Managing Transmission Line Ratings

A STAFF PAPER:
FEDERAL ENERGY REGULATORY COMMISSION

AUGUST 2019

DOCKET NO. AD19-15-000

For further information, please contact:
Dillon Kolkmann
Office of Energy Policy and Innovation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8650
Dillon.Kolkmann@ferc.gov

Contents

The opinions and views expressed in this FERC staff paper do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

Executive Summary

Transmission line ratings are used by reliability coordinators, transmission system operators, planning authorities, and transmission planners in reliability models and market models to ensure that flows on transmission lines do not increase risks of reliability events or damage to lines or equipment. The transmission line ratings directly affect flows on electric power systems, and thus affect the price of electric power and the reliability of the electric grid. These ratings are determined by transmission owners. It appears that transmission owners sometimes set these ratings with few or no updates to reflect changes in ambient conditions, and with limited transparency into both the methodology and resulting rating. Improving the methods for determining thermal transmission line ratings could reduce costs, increase efficiency, and provide reliability benefits. This paper reviews various transmission line rating practices. These practices along with potential improvements to managing transmission line ratings will be discussed at the upcoming FERC staff-led technical conference to be held in September 2019 in Washington, DC. There will also be an opportunity to file post-technical conference comments in this docket, *Managing Transmission Line Ratings*, Docket No. AD19-15-000.

This paper draws on staff outreach, which included discussions with regional transmission organizations/independent system operators (RTOs/ISOs), transmission owners, and trade groups, as well as staff participation in a November 2017 Idaho National Laboratory workshop. During outreach, FERC staff reviewed existing and advanced approaches to transmission line ratings and discussed the potential adoption of advanced approaches, and more efficient and reliable use of transmission assets.

This paper focuses on transmission line ratings that are based on the thermal limits of transmission lines to assure that lines do not overheat. In determining thermal limits, engineers balance environmental and physical design factors that contribute to line heating and cooling, in order to prevent the line from overheating. Overheating can damage a line or cause it to sag and create reliability and/or public safety concerns. There is a spectrum of approaches to line ratings, across which the approaches are more responsive or less responsive to changes in the relevant ambient weather conditions that underpin the ratings. On the least dynamic end of the spectrum, "static line ratings" are derived using conservative assumptions for ambient weather conditions. On the most dynamic end of the spectrum, "dynamic line ratings" (DLRs) account for real-time ambient conditions such as air temperature, wind conditions, and solar irradiance intensity, among other things, and update ratings frequently (e.g., hourly or every 15 minutes).

Today, most RTOs/ISOs implement either static line ratings or “seasonal line ratings,” as provided by transmission owners for use in reliability planning, operations and market models.[1] On the less dynamic end of the spectrum, seasonal line ratings are similar to static line ratings, but transmission owners determine different line ratings for different seasons (typically winter and summer), based on worst case assumptions for each season. Using a more dynamic approach, the Electric Reliability Council of Texas (ERCOT) and PJM implement “ambient-adjusted ratings” (AARs) which adjust frequently based on local ambient air temperatures.[2] Non-RTO/ISO transmission owners generally implement seasonal line ratings.

Aside from these standard practices, there have been several pilot projects to test the development and potential application of DLRs. For the most part, these DLRs have not been deployed in real-time system or market operations.[3]

Drawing on the outreach discussed above, this staff paper:

1) Discusses and evaluates the spectrum of transmission line rating methodologies;
2) Describes current RTO/ISO practices;

[1] The seven RTOs/ISOs in the United States are all registered by the North American Electric Reliability Corporation (NERC) as balancing authorities, reliability coordinators, planning authorities/coordinators and transmission service providers. All of these registered functions use transmission line ratings for their respective reliability models. The six FERC-jurisdictional RTOs/ISOs under sections 205 and 215 of the Federal Power Act are: California Independent System Operator Corporation (CAISO), ISO New England Inc. (ISO-NE), Midcontinent Independent System Operator, Inc. (MISO), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), Southwest Power Pool, Inc. (SPP).

[2] MISO and SPP also can accommodate ambient-adjusted ratings in their real-time models.

[3] Researching projects involving dynamic line ratings is not a new concept. These activities date back decades.

3) Highlights some prominent advanced transmission rating pilot projects; and
4) Presents potential improvements to managing transmission line ratings for discussion at the FERC staff-led technical conference. These are:
    a. Whether to require all transmission owners to implement AARs on their lines;
    b. Whether to require all RTOs/ISOs to implement software and communications capabilities and standards to allow transmission owners to flow DLR data directly into the RTO/ISO's energy management systems (EMS);
    c. Whether transmission owners should study their most congested transmission lines to assess whether DLRs would be cost effective; and
    d. Whether to make line rating methodologies more transparent.

1. Background

In spring 2019, a FERC staff team conducted outreach to all FERC-jurisdictional RTOs/ISOs, ERCOT,[4] seven transmission owners, Potomac Economics (the market monitor for MISO, NYISO, ISO-NE and ERCOT), and Working for Advanced Transmission Technologies (WATT, a trade group representing manufacturers of advanced transmission technologies). In addition, staff attended and presented at a November 2017 technical workshop on DLRs at the Idaho National Laboratory.

This paper draws on this outreach to examine approaches to transmission line rating and to present possible policy options to facilitate the adoption of more advanced line rating methodologies in order to reduce costs and achieve increased efficiency in the use of transmission assets without undermining reliability.[5] Increased efficiency can result in important economic benefits, such as lower costs, as well as reliability and operational benefits. More advanced line rating methodologies, however, also present challenges relating to DLR sensor management, forecasting, rating coordination, and reliability, among other things.

A. Transmission Line Rating Basics

Transmission line ratings are used by reliability coordinators, transmission system operators, planning authorities, and transmission planners in reliability models and market models to ensure that flows on transmission lines do not increase risks of reliability events or damage to lines or equipment.[6] They can be expressed in terms of either electrical current (measured in units of amps (A)) or power-carrying capacity

---

[4] ERCOT is jurisdictional under section 215 of the Federal Power Act.

[5] While this paper draws on FERC staff outreach, the views expressed may not necessarily reflect the positions of the outreach entities. Any errors in the representation of outreach entities' positions are unintentional.

[6] Some entities in this list of transmission line rating users have overlapping roles. For example, an RTO/ISO is transmission system operator and a transmission system operator may also be a NERC reliability coordinator.

(measured in units of megawatts (MW) or megavolt-amps (MVA)). In this paper, a transmission line rating respects the most limiting applicable equipment rating of the individual equipment associated with the line,[7] and is based on the thermal limit.[8]

The electric current flowing through a transmission line heats the line due to the line's electrical resistance. Other conditions and phenomena can also tend to heat transmission lines, particularly solar irradiance. Conversely, some conditions and phenomena tend to cool transmission lines, particularly convective cooling from wind. Thermal transmission line ratings are generally negatively correlated to ambient temperature and solar irradiance intensity, but positively correlated with wind speeds. Conductor temperatures further depend upon conductor material properties, conductor diameters, and conductor surface conditions. Engineers consider these environmental and physical design factors when establishing thermal limits of transmission lines.

B. Common Approaches to Transmission Line Ratings

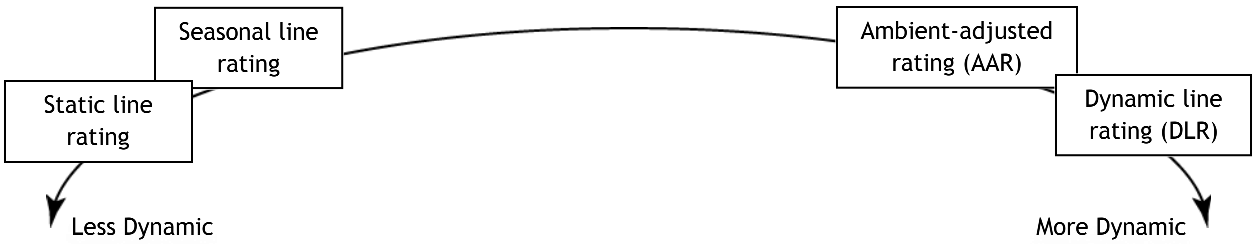
To ensure that transmission line ratings used in the reliable planning and operation of the bulk electric system (BES) are determined based on technically-sound principles, the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-008-3 requires each transmission owner to have a documented methodology for determining transmission line ratings. The standard affords flexibility on underlying methodologies and assumptions, including how changing ambient conditions are used. In practice, rating methodologies have evolved along a spectrum from fully static ratings with no change in ambient condition assumptions for thermal limits on conductors (or sometimes based on "nameplate ratings" for limiting transmission equipment) to nearly

[7] Specifically, the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) includes a transmission line in its definition for a facility ("A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)") and defines a facility rating as: "The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility."

[8] Staff note that transmission lines can be limited by their thermal rating, a voltage limit, or a stability limit. The advanced line rating approaches discussed in this paper would directly affect only lines that are limited by a thermal rating.

"real-time" ratings where ambient condition assumptions are updated every hour or multiple times an hour. Figure 1 shows this spectrum of line rating practices:

Figure 1: Common line rating methodologies on the spectrum from least dynamic to most dynamic



During industry outreach, staff observed that the terms "AAR" and "DLR" were not well defined and not always used in a consistent manner. For the purposes of this paper and subsequent discussions in this docket, FERC staff uses the terms "static line ratings," "seasonal line ratings," AARs, and DLRs in specific ways as defined below.

In each type of transmission line rating, ratings may depend on the limitations of individual segments of the transmission line. And the limits on the individual line segments may depend on different ambient condition assumptions.

i. Static Ratings

Static ratings are the least dynamic rating methodology, and are intended to reflect ratings under the worst case ambient condition assumptions. Often, static ratings reflect a manufacturer's equipment "nameplate rating" reflecting such worst-case assumptions. Static ratings are only updated when equipment is changed or ambient condition assumptions are updated. Thus, static ratings may remain unchanged for years or decades, or may never change at all during the lifetime of a transmission line. While the assumptions used to inform static transmission line ratings vary by transmission owner, one outreach participant, for example, indicated that its static ratings assumed an ambient air temperature of 40 degrees Celsius (104 degrees Fahrenheit), wind speeds and direction of 2 feet per second at a 90-degree wind-conductor angle, and clear atmospheric with noontime sun intensity.

ii. Seasonal Ratings

Seasonal ratings are similar to static ratings but use a different set of ambient condition assumptions for summer and winter. Summer ratings are commonly used from May through October, and winter ratings are commonly used from November through April. Seasonal ratings are the most commonly used ratings. Summer transmission line ratings use conservative ambient temperature assumptions, and are often based on 95 or 100 degrees Fahrenheit. Winter ratings are often based on 32 degrees Fahrenheit.

iii. Ambient-Adjusted Ratings (AARs)

AAR transmission line ratings are more dynamic than static and seasonal ratings, and their rating values change on a more frequent basis (e.g., daily, hourly, or every 15 minutes).

Ambient air temperature forecasting is critical to the use of AARs. Some transmission owners or AAR/DLR vendors perform temperature forecasting using relevant ambient air temperature data from online weather monitoring services (such as the National Oceanic and Atmospheric Administration (NOAA)), and then use those temperature forecasts to calculate updated line ratings. In ERCOT and PJM, AARs are implemented using step functions where AAR line ratings exist for 5-degree temperature blocks (5 degrees Fahrenheit for ERCOT and 5 degrees Celsius for PJM).

iv. Dynamic Line Ratings (DLRs)

Presently, DLRs are the most dynamic line rating methodology incorporating ambient conditions such as local weather conditions, solar irradiance, and/or line tension, photo-spatial sensors (e.g., LIDAR), and/or line sensors installed on or close to the monitored line.[9] DLR weather sensors can measure weather parameters such as ambient temperature, precipitation, wind speed/direction, and solar irradiance intensity. DLR photo-spatial sensors or line sensors may measure conductor parameters such as temperature, tension, and conductor clearance. DLR determined ratings can be updated frequently depending on the characteristics of the DLR monitoring equipment.

---

[9] LIDAR, or Light Detection and Ranging, is a commonly used surveying technique to measure distance to a target by illuminating the target with a laser and using a sensor to measure reflected light.

As with AARs, weather forecasting over a reasonable period of time (e.g., one hour or 15 minutes) is important with DLR systems to allow transmission operators to more efficiently and reliably operate their systems. When employing DLRs, automatic processing of sensor data translates monitored data into updated line ratings.

C. Dynamic Line Ratings Technology Considerations

The previous section provided introductory information on transmission line rating methodologies. As background, this section presents a snapshot of important technical information about how some transmission owners and RTOs/ISOs implement DLRs. This section also discusses some of the key technical challenges related to implementing DLRs, but which are not necessarily relevant to implementing AARs.

The Institute of Electrical and Electronics Engineers (IEEE) and the Council on Large Electric Systems (CIGRE) standards establish the accepted methods for calculating the thermal behavior of transmission lines based on the conductor properties and weather conditions.[10] Based on these standards, modern technologies work in a coordinated manner to calculate and update transmission line ratings in real-time, and to communicate these updates to transmission system operators. These technologies include remote sensing, measurement, communication, data analytics, high-performance computing (including cloud computing), networking, and automation (including artificial intelligence). Implementing a DLR system requires the following steps: line identification; sensor installation; data communication; data analytics; computing and temperature forecasting; and, finally, validation. These implementation steps are discussed in greater detail below.

i. Line identification and sensor installation

As a first implementation step, transmission owners and/or RTOs/ISOs identify the transmission lines on which DLRs would be cost-effective. Use of DLRs is typically

[10] *See* IEEE Standard 738-2012, "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors," 2012 (IEEE 738); and CIGRÉ Technical Brochure 207, "Thermal Behavior of Overhead Conductors, Working Group 22.12," 2002(CIGRÉ 207).

cost-effective on a subset of a transmission owner's transmission lines. Transmission lines that are not sufficiently congested, such that they do not sufficiently limit desired market activity, may not benefit from DLRs. Similarly, transmission systems that are constrained by voltage, stability, or substation limitations may not benefit from DLRs. In addition to identifying the transmission lines that will benefit from DLRs, the transmission owners must identify which specific line spans need to be monitored, and whether ground-based or line-based sensors should be used, as discussed further below in Section 4.B.ii.

Both ground-based and line-based sensor approaches to DLRs have their advantages and disadvantages. Line-based conductor measurements provide more direct and accurate data on line conditions than measurement of ambient weather conditions. However, line-based measurements have limits to how they can be extrapolated to yield reliable information on non-monitored line segments. Also, line-based sensors may require transmission line outages to install and maintain. Ground-based sensors can be easier to install and maintain, but are more vulnerable to physical tampering.

ii. Data communication and analytics

Once sensors are operational, as a next implementation step, their data are typically collected at a data concentrator and/or managed by a Supervisory Control and Data Acquisition (SCADA) system or EMS. Measurement data or information is commonly collected from individual sensors or sensor stations using a cellular network, but satellite, microwave, or radio networks are also possible. The choice of communication medium and methods depends on location, amount of data, and required data transmission rate. Also, DLR system reliability, physical and cyber security features are important factors in complying with NERC Reliability Standards to ensure the availability, integrity, and confidentiality of DLR systems and data. Relevant Reliability Standards include the following:

- FAC-008-3, Facility Ratings, Requirements R7 and R8;[11]

[11] On June 7, 2019, in Docket RM19-7-000 (pending), NERC filed a petition to retire certain requirements of various reliability standards, including Requirements R7 and R8 of Reliability Standard FAC-008-3, which require transmission and generator

- CIP-002-5.1a, Cyber Security – BES Cyber System Categorization;
- CIP-006-6, Cyber Security – Physical Security of BES Cyber Systems;
- CIP-012-1, Cyber Security – Communications between Control Centers;[12] and
- CIP-014-1, Physical Security.

iii. Computing and forecasting

After the relevant data is collected, it is processed and translated (according to the technical standards discussed above) into a line current-carrying capacity in amps (A), which is further used to determine the transmission line's power-carrying capacity in MW. As mentioned earlier, forecasting of the relevant weather conditions and line ratings over some operationally useful period (e.g., one hour or fifteen minutes) is necessary for DLR implementation.

iv. Validation

The final implementation step is validation. Rating validation should detect data anomalies, possibly utilizing sensitivities that can limit the change in weather data parameters that in turn can change transmission line ratings, and automatically integrate DLRs into the control room SCADA, EMS, and/or security constrained economic dispatch (SCED) engine.[13] This step ensures confidence in the resulting transmission line ratings.

---

owners to provide facility ratings to reliability coordinators, transmission system operators and other entities upon request.

[12] On April 18, 2019, in Docket No. RM18-20-000 (pending), the Commission issued a notice of proposed rulemaking to approve CIP-012-1 (Cybersecurity-Communications between Control Centers) and to direct NERC to develop certain modifications to require protections regarding the availability of communication links and data communicated between bulk electric system control centers and, further, to clarify the types of data that must be protected.

[13] While exact SCED definitions vary, one representative definition is "an algorithm capable of clearing, dispatching, and pricing Energy, Operating Reserve, Up Ramp Capability, and Down Ramp Capability in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple

During outreach, multiple parties indicated that reliability and operational complexity concerns have hampered DLR (and AAR) adoption. Specifically, they expressed concern that inaccurate or unreliable line ratings could be communicated directly to transmission system operators, who would then be burdened with determining whether to rely upon the ratings. However, line rating and human factors engineering experts that FERC staff spoke to during outreach argued that proper implementation can address this concern. The human factors engineering experts contended that all data and rating validation must be complete *before* a transmission system operator ever sees a DLR or AAR rating, allowing the operator to have confidence in the accuracy of DLR/AAR ratings. Engineers should ensure that the rating is appropriate for the current operational horizon so that the transmission system operator does not have to second-guess the rating. In this way, the human factors engineering experts asserted, a transmission system operator's use of DLRs or AARs should be similar to the use of static ratings.

One difference between DLRs/AARs and static ratings, however, is that the DLRs and AARs change across their forecasting periods. As such, transmission system operators may need access to the future period's rating forecasts, and/or be notified by EMS if significant rating changes will take place.

2. Line Rating Approaches in RTOs/ISOs

Transmission owners in RTOs/ISOs use either seasonal ratings or AARs to calculate thermal transmission line ratings. In CAISO, ISO-NE, MISO, NYISO, and SPP, seasonal ratings are the norm.[14] In ERCOT and PJM, AARs are used.

security constraints. The algorithm keeps the commitment of Resources fixed in the dispatch. The model is described in Schedule 29." MISO Open Access Transmission Tariff, Module A.

[14] MISO and SPP also can accommodate ambient-adjusted ratings in their real-time models, but our understanding is that few participants currently use this functionality.

A. Use of Seasonal Line Ratings in RTOs/ISOs

Five RTOs/ISOs – CAISO, ISO-NE, MISO, NYISO and SPP – predominantly use seasonal line ratings, but with important regional differences. Some RTOs/ISOs tend to be more deferential to transmission owner-developed line ratings than others. Certain RTOs/ISOs indicated that some transmission owners provide seasonal ratings in which winter line ratings equal summer ratings. Partially at the request of their transmission owners, both MISO and SPP have updated their EMS to automatically accept frequently changing line ratings. In MISO and SPP, transmission owners can automatically update transmission line ratings hourly in the real-time reliability and market models in addition to updates to current day and day-ahead transmission line ratings.

Several of the RTOs/ISOs indicated that they used a process whereby the RTO/ISO, on an *ad hoc* basis, could request real-time transmission line rating "uprates" which, if available, could be granted by the transmission owner based on differences between actual ambient air temperatures and seasonal line rating assumptions. They indicated that such practices are used to manage conditions such as outages, congestion, or possible reliability events. Frequency and timing of usage varies by RTO/ISO. One RTO/ISO described uprates occurring only on congested lines in the summer. Uprates may be limited to the real-time reliability and market models or specific load pockets, depending on the RTO/ISO.

B. Use of AARs in PJM and ERCOT

PJM and ERCOT rate transmission lines using AAR methodologies with regional variations. Both PJM and ERCOT use temperature-rating step functions to rate transmission facilities. In the real-time market, using transmission owner-submitted temperature-based line ratings, a PJM computer program selects transmission line ratings based on temperature readings taken from local weather stations for 5 degree Celsius (9 degree Fahrenheit) temperature increments from zero to 40 degree Celsius (32 to 104 degree Fahrenheit). In the PJM day-ahead market, transmission line ratings are determined from forecasted ambient air temperatures specific to each zone in its day-ahead studies.

ERCOT has a similar practice, in which real-time transmission line ratings are automatically updated based on temperature fluctuations according to temperature tables provided by each transmission owner and which reside within the ERCOT network model.[15] ERCOT temperature tables are stepwise functions for each 5 degree Fahrenheit (2.8 degree Celsius) increment between 20 and 115 degree Fahrenheit (approx. −7 to 46 degree Celsius). Similar to PJM, for the day-ahead market, ERCOT obtains forecasted temperatures for the next operating day, and uses transmission owner's temperature tables to obtain line ratings for its day-ahead studies.

C. Use of Static Ratings in Long Term Planning

Each RTO/ISO conducts long term transmission planning using seasonal static ratings. None of the RTOs/ISOs consider using DLRs or AARs as an alternative to building physical transmission.[16] Outreach consensus suggests that both transmission owners the RTOs/ISOs consider it important to plan transmission for summer and winter peak loading conditions while using seasonal static ratings and believe that neither DLRs nor AARs can substitute for building and repairing transmission lines. While Order No. 890-A held (and Order No. 1000 reiterated) the transmission planning process is generally required to have comparable treatment for advanced technologies,[17] neither order provided specific guidance on how advanced technologies should be considered. While some outreach participants acknowledged that the use of DLRs could replace some economic projects (i.e., projects designed to reduce congestion costs rather than to address a reliability need), these participants reiterated the need to plan for the worst case conditions when planning transmission because worst case conditions do materialize.

---

[15] ERCOT Nodal Protocols. Section 3.10.8 Dynamic Ratings. February 7, 2018, available at http://www.ercot.com/mktrules/nprotocols/current.

[16] This is also the norm outside of RTO/ISOs.

[17] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890 at P 494, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297, at P 215-16 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323, at P 315 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

3.Dynamic Line Rating Pilot Projects

Most of the seven transmission owners with whom FERC staff spoke indicated that they had some experience using dynamic line ratings in research projects. However, transmission owners typically test DLRs on only a few transmission lines, do not incorporate DLRs into RTO/ISO markets, and do not publicize the test results widely. Some prominent DLR pilots have been undertaken in ERCOT, NYISO, and PJM.

Two of the better documented and publicized DLR pilot projects were undertaken by the ERCOT transmission owner, transmission operator, transmission planner and distribution provider ONCOR, and by the NYISO generator owner, generator operator, transmission planner and transmission owner New York Power Authority (NYPA), both funded through grants under the Department of Energy's Smart Grid Demonstration Program. The NYPA project partnered with the Electric Power Research Institute (EPRI) to install EPRI sensor technology designed to measure conductor temperature, weather conditions, and conductor sag on three 230 kilovolt (kV) transmission lines. NYPA's goal was to test a variety of prototype technologies; demonstrate the viability for use in system engineering, operations, and planning; and demonstrate a correlation between increased dynamic ratings and increased wind generation. The results of the NYPA pilot were calculations of DLRs, on average, in excess of 30 to 44 percent above static ratings.[18]

Partnering with the cable and transmission line manufacturer Nexans, ONCOR tested conductor tension-monitor technology along with conductor sag and clearance monitors on eight transmission circuits (138 kV and 345 kV). Similar to NYPA, ONCOR's goals were to test the commercial viability of DLR technology. But ONCOR also incorporated DLRs into real-time operations and developed a DLRs best practice guide. ONCOR succeeded in incorporating DLRs directly into ERCOT's EMS. ONCOR's project also identified the potential for DLRs to integrate wind resources,

---

[18] Wang, Warren and Pinter, Sarah. *Dynamic Line Rating Systems for Transmission Lines*. April 25, 2014 p. 36, available at https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf.

observing a relative increase in wind generation at the same times when DLR systems increased study lines' transmission capacities. Lastly, ONCOR calculated DLRs of, on average, 30 to 70 percent greater than static line ratings. Relative to ERCOT's normal AARs, however, ONCOR observed real-time rating increases between only 6 and 14 percent on average (when excluding data anomalies, outage periods, and periods when the DLR may have been lower than AARs).[19]

In PJM, DLR pilot studies were conducted on the 345 kV Cook-Olive transmission line and on a second target transmission line.[20] In the first phase of DLR testing, LineVision, AEP, and PJM installed LineVision-designed ground-based sensors to measure power flow, conductor position/sag, and weather conditions in order to calculate DLRs along AEP's Cook-Olive transmission line. The results of this first phase indicated that Cook-Olive's DLRs were significantly greater than static ratings.[21]

In phase two, LineVision, AEP, and PJM attempted to quantify the financial impact of DLRs. To do this, LineVision, AEP, and PJM identified a target transmission line similar to Cook-Olive, and which had already demonstrated DLR viability. The target line was chosen because both it and Cook-Olive are high voltage transmission lines of similar length (18 and 22 miles respectively), both are heavily congested, and both have a straight transmission path, making DLR implementation easier.[22]

---

[19] *Id.* at 59.

[20] The Cook-Olive transmission line is located in the AEP footprint spanning southwest Michigan to northern Indiana.

[21] Marmillo, J, Mehraban, B, Murphy, S, and Pinney, N. *A Non-Contact Sensing Approach for the Measurement of Overhead Conductor Parameters and Dynamic Line Ratings*. CIGRE US National Committee 2017 Grid of the Future Symposium, Cleveland, OH, available at https://watttransmission.files.wordpress.com/2017/11/genscape-cigre-gotf-whitepaper-2017.pdf.

[22] Straight transmission paths can make DLR implementation easier by increasing the consistency of the speed and direction at which the wind contacts a transmission line,

Absent installing DLR sensors in phase two, LineVision, AEP, and PJM extrapolated DLRs for the target line using weather data from NOAA at urban-center and airport-based meteorological stations. To quantify the benefits, the study conducted an analysis comparing a study year 2018 with static ratings to simulated market results using DLRs on the target line. The analysis results demonstrated approximately $10.4 million in annual congestion savings along the target line, but also found increased downstream congestion on several nearby 230 kV lines, resulting in approximately $4 million in annual net congestion savings. PJM explained that the analysis was not able to respect other possibly limiting constraints, such as voltage constraints or substation-based constraints. PJM indicated that a key drawback to its study is that the 2018 target line's limiting element was often set by substation equipment, not line limits.[23] (For more information on challenges created by other limiting elements see Section 4.A.ii.c).)

Other examples FERC staff encountered of transmission owners or RTOs/ISOs implementing pilots or test DLRs indicated that these entities considered testing DLRs as a means to mitigate the effects of transmission outages by increasing transmission line limits. Separate entities described different DLR pilots implemented to improve transmission access to a load pocket, to provide additional bridge transmission capacity as transmission was built or rebuilt, and, one in the late 1990s, to alleviate congestion as transmission upgrades were being built.

---

thus minimizing differing rating patterns across a transmission line. Straight transmission paths can also make radio transmission of data easier, when relevant.

[23] Dumitriu, N, Marmillo, J, Mehraban, B, Murphy, S, and Pinney, N. *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, Reston, VA, available at https://cdn2.hubspot.net/hubfs/4412998/CIGRE%20GOTF%202018%20NGN%20-%20PJM%20AEP%20LineVision%20-%20Final.pdf?t=1540927429509.

4. Analysis

A. Evaluation of Dynamic Line Ratings and Ambient-Adjusted Ratings

As a general matter, the more dynamic a transmission line rating, the more accurate the line capacity and potential benefits, as well as challenges are expected from its implementation. Outreach indicates that while the benefits of DLRs may be greater than the benefits of AARs, the use of DLRs has greater challenges and costs. As discussed below, some of the benefits and challenges accrue to both DLRs and AARs, and some only to DLRs.

i. Benefits

a) Economic Benefits

Rating transmission lines more dynamically allows for adjusting line limits of those lines, which have the potential to increase transmission system efficiency; reduce production costs, congestion costs, curtailments, and reserve requirements; and help manage system disturbances. Both DLRs and AARs tend to provide more accurate line limits. Particularly in the summer season, this greater accuracy tends to raise transmission line ratings, which has the potential to increase system efficiency.[24] For example, in MISO, Potomac Economics found that the potential savings as a result of AARs reducing congestion costs would have been $165 million in 2015, $155 million in 2016, and $127 million in 2017.[25] Similarly, increasing transmission flows into load pockets can improve access for low cost generation, reduce curtailments, and may reduce

---

[24] Staff notes, however, increased accuracy may not result in increased line ratings. Particularly during the winter season, when real-time ambient air temperatures may be greater than the static winter temperature assumption, line capacities under DLRs or AARs may decrease from their seasonal ratings.

[25] Potomac Economics. 2017 State of the Market Report for the MISO Electricity Markets. June 2018. p. 83-84.

reserve requirements. Lastly, in the event of a generation or transmission outage, both DLRs and AARs may help mitigate the resulting congestion impacts.[26]

DLRs and AARs can potentially defer capital costs by improving utilization of existing assets. Outreach participants indicated that, because transmission upgrades can be difficult to build, DLRs are an important bridge source of transmission capacity in the interim between the identification of need and project completion. Deferred capital costs can be a benefit of AARs, but to a lesser degree.

DLRs (but not AARs) may also be particularly beneficial for transmission owners integrating wind generation. When wind speed increases, this increases output from wind generators. However, the increase in wind speed also lowers the temperature of the transmission line which, under a DLR, would increase the rating of the line. This benefit was demonstrated by the NYPA and ONCOR pilot projects discussed above. Recognizing this correlation between wind production and lower transmission line temperatures, at least one transmission owner suggested that a wind generator could utilize DLRs to cost-effectively reduce the size of its interconnection facility. They explained that interconnection studies typically use static line rating assumptions that often have wind speed assumptions that are lower than is needed to power a wind turbine. They suggested that, by conducting wind generator interconnection studies using higher wind speed assumptions, it may be possible to increase wind power deliverability assumptions and lower interconnection costs for wind generators, at least in some circumstances.[27]

---

[26] An important caveat repeatedly mentioned during outreach, however, was the applicability of DLRs to older transmission lines. Outreach participants explained that many of the most congested lines are older lines. Applying DLRs to such lines may have short-term value, but such lines may be reaching the end of their useful life. In such instances, it may be more cost-efficient to simply repair and/or rebuild the line. However, repaired or rebuilt lines tend to not be congested. Even so, there may be value to applying DLRs as a bridge to manage a transmission line while repairs occur.

[27] Interconnection facilities are defined using the same definition as FERC Order No. 2003, which explained that “Interconnection Facilities are found between the Interconnection Customer's Generating Facility and the Transmission Provider's Transmission System…Network Upgrades include only facilities at or beyond the point

Some outreach participants, however, expressed skepticism regarding the possibility of using DLRs to reduce interconnection costs for wind generation. The interconnection process currently utilizes static line rating assumptions to determine interconnection cost responsibilities. Transmission owners and RTOs/ISOs stress the need to plan for worst case conditions. Outreach also indicates that wind developers and/or their financing partners may be reluctant to make major generation investments without building the full interconnection capacity to deliver the generation's total output to the system.

b) Reliability/Operational Benefits

DLRs and AARs can also provide reliability benefits by helping to avoid and/or relieve transmission overloads without the need to re-dispatch, curtail transmission service, shed load or reconfigure the system.

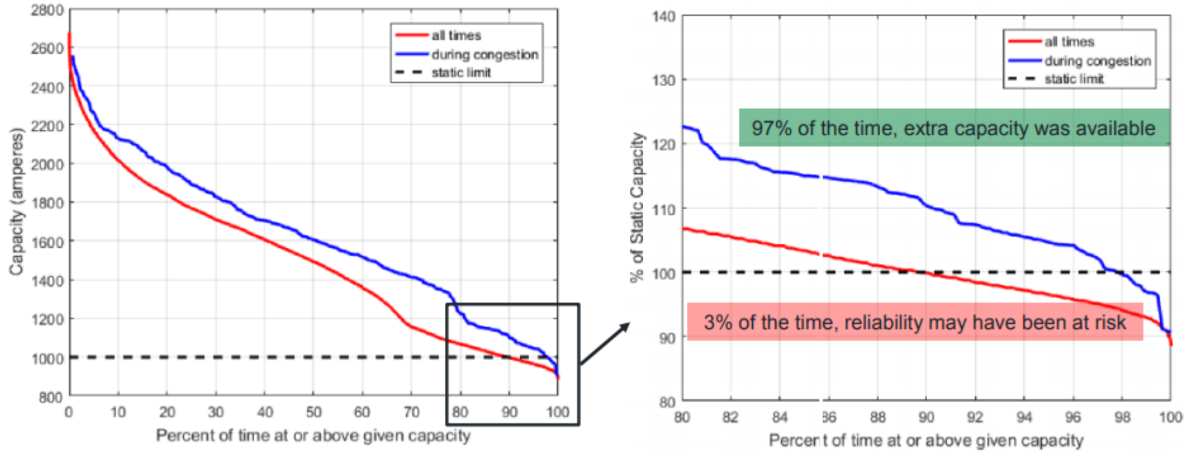
DLRs (but not AARs) can provide transmission owners more information about the status of a transmission line. By using actual, real-time inputs, DLRs provide reliability benefits by reflecting the actual current-carrying capabilities of the conductor which may, at times, be less than a static rating would have allowed. Outreach highlighted the ability of DLR systems to inform transmission owners and RTOs/ISOs of the small percentage of instances in which static ratings exceeded a DLR, and in which there may be a heightened risk of either a reliability event or damage to either transmission lines or equipment. During outreach, one outreach participant estimated that these instances where static ratings exceed DLRs could be up to five percent of intervals, while data from LineVision presented at the 2017 Idaho National Laboratory's

---

where the Interconnection Customer's Generating Facility interconnects to the Transmission Provider's Transmission System." *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 21 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

2017 DLR workshop estimated that such instances constituted about three percent of intervals, as shown in Figure 2.

Figure 2. Indicative Transmission Line Rating Static and Dynamic Line Rating Duration Curve[28]



The additional information about a transmission line provided by DLRs can also increase situational awareness, helping an RTO/ISO or transmission owner to monitor the condition/health of a line in real-time. For example, in addition to informing an RTO/ISO or transmission owner of instances in which the actual current-carrying capabilities of the conductor is less than a static rating, such information gained through increased situational awareness can allow an RTO/ISO or transmission owner to detect dangerous instances of transmission icing and conductor galloping.[29]

---

[28] Marmillo, Jonathan (2017, November). Genscape LineVision. *Vision for Integration into Overall Asset Management Strategy*, Idaho National Laboratory 2017 Dynamic Line Ratings Workshop, Idaho Falls, Idaho. p. 8, available at https://renewableenergy.inl.gov/Conventional%20Renewable%20Energy/2017%20DLR%20Workshop/DLR%202017%20Presentations/11.8%20Vision%20for%20Integration%20(Genscape)_Marmillo.pdf (used by permission).

[29] Conductor galloping is a low-frequency physical oscillation of power lines caused by wind. Galloping can lead to increases in stress on insulators and transmission structures, increasing the risk of line or structure failure, or shortening equipment life. Galloping can also affect line clearances, raising the risk of electrical faults. Some types of DLR sensors can detect and/or monitor lines for galloping.

c) *Open Access Benefits*

DLRs and AARs can also provide open access benefits, such as reducing the likelihood of *ad hoc* transmission uprates, and thereby helping to ensure equal access to the transmission system via markets on a comparable basis.[30] Current releases of additional transfer capability may lack the transparency that should be afforded to all transmission customers. Upon RTO/ISO request, typically during periods of tight operations, transmission owners periodically provide transmission uprates, temporarily increasing transmission line limits. Generally, these transmission uprates help reliability. Making these increases part of normal operations through the adoption of DLRs or AARs on a transparent basis may help reduce the frequency of *ad hoc* transmission uprates. While transmission uprates may frequently make available transmission capability in real-time that was not reasonably foreseeable in advance, adoption of DLRs or AARs could help ensure that all market participants are able to access the transmission system on a comparable basis.

ii. Challenges

Many of the challenges to advanced line rating methodology implementation are unique to DLRs. Challenges unique to DLR implementation relate to sensor placement, sensor maintenance, and physical and cyber risks, as well as its tendency to cause line rating fluctuations. By contrast, both DLRs and AARs face challenges related to automation, coordination with other transmission owners, market coordination, limiting elements, and reliability.

---

[30] *See 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, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 77 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002).

a) DLR Sensors

The most obvious challenges applicable only to DLRs are the placement and maintenance of DLR sensors. First, sensor placement is a challenge because more sensors are needed the longer a line is. But while placing more sensors at limiting elements ensures more geographically-granular data to calculate line ratings at more line spans, it costs more. While placing fewer sensors costs less, it requires the extrapolation of data using complicated software and analysis to predict weather conditions, which can be difficult or impractical. Extrapolating line conditions on monitored line spans to other spans, particularly over varied terrain, can be difficult. Moreover, the more turns in a transmission path and/or the more diverse the terrain a transmission line traverses, the greater the number of sensors required and the more difficult it is to use one sensor to extrapolate over multiple spans. Consequently, sensor placement challenges are often more acute both with Midwestern utilities that tend to have longer transmission lines and with utilities located in hilly, mountainous, or generally varied terrain.

Sensor maintenance can also be challenging. Repairs to DLR sensors often require a specially trained technician. If a sensor is placed on a line, repairs may require coordination between the transmission owner and a repair technician. Repairing line-based sensors may also require a line to be taken out of service, which could necessitate coordination between the transmission owner and the RTO/ISO. Further, ground-based sensors can be susceptible to physical tampering that could either take them out of service or create false data readings. Lastly, when transmitting DLR sensor data, there may be potential cyber security risks.

b) Forecasting Challenges

Both DLRs and AARs require weather forecasting to be successfully implemented. But because DLRs can be particularly sensitive to both wind speeds and direction, forecasts for DLRs can be more difficult to produce. Swirling winds and changing wind speeds can cause significant rating fluctuations that would be difficult for transmission system operators to implement if such ratings were sent in raw form. In the presence of hard-to-forecast wind conditions, DLR line rating forecasts may need to assume that wind cooling cannot be relied upon. Under such assumptions, DLRs may provide little benefit beyond what could be obtained with the simpler AARs.

c) Limiting Elements

Physical limitations, other than those related to the transmission line conductor, can reduce the benefits of DLRs and AARs. Because overall transmission line ratings must be set by the most limiting element for each transmission line, substation equipment (e.g., breaker, wave trap, or switch) limits could be a limiting element for a line regardless of the effect of AARs or DLRs. For example, many wind generating facilities are located at the top of hills and are connected by transmission lines running through valleys. DLR implementation (but not AAR) would have to account for differing wind conditions across the terrain, only increasing a transmission rating by the most limiting wind condition, likely at the floor of a valley. Additionally, transmission owners explained that many wind facilities, particularly in the Midwest, tend to be interconnected via long transmission lines. Longer AC transmission lines tend to be voltage constrained, not thermally constrained.

d) Automation and Data Coordination

Implementation of both DLRs and AARs requires automation and data coordination. DLRs require at least automatic weather and/or line measurements, and communication of that data to a transmission operator control center where that data is used to calculate a rating forecast. AARs are typically derived by obtaining their ambient air temperature data from NOAA or similar weather services, so measurement and data communication are less of an issue. But under AARs, online data must still be downloaded and used to calculate a rating forecast. As an example of the interaction between data availability and AAR implementation, outreach indicated that the five week U.S. Government shut-down of 2018-2019 resulted in limited data availability from NOAA, which affected AAR implementation.

After collecting and communicating data and using that data to calculate updated DLRs or AARs, several additional automation and data coordination challenges remain. Calculated transmission line ratings must be automatically checked before being transmitted to the RTO/ISO or transmission operator control center. Finally, the transmission line ratings are input to a SCED and/or EMS, ideally automatically.

Most RTOs/ISOs indicated that automation of this kind is possible. However, due to the additional costs and technological requirements, the amount of automation and database management needed may be difficult for some non-RTO/ISO transmission owners to implement. Further, outreach indicated that this level of constant automation and data coordination also creates a database management challenge.

e) Market Alignment

Some outreach participants expressed concern with using line ratings other than static or seasonal ratings in the day-ahead market. They explained that if AAR or DLR ratings were used in the day-ahead market, and weather was warmer than expected, the anticipated transmission capacity may not materialize in real-time, while load would simultaneously be higher than expected, causing reliability concerns. However, in such instances, not implementing either AARs or DLRs in both the real-time and day-ahead market might result in misalignments between day-ahead and real-time markets, creating inefficiencies. Other outreach participants indicated that an appropriately conservative implementation of AARs and/or DLRs could be made in the day-ahead timeframe in a way that would help align the day-ahead and real-time markets, while still maintaining reliability.

The use of AARs or DLRs in real-time and day-ahead markets could also result in coordination challenges with the financial transmission rights (FTR) market.[31] Static line ratings are typically used to determine the amount of transmission capacity available for auction in FTR and related auctions in RTOs/ISOs. The exception appears to be ERCOT, which conducts a historical analysis of the maximum peak-hour temperatures for the previous 10 years, for each month, to determine the amount of transmission capacity available for auction in FTR auctions. In the two markets (ERCOT and PJM) that

---

[31] While exact FTR definitions vary, one representative definition is "a financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission System is congested and differences in Marginal Congestion Components of Day-Ahead Ex Post LMPs result." MISO Open Access Transmission Tariff, Module A. FTRs go by different names in different RTOs/ISOs. PJM, MISO and ISO-NE use the term FTR. However, CAISO uses the term Congestion Revenue Right (CRR). NYISO uses the term Transmission Congestion Contract (TCC). SPP uses the term Transmission Congestion Right (TCR). For simplicity, this paper uses the term FTR to refer to the relevant product in all these markets interchangeably.

presently use AARs during operations, the use of AARs is transparent to market participants, and informs all market participants of where congestion is anticipated so that this information can be factored into FTR bids submitted by market participants.[32]

f) Coordination between Transmission Owners

DLR or AAR implementation may lead to coordination challenges, if not all transmission owners implement the same transmission rating methodology. For example, for power that flows over multiple owners' transmission lines, if only one of those transmission owners is updating their transmission ratings using either AARs or DLRs, then transmission flows may be limited by the transmission owners that do not implement AARs or DLRs.

g) Reliability Margins

Some outreach parties indicated that implementing either DLRs or AARs may create reliability challenges by reducing their reliability margins. Specifically, a reliability margin can be thought of as the difference between the true thermal transmission line limit, calculated by accurately incorporating all relevant line rating inputs, and the transmission line limit currently implemented. When transmission owners implement DLRs or AARs, they typically understand that, for most hours of the year, their transmission lines in fact will have more capacity than their static or seasonal ratings. However, because transmission owners rate transmission lines, and because there is not currently a mechanism for a third party (except, in some circumstances, for an RTO/ISO) to request to use uprated transmission capacity, currently only transmission owners may know about or be able to use this additional capacity.

While some argue that implementing AARs or DLRs may create reliability challenges, AARs and DLRs tend to also provide more accurate line ratings. Particularly in the winter season, AAR and DLR implementation could result in less transmission line

[32] PJM publishes Transmission Owner Guidelines. According to the introduction, "they are intended to provide common PJM Transmission Provider connection requirement criteria concerning design philosophy, design requirements and operating practices for interconnecting Generation Facilities, Transmission Facilities, and End-User Facilities", available at https://www.pjm.com/planning/design-engineering/maac-to-guidelines.aspx.

capacity for those hours during the year when DLRs and AARs are less than current static or seasonal ratings. In response to questions about AAR and DLR reliability challenges, some outreach participants indicated their view that reliability reserve margin capacity should be reserved to accommodate unexpected events to ensure reliability of the electrical grid. However, FERC staff believes that reserve margins should not be dependent on capacity that may or may not be available depending on ambient conditions. AAR and DLR implementation may reduce transmission capability margins. However, on balance, the more accurate winter ratings, reducing transmission line capacity for those hours during the year when DLRs and AARs are less than current static or seasonal ratings, may appropriately counterbalance the loss of transmission capability margins, while ensuring reserve margins are accurately calculated.

B. Discussion on Potential Improvements to Managing Transmission Line Ratings

In light of FERC staff's outreach and research, staff sets forth four ideas to improve methods for determining transmission line ratings, including making the information about the line ratings more transparent to all users of the transmission system. These options will be used to guide further discussion about transmission line rating practices at the September 2019 technical conference. FERC staff expects that these improvements could reduce costs, increase efficiency, and provide reliability benefits without compromising reliability of the transmission system. In addition to the benefits and challenges discussed earlier, FERC staff anticipates learning from stakeholders more about current transmission line rating practices, the benefits and challenges of these and other practices, and about possible ways to incent increased DLR implementation.[33]

---

[33] In its recent inquiry regarding the Commission's electric transmission incentives policy, the Commission sought and received comment on over one hundred questions. Topics on which the Commission sought comment included whether the costs of dynamic line ratings should be considered for inclusion in rate base as a regulatory asset, and whether and how flexible transmission characteristics, such as increased line rating precision and greater power flow control, should be incentivized. *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019).

i. Implementing AARs

As one option, transmission owners could adopt AARs, under which a transmission owner would adjust transmission line ratings based on ambient air temperatures. Such an approach could realize the benefits of more accurate line ratings without the costs and complexities of implementing DLR technologies. In particular, AARs have the potential to reduce congestion, improve planned outage coordination, and provide reliability benefits. At the same time, AARs do not implicate challenges that apply to DLR implementation such as sensor placement, sensor maintenance, and physical risks. Further, as noted above, several transmission owners actively implementing AARs said they see little net benefits to DLR implementation above those already provided by AAR implementation on their specific transmission lines.

Under this option, an RTO/ISO could use AARs in operations planning (transmission line outage scheduling) and directly in its security-constrained economic dispatch process to dispatch resources and calculate market prices. AARs could be applied to all transmission lines or a subset of transmission lines. Staff understands, for instance, that transmission owners in PJM and ERCOT typically apply AARs to all of their transmission lines. However, it may be reasonable to apply AARs only to congested transmission lines, or at least to exclude some transmission lines that are expected to never be congested, even under unexpected circumstances.

Transmission owners in bilateral markets could incorporate AARs into the ATC calculations for the appropriate point-to-point transmission service (expected to be daily and hourly point-to-point transmission service). To the extent practical, the application to ATC calculations may help increase the frequency that real-time weather related transmission uprates are also made available to third parties on a consistent basis.

ii. Integrating DLRs into EMS

Under this option, an RTO/ISO would implement software and communication changes to allow transmission owners to flow DLR data directly into the RTO/ISOs' EMSs. While, on a generic basis, an AAR approach to transmission line ratings may be most appropriate, the information obtained during FERC staff outreach suggests that there may be specific transmission lines on which the costs and complexities of DLRs are in fact outweighed by the benefits. This option would require RTOs/ISOs to adopt minimum software and communication capabilities and standards (data formats, internet protocols, cyber security requirements, etc.) necessary to ensure transmission owners are able to flow DLR data directly into the RTO/ISO's EMS. Outreach indicates that these minimum capabilities and standards already exist in some RTOs/ISOs. Requiring RTOs/ISOs to adopt minimum capabilities and standards to accept DLRs into their EMS would remove barriers to entry for DLR technology. Absent these minimum capabilities and standards, the implementation of DLRs by transmission owners in RTOs/ISOs would be of limited value as the more dynamic ratings may not be incorporated into RTO/ISO markets.

iii. Study of the most congested transmission lines

To help highlight some locations where DLR implementation might be cost-effective, transmission owners could perform studies of the cost-effectiveness of implementing DLRs on the most congested transmission lines. Under such an option, FERC staff initially suggest that transmission owners identify the most congested transmission lines based on cost of congestion (rather than MWh or hours of congestion). These and many other details would need to be discussed and developed. Among such details is whether the transmission owner is the best entity to perform such studies, or whether another entity such as an RTO/ISO or an independent evaluator might be better placed to conduct such studies.

iv. Transparency of transmission line rating methodologies

Finally, some outreach participants commented that line rating methodologies are opaque, particularly in systems where transmission charges are increasing rapidly. These participants stated that they have had little success obtaining information on how transmission line ratings are set, what assumptions the ratings are based on, or how often such ratings and assumptions are updated. With this concern in mind, it might be necessary to make the basic details of line rating methodologies transparent, for instance, by either publicly posting or incorporating them into both RTO/ISO and TO tariffs.[34]

---

[34] Staff notes that NERC reliability standard FAC-008-3 R8 requires transmission owners to make their transmission rating methodologies available upon request, but such requests can only be made by reliability coordinators, planning coordinators, transmission Planners, Transmission Owners and Transmission Operators. However, such requests ensure that the transmission line rating methodologies remain non-public. Moreover, on

June 7, 2019, FAC-008-3's R8 was proposed to be removed in Docket No. RM19-7-000. This would remove the possibility of even non-public requests for transmission line rating methodologies.

Document Content(s)