to renewable energy projects seeking to interconnect to the grid can delay or defeat efforts to interconnect less expensive generation sources. Using DLR to measure the full capacity of existing connections could reduce, defer, or eliminate those costs and enable cheaper, cleaner generation. DLR can also be installed relatively quickly, increasing transmission capacity in a much shorter time frame than the many years typically required for traditional transmission expansion methods. A report by the Brattle Group found that DLR, in conjunction with other GETs, could double the capacity of new renewable energy to interconnect without additional transmission upgrades, saving ratepayers $175 million per year in Kansas and Oklahoma.[14] Just and reasonable generation interconnection cost assignments and interconnection procedures therefore require accurate line ratings.
3) **Reducing curtailment:** Because wind speed is the most influential factor in transmission line cooling, increased capacity from DLR is correlated with wind generation output. DLR can increase transmission capacity when renewable energy production is high, preventing the curtailment of the lowest-cost available resources. A modeling study of DLR deployment in Europe found renewable curtailment could be reduced by 47%.[15] Wholesale power rates are higher when output from low-cost generation is curtailed, so just and reasonable wholesale energy rates require accurate line ratings.

2. *What, if any, barriers to DLR implementation exist today? Are potential requirements to implement DLRs necessary to address these existing barriers? Why or why not?*

The cost-of-service business model and traditional planning reliability requirements and financial incentives are understood as the primary reasons that transmission owners are not deploying DLR in the U.S. Existing regulatory cost recovery paradigms incentivize transmission owners to focus on large, capital-intensive projects that attempt to maximize returns for their shareholders. A requirement to implement DLR as appropriate, or provision for an explicit incentive could help avoid the limitation implicit in the cost-of-service model and in some transmission planning

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[11] K. Engel, J. Marmillo, M. Amini, H. Elyas, B. Enayati, *An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies*, July 2, 2021.
[12] Potomac Economics, *2020 State of the Market Report for the MISO Electricity Markets*, at 65, May 7, 2021.
[13] Consentec, *The Benefits of Innovative Grid Technologies*, December 8, 2021.
[14] T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, February 1, 2021.
[15] Consentec, *The Benefits of Innovative Grid Technologies*, December 8, 2021.

regimes. An example of one such incentive is the shared savings incentive proposed by the WATT Coalition and AEE and considered by FERC in the September 10, 2021 technical conference.

The barrier between operating expenses and capital expenditures can also be an issue in deploying commercial DLR solutions where software-based services and cloud-based computing are integral to their operation. Consistent with FASB accounting requirements, cloud- and software-based services must over the long term be recognized by operators in their annual costs as OPEX. A recent white paper by AEE and the Edison Electric Institute states, "When cloud computing solutions are classified as an operational expense, they increase operating expenditures, making it more difficult to manage costs efficiently and retain savings from reductions in operating expenditures. Likewise, operating savings generally do not generate any direct returns, unlike the on-premises solutions they are replacing. As a result, this methodology ignores many of the long-term benefits that cloud solutions and data investments could provide to utilities and their customers."[16]

While requirements to implement DLR may not be the only solution to address the structural business model and rate recovery barriers that have prevented deployment of this technology to date, available evidence regarding the benefits of DLR adoption to ensuring just and reasonable rates would support putting requirements in place (including those noted above regarding transmission planning and the determination of required upgrades for interconnection). The Commission must choose a path or combination of paths (requirements and/or rate incentives), and time is of the essence. The need for transmission capacity is growing and congestion is rising in many locations.

III. Questions on Potential Criteria for DLR Requirements

3. *If the Commission were to require DLR implementation, should it require the implementation only on certain transmission lines, and, if so, what set of criteria should be considered to identify transmission lines for DLR implementation? Examples of such criteria could include congestion, curtailment levels, voltage levels, infrastructure, and/or geography/terrain. Explain why such criteria would identify the set of transmission lines on which DLRs need to be implemented in order to produce just and reasonable wholesale rates.*

In March 2021 comments to FERC, the WATT Coalition proposed an initial minimum set of criteria for DLR requirements. FERC's Order No. 881 has changed the baseline assumptions: AAR will be used on all lines and will provide capacity increases in many areas. However, AAR can overstate the capacity of lines – by over 20% of the time in one study.[17] The same study found that DLR unlocked more than double the additive capacity on average, compared to AAR.

[16] Edison Electric Institute and Advanced Energy Economy, *Reaching for the Cloud: Solutions for Regulatory Parity for Cloud Services for Utilities*, at 1, February 2022.
[17] K. Engel, J. Marmillo, M. Amini, H. Elyas, B. Enayati, *An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies*, July 2, 2021.

Given this expected reduction in total congestion, combined with the potential for AAR to overstate available capacity, the Clean Energy Entities now suggest:

- Actual market congestion totaling over $500,000 has occurred within the past 1 year, OR
- The line is identified as being a constraint projected to have market congestion over $500,000 in the future, or is a reliability-based constraint, OR
- Thermally limited lines identified as limiting in generator interconnection system impact studies or transmission service studies, OR
- Generation curtailed by more than 10% on average for 1 year due to factors that include line capacity.
- Lines where benefits are likely high: high average wind speed areas where conductor-limited lines over a given voltage threshold.

Given the estimate in FERC's NOI from the MISO transmission owners that DLR could cost between $100,000 and $200,000 per line,[18] and the expectation that DLR will increase transmission capacity by 16%[19] more than AAR, customers should break even on DLR installations within about two years and see significant net benefits in future years for lines meeting the above thresholds.

4. *How should transmission lines be evaluated for whether they satisfy such criteria, both initially and going forward? Please estimate the number and proportion of transmission lines that would likely be implicated by any criteria you recommend.*

Transmission lines should be evaluated based on the initial evaluation criteria suggested above in Question 3, and transmission owners should have information available to them concerning how much congestion each line has had. Information from generator interconnection studies and generation curtailment can be gathered from RTOs/ISOs and generation owners.

5. *If the Commission were to require DLR implementation based on certain criteria, should the criteria be regularly reevaluated to ensure such criteria continue to ensure accurate transmission line ratings, and, if so, at what interval(s)? How should such regular reevaluations work practically?*

As U.S. transmission owners develop competency in DLR and the energy resource transition continues, alternative or additional criteria for DLR may make sense. Clean Energy Entities recommend that the Commission re-evaluate its criteria every two to five years. The Commission should balance the need for re-evaluating criteria as circumstances change and experience is gained with DLRs against the need to ensure consistency of the criteria for the purpose of studies and certainty in investment.

6. *If such criteria included the magnitude of congestion on a transmission line, what metrics exist that assess the magnitude of congestion in both or either RTO/ISO and/or non-*

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[18] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110, at 10, February 17, 2022.

[19] K. Engel, J. Marmillo, M. Amini, H. Elyas, B. Enayati, *An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies*, July 2, 2021.

RTO/ISO regions? For any congestion metrics suggested, what data sources are available?

In RTOs, congestion costs are transparently provided through posted Locational Marginal Prices. FERC can, and should, require that more data be provided on the cause(s) of the congestion, including whether it was due to thermal line limits or substation equipment limits, which are directly addressed by DLR, or other kinds of limits not addressed by DLR, such as voltage or stability. Outside of RTOs, FERC should require reporting with similar detail and transparency as RTO areas for any transmission congestion that results in Transmission Loading Relief (TLR) events of any level, and all networked, conductor-limited 69kV and higher transmission lines in areas with an average wind speed of greater than 4 meters per second at 40 meters above surface level, as identified by NREL.[20] Candidate DLR deployment outside RTOs could be on those lines with a history of TLR 3 or higher events or expected to result in such events in the near future due to, for example, scheduled transmission outages of significant duration. Requiring this transparency is not only important to establishing clear and actionable criteria for DLR requirements but is consistent with long-standing FERC policy on open access transmission.

7. *Implementation of the requirements adopted in Order No. 881 are expected to change congestion patterns. How should these congestion pattern changes be accounted for when considering whether a transmission line satisfies the criteria established as part of any potential DLR requirements?*

The expected congestion relief impacts from AAR can be modeled during the design of a DLR implementation, and for those instances where overall congestion cost reduction is lower than the cost of a DLR system implementation, DLR would not be considered cost-effective and would not be implemented. The Commission does not need to wait until after AARs are fully deployed to implement requirements for DLR.

8. *What are the differences, if any, between RTOs/ISOs and non-RTO/ISO transmission providers that the Commission should account for when considering any DLR requirements?*

In general, requirements to implement DLR should be uniform between RTOs/ISOs and non-RTO/ISO regions. The only reasonable difference could be the metrics that are used to establish the requirements. For example, in RTO markets the metrics could be based on market clearing results, which provide a transparent measure of the system congestion that DLR would alleviate. Outside of the RTO markets, the metrics could be based on physical conditions conducive to DLR efficiencies, and TLR event frequency, as those data are available. The same physics, engineering, and economics apply—DLR can make more capacity available, enabling lower-cost dispatch to benefit customers and reducing pressure on transmission interconnection queues. Given the fact that RTO/ISO markets generally provide more transparency with respect to

[20] NREL, *Wind Resources of the United States*, September 18, 2017.

congestion then non-RTO/ISO markets, the Commission could consider providing RTOs/ISOs with some flexibility in implementing DLR.

9. *If the Commission were to require DLR implementation based on certain criteria, should it require that new transmission lines be evaluated to determine whether they must implement DLRs? Are there any characteristics of new transmission lines that warrant different criteria?*

While new lines may be designed to avoid a thermal limit, use of sensors that enable DLR could still be beneficial by providing situational awareness and supporting asset management. The digital sensors that feed critical inputs to inform line rating methodologies also provide situational awareness capabilities for grid operators to detect line slap, clearance violations, icing, galloping, or other asset health issues, which is critical to enhancing grid reliability. DLR can be cost effective in this case and a least costly alternative solution to traditional transmission investments. Transmission planning processes should account for the potential for DLRs to meet identified transmission needs.

10. *If the Commission were to require DLR implementation, how should that requirement be considered in regional transmission planning and interconnection processes?*

Power flow cases used in planning scenarios and interconnection studies should be internally consistent. With respect to DLR, the cases should reflect ratings on lines with DLR that are consistent with the assumptions made for other weather-driven resources, particularly wind and solar dispatch. For example, a case that models high wind dispatch should account for such higher wind to set the ratings for involved lines with DLR equipment.

Generally, the same set of criteria should serve in the interconnection process for requiring DLR. In addition, with appropriate analysis, interconnection customers should be able to propose GETs where they can resolve transmission constraints. If the interconnection customer is able to demonstrate that GETs are likely to facilitate interconnection, a study should be prepared involving the transmission owner to validate asserted GETs' benefits. If the results are verified with transparent modeling data and rationale, including cost-effectiveness, DLR could be implemented. Interconnection customers must have recourse to FERC if they believe the transmission owner refused the use of GETs on insufficient grounds. Cost allocation rules should be included in a requirement, and while beneficiary-pays allocation could be chosen, it is worth considering that the ratepayer benefits may exceed the costs of DLR in the interconnection application.

In the planning context, the Clean Energy Entities recognizes that planners often are required to assume worst-case conditions which would not routinely model the impacts of DLR. However, widespread deployment of DLR would reduce congestion and change flow patterns, which should affect transmission planning studies and results. Planning protocols for line upgrades should always consider GETs as an alternative to other approaches.

11. *If the Commission were to require DLR implementation based on certain criteria, what transparency measures should the Commission require? For example, should the Commission consider requiring transmission providers to submit informational reports that show which transmission lines meet any determined criteria for DLR implementation? And/or should the Commission require transmission providers to post the same on their Open Access Same-Time Information System websites?*

Yes, transmission providers should be required to post information on their OASIS sites consistent with Critical Energy Infrastructure Information (CEII) requirements. Utilities should provide transparency by reporting the facility ratings for all elements along a circuit pathway, again consistent with CEII requirements.

IV. Questions on the Benefits, Costs, and Challenges of Implementing DLRs

12. *For any DLR requirement criteria you identified in response to question Q3 above, please explain and, if possible, quantify the potential annual gross market benefits that would be expected to result from such a requirement.*

    a. *If possible, please also provide estimated upper and lower bounds on such gross market benefit estimations based on favorable and unfavorable assumptions.*

In MISO, the market monitor found that AAR and emergency ratings would cut 11% of congestion cost across the footprint – at the time representing $150 million per year.[21] DLR would exceed that value to the system, though with Order No. 881, AAR would already achieve about half of those savings. That still amounts to approximately $75 million per year in savings in MISO alone, however.

Another analysis estimates total congestion costs in the U.S. at $6-$8 billion.[22] If DLR could reduce that by 11%, per the MISO estimate, that would lead to savings of at least $600 million per year.

Other models have looked beyond congestion cost savings and investigated the additional production costs savings DLR would unlock by speeding the interconnection and integration of new, cheaper energy resources. A study by the Brattle Group[23] based on the 2020 interconnection queue in Oklahoma and Kansas and historical weather snapshots found that the deployment of DLRs on 56 lines, advanced power flow control in 8 locations, and topology optimization combined would create $175 million in annual production cost savings.

The Brattle method was "favorable" in that GETs were evaluated for comprehensive deployment for maximum benefit, rather than on a project-by-project basis. The Clean Energy Entities recommend that RTOs and transmission owners study the benefits of system-wide deployment to unlock the full benefits of GETs. On the other hand, the study was limited to something less than

[21] *Post-Technical Conference Comments of Potomac Economics, LTD.*, Docket No. AD19-15, November 1, 2019.
[22] Jesse Schneider, "Transmission Congestion Costs in the U.S. RTOs," November 12, 2020.
[23] T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, February 1, 2021.

the RTO's full footprint and could be considered "unfavorable" because electricity imports and exports from the study area were held constant. If the full region was modeled with imports and exports, there could be significantly more capacity for renewable generation in Oklahoma and Kansas, two wind- and solar-rich states. GETs should increase cross-border transfer capacity when looked at more regionally.

A study by the Department of Energy (mentioned in the introduction to these comments) evaluated DLR on 16 lines in New York and found $1.8 million in production cost savings and curtailment reduction and a 9% annual reduction in gigawatt hours of generation curtailment. The total cost of the modeled deployment was well below $3 million was thus projected to be providing net benefits within a couple of years.[24]

b. *How might these benefits change with geography/terrain, communication infrastructure, and transmission path?*

In general, DLR installations do not always use utility communications infrastructure. Some use satellite communications to ensure coverage in remote regions, so communications infrastructure is not necessarily a constraint.

The premise of DLR, that a transmission line's capacity varies based on environmental factors, naturally points to the relevance of geography and path. Accordingly, the impact of local conditions on the value of DLR will need to be evaluated for each candidate line. However, DLR installations can take place on live lines and by helicopter if necessary, so transmission path and terrain can be addressed where DLR benefits exceed costs.

Regarding specific areas for the selection of the deployment of DLR, a recently released DOE report on Grid-Enhancing Technologies concluded that finding the 'perfect' location for GETs is unnecessary. It also *"proves that GETs can be considered alongside traditional upgrades to optimize infrastructure investments in support of customer and policy interests today. Extensive study and overoptimization could lead to increased ratepayer costs in the time required to decide upon an optimized deployment scheme. Analysis is required, but utilities and regulators should be motivated by the full suite of GETs benefits rather than intricate cost-benefit optimization Studies."*[25]

c. *To what extent might DLR implementation shift congestion to new areas? How would these shifts in congestions patterns affect the overall benefits of DLR implementation?*

It is possible that resolving one constraint and increasing power flow over a certain line with DLR would lead to other lines becoming more highly loaded. This should be studied during a DLR implementation and DLR could be implemented in congestion pockets in such a case.

[24] Department of Energy, *Grid Enhancing Technologies, A Case Study on Ratepayer Impact*, at 40-44, April 20, 2022
[25] U.S. Department of Energy, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*, at 70, April 20, 2022.

d. *Please describe the method and assumptions used to estimate gross market benefits.*

The study assumptions were described in Q12a.

13. *If you have experience implementing (or evaluating the implementation of) DLRs, please describe your experience and, if applicable, explain your specific DLR design, installation, and operating decisions, choice of facilities on which to implement DLRs, the implications for reliability, and how such DLR implementation affected transmission transfer capability.*

The choice of transmission facilities has been well-addressed by other questions in Section III.

As Clean Energy Entities' membership includes several DLR providers, this response will not be specific to any particular installation or DLR provider's technology. However, from a DLR provider perspective, once a transmission line has been selected for a DLR implementation, the steps the transmission owner must take in conjunction with the DLR provider are:

1) Determine what type of DLR is needed: real-time, steady state, forecast (and over what horizons), and/or transient.
2) Perform an analysis of the line to determine on which transmission spans the DLR sensors specific to the selected provider should be located. This may include–but are not limited to–such criteria as span clearance-to-ground, topography, vegetation profiles, the directional orientation of the line, installation impediments, and prevailing weather conditions. DLR sensor locations and the number of sensors to be installed should be based on such analysis.

Other factors which should be considered should include the ampacity of next-limiting elements, any existing communication infrastructure limitations, and any special cyber-security requirements.

14. *What are the expected costs and challenges of implementing DLRs (separate from the costs associated with Order No. 881 implementation)?*

While it is important to understand the cost of DLR, that cost should be considered in comparison to the expensive and challenging problem of creating more transmission capacity via traditional methods and the reduction of congestion costs, rather than as a standalone cost. DLR makes transmission capacity available at an average unit cost of less than 1/20th of traditional line construction or reconductoring costs. In addition, the technologies' costs will decline as they reach economies of scale through wider deployment.

a. *How are these costs and challenges divided between initial implementation (e.g., sensor purchase and installation, EMS upgrades, and communications upgrades) and ongoing operations and maintenance (e.g., sensor maintenance, communications maintenance, and forecasting)?*

EMS upgrade costs will be driven by Order No. 881 compliance, and there are minimal if any incremental EMS costs expected for DLR support by the TO or ISO. There will be data integration costs required by the TO to bring data from the DLR provider securely into the EMS, but that typically would be a one-time cost. Annual licensing costs would be recurrent.

b. *How might these costs and challenges change with geography/terrain, communication infrastructure, and transmission path?*

Costs for DLR implementations vary only slightly site-by-site based on differences in line design, the number of changes in line heading, and length of stringing section. Availability of communications infrastructure is not necessarily a significant cost factor.

c. *Are there any published reports or studies assessing the costs, benefits and challenges of DLR implementation? If so, please identify and briefly describe these studies.*

The Final Report on Dynamic Line Rating prepared by ONCOR under DOE Award No. DE-OE000320[26] covers challenges to DLR implementation, such as integrating with system operations, and how ONCOR dealt with them.

Many studies cover the benefits of DLR implementation. Table 20[27] in the Department of Energy's case study in New York covers the impacts that can be quantified: congestion relief, asset deferral, renewable integration, situational awareness, resilience and contingency support, and asset health monitoring.

Other studies have evaluated specific DLR implementations:

- Ampacimon, "Wind Integration Use Case," 2019.
- S. Murphy, N. Dumitriu, N. Pinney, J. Marmillo. B. Mehraban, "Simulating the Economic Impact of a Dynamic Line Rating Project in a Regional Transmission Operator (RTO) Environment," CIGRE US National Committee 2018 Grid of the Future Symposium.
- B. Mehraban, D. Bowman, N. Pinney, J. Marmillo., "An Analysis on the Economic Impacts of Dynamic Line Ratings on a Congested Transmission Line in Southwest Power Pool," CIGRE US National Committee 2018 Grid of the Future Symposium.
- Bhattarai, Bishnu P., Gentle, Jake P., Hill, Porter, McJunkin, Tim Myers, Kurt S. Abbound, Alex, Renwick, Rodger Hengst, David, Transmission Line Ampacity Improvements of AltaLink Wind Plant Overhead Tie-Lines Using Weather-Based Dynamic Line Rating, July 1, 2017.

More studies of DLR impacts are collected at watt-transmission.org/resources-2.

d. *Please identify any factors or situations that might cause DLR implementation to be prohibitively expensive, and please describe alternative implementation approaches that could limit those costs.*

[26] Oncor Electric Delivery Company, *Dynamic Line Rating Oncor Electric Delivery Smart Grid Program*, DOE Contract ID DE-OE000320, August 2013.

[27] Department of Energy, *Grid Enhancing Technologies, A Case Study on Ratepayer Impact*, at 58, April 20, 2022

DLR monitoring systems have been successfully implemented across a wide range of geographies, line voltages and tower designs in the US and around the world.[28] One of the systems with the widest use of DLRs is Belgium, where the transmission system operator Elia has used DLR since 2008.[29] There are no anticipated factors that would cause DLR implementation to be prohibitively expensive for most installations where the cost of congestion is significant enough. Again, in any given instance the costs of DLR will be assessed against the congestion cost reduction and other savings the DLR project would create, and if savings do not exceed the costs, DLR would not be a cost-effective solution and would not be implemented.

e. *Please describe any advantages or disadvantages related to costs and challenges to implementing DLRs concurrently with the requirements of Order No. 881 (as opposed to after Order No. 881 is implemented). For example, are the EMS and communication upgrades required to implement AARs sufficient to support the use of DLRs?*

There are strong advantages to explicitly requiring ISO/RTOs and transmission owners to implement support for AARs and DLRs concurrently. The EMS upgrades to support AARs will be well aligned with the requirements for DLR, and the costs are likely to be lower if this upgrade is done concurrently to support both line ratings methodologies.

15. *Please describe the cybersecurity challenges of DLR implementation. What are the potential impacts to reliable operations if the digital devices that monitor or communicate line conditions used for establishing DLRs are manipulated or rendered inoperable by a cyber event? What relevant procedural or technical cybersecurity controls exist that would mitigate such risk?*

DLR alone does not increase cyber risk, as it only provides more information to operators. Nor does obtaining information on line sag or wind provide attackers the ability to directly control and therefore disrupt a system. The communications channel used by DLR systems is typically separate from a utility or transmission owner's communication network, minimizing the risk of compromising normal communication channels.

It is not necessary for the EMS to take rating data directly from a DLR system, that is, merge the DLR system into the real-time network, although this may be an efficient approach. Data could be accessed through a historian, or separate advanced application reducing cyber security risk. The appropriate and most cost-effective approach for a given line, including cybersecurity risks associated with the collection and transfer of data, should be analyzed as part of the implementation process.

While cyber risk is inherent with any utility operated system that is not isolated from incoming data streams, practices currently exist to minimize such risks. The Commission could clarify that operators may always default to a static rating if there is a lapse or suspected corruption of the information being sent, provided the corruption is detectable. Like all electronic systems, DLR equipment can and should be physically and cyber protected to safeguard the accuracy of the

[28] IRENA, Dynamic Line Rating Innovation Landscape Brief, on 15, 2020
[29] Elia, Dynamic Line Rating, Accessed April 25, 2022

measurements of actual conditions. Many DLR deployments worldwide show that these cyber risks can be effectively managed.

16. *If the Commission were to require DLR implementation, should the Commission direct NERC to evaluate how this requirement could introduce new risks to the reliable operation of the BES and whether any standards require modification to address any risks?*

NERC CIP requirements are generally met by a DLR provider's certification to ISO-27001 or adherence to ISO-27001 requirements.

In addition, DLR offers the ability to increase system reliability because real-time line conditions and capacity would become known to operators. Some DLR technologies are also helpful in identifying damaged or aging infrastructure to allow operators to prevent or respond more quickly to outages. As cited in the introduction of these comments, in 2006, the U.S.-Canada Power System Outage Task Force recommended that NERC should enforce line rating methodologies, including DLR, that should be required on all lines.[30]

NERC is responsible for evaluating reliability risks and setting standards to manage reliability risks to the grid. We assume that would carry over to the implementation of DLR as FERC and NERC deem appropriate.

V. Questions on the Nature of Potential DLR Requirements

17. *If the Commission required DLRs in some circumstances, would it be appropriate to require transmission providers to calculate transmission line ratings based on up-to-date forecasts of additional weather factors beyond those required in Order No. 881? Why or why not? If so, please explain what additional factors (e.g., wind speed, wind direction, solar irradiance (beyond day/night)) should be considered in transmission line rating calculations.*

Order No. 881 only requires the use of forecasted temperature, which is consistent with AAR. DLR accounts for line rating methods detailed in IEEE Standard 738 and/or CIGRE Technical Brochure 601 which cover all of the factors that may impact the thermal rating of a transmission line. Of these, wind has the greatest effect and therefore all DLR systems require the use of real-time and/or forecasted values of wind in addition to temperature. The use of additional factors varies by DLR provider.

18. *To what extent would it be appropriate to rely on sensor-based measurements of line parameters such as line sag, line tension, or conductor temperature in calculating line ratings, either in addition to, or in lieu of, forecasted weather factors described in Q17? In what circumstances should DLR approaches augment any sensor-based measurements of transmission line parameters with weather forecasts (e.g., from the National Oceanic and Atmospheric Administration or another weather service)? To what extent are sensor-based measurements of line parameters useful in determining longer-*

[30] U.S. - Canada Power System Outage Task Force, *Final Report on the Implementation of Task Force Recommendations*, at 54, June 16, 2006.

term forecasted line ratings (e.g., 2-7 days ahead), rather than just instantaneous or very short-term calculations of line ratings? How does the ability to forecast line ratings compare between DLR approaches that rely primarily upon sensor-based measurements of transmission line parameters and those that rely upon weather data?

Available DLR systems are based upon weather data, sensor-based measurements, or most commonly a combination of the two.

A variety of DLR systems are available which provide longer-term forecasted ratings.

Any entity considering the selection of a DLR provider must ensure that the provider's approach agrees with that entity's requirements regarding sensor-based measurements, the use of forecasted weather data, and the methods and data used in the determination of any desired ratings, whether they be transient, short term, or longer-term forecasted ratings.

19. *Should the Commission consider sensor-based DLR requirements, such as those suggested by WATT? If yes, what level of sensor coverage and performance requirements for such sensors should be required? Please explain whether the Commission would need to specify details like the types of sensors, how many are installed, what they measure, and the quality of their data? Would a sensor-focused requirement that specifies the types of technologies potentially become stale as DLR technologies evolve? Why or why not?*

The Commission should not consider specific sensor-based DLR requirements as these requirements can and will vary by DLR system provider. The response to Q13 outlines the general approach and method for sensor placement used by all DLR system providers. The Commission should leave sensor requirement details to the transmission owners and the DLR system providers. This is consistent with other transmission owners practices. For example, the Commission does not specify the type of equipment used for individual transmission lines. Rather, transmission engineers design the lines based on the specifics of each project and take into account company or regional policies and practices.

20. *In Order No. 881, the Commission adopted exceptions from the AAR requirements to ensure the safety and reliability of the transmission system and for transmission lines with transmission line ratings that are not affected by ambient air temperature or solar heating. Please explain whether the Commission should adopt the same or similar exceptions for DLR requirements. Are there any different/other exceptions from the application of DLR requirements that the Commission should consider? If so, what are these exceptions?*

It would make sense to exempt lines from DLR if their ratings are unlikely to change due to ambient conditions, such as underground lines. The Commission should take the same intent of the AAR exceptions and apply it to DLR. In addition to assessing the effect of ambient air temperature and solar heating, the exceptions should also factor in the effect of wind on the transmission line ratings. An exception based on the creation of excessive downstream congestion may also be appropriate.

21. *In Order No. 881, the Commission established requirements for AARs to be applied to a period not greater than one hour and for AARs to be updated hourly. Is this time*

resolution and calculation frequency also appropriate for DLR requirements or should an alternative approach be considered? Why?

The hourly time resolution and calculation frequency established for AARs could be an appropriate starting point if there is a potential to adjust the approach later on. Given that many impactful ambient conditions, such as the wind, change more frequently than hourly, moving to DLRs that are updated more frequently (i.e., 10-15 minutes) will provide additional upside capacity which would take advantage of the shorter duration time periods when favorable conditions are present and recorded by the field sensors.

The best practice would be for DLR inputs to have the same frequency as the real-time market for consistency reasons. Complexity or cost would not change much when shifting from hourly to 5, 10 or 15 minutes although much more data will be collected and transferred. EMS and MMS, for example, already take and produce information at the same or higher frequency as the real-time market. Renewable forecasts and load forecasts are all produced every few minutes. The real-time market clears every 5 minutes in RTO markets, but they could clear every 15 minutes in other markets.

It should also be noted that conductor size plays a role. The thermal mass of large diameter conductors can make the use of 10 or 15-minute ratings possible, whereas no change would be likely be seen on a 5-minute scale. However, 5-minute ratings may be realistic for smaller diameter conductors.

22. *How might the Commission consider potential requirements for DLR implementation on transmission lines that are on the seam of multiple transmission provider service territories? What additional coordination between neighboring transmission owners and transmission providers, if any, might be necessary?*

There should be a clear owner for each line even if it is on a seam but compatibility in ratings across service territories will be an important consideration. In the case of jointly owned lines, they will need to agree on their ratings methodology. Requirements related to increased transfer capacity during normal or more extreme system conditions should be evaluated/considered.

23. *In Order No. 881, the Commission required AARs to be used for near-term transmission service, defined as transmission service that ends not more than 10 days after the transmission service request date (i.e., within the next 10 days).*

    a. *Within what timeframes should the Commission require transmission providers to calculate transmission line ratings using DLRs (on transmission lines for which DLRs are required)? Does this depend on which DLR approach (weather-based or line parameter-based) is used for a particular DLR implementation?*

We support the application of DLR in near-term transmission service as defined above. That would include integration into real-time and day-ahead congestion management in RTOs. If it reduces the burden on transmission services, the forecasts could be reduced to within three to five days and lines could continue to use AARs for the remaining forecast days. The time frames should not depend on the type of DLR approach.

b. *For which transmission services (e.g., hourly point-to -point transmission service, daily point-to -point transmission service, weekly point-to -point transmission service, etc.) should the Commission require the use of DLRs?*

We support the application to hourly point-to-point transmission service and daily point-to-point transmission service. Beyond this, the dynamic transmission ratings will likely not have a substantial impact on markets or on reducing congestion.

c. *What data on the accuracy of forecasting wind speed, wind direction, and/or other DLR variables would support the DLR implementation timeframes and transmission services you recommend above in (a) and (b)?*

In Question 21 we note that conductor size may limit the short-term timeframe in which DLR ratings may change.

DLR systems provide statistical methods to accommodate comparisons of actual and forecasted variables, and support our recommendations in (a) and (b) above.

24. *If the Commission were to decide that a requirement to implement DLR is appropriate:*

a. *Should the Commission limit the number or proportion of transmission elements that a transmission provider must implement DLRs on at any one time, even if such elements otherwise met the criteria for a DLR requirement? If so, should such a limit be based on a number or percentage of transmission elements, and if so, what number or percentage?*

The Commission should not limit the number or proportion of transmission elements with DLR implementations at any one time. Utilities can and should be relied upon to pursue those system-wide investments that improve their reliability and cost performance. Our proposed requirements (e.g., a $500,000 yearly congestion threshold) would already significantly limit the number of required installations. Initial identification of applicable lines, selecting technology, and planning are likely the phases of greatest duration. Actual implementation does not need to be phased if proper planning occurs.

b. *Should the relevant transmission element for such a limit be considered individual transmission lines, or individual transmission line-miles, or some other unit? Or, if such a limit is necessary, would some other approach be better? Explain why you recommend any particular approach.*

We do not recommend any limits, and any rule should allow transmission owners to explain why they would need a limit should that be the case.

c. *Should such a limit be applied each time a transmission provider is required to evaluate whether DLRs need to be implemented on additional transmission lines (as contemplated below in Q29)?*

See Q24b and c above.

25. *If changed circumstances result in a transmission line no longer meeting the DLR criteria, should the transmission provider continue to be required to use the DLR to calculate the rating for that line? Please explain why or why not.*

The transmission owner should not be required to continue using DLRs for a line that no longer meets the criteria. However, at that point there may be little cost to keep the DLR system in place and available in the event future system changes, interconnections, contingencies, etc., arise that may benefit from the knowledge of DLR. It is possible a TO would wish to continue monitoring a line once the system is in place, especially as many DLR systems provide other benefits such as the monitoring of conductor aging.

Many DLR systems are modular and it could be a beneficial practice to utilize DLR systems for a period of time that DLR is beneficial. A line that meets the DLR requirements today can later be re-conductored or additional transmission lines can be added to the system to permanently increase capacity. In this way, DLR can complement transmission enhancements and expansion. Because many DLR systems are modular, when no longer needed the DLR system could be redeployed on another line or network area.

VI. Questions on Potential Timeframes for Implementing DLR Requirements

26. *What would be the appropriate amount of time, either from your experience or by your estimation, necessary for each of the following DLR implementation steps identified below?*

    a. *Transmission line identification for DLR system application.*

Timelines can vary based on system complexity. Lines posting current congestion usually can be identified quickly. If there are minimum congestion requirements (say $500,000/Year), for example, this information is typically already known by line. Some applications can also be identified immediately by way of looking at bottlenecks for generation interconnections or studies in current transmission planning or operations studies. On the other hand, studies may need to be performed to predict future congestion, including downstream congestion resulting from DLR implementation.

At the surface, lines identified immediately as having thermal constraints could be considered clear candidates for DLR. However, if these lines do not have favorable climatologies, false positives could occur due to, for example, wind conditions, and thus may not result in higher capacity.

The climatology situation may not be well understood in some instances; therefore, some amount of time should be factored in for transmission owners to perform a proper identification study. An assessment of the climatologies can be considered as part of the DLR requirement to avoid false positives.

    b. *DLR System design*

        i. *Field sensors and/or monitoring equipment design including specification, procurement, and installation.*

DLR systems are typically composed of a network of strategically placed monitoring sensors to accurately represent the actual overall transmission line rating for the lines. However, deciding on the number and locations of DLR sensors, as discussed in Q19), may or may not be trivial. Such determination can be expected to take as few as 6 weeks, and up to 6 months or more and is always project dependent. Procurement and installation can also take 2-6 months depending on the time of year (weather conditions). This is a reasonable timeline for utility procurement, and much faster than for some other types of equipment.

ii. *Communication infrastructure design, including specification, procurement, and installation.*

The communication infrastructure design timeline is relatively quick and likely unaffected by new projects beyond the first project with the transmission owner. The configuration of a communication network can vary, depending on the method that is utilized (i.e., out of the box LTE modems). We estimate the timeline to be as short as between two to four months. This step would be completed in parallel with paragraph b(i).

iii. *Process coordination between DLR field data and EMS, including any line rating database upgrades or necessary modifications.*

The process coordination timeline is relatively quick and likely unaffected by new projects beyond the first project with the transmission owner. This timeline can vary – should modifications to an EMS be necessary, this would extend the integration timeline. The time duration can be as short as weeks depending upon TO expertise and staff availability.

iv. *DLR system integration and testing.*

Integration and testing can depend on the project area. The forecasting calibration could take some additional time as a result of the complexity of the geography. The timeline for paragraph b(iii) and b(iv) combined could be anywhere from one month to one year or more, depending on the level of complexity of IT/Security Requirements. A cloud to EMS integration can take place in as little as a few weeks. An on-premises system has many dependencies on the utilities' speed and could take anywhere from three months to one year or more. IT and cyber security standards specific to DLR will speed implementation.

c. *Any other steps needed to implement DLR system*

Transmission owners and RTOs will need to coordinate on the line rating values and evaluate how application of DLR ratings could be applied consistently across interconnection, transmission planning, and market operations models.

27. *Can any of the steps identified in Q26, be completed concurrently such that the total estimated DLR installation time might be faster than the sum of each step? If so, which steps can be completed concurrently? How might the implementation of Order No. 881 affect the time needed to implement DLR?*

Yes. b(i) and b(ii) can be done concurrently, and b(iii) and b(iv) can be done concurrently in many instances.

28. *If, after the initial implementation of DLRs, the transmission provider identifies additional transmission lines that meet the DLR criteria, how long would it take to implement DLRs on those additional transmission lines?*

Once an initial integration process between DLR system data and utility system operations has been completed, resources for subsequent installations on additional lines will be reduced to the time needed to determine the number and locations of new DLR sensors and for procurement and installation of the same. See the response to Q 26, b(i)The system integration itself is essentially a one-time engineering effort for an integration before it becomes largely plug-and-play

29. *.If the Commission required DLRs in certain situations based on transmission line criteria, how frequently should transmission owners consider whether additional lines might meet the criteria for DLR implementation? That is, should the Commission require a periodic restudy of transmission systems to determine if additional transmission lines meet the criteria for DLR implementation? Please explain why or why not. If, during a periodic restudy, the transmission provider determines that additional lines meet the criteria for DLR implementation, when should the Commission require the transmission provider to implement DLRs on those additional lines?*

Transmission owners should consider whether additional lines might meet the criteria for DLR implementation as part of any regular evaluation of the transmission needs on their system – in the interconnection, transmission planning and operations processes. Likewise, DLR should be considered in any RTO planning cycle when transmission needs are evaluated. For instance, DLR should be considered when a line upgrade is proposed as a bridge solution or alternative.

In addition, transmission owners and RTOs should evaluate whether DLR can improve reliability or market efficiency during planned outages. Some outages can be of long duration causing specific constraints to limit transfer of low-cost generation to load centers. Furthermore, some facilities are known to start to bind during specific outages (e.g. a specific low-voltage constraint for the outage of a 345kv line; a 345kv line for the outage of another 345kv line) and could be candidates for DLR implementation.

Respectfully submitted,

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