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Incorporating Dynamic Line Ratings to Alleviate Transmission Congestion, Increase Wind Resource Utilization, and Improve Power Market Efficiency

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SUMMARY

Wind-driven congestion is negatively impacting revenues from wind farms, causing curtailments and impacting market efficiency. Dynamic Line Rating (DLR) technologies could be used to monitor congested transmission lines to reveal additional thermal capacity for use in real-time market and system operations. This additional carrying capacity will reduce wind-driven congestion and enhance market efficiency. A case study outlining the potential beneficial effects that utilizing dynamic line ratings on the Neosho-Riverton transmission line would have on the Caney River wind farm are presented herein.

KEYWORDS

Dynamic Line Ratings, DLR, Congestion, Wind Integration, Market Efficiency

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1. Introduction

Technologies such as Dynamic Line Ratings are able to alleviate persistently occurring overhead transmission line congestion that is primarily caused by the operation of multiple wind generation resources. The economic impact of this congestion is reflected in the real-time power market causing wind farm operators to experience low or negative Locational Marginal Pricing (LMP), which adversely impacts their revenues, causing curtailments, and creates market inefficiency. The primary factor driving an increase in an overhead conductor's real-time capacity is the effective perpendicular wind speed on that line [1]. When strong wind speeds are present enough to bring wind farm production online, wind is likely to be flowing across an overhead transmission line in nearby proximity, and the wind's convective cooling will concurrently increase the line's capacity. An overhead conductor monitored with a Dynamic Line Rating system can accurately measure this increase in capacity which could then be used to reduce the congestion seen in real-time system and market operations. This would lead to the increased utilization of wind resources and result in increased market efficiency by avoiding re-dispatching expensive generators while maintaining system reliability.

2. Dynamic Line Ratings

The power flow capacity of overhead transmission lines shorter than 100 miles is typically limited by the maximum operating temperature (MOT) of the overhead conductors, typically between 80-120 ºC. A transmission line's thermal rating represents the maximum amount of power (or current) that can flow through the line without the line exceeding the conductor MOT. The achieved temperature of an overhead conductor depends on several variables:

- Electrical current flow through the line, causing resistive heating
- Sunlight warming the conductor surface
- Blackbody (radiative) cooling of the conductor
- Convective cooling of the conductor caused by wind or other natural air convection
- Rain, ice, or other foreign matter touching the conductor

Transmission operators typically establish a static line rating (SLR) or seasonal thermal rating based on near-worst-case values of the weather variables listed above for the region through which the rated transmission line passes [2]. The thermal rating of a transmission line's overhead conductors becomes the power transfer limit for the entire path provided the conductor rating is below the thermal rating of other components of the transmission line, including breakers, wave traps, transformers, etc., often referred to as next-limiting-elements (NLE).

Dynamic line rating (DLR) methods rely on the fact that actual weather conditions are often much more favorable than worst-case assumptions, often allowing for significantly greater power flows on a given line without risk of exceeding the conductor MOT. DLR calculation methods incorporate a variety of data inputs, preferably including physical measurement of the sag or temperature of the overhead conductor, to compute a variable thermal rating that changes in relation to the weather's influence on the transmission line [3].

Among the weather variables that influence conductor temperature, wind speed is the most dynamic [3]. DLR is also highly sensitive to changes in wind speed, making accurate knowledge of the effective wind speed a critical component of calculating DLR. Conservative weather condition assumptions are used when determining a line's SLR but a nominal increase in wind speed of an additional 0.914 m/s (3 ft/s) at a 45° angle to the transmission line has been shown to increase its capacity by 35%, or by 44% when perpendicular to the line [1]. Wind speed is variable both temporally and spatially, especially at conductor height (10-25m) over the course of a transmission line path that includes significant changes in heading, elevation, and land use (forest/rural/industrial/urban). In areas where moderate or strong winds are common, the use of a DLR monitoring system can increase the achieved power flow capacity of overhead conductors by 5-25%

when compared to an SLR for ~80-90% of the time (results vary across different lines and geographic regions) [1]. In areas where wind turbine farms are installed providing a low-cost renewable energy resource, utilization of DLRs on connected transmission lines can provide additional transfer capacity when it is needed most, *i.e.*, when the wind is blowing. However, we must consider that the effective wind speeds at the height a wind turbine hub (~100 m) may differ from wind speeds at typical overhead conductor heights (10-25 m), resulting in DLRs that may not correlate robustly with wind generation at all times. In addition, wind speeds will also vary along the length of a typical transmission line, which must be considered when designing and installing a monitoring system to accurately capture a line's dynamic thermal capacity along its entire path.

With Independent System Operators (ISO) running a Security-Constrained Economic Dispatch (SCED) optimization typically every 5 minutes, a DLR calculated and reported to the ISO/RTO at the start of the dispatch period will remain valid for the duration of the period, since the typical thermal time constant of overhead lines ranges between 15-30 minutes. Even if weather conditions change within the dispatch period, due to the conductor thermal time constant the conductor temperature will not exceed MOT before the next DLR is delivered and SCED is recalculated. As such, periodically-calculated DLRs can be relied on in real-time energy markets to improve dispatch optimization and reduce or eliminate congestion [14].

3. DLRs based on historical weather data: Neosho-Riverton

The Neosho-Riverton path is a 161kV transmission line in southeastern Kansas, USA. This line has been the locus of frequent transmission congestion during 2015-2016 in the Southwest Power Pool wholesale market, posting over 500 hours of congestion in this period [15]. The market penetration of wind generation capacity in southern Kansas and Oklahoma is hampered by congestion on west-to-east transmission paths, including Neosho-Riverton.

In hindsight, the impact that a DLR system would have had on historical congestion on the Neosho-Riverton path can be calculated and analyzed. Considering the often windy conditions that have spurred the construction of multiple wind farms in the region, we can assume that DLRs will generally offer greater capacity than static ratings based on worst-case low wind speeds. We examine this assumption by calculating retrospective DLRs for the Neosho-Riverton path and comparing them against a model static rating for the past year, paying special attention to periods where posted congestion limited eastward power flows on Neosho-Riverton.

DLRs for the Neosho-Riverton path were calculated using:

- Assumed conductor properties:
  - Conductor Type: Not knowing the actual engineering specification, we choose ACSR 795.0 "Drake" as a model conductor for this study. Other conductor gauges/stranding will have different absolute capacity ratings, but the relative impact of Dynamic versus Static ratings will be shared in common across the range of typical ACSR and ACSS conductor models.
  - Conductor emissivity: We assume the conductor to have emissivity/absorptivity coefficients of 0.6/0.6.
- Assumed conductor height: We assume a minimum conductor height of 36 feet (11 m)
- Actual conductor heading and elevation: Based on available satellite imagery databases, we determine the line heading (125º) and approximate elevation (900 ft. above sea level) of the Neosho-Riverton right-of-way.
- Estimated solar irradiance: Using date, time of day, and the latitude, longitude and elevation of the Neosho-Riverton right-of-way, we estimate solar irradiance based on standard methods [5]. We conservatively assume no cloud cover.
- Wind speed/direction and ambient temperature data from the NOAA-affiliated airports nearest the Neosho-Riverton path (see Section 4).

Static and Dynamic Line Ratings were computed using the methods outlined in IEEE Standard 738-2012.

4. NOAA Airport Weather Data

A Dynamic Line Rating system suitable for use in real-time operations would require real-time local measurements of overhead conductor properties (temperature, sag) and ambient weather conditions at multiple points along a typical transmission line. Because the Neosho-Riverton path is not yet equipped with the necessary instruments, we estimate effective DLRs using publicly-available meteorological data from the two nearest NOAA-affiliated airports. The use of airport weather data is not recommended for use in computing real-time or forecasted Dynamic Line Ratings and has been shown to produce significant errors when compared to conductor-based or local-weather-station based ratings methods [6],[7]. However, for a historical survey intended to evaluate the potential for DLR to provide capacity increases, airport-based weather data should be sufficient to provide a general understanding of wind speed patterns and ambient temperatures in the region through which a transmission line passes.

The Tri-City (KS) and Joplin (MO) airports are 22 and 13 miles from the Neosho and Riverton substations, respectively. We collected wind speed, direction and ambient temperature data from the public datasets available for these sites for the study period between August 1, 2015 and July 31, 2016 [8]. To calculate a line rating for Neosho-Riverton, we take the most-conservative wind speed and ambient temperature values between the two airports at each hour for the study period. This means that the highest recorded ambient temperature and the lowest recorded wind speed between the two NOAA stations are used for the calculations of DLRs for the entire Neosho-Riverton path. In practice, weather conditions at the two airport sites are highly correlated, with the only significant difference being a tendency toward lower wind speeds at the Tri-City Airport over the study period, likely due to local wind shading of the anemometer at Tri-City.

Both meteorological stations are affected by anemometer stall at low wind speeds, with no wind speed data points reported between 0 and 3 mph. The inability to resolve low-level wind speeds produces a noticeable “kink” in the computed line ratings, due to the different ways that the IEEE 738 methods handle zero (or very low) vs non-zero wind speeds (*e.g.*, natural vs. forced convection)..

Figure 1 plots recorded wind speed values in descending order; with the characteristic stair-step pattern evincing the limited resolution of the anemometer (the slightly smoothed edges are the result of time-series interpolation). Reported absolute wind speed and direction are mapped against the compass heading of the Neosho-Riverton path to produce an effective wind speed in the direction perpendicular to the overhead conductors (plotted in red in Figure 1:) which is the variable that has the largest impact on the calculation of DLR.

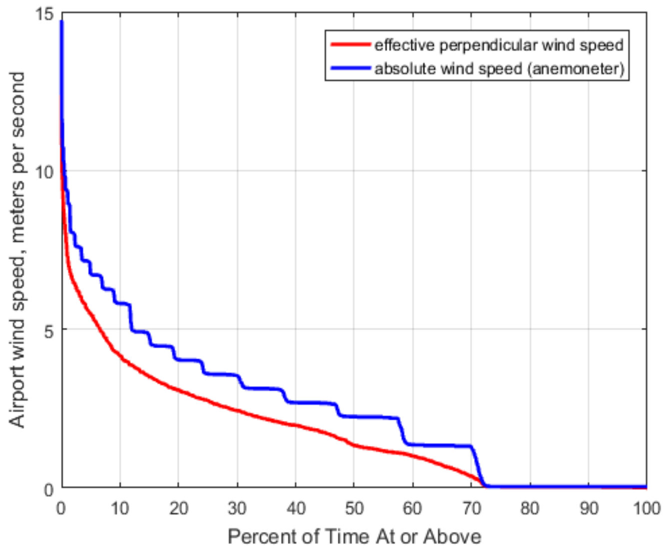

Figure 1:
(Blue) Minimum hourly wind speeds between the Joplin and Tri-City NOAA stations, August 1, 2015-July 31, 2016. Note that anemometer stall, showing zero wind speed, occurs for roughly 30% of the study period, during which no values between 0-3 mph (0-0.91 meters/second) were recorded. This phenomenon negatively affects DLR results, but would be alleviated by use of a proper DLR monitoring system that includes conductor-based measurements able to resolve conductor sag/temperature behaviors even at low wind speeds.
(Red) Effective wind speed perpendicular to the line heading of the Neosho-Riverton path, computed using the wind direction data illustrated in Figure 2:

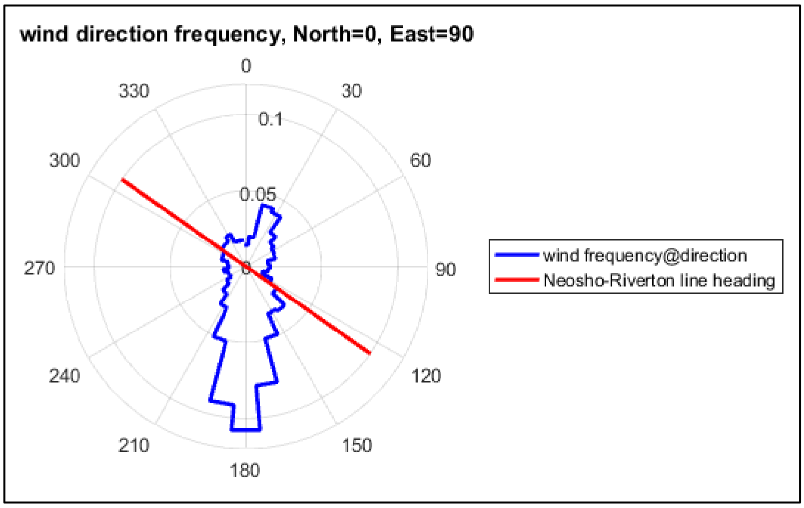

Figure 2:
(Blue) Wind direction histogram for the Joplin and Tri-City NOAA stations, August 1, 2015-July 31, 2016. Direction is only included when wind speed exceeds 3 mph (~0.91 m/s). The wind direction polar plot is not otherwise weighted by wind speed.
(Red) The predominant compass heading of the Neosho-Riverton path. Note that the predominant south-to-north wind direction will produce favorable impacts on DLRs, as convective cooling potential is maximal for wind blowing perpendicularly across the overhead conductors.

5. Historical Dynamic Line Ratings for Neosho-Riverton

For each hour in the study period, we calculate Dynamic Line Ratings based on the recorded weather data. These DLRs can be compared to a Static Line Rating, chosen based on conservative assumptions about weather conditions. Comparison between the Dynamic and Static rating input parameters are shown in Table 1:

Rating input parameter	Value for Static Line Rating	Value for Dynamic Line Rating
Conductor type	ACSR 795.0 Drake 26/7	
Conductor emissivity/absorptivity	0.6/0.6	
Conductor Max. Operating Temp	100 °C	
Solar irradiance date/time	June 10, Noon	*Based on actual date/time*
Ambient Temperature	40 °C	*Variable, NOAA data*
Perpendicular wind speed	0.6 m/s	*Variable, NOAA data (note, due to anemometer stall, includes some zero wind speeds)*

Table 1: Selected input parameters for Static vs. Dynamic Line Rating calculations

Figure 3 shows the aggregate Dynamic Line Ratings computed over the study period, in comparison with the Static Line Rating computed using conservative near-worst-case weather assumptions. In the left plot in red, we show the total aggregated DLRs for all times during the study period, sorted from highest to lowest. This representation of the data allows us to conclude that for approximately 90% of the hours in the study period, the Dynamic Line Rating for the path was at or above the static capacity, and for approximately 65% of the time the DLR was over 20% greater than the static capacity. The right plot in Figure 3 shows a zoomed-in view of the same data, focusing on the critical times when Dynamic Line Rating is just above or even slightly below the static rating. In this plot, the ordinate axis represents the relative percentage increase or decrease provided by DLR, as compared to the SLR.

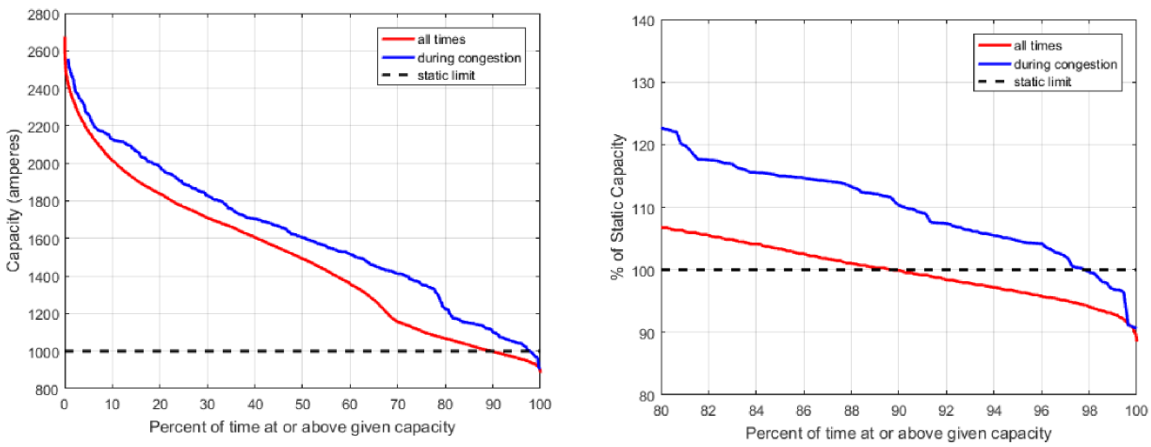

Figure 3:
(Left) Aggregate DLRs for the entire study period, August 1, 2015-July 31, 2016.
(Right) The same data as shown in the left plot, zoomed in on the low-probability region where Dynamic and Static ratings are comparable. In this plot, the capacities provided by DLR are shown as a percentage of the static rating limit.
(Red) DLRs calculated for Neosho-Riverton over all hours in the study period.
(Blue) DLRs calculated during hours in which Neosho-Riverton posted congestion on the SPP market.

Note that the DLR data shown in Figure 3 evinces the low-wind-speed anemometer stall problem, in which roughly 30% of readings from the Tri-City airport showed 0.0 mph wind speed, with no intermediate readings between 0-3mph. This data quality issue is the reason why the general shape of the aggregate DLR plot changes around 70% and above. At zero wind speed, forced convection due to blowing wind disappears, and natural convection dominates in the DLR calculation, producing a noticeably distinct ratings distribution. A full Dynamic Line Rating system involving direct measurement of conductor cooling performance would likely yield more favorable results, as low non-zero wind speeds that fail to register on an anemometer would still provide significant cooling potential for overhead conductors. We consider the data presented in Figure 3 to be fully conservative, as real wind speeds cannot be slower than zero.

The blue lines shown in the left and right plots of Figure 3 are presented to help answer a critical question about the projected benefits of DLR – "*Will the rating of the line be higher when capacity is needed most?*" The blue line represents the distribution of DLRs computed during hours in which Neosho-Riverton was congested in the study period. Additional capacity (vs. static) was available on Neosho-Riverton over 97% of the hours posting congestion, with more than 10% additional capacity during 90% of the hours. Were a DLR system in place for Neosho-Riverton, the negative market impacts of congestion on that line would have been reduced, or perhaps even eliminated, 97% of the time. We note that this impressive result is achieved even while using overly-conservative wind speeds due to anemometer stall in the computation of DLRs, and a proper DLR implementation would likely yield even greater congestion relief.

The correlation between congestion and increased dynamic line ratings is hardly a surprise – the west-to-east congestion on the Neosho-Riverton path is primarily driven by wind generation to the west of the region, and the same windy conditions that produce high wind farm outputs would also increase convective cooling of the conductors carrying the produced power eastward. Implementation of DLR on the west-to-east paths in this region would frequently reduce or eliminate congestion associated with the use of static thermal conductor ratings, at least reducing congestion up to the point that next-limiting-elements (transformers, wave traps, etc.) become cause for congestion concern.

6. Growth of Wind-Driven Congestion

Currently, in the central region of the United States, there are many large wind farms located away from load centers such as cities, and there is inadequate transmission capacity between the two locations. At full wind generation output, the existing network of transmission lines often offers insufficient capacity to carry all of the available wind energy to urban load centers without threatening the Static Line Ratings (SLR) of lines. More expensive non-renewable generators, such as gas combustion turbines, located closer to the load centers are often called upon to generate during transmission congestion to act as an alternate power source for the city. This occurs if too many wind generators are transferring power over a given path at the same time, putting one or more lines along the path at risk of violating its SLR in the event of an N-1 contingency event. This creates a potentially unreliable condition for the electricity grid, and congestion constraints are created in the market to account for this. When transmission congestion occurs, market price signals trigger the dispatch of the generators closer to load centers, and remote wind farms are forced to choose to curtail their output or accept low prices or even financial losses for their production.

This situation has developed because the areas of the US with the most abundant wind resources (see Figure 4:) are also some of the most sparsely populated (see Figure 5:). Historically, these sparsely populated areas did not have the need for the large transmission infrastructure necessary to connect wind resources to major load centers. The harvesting of wind energy in these regions is largely a new phenomenon which has allowed wind generation output to double over the last 5 years and increase sevenfold over the last decade [9].

Growth of wind generation in the Southwest Power Pool (SPP), the power market in which the Neosho-Riverton line is located, has been particularly rapid. SPP is forecasted to reach 16,960 MW of installed wind capacity by the end of 2016. A recent SPP Wind Integration Study [16] analyzed cases in which wind constitutes 30, 45 and 60% of generation in the system. In these high-penetration cases, the study showed that system reliability could be maintained, but would necessitate congestion-driven curtailment of up to 35% of the available wind power, largely offset by coal-fired generation.

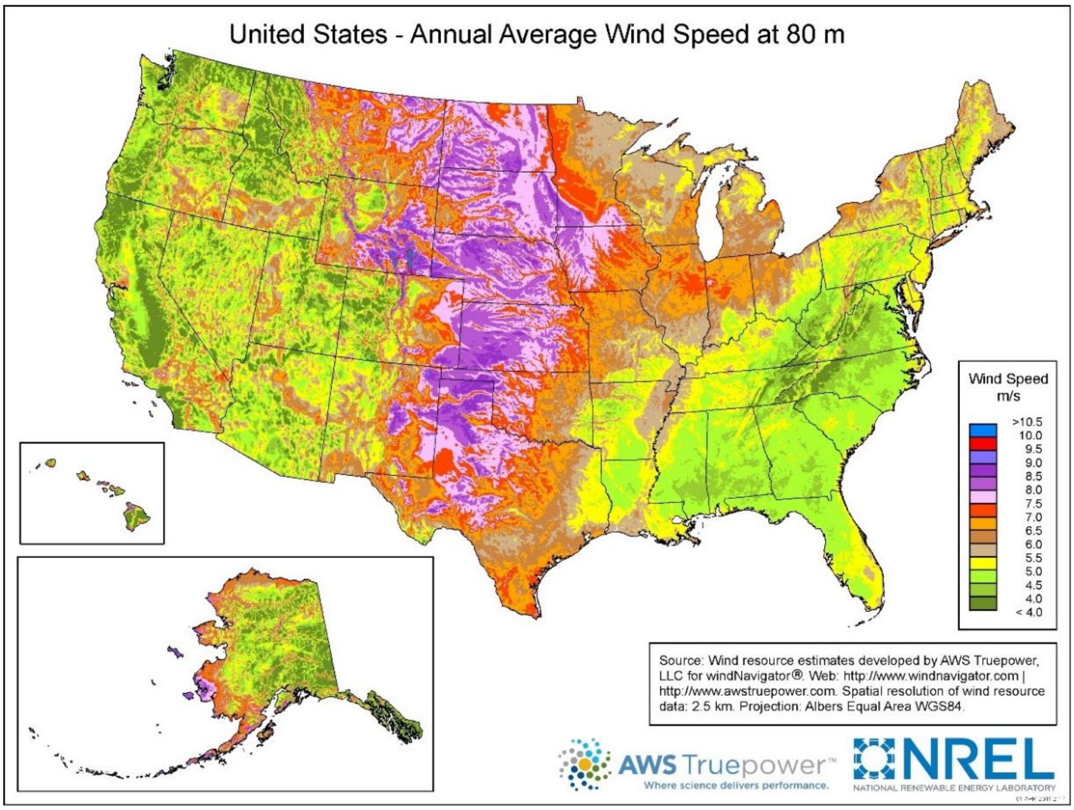

Figure 4:
Annual Wind Speed Average at 80 m across the United States.
Source: http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg

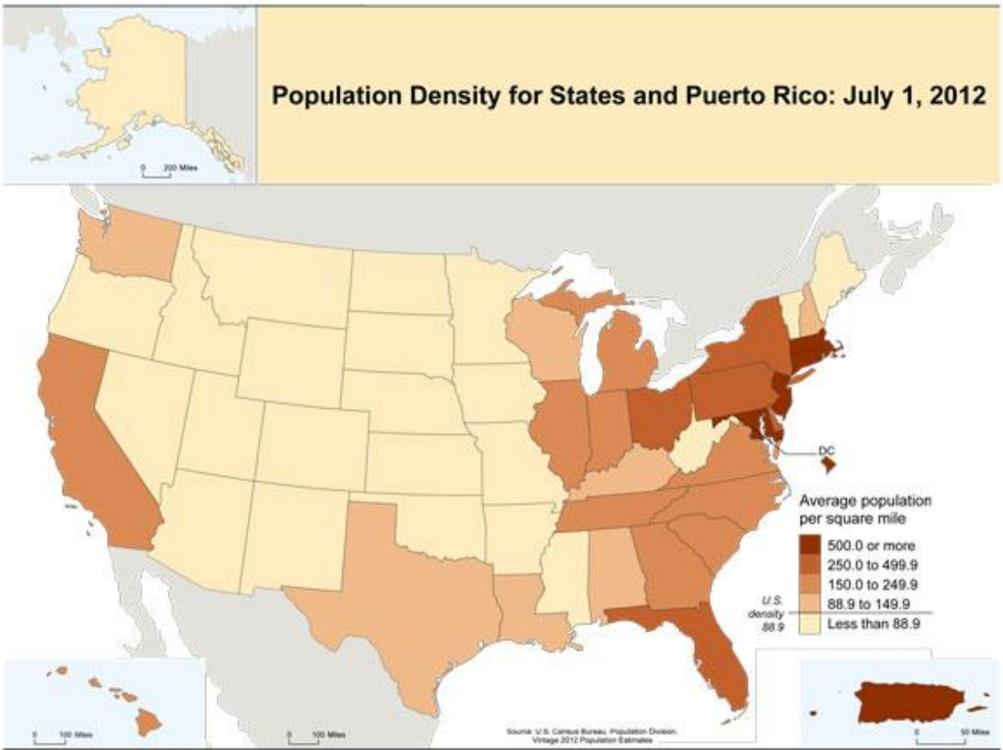

Figure 5:
Population Density for the United State and Puerto Rico, July 1, 2012.
Source: https://www.census.gov/popest/data/maps/2012/popdens-2012.html

7. Power Market Economics Coupled to Reliability

A well-functioning electricity market meets the electricity needs of consumers at the lowest possible cost while maintaining the reliability of the grid. Regulating bodies such as Independent System Operators (ISO) facilitate this optimization by continuously working to balance electricity supply and demand. A mismatch in the quantity of power supplied and the quantity demanded threatens the reliability of the grid. At a given level of demand, if there is not enough supply then the lights won't turn on but; conversely, if there is too much supply on a particular transmission line its reliability, and that of the grid as a whole, can become compromised.

Finding the lowest possible cost while maintaining the reliability of the grid starts by exhausting the cheapest available electricity generation before using more expensive generation. However, there are times when the physical limits of the electricity grid restrict the cheapest available electricity from freely travelling to where it is needed [10]. In this 'congested' situation, more expensive generation is dispatched where needed. The additional production by more-expensive generators must be offset by a reduction of cheaper generating resources to match the given level of demand.

Locational Marginal Pricing (LMP) is the economic mechanism which aligns the reliability of the grid with the financial incentives of market participants [10]. This pricing system puts a value to electricity at a specific delivery location and specific time subject to operating conditions of the transmission system. The result is a unique price at every delivery point on the grid calculated by the ISO typically every 5 minutes. Put simply, if the market needs more generation to come on in a certain area, prices rise in that area which financially incentivizes more generation. If the market has too much generation in a certain area, putting lines at risk of a violating their limit, then prices will fall in that area to a point where it is no longer profitable for some generators to be online.

The details of the LMP system can be further explained in three parts. The first step to this pricing system is an aggregate market clearing or equilibrium price known as the Marginal Energy Cost (MEC). As in all markets, the equilibrium price equates the quantity demanded to quantity supplied at a price which is the lowest acceptable price for the producer of the next, or marginal, unit. In other words, at a given price the field is surveyed to see who would be willing to produce power; if there aren't enough willing producers to meet the electrical needs, then the price is increased until there are enough willing producers. This pricing process exhausts the cheapest available electricity generation before using more expensive generation to service demand. The Marginal Energy Cost is the aggregate clearing price across the market before consideration of operating conditions of the transmission grid and excluding transportation costs.

The second part of this pricing system and most important part for the sake of this paper is the Marginal Congestion Cost (MCC). "Congestion" is the term used when there is heavy use of the transmission system, and the power from the cheapest, willing producers determined by the MEC cannot freely flow to where the power is needed without risk of overloading of one or more transmission lines. To prevent the situation of line potentially reaching its limit, and to ensure grid reliability, inexpensive generation must cut back on one side of the line while more expensive generation must come online on the other side, which ultimately increases the total cost to service our electricity needs. So, in situations where there are large wind farms that lack sufficient transmission capacity to deliver peak wind generation output to demand centers, the grid will experience systematic congestion during periods of strong wind, threatening the reliability of the grid. The market response to this phenomenon is that prices will fall at the wind farms and rise near demand centers, resulting in wind generation curtailments and more expensive generators, like gas turbines, closer to the load center to come online. In this example, MCCs would be negative for the wind farms and positive for the gas turbine. In an uncongested part of the grid, MCCs are zero.

Finally, moving power over a distance from generator to consumer results in some degree of electrical loss due to physical resistance associated with a conductor; these transportation costs, known as Marginal Loss Costs (MLC), are also captured in the LMP.

This results in the governing equation for LMP [11], Equation 1:

$$LMP = MEC + MCC + MLC \qquad (1)$$

8. Understanding the Marginal Congestion Cost

Marginal Congestion cost is defined in Equation 2 [11]:

$$MCC = \text{Shadow Price} * \text{Shift Factor} \qquad (2)$$

There are two important concepts left to understand: the total cost to the market attributed to congestion and which generators bear these costs. Congestion increases the total cost to service electricity demand. When congestion occurs, inexpensive generation must to be reduced and more expensive generation must come online in order to reduce flows on overloading lines and ensure grid reliability. This additional cost to the market associated with congestion is called the Shadow Price.

The Shift Factor is calculated based on power flow models and shows how much an injection or withdrawal of 1MW at a specific location increases or decreases flows on a specific line [12]. If the shift factor of Generator A for Line X is 1.0, this means that a 1.0 MW increase in output at Generator A leads to a 1.0 MW increase on Line X. In this example, Generator A is entirely responsible for flows on the specific line. If Generator B has a shift factor of 0 on a specific line, then changes in generation at B will not affect flows on the specific line. The Shift Factor of a generator can be viewed as a contributing percentage of either causing (positive shift factor) or alleviating (negative shift factor) congestion on a specific line.

Therefore, the Marginal Congestion Cost at a specific generator is determined by the Shadow Price (total cost to alleviate the congestion) multiplied by the Shift Factor (contributing percentage of flows overloading the specific line). The MCC is a per-MW cost assigned to the generator calculated by the ISO, typically every 5 minutes.

Congestion driven by strong wind generation will have a Shadow Price increasing in magnitude as wind generation increases (particularly when wind speed in the region is between 3.5 and 14 m/s); the stronger the wind, the stronger the congestion, until wind speeds are so strong that the wind farms stop producing entirely, or ‘cut out’, for safety reasons [13].

9. Long Term Impacts of Congestion Pricing on Grid Investment

Sustained systematic congestion on a given line will reduce the long term electricity price average on the side generating power (source) while raising prices on the other side of the line which is receiving the power (sink). This becomes a signal to market participants for investment opportunities. Generators will be attracted to add additional resources on the sink side of congestion to capture higher prices for their production. Industrial load, such as factories or data centers that require large quantities of electricity for operations, will be attracted to build facilities on the source side of congestion to buy the lower-cost power. Furthermore, new transmission projects will be incentivized to connect the source area to the sink area.

Each of these investments will help to alleviate the congestion. New generation on the sink side would allow the demand center to use its generated energy instead of drawing from a source with insufficient transmission. New industrial load on the source side would use the locally generated power and therefore make less available to contribute to congestion on lines. New transmission lines would provide additional capacity for the electricity to flow freely from the source to the sink.

DLR is a substantially less expensive alternative that addresses the problem of congestion as compared to the aforementioned options and optimizes existing infrastructure. If DLRs were utilized in place of the artificially low SLRs, the existing infrastructure would be able to transfer power from the source to the sink without restriction; Revealing that the currently modeled congestion is giving the wrong pricing signals for long term infrastructure investments leading to underdevelopment of generation on the source side, underutilization of power on the sink side, and the development of redundant transmission projects. DLR is a technology that unlocks this additional transfer capacity within existing transmission lines and prevents unnecessary development.

10. Caney River Wind Farm Case Study

There are two wind farms located in southeastern Kansas, a 150 MW wind farm called Elk River and a 200 MW wind farm called Caney River. The power from these wind farms most often flows east, towards Springfield, Missouri. This has been confirmed by Genscape's proprietary EMF monitors in the region which measure the output of these wind farms as well as flows on the neighboring transmission lines. Along the path between the wind farms and the Springfield demand center, the Neosho-Riverton 161kV line systematically experiences congestion during periods of strong wind.

To understand the magnitude of this problem for some market participants, we examine the impact of Neosho-Riverton congestion on the Caney River Wind Farm. The Marginal Congestion Cost at Caney River for Neosho-Riverton congestion is determined by the Neosho-Riverton Shadow Price multiplied by the Shift Factor of Caney's generation on the Neosho-Riverton line as shown in Equation 2 above.

This area of the country is a part of the Southwest Power Pool (SPP) which is an ISO that publishes historical 5 minute Real Time pricing data (such as LMP, MCC, Shadow Price, etc.). Using this data, we can calculate that Caney River has a Shift Factor of 0.046 on the Neosho-Riverton line and we assume this to be constant of the period of our study. This means that the Neosho-Riverton congestion Shadow Price multiplied by 0.046 is the Marginal Congestion Cost per MW to Caney River.

For example, if the Shadow Price in a given hour at Neosho-Riverton were -\$100/MW, the MCC for that hour would be -\$4.60/MW as calculated per Equation 3:

$$-\$100/MW*0.046 = -\$4.60/MW \tag{3}$$

Therefore, the cost in that hour to the Caney River Wind Farm at full generating capacity due to Neosho-Riverton congestion would be -\$690, as shown in Equation 4:

$$-\$4.60/MW*150\ MW = -\$690 \tag{4}$$

If this congestion were to be alleviated by DLR or other means, the resulting Shadow Price would be \$0/MW, which makes the MCC = 0. In uncongested markets, MCC = 0.

Figure 6 illustrates the calculated financial impact to at the Caney River Wind Farm due to Neosho-Riverton congestion by month from a period of August 1, 2016 to July 31, 2016. The net economic impact experienced was -\$655k.

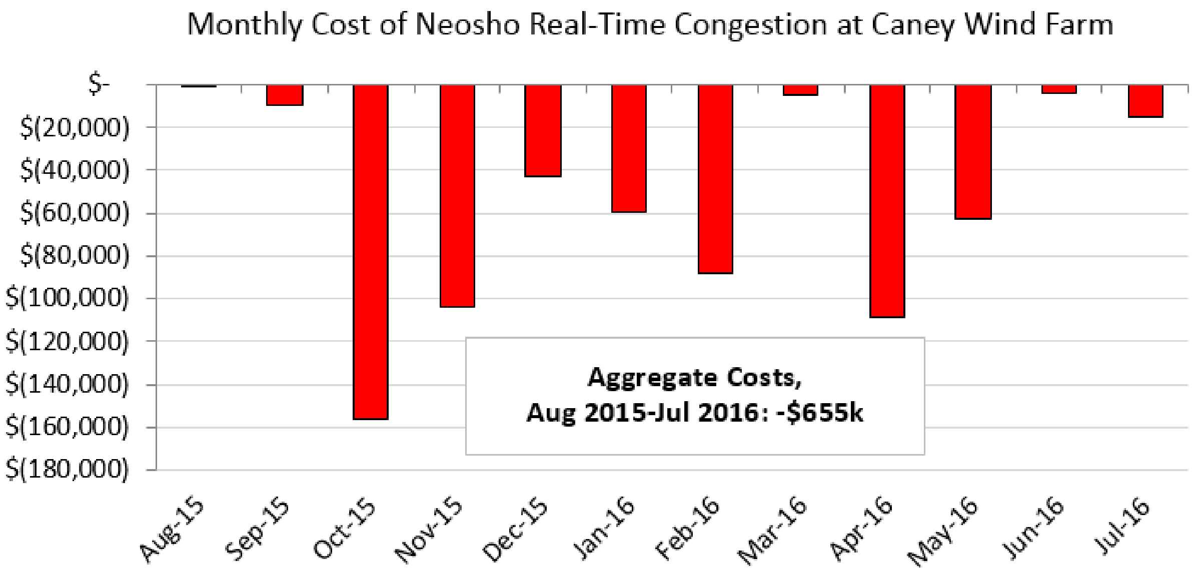

Figure 6:
Monthly Economic Impact at Caney River due
to Real-Time Congestion on Neosho-Riverton.

11. Conclusion

Assuming that the distribution of historical weather conditions over the one-year study period are representative of future weather, the future use of Dynamic Line Ratings on the Neosho-Riverton line in SPP's real-time balancing process could have a dramatic impact on the frequency and severity of congestion in this region of the SPP market. Had it been in use over the study period, a DLR system would likely have shown that additional transfer capacity was available for approximately 97% of the hours when real-time congestion posted, with more than 10% additional capacity during 90% of those hours. Any reduction in the occurrence of congestion or in MCC prices would result in more favorable net LMP pricing at the Caney River wind farm, resulting in increased generation revenues. DLR technology implemented on other transmission lines affected by wind-driven congestion would likely show similar capacity improvements.

In the short term, DLR offers grid operators additional thermal capacity that affords greater flexibility when responding to extreme weather conditions and/or generation/transmission outages. Meanwhile, congestion in real-time markets can be reduced by DLR when incorporated into market operations. The long term result of the use of DLR technology can result in greater utilization of remote renewable resources, such as wind generation, while reducing system-wide energy costs and improving market operational efficiency.

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