STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1276

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance Based Regulation	)))))	**DIRECT TESTIMONY OF EDWARD BURGESS ON BEHALF OF ATTORNEY GENERAL'S OFFICE**

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Edward Burgess. My business address is Strategen Consulting (Strategen), 10265 Rockingham Dr., Suite #100-4061, Sacramento, CA 95827.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Senior Director of Integrated Resource Planning with Strategen.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric and gas utility sectors on issues relating to resource planning, transmission planning, renewable energy, energy storage, rate design, cost of service, program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as AGO Burgess Exhibit 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Attorney General's Office (AGO).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS UTILITY COMMISSION?

A. Yes. I provided testimony to the NCUC in Docket E-2, Sub 1300 (Duke Energy Progress's 2022 Rate Case), and Docket No. E-100, Sub 179 (Duke Energy's 2022 Carbon Plan). I have also provided technical support to the Attorney General's Office on several recent proceedings including Duke Energy's 2018 and 2020 Integrated Resource Plans.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY OTHER STATE REGULATORY BODY?

A. Yes. I have testified before the California Public Utilities Commission (Docket Nos. A.19-08-002, A.20-08-002, R.20-11-003, A.21-08-004, A.21-10-010, and A.21-10-011), the Oregon Public Utilities Commission (Docket Nos. UE-375, UE-390, and UG-435), the Indiana Utility Regulatory Commission (Cause Nos. 38707 FAC 123 S1 and 38707 FAC 125), the Louisiana Public Service Commission (Docket No. U-36105), the Massachusetts Department of Public Utilities (D.P.U. 18-150 and D.P.U. 17-140), the Michigan Public Service Commission (Docket No. U-21090), the Nevada Public Utilities Commission (Docket No. 20-07023), the South Carolina Public Service Commission

(Docket Nos. 2019-186-E, 2019-185-E, 2019-184-E, and 2021-88-E), and the Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and in UE-220053/UG-220054, UE-220066/UG-220067). Additionally, I have represented numerous clients by drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at utilities commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to address several aspects of the transmission component of Duke Energy Carolinas' (DEC, Duke, or the Company) Multi-Year Rate Plan (MYRP). I describe some of the shortcomings of Duke's proposed plan and provide recommendations for how those shortcomings should be remedied as a condition of the NCUC's approval of the MYRP.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

A. Summary of Conclusions:

Q. CAN YOU PLEASE SUMMARIZE THE CONCLUSIONS FROM YOUR ANALYSIS OF DEC'S MYRP PROPOSAL AS IT RELATES TO TRANSMISSION INVESTMENTS?

A. Yes. My conclusions are as follows.

1. DEC's Red Zone Expansion Plan (RZEP) projects will assist with meeting a limited set of immediate Carbon Plan needs. However, the proposed MYRP is insufficiently comprehensive and does not appear to include certain costs that are likely to be incurred over the next few years.
2. DEC's proposed MYRP transmission investments do not include several key strategies/approaches for reducing costs, and thus may not be the most prudent or economically efficient.
3. DEC's proposed MYRP transmission investments do not fully consider the needs of the Carbon Plan.

B. Summary of Recommendations:

Q. CAN YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE COMMISSION BASED ON THESE CONCLUSIONS?

A. Yes. My recommendations are as follows. The Commission should:

1. Approve DEC's proposed RZEP projects as part of the MYRP. However, the MYRP should also be revised to include *all* anticipated costs, even if some are included contingent on future approvals (e.g., CPCNs).

Cost Related:

2. Require study of the costs/benefits of Grid Enhancing Technologies (GETs) within six months. The study should include the elements described in section V-A-1.
3. Require Duke to pursue Inflation Reduction Act (IRA) financing, where possible, for RZEP projects as described in section V-A-2. Energy

Infrastructure Reinvestment (EIR) program financing should be pursued as part of this MYRP cycle (i.e., prior to the 2026 cutoff).

4. Require DEC, during completion of each RZEP project, to study follow-on upgrades to unlock additional renewable energy injection capability, as described in section V-A-3.
5. Require additional actions to evaluate regional transmission projects, as described in section V-A-4, including: (a) study of economic regional projects associated with DEC (i.e., through SERTP); (b) study greater transmission service requests (TSR) between DEP/DEC than 700 MW.
6. Require DEC to update its non-wires solutions methodology (as described in section V-A-5) to more precisely assess benefits and adjust costs to reflect the IRA tax credits for battery storage.
7. Require DEC to report on its plans for using surplus transmission capacity to connect new generation at underutilized coal units such as Marshall Units 1 and 2 (see section V-A-6)

<u>Carbon Plan Related:</u>

8. Require Duke, as part of its first biennial Carbon Plan Integrated Resource Plan (CPIRP), to identify any near-term transmission upgrades that could facilitate onshore wind (see section V-B-1).
9. Require DEC to include transmission upgrades in the MYRP as a means to target the more-optimal 2026 retirement date for the Marshall plant (see section V-B-2). DEC should also seek DOE financing support for this (e.g., through the EIR program) as appropriate.

10. Require DEC to evaluate the potential for increased injection capability from higher voltage levels of RZEP projects and provide a comparable metric for evaluating these options in the future as described in section V-B-3.
11. Require DEC to identify additional RZEP projects in the event that more solar additions are needed in the 2028 timeframe according to the 2023/2024 Carbon Plan (see section V-B-4).

Other Matters:

12. Require MYRP rates to be updated annually to reflect annual changes in FERC formula rates.
13. Require DEC to develop a plan to provide its System Intelligence information to neighboring utilities in real time and request similar information from them.
14. Require DEC to develop a plan to implement Flexible Interconnection across its transmission and distribution system.

III. SUMMARY OF THE TRANSMISSION INVESTMENTS PROPOSED IN DEC'S MYRP

Q. FOR WHICH TRANSMISSION-RELATED INVESTMENTS DOES DEC REQUEST COST RECOVERY IN ITS APPLICATION?

A. DEC requests cost recovery for approximately $463 million in recent transmission investments since its last rate case[1] as well as $2.0 billion in future transmission investments through December 2026 as part of its MYRP.[2]

[1] Maley Direct, at 8.
[2] Maley Supplemental Direct, at 3.

Q. WILL THE TRANSMISSION INVESTMENT PLAN IN THE MYRP HAVE A MATERIAL IMPACT ON DEP CUSTOMER RATES?

A. Yes. The $2.0 billion in transmission system investments being proposed constitute approximately one third of the proposed new plant additions over the 3-year MYRP period. Thus, the necessity and relative cost efficiency of DEC's transmission investment plan will have a material impact on any approved retail rate increase.

Q. WILL THE TRANSMISSION INVESTMENT PLAN IN THE MYRP HAVE A MATERIAL IMPACT ON HOW DEC IS ABLE TO MEET ITS CARBON REDUCTION OBLIGATIONS UNDER HOUSE BILL 951 (HB 951)?

A. Yes. Regarding the transmission investments in the MYRP, the largest single category of costs pertains to "Capacity and Customer Planning" which relates to customer growth as well as projects needed to integrate new generation resources, particularly new renewables. This category also includes specific "Red Zone" projects that are being proposed to support greater integration of new solar PV generation projects in areas where the grid is already heavily constrained. In its December 2022 Order on Duke's Carbon Plan, the Commission directed Duke to procure in the 2023 to 2024 timeframe 2,350 MW of new solar resources and 600 MW of new solar plus storage resources, with the potential for more to be procured through a Volume Adjustment Mechanism (VAM).[3] These additional procurements would have target in-

[3] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179, 87 (N.C.U.C. Dec. 30, 2022) (Carbon Plan Order).

service dates of 2026 to 2028. The successful execution of these new generation projects included in the Carbon Plan depend in part upon the successful completion of the Red Zone transmission projects in the proposed MYRP.

Q. DO YOU SUPPORT DEC'S PROPOSED INCLUSION OF THE RED ZONE TRANSMISSION PROJECTS IN THE MYRP?

A. Yes. From a Carbon Plan execution standpoint, including the proposed Red Zone projects is critical to minimize execution risk. In fact, I have concerns that the proposed projects will be insufficient to achieve DEC's carbon reduction obligations by 2030 as required by HB 951. Meanwhile, DEC's proposal is also deficient because it overlooks several strategies or approaches to its transmission investments that could both (a) minimize the cost of those investments now and going forward, and (b) further minimize execution risk of the Carbon Plan. These deficiencies are addressed in Section V of my testimony.

IV. RISKS TO DEC CUSTOMERS IF THE MYRP IS NOT SUFFICIENTLY COMPREHENSIVE

Q. YOU JUST MENTIONED THAT YOU ARE CONCERNED THAT DEC'S PROPOSED TRANSMISSION PLAN IN THE MYRP WILL BE "INSUFFICIENT" TO ACHIEVE DEC'S CARBON REDUCTION OBLIGATIONS UNDER HB 951. CAN YOU ELABORATE ON THESE CONCERNS?

A. Yes. I am very concerned that if DEC's MYRP is not sufficiently comprehensive in terms of the projected capital investments—including Red

Zone projects and other transmission and generation projects related to the Carbon Plan—then the Company's application is misleading and severely underestimates the eventual cost and rate impact to DEC customers in the coming years. I am concerned that the Commission likely does not have a clear and complete picture of the rate impacts of DEC's current proposal, when coupled with other potential costs that it fails to include in the MYRP.

Q. DOES DEC'S MYRP SIMILARLY OMIT A LARGE NUMBER OF CAPITAL PROJECTS THAT ARE LIKELY TO OCCUR OVER THE NEXT FEW YEARS?

A. Yes, I believe so. This likely includes many investments necessary to achieve the Carbon Plan.

Q. WHAT ARE THE IMPLICATIONS OF A LARGE OMISSION OF EXPENSES IN THE MYRP?

A. The implications are significant. Over the last decade, I have provided expert testimony in multi-year rate plan proceedings and studied best practices of performance-based regulation (PBR), including research conducted at Arizona State University's Utility of the Future Center and commissioned by the Western Governor's Association. Based on this experience, I can attest that one of the primary purposes of a PBR/MYRP framework (such as that proposed by DEC) is to be comprehensive of all expenses, both capital and operations. This comprehensiveness is necessary to provide an accurate incentive for the company to be cost-efficient across its entire operations, and in turn pass those cost savings on to its customers. If there are significant cost items not included in the MYRP, then this incentive structure does not function properly and undermines the entire PBR framework.

Q. SEVERAL PARTIES SHARED SIMILAR CONCERNS IN THE DEP CASE. DO YOU SHARE THOSE CONCERNS IN THIS CASE FOR DEC?

A. Yes. From what I understand, a large number of expected capital projects were not included in the DEP MYRP, and I presume the same is true for the DEC MYRP. Based on Duke's rebuttal to my testimony in the DEP case, it appears that Duke may be expecting cost recovery for these investments to be addressed and authorized in future proceedings. I have concerns that this could lead to greater rate increases in future years than what the Company has portrayed in this case. This concern was raised by the Public Staff in the DEP case, and I share those same concerns here with DEC's proposal.

Q. IS THE LACK OF AN APPROVED CPCN A SUFFICIENT REASON TO EXCLUDE A PROJECT FROM THE MYRP?

A. No. I do not believe that the lack of a CPCN is a clear limitation for many if not all of the transmission projects I have examined in DEC's MYRP period. Some transmission projects may not require a CPCN. *See* N.C. Gen. Stat. § 62-101(c) (listing exceptions to the CPCN requirement, including for "the replacement or expansion of an existing line with a similar line in substantially the same location, or the rebuilding, upgrading, modifying, modernizing, or reconstructing of an existing line for the purpose of increasing capacity or widening an existing right-of-way"). Moreover, due to the imminent nature of some of these investments, presumably any necessary CPCN's have already been obtained. Even if a CPCN is needed, this should not serve as a barrier to consideration in the MYRP. There is no reason why those project costs could not be estimated and included in an MYRP, contingent on future CPCN approval, rather than excluded altogether. Again, the primary goal of the MYRP is to be comprehensive of all costs, and to motivate DEC to provide cost-effective service under a certain future revenue expectation. This remains true even if the precise project portfolio changes based on which projects ultimately receive CPCNs. I recognize that this places some additional execution risk on the Company, but I believe that is a fair and balanced tradeoff in exchange for greater revenue certainty and will help to shift some portion of the risk burden off of DEC customers.

Q. DO YOU HAVE ANY RECOMMENDATIONS BASED ON THIS?

A. Yes. DEC should be required to revise its MYRP such that it includes *all* anticipated costs during the MYRP period, even those that may still require a CPCN.

V. DEFICIENCIES IN THE TRANSMISSION COMPONENT OF DEC'S MYRP

A. The proposed "capacity and customer planning" transmission investments in DEC's MYRP do not adequately consider key strategies for minimizing costs of these investments and to the operation of DEC's system going forward.

Q. CONSIDERING THE PROPOSED "CAPACITY AND CUSTOMER PLANNING" TRANSMISSION INVESTMENTS, HAS DEC TAKEN A COMPREHENSIVE APPROACH TO MINIMIZING COSTS TO ITS CUSTOMERS?

A. No. I believe there are several strategies or approaches that DEC overlooks in its MYRP that could potentially reduce the cost of its Capacity and Customer Planning transmission investments directly or achieve other cost savings going forward. Those strategies include:

1. Investments in GETs (including Ambient Adjusted Ratings) to reduce both capital and operating costs and/or facilitate new resource integration.
2. Use of federal financing opportunities (e.g., through the Inflation Reduction Act) to reduce costs of RZEP projects and other projects.
3. Identification of low-cost follow-on solutions to increase the injection capability of RZEP projects in a cost-efficient manner.
4. Evaluation of regional or interregional projects in lieu of a potentially more costly series of local projects.
5. A more complete and up-to-date evaluation of non-wires solutions.

DEC's failure to include these approaches is likely to increase costs to its customers both during the MYRP and beyond. As such, any MYRP that does not thoroughly incorporate these strategies into its approach to transmission investment cannot be considered prudent. I will discuss each of these strategies in my testimony below.

1. Grid-Enhancing Technologies

Q. WHAT ARE GRID-ENHANCING TECHNOLOGIES AND WHAT ARE THEIR ADVANTAGES?

A. GETs include several technologies—both hardware and software—that can enhance transmission planning and operations by increasing the real-time transfer capacity of the existing transmission network, helping to maximize both cost-efficiency and renewable integration. A primary advantage of GETs is that they can be deployed more rapidly than transmission expansion projects, providing additional transmission capacity in the near-term to complement long-term transmission infrastructure buildout.

Q. WHAT ARE SOME EXAMPLES OF GETs?

A. Some examples of GETs include:

- Advanced Power Flow Control: Injects voltage in series with a facility to increase or decrease effective reactance, thereby pushing power off overloaded facilities or pulling power on to underutilized facilities.
- Dynamic Line Ratings: Adjusts thermal ratings based on actual weather conditions, including ambient temperature and wind, in conjunction with real-time monitoring of resulting line behavior.
- Topology Optimization: Automatically finds reconfiguration to re-route flow around congested or overloaded facilities while meeting reliability criteria.

Q. WHAT ARE SOME OF THE BENEFITS OF GRID-ENHANCING TECHNOLOGIES?

A. A useful summary of key benefits of GETs is set out in the table below, as excerpted from a recent report from the US Department of Energy:[4]

Table 20. Summary of key GETs benefits.

Benefit Type	Description
Reduced congestion via operational flexibility	GETs can increase available transmission capacity and improve operational efficiencies by reducing production costs, congestion costs, renewable generation curtailments, and reserve requirements. Higher ratings also mitigate the impact of contingences, such as generation or transmission system outages.
Asset deferral	By unlocking unused transmission capacity, GETs can defer capital expenditure for system upgrades and serve as an important bridge source of transmission capacity while longer-term solutions are implemented.
Renewable integration	GETs facilitate renewable integration by reducing the extent of system upgrades required to interconnect and dispatch the new generation sources.
Situational awareness	DLR provides more accurate line condition information to improve operators' decision-making. While primarily useful for safe real-time operations, the situational awareness provided by sensor-based DLR solutions can also be used to infer icing conditions on the power line and useful in detecting wildfire conditions that affect local line rating parameters and endanger the public.
Resilience and Contingency Support	DLRs are generally more accurate than ratings calculated using current methods. This enhances system resilience by reducing or avoiding transmission overloads that reduce the service life of transmission lines or cause outages due to faults from excessive sagging of lines. The flexibility afforded by GETs—in general—and the control enabled by PFCs—in particular—are useful in contingency and short-duration emergency conditions as the system is stressed.
Asset health monitoring	The acquisition and analysis of DLR information supports the assessment of line condition and the development of predictive and preventive maintenance measures for the line.

Thus, GETs have the potential to achieve reduced operating costs (e.g., lower production costs), as well as reduced capital costs (e.g., deferred transmission upgrades). For example, a 2021 study by Brattle focused on the Southwest

[4] Grid-Enhancing Technologies: A Case Study on Ratepayer Impact, U.S. Department of Energy (Feb. 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

Power Pool found that with the three aforementioned GETs, Kansas and Oklahoma can integrate an additional 2,670 MW/8,776 GWh of renewables, representing more than twice the amount of renewables to be integrated under a scenario without GETs, while yielding $175 million in annual production cost savings.[5] I have attached the study as AGO Burgess Exhibit 2.

Q. IN ADDITION TO COST SAVINGS, COULD GETs ALSO ASSIST DEP IN MEETING ITS CARBON PLAN REQUIREMENTS?

A. Yes. To the extent that GETs can facilitate interconnection of renewable energy projects, they may be able to minimize execution risk of meeting the Carbon Plan requirements.

Q. DID DEC CONSIDER INVESTMENTS IN GETs FOR THIS MYRP?

A. Not fully. DEC states that it "considered but did not formally study GETs for the projects included in the MYRP."[6] Rather, the Company used "engineering judgement" to eliminate many of the alternatives to traditional transmission infrastructure.[7]

Q. IS DEC REQUIRED TO PURSUE TECHNOLOGIES, LIKE GETs, THAT INCREASE THE CAPABILITIES OF ITS EXISTING TRANSMISSION NETWORK?

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[5] Brattle, Unlocking the Queue with Grid-Enhancing Technologies (2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf
[6] DEC Response to AGO Data Request 2-1 (attached as AGO Burgess Exhibit 4).
[7] AGO Burgess Exhibit 4.

A. Yes. DEC is working to implement FERC Order 881 which directs transmission owners to implement Ambient Adjusted Ratings (AARs) by 2025.[8] Even though AARs are not as advanced as Dynamic Line Ratings (DLRs) and may not be considered a GET *per se*, the two approaches have many similarities. For example, AAR will likely affect the Company's transmission planning assumptions (*e.g.*, Total Transfer Capability and Available Transfer Capability) and efficiency of real-time operations during the MYRP.

Q. DID DEC DISCUSS ANY ACTIVITIES TO COMPLY WITH FERC ORDER 881?

A. No, DEC did not describe any specific AAR-related investments during the MYRP to comply with FERC Order 881, despite the Company's own comments to the FERC that implementing AAR would require fundamental software changes that would take millions of dollars and several years to complete.[9]

Q. IS THE LACK OF DISCUSSION ON AAR IN DEC'S APPLICATION CONCERNING TO YOU?

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[8] AGO Burgess Exhibit 4. *See* AGO Burgess Exhibit 2; *see also* Managing Transmission Line Ratings, Order No. 881, 2021 FERC LEXIS 1735, 177 FERC ¶ 61,179 (2021) (Order 881), modified and affirmed in part, 18 CFR Part 35, 179 FERC ¶ 61,125 (2022).

[9] See FERC Order 881, Docket No. RM20-16-000, at 44 (Dec. 16, 2021); *see also id.* at ¶ 55 ("Duke Energy states that it already employs AARs in real-time operations and supports the Commission's proposed requirements for transmission providers to implement AARs in real-time operations. However, Duke Energy also argues that, because incorporating AARs into ATC calculations would require fundamental software changes that may take several million dollars and multiple years to complete, the benefits may not outweigh the costs. Duke Energy suggests that the Commission should instead require transmission providers to submit a compliance filing in which they may propose a process to identify the transmission facilities for which the implementation of AARs and seasonal line ratings will provide the most benefits to customers.").

A. Yes. The lack of discussion of investments to enable AAR (which the Company is already required to implement by FERC) is concerning because the compliance deadline for Order 881 is in 2025; thus, any necessary investments would squarely overlap with the MYRP period. Yet the Company stated that "[a]t this time no discrete projects are generated to specifically address FO881, and therefore none are included in MYRP."[10] This suggests that the Company's MYRP has not prioritized all appropriate strategies to enhance the efficiency and capability of its existing transmission system that could reduce overall transmission costs to customers. Instead, the Company is more focused on building new traditional transmission infrastructure in order to expand its rate base.

Q. IN ITS RESPONSE TO AGO 2-1, DEC SUGGESTED THAT UNCERTAINTIES WITH AMBIENT CONDITION FORECASTING CREATE CHALLENGES FOR IMPLEMENTING GETs. DO YOU AGREE?

A. No. In Order 881, FERC considered this issue but ultimately concluded that requiring AARs was still necessary and appropriate. More specifically, Order 881 allows for a margin of uncertainty when forecasting ambient conditions, and for these margins to be evaluated and adjusted over time as necessary to maintain reliability. A similar approach can be taken with DLRs. Further FERC cites an analysis from the National Oceanic and Atmospheric Administration (NOAA) National Blend of Models (NBM) forecasts that indicates the potential

[10] DEC Response to AGO Data Request 2-46.

error in forecasts is limited.[11] Finally, it should be noted that existing grid operations already rely substantially on forward weather forecasting.

Q. HAVE DLRs BEEN COMMERCIALLY DEPLOYED?

A. Yes. GETs have been successfully deployed both in the United States[12] and internationally, with significant deployments by grid operators in in Europe and Australia.[13] In the US, the Oncor Electric Delivery Company in Texas implemented two separate DLR projects. The first increased the capacity of transmission lines by 8 to 12 percent and from 6 to 14 percent on average for its 138 kV and 345 kV lines, respectively. The second project deployed DLR on five lines in West Texas to enable congestion relief. Similarly in Texas, in 2006 American Electric Power enabled real-time line ratings on a 138 kV transmission line, allowing them to avoid a $20 million upgrade which would otherwise have become a stranded asset with future transmission capacity investments.[14] Kansas City Power and Light deployed a DLR system in 2002 on its LaCygne-Stilwell 345kV 32-mile line in southeast KS. The project paid

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[11] Final Rule: Managing Transmission Line Ratings, 87 Fed. Reg. 31712, 31717 (May 25, 2022).

[12] Oncor's Pioneering Transmission Dynamic Line Rating (DLR) Demonstration Lays Foundation for Follow-On Deployment, U.S. Dept. of Energy (May 5, 2014), https://www.energy.gov/sites/prod/files/2016/12/f34/Oncor_DLR_Case_Study_05-20-14_FINAL.pdf

[13] Improving Transmission Operation with Advanced Technologies, Brattle Group (June 24, 2019), https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paperimprovingtransmissionoperationwithadvancedtechnologies.pdf; Dynamic Line Rating, International Renewable Energy Agency (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Dynamic_line_rating_2020.pdf?la=en&hash=A8129CE4C516895E7749FD495C32C8B818112D7C.

[14] Sandy K. Aivaliotis, Dynamic Line Ratings for Optimal and Reliable Power Flow: Enhanced Power Flow for the Smart Grid, FERC Technical Conference, page 29. https://cms.ferc.gov/sites/default/files/2020-05/20100623162026-Aivaliotis%2C%2520The%2520Valley%2520Group%25206-24-10.pdfhttps://cms.ferc.gov/sites/default/files/2020-05/20100623162026-Aivaliotis%2C%2520The%2520Valley%2520Group%25206-24-10.pdf

for itself in less than three months.[15] There are further examples of DLR deployments in New York by National Grid,[16] in the Northwest by PacifiCorp, in California by Pacific Gas & Electric, and in Quebec, Canada by Hydro Quebec.[17]

Q. DEC HAS SUGGESTED THAT GETs DEPLOYMENT MAY BE OF LIMITED VALUE SINCE MANY OF THE PROPOSED TRANSMISSION PROJECTS WILL STILL BE REQUIRED OVER THE LONGER TERM.[18] DO YOU AGREE?

A. No. While GETs may not be able to eliminate transmission infrastructure upgrades in all cases, they may be able to defer those upgrades or provide other benefits. From a ratepayer cost perspective, deferral of transmission investment can still result in net positive ratepayer benefits from an opportunity cost perspective. Even if those costs are eventually recovered in a future MYRP, there is still a benefit to avoiding them in the current MYRP due to the time value of money. Additionally, since transmission investment can require long development timeframes, GET investments can help to alleviate solar interconnection timelines in the shorter term, thus minimizing Carbon Plan execution risk. Finally, the deployment of GET approaches will provide the Company with added real-time visibility and awareness on the operations of the

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[15] Dynamic Line Ratings for Optimal and Reliable Power Flow: Enhanced Power Flow for the Smart Grid, FERC Technical Conference, page 26.
[16] National Grid and LineVision Deploy Largest Dynamic Line Rating Project in the United States, LineVision, 2022. https://www.prnewswire.com/news-releases/national-grid-and-linevision-deploy-largest-dynamic-line-rating-project-in-the-united-states-301653906.html
[17] Jeff St. John, Dynamic Line Rating: Expanding Transmission Grid Capacity for Clean Energy (Dec. 7, 2020), https://www.greentechmedia.com/articles/read/dynamic-line-rating-pushing-the-transmission-grid-envelope-on-clean-energy-capacity.
[18] AGO Burgess Exhibit 4.

transmission system, elements that will be increasingly important in maintaining reliable and efficient operations. This real-time visibility may allow the Company to dispatch its generation fleet more efficiently, thereby reducing operating costs.

Q. WHAT ARE YOUR RECOMMENDATIONS IN REGARDS TO GETs?

A. As a condition of approving the proposed MYRP, I recommend that the Commission require Duke to conduct a study on the costs and benefits of GETs for the Company's transmission system within six months. At a minimum, the study should include:

- Estimated increase in line ratings for DEC's existing transmission system.
- Estimated increases in line ratings of proposed new transmission projects.
- Identification of specific transmission project deferral opportunities.
- Estimated increase in incremental solar that could be integrated.
- Estimated operating cost savings.
- Reliability benefits.
- A near-term action plan for implementing GETs that are found to be beneficial.

Additionally, I recommend that DEC update its MYRP to include the investments necessary to comply with FERC Order 881.

2. *Use of IRA funding and financing opportunities to reduce transmission project costs.*

Q. DID THE COMPANY'S INITIAL APPLICATION ANTICIPATE LEVERAGING ANY TRANSMISSION PROVISIONS UNDER THE INFLATION REDUCTION ACT DURING THE MYRP?

A. No. In fact, the Company initially stated that it "does not expect transmission projects in the MYRP to be eligible for provisions of the Inflation Reduction Act" because the Company "expects that those provisions are intended to incentivize the development of renewable and alternative carbon-free energy sources, not specifically transmission infrastructure."[19]

Q. IS THE COMPANY CORRECT THAT TRANSMISSION INFRASTRUCTURE IS NOT A TARGET OF THE INFLATION REDUCTION ACT?

A. No. In fact, the Inflation Reduction Act includes several provisions for the transmission system, including:[20]

- Section 50151 (Transmission Facility Financing): $2 billion in direct loans for transmission projects located in a National Interest Electric Transmission Corridor.
- Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines): $760 million in grants aimed at facilitating the siting of certain onshore and offshore transmission lines.

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[19] DEC Response to AGO Data Request 2-15.

[20] Congressional Research Service. 2022. *Electricity Transmission Provisions in the Inflation Reduction Act of 2022*. https://crsreports.congress.gov/product/pdf/IN/IN11981

- Section 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis): $100 million for expenses for convening stakeholders and conducting analysis related to the development of interregional transmission and transmission for offshore wind energy.
- Section 50144 (Energy Infrastructure Reinvestment Financing): $250 billion in loans for projects that (1) retool, repower, repurpose, or replace energy infrastructure that has ceased operations, or (2) enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases.

Many of the Company's proposed transmission investments are likely to be eligible for at least one of these funding and financing sources. For example, transmission investments to support solar additions (such as RZEP projects) or transmission investments related to coal retirements are likely to qualify for the EIR Program. By providing low-cost loans, this program could lower financing costs for DEC and unlock significant savings for ratepayers. DEC's initial failure to identify and pursue these provisions, based purely on the Company's incorrect expectation that transmission investments are not the target of the Inflation Reduction Act, suggests that the Company is not acting prudently to proactively and reasonably seek out and prioritize cost saving opportunities for its ratepayers.

Q. ARE OTHER UTILITIES PURSUING IRA FUNDING AND FINANCING FOR GRID INVESTMENTS?

A. Yes. For example, Pacific Gas & Electric recently applied for an approximately $7 billion loan from the EIR for infrastructure[21] upgrades to support decarbonization.[22] The utility estimates that it could save millions of dollars in financing costs.

Q. HAS THE DEPARTMENT OF ENERGY INDICATED THAT THE EIR PROGRAM IS APPLICABLE TO TRANSMISSION?

A. Yes. In fact, the Director of the Loan Program Office (LPO), which oversees the EIR program recently wrote an article describing several hypothetical examples of projects that could be eligible.[23] I have attached this article as AGO Burgess Exhibit 3. One of the example projects was described as follows:

- **Transmission reconductoring:** A utility plans to upgrade several high-voltage transmission lines through reconductoring. The utility estimates that replacing the conductive core of older transmission lines will double the electricity carrying capacity compared to the existing conductors, while reducing line losses by up to 50%. The reconductoring plan will retool the existing towers and utilize established rights-of-way. This investment will significantly increase the utility's ability to interconnect new clean energy generation without requiring the time and expense associated with the permitting and construction of new transmission lines. The reconductoring

[21] U.S. Department of Energy Loan Programs Office, *Energy Infrastructure Reinvestment*, https://www.energy.gov/lpo/energy-infrastructure-reinvestment.

[22] S&P Capital IQ. PG&E requests about $7B federal loan for grid, energy transition upgrades. 2023. https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=76360643&KeyProductLinkType=14&utm_campaign=top_news_3&utm_medium=top_news&utm_source=news_home

[23] Utility Dive. Tapping into DOE's $250B of loan authority for projects that reinvest in US clean energy infrastructure. 2023. https://www.utilitydive.com/news/department-of-energy-doe-250-billion-loan-authority-solar-wind-storage-nuclear-clean-energy/653530/

plan has received regulatory approval for cost recovery, which LPO considers sufficient to ensure reasonable prospect of repayment on the loan.

This description could clearly apply to certain RZEP projects, including those proposed in DEC's MYRP, as well as other projects the Company has not yet proposed.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE TIMING AND AVAILABILITY OF THE EIR FUNDING RELATIVE TO THIS PROCEEDING AND DEC'S MYRP?

A. Yes. I'm concerned that if DEC and the Commission do not address this issue in the current proceeding (and in the concurrent DEP rate case), they may ultimately miss the opportunity to secure hundreds of millions of dollars in cost savings for North Carolina ratepayers. The example in the article mentioned above alludes to the fact that projects may need "regulatory approval for cost recovery" in order for the LPO to consider the loan to have a reasonable prospect of repayment. This means that any project not included in the MYRP (including transmission and generation) may have a harder time accessing these EIR funds, and thus may be more costly to DEC ratepayers. Furthermore, the article states that "Conditional commitments (agreed upon term sheets with stipulations the borrower must meet before financial close) must be made by Sept. 30, 2026, for loan disbursements available through Sept. 30, 2031." Thus, the EIR program may be able to finance transmission and other projects deployed well beyond the proposed MYRP period. However, if DEC waits until the next MYRP proceeding to propose this, it may be too late to secure a "conditional commitment" from DOE before the 2026 deadline.

Q. IS DEC'S APPROACH TO THE IRA CONSISTENT WITH ITS APPROACH TO OTHER SOURCES OF FEDERAL FUNDING?

A. No. DEC is apparently pursuing federal funding opportunities for transmission offered through the Infrastructure Investment and Jobs Act (IIJA),[24] and specifically DOE's Grid Resiliency and Innovation Partnership program. It is unclear why DEC chose not to do so for the IRA programs. Indeed, to date it appears that DEC has had no communication with DOE and no internal effort related to determining eligibility for EIR funding.[25]

Q. IN CONTRAST TO DEC, HAS DEP CONSIDERED THE APPLICABILITY OF IRA FUNDING SOURCES TO ITS TRANSMISSION PROJECTS?

A. Yes. While DEP initially claimed that transmission was categorically ineligible for IRA funding, it appears that DEP has reconsidered how to obtain this funding in response to data requests from the AGO and other parties. I am not sure why DEC did not similarly pursue DOE funding while DEP did.

Q. HAVE YOU ESTIMATED THE POTENTIAL COST SAVINGS IF THE RZEP PROJECTS WERE TO BE FINANCED THROUGH THE EIR PROGRAM?

A. Yes. I estimate that these savings to RZEP project costs from EIR financing alone could be on the order of $91 million (net present value). Bear in mind that

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[24] DEC Response to Public Staff Data Request 178-1.
[25] DEC Response to AGO DR 2-15.

DEC only proposed a very small number of RZEP projects. Thus, this estimate does not include potentially even more significant savings from using the program to finance additional transmission upgrades, DEC-owned generation projects such as solar PV supported by the RZEP projects, or battery storage projects located at retiring coal plant facilities.

Q. WHAT ARE YOUR RECOMMENDATIONS IN REGARD TO IRA FUNDING AND FINANCING OPPORTUNITIES?

A. I recommend that the Commission direct the Company to pursue funding and financing opportunities under the IRA where possible, including for RZEP transmission projects. These savings should be passed along to DEC customers, ideally through annual adjustments as part of the annual MYRP review, or at least through the subsequent MYRP. As part of the annual MYRP review, the Company should also provide a transparent and comprehensive report on all activities it has undertaken to secure federal financing opportunities resulting from the IRA and IIJA.

3. *<u>Identification of smaller follow-on upgrades to RZEP projects that can enhance their ability to integrate new capacity.</u>*

Q. BEYOND PROACTIVE TRANSMISSION PLANNING FOR RZEP PROJECTS, ARE THERE LOW-COST WAYS TO INCREASE THE INJECTION CAPABILITY OF THE GRID TO ACCOMMODATE FUTURE RENEWABLES?

A. Yes. In one recent example, Tri-State Generation and Transmission (Tri-State) in Colorado sought several major new additions to its transmission system costing over $400 million to accommodate 400 MW of new renewable energy resources to be connected as part of its Responsible Energy Plan.[26] As part of a settlement agreement[27] approving the new transmission lines, Tri-State agreed to conduct a follow-on study to identify incremental transmission improvements (Incremental Improvements Study)[28] that could increase the injection capabilities of the new lines to allow even more renewable resources to be connected. The results of the study showed that a modest incremental investment of approximately $270,000 could allow up to an additional 430 MW to be injected. Thus, the study revealed significant low-cost "low hanging fruit" in incremental improvements that could be made to maximize the injection capability of the new lines. While every transmission system is different, it is certainly possible similar circumstances could arise on Duke's system. Thus, I recommend that the Commission require Duke to follow a similar practice as part of its deployment of RZEP projects during the MYRP. This will help minimize the execution risk of adding significant amounts of new solar to the DEC system.

Q. WHAT SPECIFICALLY SHOULD THE COMMISSION DIRECT DEC TO DO?

[26] Colorado PUC Proceeding No. 22A-0085E

[27] Unopposed Comprehensive Settlement Agreement, Proceeding No. 22A-0085E, Decision No. R22-0533 (July 1, 2022), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=980248&p_session_id=

[28] Incremental Improvements Study Report, Tri-State Generation & Transmission Association (Aug. 5, 2022), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=980375&p_session_id=

A. I recommend that before or during the completion of each RZEP project, DEC be required to conduct an Incremental Improvements Study to identify any low-cost incremental improvements that could increase the injection capability of each RZEP project. These studies should be made publicly available. If the studies show that incremental improvements costing less than a certain threshold (e.g. <$1 million or <5% of the original project cost) are able to increase injection capability by a certain amount (e.g., >20 MW, or >5% of the original MVAR increase), then these improvements should automatically be deemed prudent, and DEC should be required to implement them as early as is practicable.

4. <u>Regional transmission projects</u>

Q. WHAT ARE THE BENEFITS OF REGIONAL TRANSMISSION LINKS?

A. Many studies have demonstrated the importance of greater regional coordination for (1) economic benefits, (2) renewable energy integration, and (3) reliability. Interconnected transmission networks enable geographic diversity and resource diversity of renewables, producing significant reduction in system-wide costs and generation curtailments. A 2020 study from Boston University demonstrated that when two regional systems/submarkets with different renewable resource production profiles are interconnected, there can be a reduction in annual production costs between 2% to 23% and a decline in annual renewable curtailments between 45% to 90%.[29] The study also

[29] Boston University ISE, The Brattle Group. 2020. *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*. https://open.bu.edu/handle/2144/41451

concluded that there may be additional benefits from regional integration due to the increased ability to manage uncertainty between day-ahead scheduling and sub-hourly real-time operations. Additionally, a recent empirical study from the Lawrence Berkeley National Lab (LBNL) showed that transmission links have historically provided significant economic value, with many regional links yielding more than $130 million in benefits per year per 1000 MW of transfer capability, and interregional links showing double that value.[30]

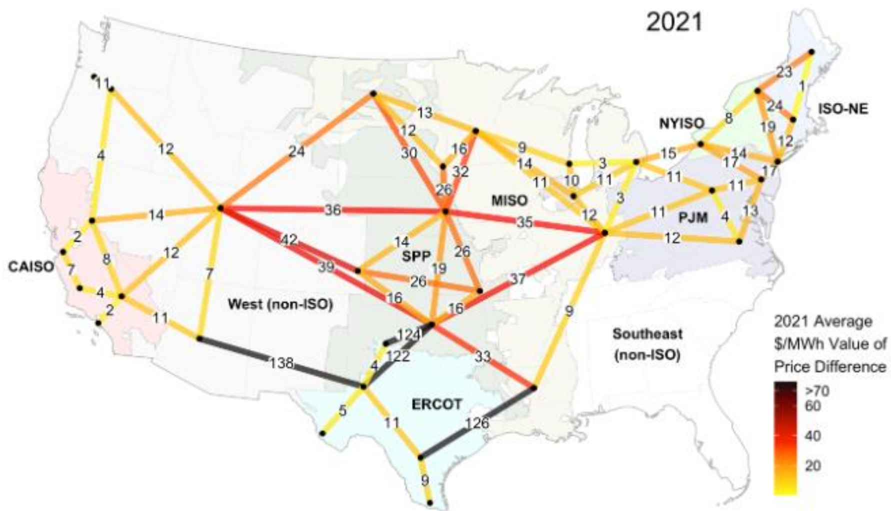

Figure 2. Marginal value of transmission in relieving congestion and facilitating trade in 2021.

The map above illustrates the economic value of various transmission links from relieving congestion and facilitating trade in 2021. Notably, the Southeastern US (which includes Duke's service territory) was the only region the researchers were unable to evaluate due to a lack of transparent market data. The study observed that the value of these links is especially high during grid stress events like Winter Storm Uri.

[30] Lawrence Berkeley National Lab. 2022, *Empirical Estimates of Transmission Value using Locational Marginal Prices*, https://emp.lbl.gov/publications/empirical-estimates-transmission.

Q. WILL MORE REGIONAL TRANSMISSION ASSIST DEC WITH ITS CARBON PLAN OBLIGATIONS?

A. Yes. This will allow for greater access to a broader diversity of renewable energy resources—especially wind from the mid-west that can complement local solar.

Q. ARE ANY OF DEC'S PROPOSED TRANSMISSION INVESTMENTS DESIGNED TO SUPPORT REGIONAL AND INTERREGIONAL TRANSMISSION LINKS?

A. No. None of the Company's proposed transmission investments are designed to enhance import/export capability.[31]

Q. IS DEC SUFFICIENTLY PLANNING FOR FUTURE REGIONAL AND INTERREGIONAL TRANSMISSION LINKS THROUGH ITS MYRP?

A. No. The only regional transmission project Duke is undertaking concerns approximately 700 MW of transmission service requests (TSRs) from DEC to DEP. However, according to the Company the associated upgrades have largely been completed. This limited number of regional upgrades considered by Duke appears to leave out other regions or potential transmission customers, including existing connections or new connections.[32] DEC also stated that it does not generally explore potential regional and interregional projects before receiving a TSR from an outside entity.[33] This stands in contrast with the Company's more proactive planning approach that it employs towards local

[31] DEC Response to AGO Data Request 2-3(a) (attached as AGO Burgess Exhibit 5).
[32] AGO Burgess Exhibit 5 at (b).
[33] AGO Burgess Exhibit 5 at (c).

RZEP projects. Additionally, the fact that DEC has not identified any transmission limitations on imported resources suggests that significantly more imported resources (e.g., onshore wind from PJM) might be a viable option in future Carbon Plans.

Q. HOW DO THE POTENTIAL BENEFIT OF DEC'S INVESTMENTS IN REGIONAL TRANSMISSION COMPARE TO THEIR COSTS?

A. It is difficult to say with certainty due to the lack of studies and transparent information provided by the Company. However, as a high level estimate I think it is worth noting that that DEP identified only about $20 million in costs for recent upgrades to unlock 700 MW of transfer capability with DEC. Using the LBNL Study I mentioned above as a benchmark (i.e., $130 million in annual benefits per 1000 MW), 700 MW of transfer capability could equate to over $90 million in benefits per year. Assuming DEP's investments provide benefits of the same level of magnitude, they would pay for themselves within a year. Thus, if DEC is truly interested in reducing costs for its customers it is difficult to understand why similar regional projects are not a higher priority and indeed a central focus of the Company's transmission investment plan in the MYRP.

Q. IS IT POSSIBLE THAT CERTAIN REGIONAL TRANSMISSION PROJECTS COULD DISPLACE LOCAL PROJECTS, INCLUDING THOSE IN THE MYRP?

A. Yes. It is possible that regional transmission projects could reduce or eliminate the need for local projects (including those in the proposed MYRP) and may even be more economic than those local solutions in combination. This potential benefit is difficult to assess, however, given that it has not been thoroughly studied by DEC. In response to AGO 2-5, DEC stated that the regional transmission planning process it participates in (i.e., the Southeastern Regional Transmission Planning process, or SERTP) did not identify the need for any regional projects for the MYRP time period.

Q. DO YOU THINK SERTP'S MOST RECENT ANALYSIS PROVIDES A COMPLETE OR ACCURATE ASSESSMENT OF THE POTENTIAL VALUE OF REGIONAL TRANSMISSION PROJECTS TO DEC RATEPAYERS?

A. No. Based on my review of recent SERTP planning studies in which Duke participated, I believe they were highly inadequate in terms of identifying potentially beneficial regional projects for DEC. In late 2022 (prior to DEC's application in this case) SERTP completed both a "Regional Transmission Planning Analyses" report,[34] and an "Economic Planning Studies" report,[35] both of which purport to evaluate regional projects in the SERTP region. However, the Economic Planning Studies report only evaluated the costs of the projects and did not evaluate any benefits, thus making it wholly insufficient for determining the value of regional projects. Meanwhile, the Regional Transmission Planning Analyses evaluated just two new transmission projects across the entire SERTP region, only one of which was connected to DEC

[34] Regional Transmission Planning Analyses, SERTP (Nov. 17, 2022), http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf.

[35] Economic Planning Studies Final Results, SERTP, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Economic_Study_Results_Final.pdf

(specifically, a new link between DEC and DEP). The analysis did not evaluate any projects between DEC and other balancing authorities in the region. Moreover, while SERTP's Regional Transmission Planning Analyses concluded that neither of the two projects were cost effective, this may be due not only to the limited number of projects assessed but also to deficiencies in the methodology used. SERTP's methodology only compares the cost of potential regional projects to potential local projects in the baseline regional transmission plan that might be replaced, rather than accounting for the broader benefits provided by the regional transmission lines. For this reason, SERTP was recently given an F rating, the lowest of any region in the US, by Americans for a Clean Energy Grid's Transmission Planning and Development Regional Report Card.[36] If the potential benefits of regional transmission projects were fully assessed—either by Duke or by SERTP—regional projects may emerge as the more economic option compared to a combination of local projects. Finally, it is worth noting that the NCTPC process only examines local projects.

Q. WHAT ARE YOUR RECOMMENDATIONS IN REGARD TO REGIONAL TRANSMISSION PROJECTS?

A. As a condition of approving the MYRP, I recommend that the Commission require the Company to take several actions that could lead to more cost-efficient regional transmission solutions in the future. These include:

[36] Americans for a Clean Energy Grid. *Transmission Planning and Development Regional Report Card*. https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf

- *Study additional regional transmission projects associated with DEC*: Within six months, DEC should provide to the Commission a study of the costs and benefits of additional regional transmission projects connected to DEC's system. To the extent possible this should be coordinated with SERTP.
- *Study greater TSRs between DEP and DEC than 700 MW*: Within six months, DEC should provide to the Commission a study of the costs and benefits of increasing transmission service between DEC and DEP's system beyond the 700 MW that has recently been implemented.
- *Study incremental TSRs between DEC and PJM*.

5. <u>Non-wires solutions</u>

Q. WHAT ARE NON-WIRES SOLUTIONS?

A. Non-wires solutions are alternative technologies that can avoid or defer traditional transmission upgrades, potentially at a lower cost. This could include resources like battery storage or demand-side management.

Q. DID DEC CONSIDER NON-WIRES SOLUTIONS AS ALTERNATIVES TO ITS PROPOSED MYRP TRANSMISSION PROJECTS?

A. According to DEC, the Company did consider non-wires solutions but determined that that none of these solutions were cost-effective.[37]

Q. WHAT METHODOLOGY DID DEC USE TO ARRIVE AT THIS CONCLUSION?

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[37] DEC Response to AGO Data Request 2-13.

A. According to the Company's response to AGO 2-14, the methodology is described as part of DEC's ISOP evaluation. This methodology uses an initial screening that focused on battery storage technologies and assumed a 50% reduction in the capital cost of the battery as a "placeholder for capacity, energy, and ancillary service values."[38]

Q. DO YOU HAVE CONCERNS ABOUT THIS APPROACH?

A. Yes. First, I find the 50% reduction to be somewhat arbitrary and should be more closely linked to an analysis of the specific system benefits that the batteries could bring. Second, it does not appear that DEC considered any recent changes to the cost of non-wires solutions due to federal legislation. For example, the federal tax credits associated with the IRA significantly reduce the cost of standalone battery storage projects; however, it's unclear to me that DEC's ISOP methodology was updated to consider this change.

Q. WHAT ARE YOUR RECOMMENDATIONS IN REGARD TO NON-WIRES SOLUTIONS?

A. The Commission should require Duke to update its methodology used to evaluate non-wires solutions, to include a more precise analysis of benefits and to reflect cost reductions enabled by the IRA. This updated methodology should be provided to the Commission within six months, along with a re-evaluation of non-wires solutions for any remaining transmission projects in the MYRP that have not yet begun construction. Notably, in DEC's MYRP there are at least 140 planned transmission projects with in-service dates in 2026 or later,

[38] DEC Response to AGO Data Request 2-14.

with capital costs totaling over $649 million that could potentially be reduced if the updated methodology shows non-wires solutions to be cost effective.

Q. WITNESS MALEY ARGUED IN THE DEP GENERAL RATE CASE THAT YOUR RECOMMENDATION FOR CHANGES TO THE COMPANY'S NON-TRADITIONAL SOLUTION (NTS) SCREENING METHODOLOGY IS UNNECESSARY. ARE THOSE CRITIQUES VALID IN DEC'S CASE?

A. In the DEP rate case, Witness Maley stated that the Company already plans to incorporate the standalone storage investment tax credit into its screening process and that storage projects that pass through NTS screening today would not be online in time to address the transmission constraints being solved during the MYRP period. This argument is not convincing to me in either DEP's or the instant rate case. That is because there is no reason to believe an NTS, such as a battery storage project, cannot come online by the 2026 timeframe and address transmission constraints during the MYRP period. Duke's failure to update the NTS screening methodology means that the Company's ratepayers will be missing out on potential cost-saving opportunities from projects that are highly subsidized by IRA funding during the MYRP period.

6. Use of surplus interconnection capacity at underutilized generation facilities

Q. ARE THERE GENERATION FACILITIES ON DEC'S SYSTEM WITH ASSIGNED TRANSMISSION RIGHTS THAT ARE CURRENTLY UNDERUTILIZED?

A. Yes. Notably, in 2022 the 380 MW Marshall Unit 1 only operated with a 26% capacity factor and the 380 MW Marshall Unit 2 only operated with a 16% capacity factor.[39] This means that during the majority of hours the units are either not running, or running at very low levels of output relative to their nameplate rating. During those times, new generation located at or near the plants could be utilizing the transmission capability currently assigned to those plants. This could aid in meeting DEC's overall generation needs, and Carbon Plan obligations, while minimizing the cost and time needed for transmission upgrades.

Q. COULD DEC REASSIGN A PORTION OF THE TRANSMISSION RIGHTS FROM EACH COAL FACILITY EVEN PRIOR TO THEIR RETIREMENT DATES?

A. Yes. This concept of "surplus transmission interconnection" is already common practice for many grid operators.[40] In fact, DEC appears to be taking this approach for a storage facility it is planning to add to an existing solar project as part of this MYRP.[41] However, the sheer magnitude of the Marshall units means that their surplus transmission could likely support a large amount of the battery storage capacity DEC is currently pursuing while significantly minimizing transmission upgrade costs. Unfortunately, this was not considered by DEC in its application.

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[39] S&P Capital IQ Power Plant Profile.

[40] For example, PJM offers Surplus Interconnection Service, for generators to "utilize any unused portion of an existing generating facility's interconnection service" https://www.pjm.com/planning/services-requests; Similarly PacifiCorp allows for surplus interconnection and is seeking to allow storage to interconnect at existing facilities under pre-defined operating limits (see FERC Docket No. ER23-754).

[41] See Meeks/Shearer Exhibit 2, specifically the Monroe project.

Q. WHAT DO YOU RECOMMEND?

A. In each annual MYRP review, DEC should also be required to report on its plans for reassigning coal transmission capacity both for retirements, as well as through surplus capacity at remaining operating units.

B. The transmission components of DEC's MYRP do not adequately consider steps that would minimize the execution risk of the Carbon Plan.

1. <u>Transmission for wind resources</u>

Q. ARE ANY TRANSMISSION PROJECTS IN THE MYRP DESIGNED TO ACCESS THE ONSHORE AND OFFSHORE WIND RESOURCES IDENTIFIED IN THE CARBON PLAN?

A. No. The Company did not include any transmission projects designed to access the onshore and offshore wind resources identified in the Carbon Plan.[42]

Q. IS THIS CONCERNING TO YOU?

A. Yes. While the NCUC Order on the Carbon Plan did not direct any near-term procurement of wind resources, it did suggest that Duke should continue to consider wind in its Carbon Plan and Integrated Resource Plan (CPIRP), especially if selected via the EnCompass model. According to the EnCompass modeling performed by AGO in that proceeding, it was most optimal to add wind resources at the earliest practicable date (e.g., in the 2027 timeframe), even without accounting for the benefits of the Inflation Reduction Act. Duke's own modeling also supported wind additions by the earliest allowable date, but the Company arbitrarily prevented wind resources from being added until 2029

[42] DEC Response to AGO Data Request 2-4.

or later. Given the likelihood of future wind additions continuing to be included in the CPIRP (especially in light of the IRA), I believe it would have been appropriate for Duke to consider proactive transmission planning to accommodate this, akin to its approach to the RZEP for solar projects.

Q. WHAT DO YOU RECOMMEND?

A. Within six months, the Commission should require Duke to complete an analysis to identify any near-term transmission upgrades that would be needed to facilitate at least 600 MW onshore wind. This amount of wind is consistent with what Duke initially proposed in its 2022 Carbon Plan (i.e., to procure in the 2023-2024 timeframe with in-service dates in the 2029 timeframe). This analysis should also be included as part of the Company's first biennial CPRIP. To put this in context, providing the transmission necessary to unlock 600 MW of wind investment could result in over $55 million annually in fuel and purchased power cost savings.

2. *<u>Transmission projects related to coal retirements.</u>*

Q. IN ITS 2022 CARBON PLAN, DID DEC IDENTIFY ANY TRANSMISSION PROJECTS NECESSARY TO ALLOW FOR COAL PLANT RETIREMENTS? IF SO, ARE ANY OF THE TRANSMISSION PROJECTS IN THE MYRP RELATED TO THESE COAL RETIREMENTS?

A. DEC identified one transmission project related to the retirement of the Allen coal units.[43] However, the retirements of the Allen units are already planned by

[43] DEC Response to AGO Data Request 2-2.

2024 and were not re-optimized in the Carbon Plan. DEC did not identify in its MYRP any transmission projects related to the retirement of other DEC coal units considered in the Carbon Plan for HB 951 compliance.

Q. IS THIS SURPRISING TO YOU?

A. Yes. Given the necessity of retiring and replacing the Cliffside Unit 5 and Marshall Units 1 and 2 under all scenarios—and Belews Creek 1 and 2 under some scenarios—in order to meet the Company's 2030 obligations under HB 951, I would have expected DEC to begin investing in these transmission upgrades during the upcoming MYRP period rather than waiting until later. This would be consistent with the NCUC's Carbon Plan Order which requires Duke to "take appropriate steps to optimally retire its coal fleet on a schedule commensurate with its Carbon Plan proposal filed on May 16, 2022." In fact, the time necessary to complete these retirement-related transmission upgrades was DEC's primary rationale for delaying certain coal retirements beyond their economically optimal retirement dates.

Q. CAN YOU PROVIDE ANY EXAMPLES?

A. Yes. During the Carbon Plan proceeding, the Company's modeling resulted in the endogenous optimal retirement date of 2026 for Marshall Units 1 and 2. However, the Company delayed Marshall Units 1 and 2's retirement to the sub-optimal date of 2029, citing the need for transmission upgrades to be completed before the units can be retired. If DEC pursued these upgrades as part of its proposed MYRP (ending in 2026), then it is possible that Marshall Units 1 and 2 could be retired closer to their economically optimal date. Instead, the

Company has chosen to delay the necessary investments to enable the plant's optimal retirement, thereby requiring Marshall Units 1 and 2 to operate past their economically optimal date. In my opinion, this is not a prudent course of action both in terms of cost to ratepayers and Carbon Plan execution risk. In the DEP rate case and Carbon Plan, the Company conceded that retirement-related transmission upgrades could be avoided if "replacement generation can be located at the site of the retiring generation."[44] However, if this is also DEC's plan, it is not clear why the Company did not include any replacement generation in its MYRP. In particular, I believe battery storage would have been a good candidate for a replacement resource at the Marshall site within the MYRP timeframe. This would be consistent with DEC's 2022 Carbon Plan indicating that new battery storage project deployment would be achievable by the 2025 timeframe. It would also allow Marshall Units 1 and 2 to retire closer to the optimal date of 2026.

Q. ARE THERE OTHER PLANTS WITH OPTIMAL RETIREMENT DATES IN THE NEAR TERM THAT MIGHT REQUIRE TRANSMISSION UPGRADES DURING THE PROPOSED MYRP PERIOD?

A. According to DEC's initial Carbon Plan analysis, the optimal retirement date for Belews Creek Units 1 and 2 was 2030 under the P1 scenario. To the extent that transmission upgrades are required prior to this, they could also overlap with the 2023-2026 MYRP period. While some of these could theoretically be

[44] Carbon Plan Appendix P, at 15.

accomplished in the next MYRP, this would be a riskier approach from a Carbon Plan execution standpoint.

Q. ASIDE FROM THE REQUIRED UPGRADES, COULD EARLIER COAL RETIREMENTS HELP REDUCE DEC'S TRANSMISSION COSTS IN THIS OR A FUTURE MYRP?

A. Yes. DEC's response to AGO 2-9 confirms that the Company has a process for reassigning the transmission rights from a retiring generation facility to a new generation facility. By repurposing these transmission assets, DEC could minimize the amount of capacity-driven transmission upgrades needed to connect new generation to DEC's system. However, DEC's application does not specify if or when it plans to utilize the reassignment process. This is true even for the Allen units despite their planned retirement date of 2024 falling well within the MYRP period.

Q. WHAT DO YOU RECOMMEND?

A. As a condition of approval, I recommend that the Commission direct DEC to revise its MYRP to include the transmission upgrades required to enable the retirement of Marshall Units 1 and 2 in the more optimal 2026 timeframe. Similarly, I also recommend including the upgrades necessary to retire Belews Creek Units 1 and 2 to minimize the execution risk of retiring these units by 2030, which would be required under some scenarios. DEC should also seek financing support from the DOE for these upgrades (e.g., through the EIR program). Notably, the EIR program requires participants to secure funding by 2026. Furthermore, in each annual MYRP review, DEC should also be required to report on its plans for reassigning coal transmission capacity both for retirements, as well as through surplus capacity at remaining operating units.

3. <u>RZEP Project Voltage Levels</u>

Q. FOR THE RZEP PROJECTS, DID DEP's MYRP EXPLORE LINE REBUILDS AT HIGHER VOLTAGES?

A. Not fully. In the DEP case, the Company claimed that rebuilding lines to higher voltages (e.g., 115 kV to 230 kV or 230 kV to 500 kV) would be difficult, time-consuming, and expensive. I suspect that DEC would make a similar claim here.

Q. WHAT ARE THE BENEFITS OF REBUILDING LINES AT HIGHER VOLTAGES AND WHAT ARE THE RISKS ASSOCIATED WITH NOT DOING SO?

A. Higher voltage lines can accommodate higher injection capacity, which could in turn support additional renewable energy development beyond the Company's immediate need. It is likely that the Company will need additional transmission capacity in the future to support renewable energy deployments identified in future Carbon Plan updates. Failure to plan for this possibility will expose the Company and its ratepayers to the risk of its proposed investments having to be rebuilt again in the near future to accommodate additional renewables.

Q. DID DEC'S MYRP EVALUATE THE RZEP ADDITIONS IN THE CONTEXT OF ITS LONGER-TERM PLANNING NEEDS (I.E., 10-20 YEARS)?

A. Not to my knowledge. This is somewhat concerning due to the fact that DEC should be planning not just for the immediate 2,350 MW of solar that the NCUC recently directed Duke to procure, but also for the longer-term Carbon Plan portfolio, which includes multiple times that amount.

Q. WHAT DO YOU RECOMMEND?

A. Within six months, the Commission should require Duke to provide an evaluation of the potential for increased injection capability from higher voltage levels for each remaining RZEP project that has not begun construction. While this will come at an increased cost, the different options could be compared on a per unit basis (e.g., $/MW of injection capability) to determine if there might be efficiencies to be gained from investing a larger sized project now, rather than replacing it later.

4. *<u>Future transmission needs from Carbon Plan updates</u>*

Q. HOW MUCH SOLAR DOES DUKE NEED TO PROCURE IN THE NEAR TERM UNDER THE CARBON PLAN?

A. The Commission directed Duke to procure 2,350 MW of solar in the near term (i.e., in service by 2028). However, several other parties, including the AGO, conducted modeling that suggested that a higher amount of near-term solar additions would be more optimal. For example, portfolio SP-AGO included over 4,200 MW of solar additions in the near term and over 6,000 MW by 2030.

Q. HOW MUCH SOLAR WILL BE ENABLED BY DUKE'S TRANSMISSION INVESTMENTS DURING THE MYRP? ARE THE PROPOSED RZEP PROJECTS SUFFICIENT?

A. Duke reported that the RZEP projects will support 981 MW and 2,778 MW in DEC and DEP, respectively, or about 3,760 MW in total.[45] This amount would be sufficient to meet the minimum amount required by the Commission (2,350 MW) in its Carbon Plan Order but could be insufficient to meet any substantial increase that may emerge from a volume adjustment or future Carbon Plan Order that the Commission may issue in 2024. It would also be inconsistent with the SP-AGO portfolio and several other intervenor-proposed portfolios. It is possible that the Company's September 2023 Carbon Plan update will include more renewable energy additions. The Company itself acknowledges that some additional transmission projects may be necessary in the future to support interconnection requests from solar generation facilities.[46] However, the Company does not specify whether and how it will plan for and seek cost recovery for these projects since they are not included in the MYRP. The Commission should ensure that any incremental transmission needs resulting from near-term Carbon Plan updates or volume adjustments can be accommodated. However, the Company should also be directed to provide a more comprehensive MYRP that would include these incremental needs at the outset.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. In each annual MYRP review, the Commission should require that DEC identify any additional red zone upgrades that could accommodate incremental amounts of solar additions and how much each upgrade could accommodate in

[45] DEC Response to AGO Data Request 2-6(c).
[46] DEC Response to AGO Data Request 2-6(e).

MW. These should also be provided as part of DEC's 2023 Carbon Plan update and 2024 Carbon Plan, particularly if such updates identify a need for higher amounts of renewable energy.

5. *<u>Relevance of Carbon Plan-related issues to this proceeding</u>*

Q. WHY SHOULD THE COMMISSION ADDRESS THE ISSUES YOU HAVE RAISED IN THIS PROCEEDING WHEN SOME OF THEM WERE CONSIDERED IN THE CARBON PLAN PROCEEDING?

A. The issues and recommendations I raised in this proceeding cannot, and should not, be limited to the Carbon Plan proceeding for several reasons:

1. To my knowledge, the Carbon Plan proceeding does not address rates or cost recovery and was never intended to. Thus, even if the Commission were to identify, within the Carbon Plan proceeding, specific transmission investments or other actions (e.g., GETs investments) that DEC should undertake, there is no mechanism within that proceeding to scrutinize these projects' specific costs to ensure they are prudently incurred and fairly recovered through rates. The Carbon Plan proceeding focuses on high-level resource portfolios and does not have the same project-specific level analysis or prudency review contained within a general rate case like this one.

2. Many of the recommendations I make in this case, as well as those in the DEP case, are for investment decisions that can and should occur regardless of Carbon Plan compliance. In many instances, they are simply more cost-effective solutions than what Duke has proposed in its MYRP.

3. If operating as intended, the MYRP should reflect a comprehensive roll up of *all* future investments, including those implicated by the Carbon Plan. Relegating Carbon Plan investments to another proceeding, where additional rate increases might be requested, would defeat the whole purpose of MYRP framework and its cost containment objectives. Duke seems to suggest that the Commission must wait until the next Carbon Plan proceeding to evaluate any transmission investment that could have some relevance to the Carbon Plan. By this same logic, the Commission should also wait to approve cost recovery for *each* of the proposed transmission projects in DEC's MYRP as it is unclear which ones may or may not be affected by the next Carbon Plan update or need to be addressed and approved in that proceeding.

C. Other Matters

1. Interaction with FERC formula rates

Q. IN ADDITION TO NCUC OVERSIGHT, ARE DEC'S TRANSMISSION INVESTMENTS AND ASSOCIATED REVENUE REQUIREMENTS OVERSEEN BY THE FEDERAL ENERGY REGULATORY COMMISSION (FERC)?

A. Yes. DEC's transmission revenue requirements and related transmission rates are typically updated on an annual basis through a formula adjustment submitted to FERC. The most recent of these annual adjustments occurred in May 2022. I anticipate that similar adjustments would occur in each year of the MYRP (i.e., in May 2023, May 2024, May 2025, and May 2026).

Q. IS IT CLEAR TO YOU HOW THESE ANNUAL ADJUSTMENTS MIGHT INTERACT WITH THE RETAIL TRANSMISSION RATES SET IN THIS PROCEEDING FOR EACH YEAR OF THE MYRP?

A. No, it is not clear to me. Notably, there will be a discrepancy between the four-year period of the MYRP and the 1-year period of the FERC formula adjustments. I'm concerned that this could result in a mismatch between the transmission revenue requirements recovered by retail versus wholesale customers and could lead to potential revenue overcollection from DEC's retail customers, especially in later years of the plan.

Q. HOW MIGHT THIS LEAD TO OVERCOLLECTION?

A. As one example, for the new transmission projects being proposed, I am concerned that the MYRP would establish full cost recovery of these projects through rates collected by DEC's retail customers without considering any offsetting wholesale revenue in the future. Meanwhile, these projects may also be able to support additional wholesale sales revenue, which should theoretically reduce the retail revenue requirement in future years. It's not clear to me that the retail rates in later years of the plan would adequately reflect this potential reduction in the retail revenue requirement. Meanwhile, the FERC formula rates would be updated each year to reflect an increase in new transmission investments.

2. Non-cost effective investments

Q. ARE ANY OF THE PROPOSED TRANSMISSION INVESTMENTS NOT COST-EFFECTIVE ACCORDING TO DEC'S EVALUATION METHOD?

A. Yes. The Monroe 100kV Line Rebuild project ($58.7 million) has a cost-benefit ratio of 0.57.[47] I recommend this project not be included in the MYRP unless DEC can provide additional rationale.

3. Better regional coordination via System Intelligence

Q. HAS DEC MADE ANY INVESTMENTS IN TRANSMISSION SYSTEM INTELLIGENCE?

A. Yes. As DEC explains, one of the transmission investments it had nearly completed at the time of its filing was a System Intelligence project that will provide remote asset monitoring and controls. This will give the Company's system operators "enhanced information to respond to changing conditions."[48]

Q. DO YOU THINK THERE ARE WAYS DEC CAN ENHANCE THE VALUE OF THIS SYSTEM INTELLIGENCE INVESTMENT DURING THE MYRP?

A. Yes. I think that DEC could leverage this investment to assist with regional coordination. For example, DEC notes that other neighboring utilities are also investing in System Intelligence[49] which could provide DEC with better visibility into grid conditions (and vice versa), especially during reliability

[47] Maley Exhibit 3, at 14.
[48] Maley Direct at 15.
[49] DEC Response to AGO Data Request 2-11.

events such as Winter Storm Elliott. DEC's MYRP does not detail how it plans to coordinate with neighboring grid operators to share real-time information from System Intelligence, even though doing so could be mutually beneficial.

Q. DO YOU HAVE ANY RECOMMENDATIONS RELATED TO SYSTEM INTELLIGENCE?

A. Yes. The Company should seek to enhance regional coordination by developing a plan to provide its System Intelligence information to neighboring utilities in real time and requesting similar information from them.

4. <u>More cost-effective integration of large-scale renewables and DERs via Flexible Interconnection</u>

Q. DOES THE COMPANY USE FLEXIBLE INTERCONNECTION?

A. No. The Company does not appear to use or propose to use a flexible interconnection framework. This is a similar concept to the "surplus interconnection" concept I discussed above in Section V-A-6, though it includes other considerations, and can apply not only to the transmission system but also to the distribution system. The lack of a flexible interconnection framework represents a significant missed opportunity to accelerate the interconnection of large-scale renewables and integrate distributed energy resources (DER) cost-effectively.

Q. HOW CAN THE COMPANY ACCELERATE THE INTERCONNECTION OF LARGE-SCALE RENEWABLES AND DEPLOY DER INTEGRATION COST-EFFECTIVELY?

A. As the Company works to rapidly increase the deployment of large-scale renewables and DERs, they should do as cost-effectively as possible. Specifically, the Company should fully utilize existing transmission and distribution system capacity to maximize large-scale renewables and DER penetration while fully utilizing existing system capacity and avoiding unnecessary transmission and distribution upgrades. Flexible interconnection (also known as active network management) is an important strategy to mitigate the issues that systems face with increased large-scale renewables and DER integration, such as network constraints and increased system costs. Flexible interconnection is a form of interconnection service that allows for autonomous (e.g., volt-watt enabled through smart inverters) or controlled curtailment of export (e.g., active network management). With flexible interconnection, developers can (1) avoid causing system constraints and triggering system upgrades, and therefore the associated costs, through curtailment of large scale renewables and DERs at specific days and/or hours and (2) increase hosting capacity enabling more large scale renewables and DER capacity to be deployed using existing system capacity. In short, flexible interconnection enables more large-scale renewables and DERs to be deployed at lower cost to the market and ratepayers.

Q. HOW CAN FLEXIBLE INTERCONNECTION BE OPERATIONALIZED?

A. To operationalize flexible interconnection, modifications need to be made to the Company's (1) transmission and distribution interconnection practices and (2) tariffs.

Q. HOW CAN INTERCONNECTION PRACTICES BE MODIFIED TO OPERATIONALIZE FLEXIBLE INTERCONNECTION?

A. Flexibly interconnecting large amounts of large-scale renewables and DERs requires increased visibility and control of the transmission and distribution system.

Q. HOW DOES SYSTEM VISIBILITY NEED TO EVOLVE TO MODERNIZE INTERCONNECTION PRACTICES?

A. In the context of distribution-level interconnection, visibility generally refers to DER hosting capacity. Today, most utilities employ static Hosting Capacity Analysis, which is based on worst case assumptions and not calculated to the degree of granularity necessary to reflect every grid level, from feeder node to substation (but rather as a single value per feeder).[50] Current approaches also typically only provide hosting capacity values for distributed generation. While current approaches typically determine one hosting capacity value per feeder, hosting capacity differs greatly across the entire feeder, depending on distance to the substation, phase, and asset.[51] In addition, hosting capacity is inherently time-varying because the underlying load, generation, temperature, control settings, circuit configuration and other system parameters vary with time.[52]

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[50] Opus One Solutions, Dynamic Hosting Capacity, A dialogue on extracting distribution maximum value from interconnected Distributed Energy Resources for distribution utilities and customers, at 3.
[51] *Id.*
[52] Electric Power Research Institute, Understanding Flexible Interconnection, at 3.

Dynamic Hosting Capacity (DHC) represents the concept of calculating the hosting capacity for a specific location in the distribution grid in real-time at given time intervals.[53] It can be further expanded to include the ability to calculate hosting capacity across all grid levels for each type of DER and can be applied to any given time frame for a specific location in the grid.[54] This methodology drastically improves the accuracy of hosting capacity, likely increases hosting capacity and informs what days and/or hours DERs should be curtailed as part of implementing flexible interconnection.

Q. HOW DOES SYSTEM CONTROL NEED TO EVOLVE TO MODERNIZE INTERCONNECTION PRACTICES?

A. In the context of distribution-level interconnection, control refers to the optimization of DERs by the DER operator or the utility itself to align with system conditions. Traditionally, given the low penetration of DERs, there has been a limited need to implement system wide control mechanisms. However, to rapidly and cost-effectively integrate DERs to support the objectives of the Carbon Plan, utilities should consider all control methods available to them. DER operators can optimize their systems to respond to grid needs using the autonomous functions found in Institute of Electrical and Electronics Engineers (IEEE) standard 1547-2018 compliant smart inverters. One important feature of smart inverters is Volt/Watt which allows solar PV inverters to decrease their output active power during over-voltage conditions.[55] This functionality could

[53] *Id*. at 4.
[54] Opus One Solutions, Dynamic Hosting Capacity, A dialogue on extracting distribution maximum value from interconnected Distributed Energy Resources for distribution utilities and customers, at 4.
[55] Impact of IEEE 1547 Standard on Smart Inverters and the Applications in Power Systems, at 5.

be used to curtail DER load as part of implementing flexible interconnection without any additional utility investments.

Alternatively, utilities could deploy Distributed Energy Resource Management System (DERM) to directly communicate with DER inverters and control them on behalf of the operator. Using a DERMS, the Company can gain visibility into and control when and how much DER facilities export. Namely, through a DERMS and active network management software, the Company can curtail the use of these resources at peak hours when they may otherwise cause grid constraints, thereby reducing the grid violations identified or reducing capacity requirement through improved system utilization (i.e., increasing hosting capacity per unit of capacity)

Q. HOW CAN UTILITY TARIFFS BE MODIFIED TO OPERATIONALIZE FLEXIBLE INTERCONNECTION?

A. In the context of the distribution system, via non-firm and limited export interconnection tariffs, DER facilities can opt in to more cost-effective arrangements that allow them to reduce the export of their resources during only a limited set of hours (through the Company's DERMS capabilities) over the course of a year, while paying less for the hosting capacity upgrades they would otherwise cause.

Traditionally, DER customers are connected under a fixed capacity agreement; this fixed export capacity is granted based on "worst case" grid conditions, such that the grid can absorb the full power generated by the DERs whenever it appears while ensuring grid reliability and power quality.[56] However, this does not account for the time varying nature of DERs. In contrast, non-firm and limited export interconnection tariffs aim to grant higher export capacity to DER units, provided that their operation can be reliably managed when and if grid congestion reaches certain levels, allowing for greater energy exports from DER units and larger DER sizes in more locations during times of less congestion.[57]

Flexible interconnection schemes can be implemented via relatively simple tariffs, and through simple or already-planned-for technology developments. Non-firm and limited export tariffs are one of the mechanisms that can foster flexible interconnection. With non-firm tariffs, DERs seeking to interconnect to the system agree to opt in with variable network access, or non-firm access. These interconnection agreements would impose limitations on interconnected DERs exporting to the grid. Generally, with non-firm tariffs, interconnected DERs will enter interconnection agreements where they are not granted firm access and thus do not have to cover upgrade costs that are associated with firm level interconnection.

5. <u>Performance target for transmission outages</u>

Q. HAS DEC ESTABLISHED ANY PERFORMANCE METRICS FOR ITS TRANSMISSION SYSTEM OPERATIONS?

[56] Electric Power Research Institute, Principles of Access for Flexible Interconnection, Cost Allocation Mechanisms and Financial Risk Management at 3.
[57] *Id.*

A. Yes. DEC witness Maley's testimony explained that the Company uses the Outages per Hundred Miles per Year – Sustained Automatic (OHMY-SA) metric to measure transmission system performance; however, witness Maley did not specify what level of OHMY-SA the Company targets.[58] Through discovery, AGO determined that DEC's target for this metric is 0.55.[59]

Q. HAS DEP EXPLAINED HOW IT DETERMINED THAT 0.55 IS AN APPROPRIATE TARGET FOR OHMY-SA?

A. No. I think some further exploration is warranted from the Commission to determine if this is an appropriate target.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[58] Maley Direct at 11.
[59] DEC Response to AGO Data Request 2-10.

STRATEGEN

Edward Burgess

Senior Director

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

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Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

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Work **Experience**

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess

Senior Director

STRATEGEN

Selected Recent Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report*.
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study*.
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard*."
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California*.

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
+ Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
+ Worked with Strategen technical team on utilizing a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

+ Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric

Energy Storage Strategy / 2016

+ Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
+ Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
+ Supported development of a competitive solicitation process for storage technology solution providers.

Xcel Energy

Time-of-use Rates / 2017 - 2018

+ Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
+ Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

+ Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
+ Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

+ Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
+ Conducted study on the use of storage as an alternative to natural gas peaker.
+ Presented workshop and study findings before the Minnesota Public Utilities Commission.

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- Pacific Power 2022 Energy Cost Adjustment Clause (Docket No. A.21-08-004)
- Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (Docket No. A.20-10-011)
- Pacific Gas and Electric's Electric Vehicle Charge 2 Application (Docket No. A.21-10-010)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Colorado Public Utilities Commission

- Tri-State Generation and Transmission Application for a CPCN (Docket No. 22A-0085E)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission

- Entergy Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105)

Massachusetts Department of Public Utilities

- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Michigan Public Service Commission

- Consumers Energy 2021 Integrated Resource Plan (Docket No. U-21090)

Nevada Public Utilities Commission

- NV Energy's Integrated Resource Plan in (Docket No. 20-07023)

North Carolina Utilities Commission

- Duke Energy Carbon Plan (Docket No. E-100, Sub 179)

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)
- Northwest Natural 2022 General Rate Case (Docket No. UG-435)

Expert Testimony (con't)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities 2020 General Rate Case (Docket No. UE-200900)
- Avista Utilities 2022 General Rate Case (Docket No. UE-220053/UG-220054)
- Puget Sound Energy 2022 General Rate Case (Docket No. UE-220066/UG-220067)

Unlocking the Queue with Grid-Enhancing Technologies

CASE STUDY OF THE SOUTHWEST POWER POOL

FINAL REPORT – PUBLIC VERSION

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WATT (Working for Advanced Transmission Technologies) Coalition

FEBRUARY 1, 2021

Brattle

Disclaimer

- This report was prepared for the WATT (Working for Advanced Transmission Technologies) Coalition with support from GridLab, EDF Renewables North America, NextEra Energy Resources, and Duke Energy Renewables. The WATT Coalition includes Ampacimon, Lindsey Manufacturing, LineVision, NewGrid, Smart Wires, and WindSim. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group (Brattle) or its clients.
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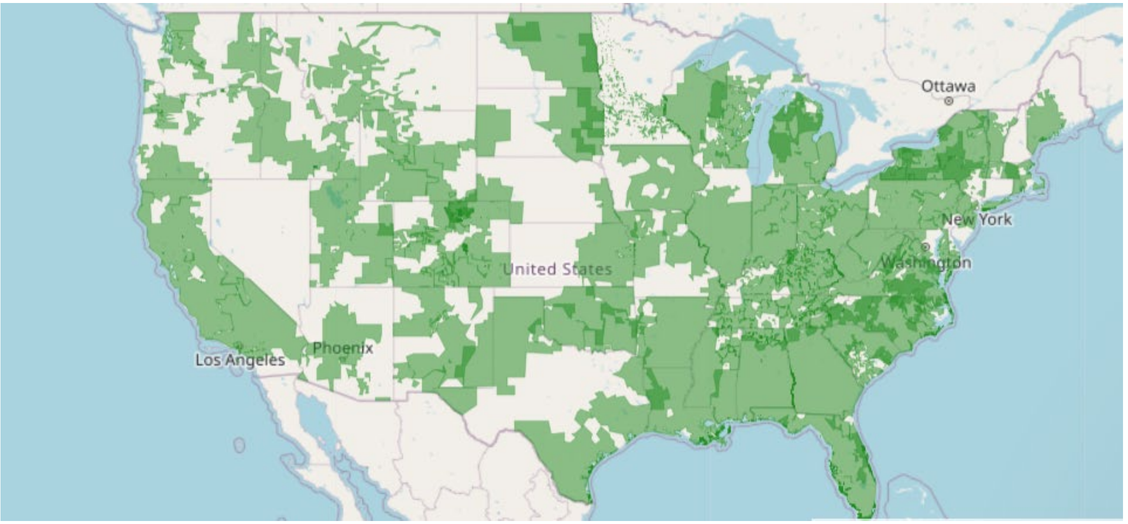
Issue at Hand - 1/2

Increasing renewable resources (often associated with carbon reduction) is a common goal.

- Many private entities including utilities, corporations, and academic institutes.
- Across jurisdictions from federal, state, to local (e.g., cities) levels.
- Increasing renewable projects provide jobs and other local benefits, and help boost the economy out from the current COVID-associated downturn.



Utility Carbon Reduction Tracker (Feb 2021)

Issue at Hand - 2/2

What are the roadblocks to integrating more renewables?

- Utilities and system operators have good understandings of the variability of renewable resources.
  - Wind became SPP's leading resource in 2020.
- Transmission availability is a major limiting factor.
  - Many renewable projects are locked up in the Generation Interconnection Queue.
  - There is a timing gap: renewables are developed (in months to years) much faster than transmission (in years to sometimes decades).
  - Utility-scale renewables are usually more cost efficient (on a $/MWh basis) compared to distributed resources.

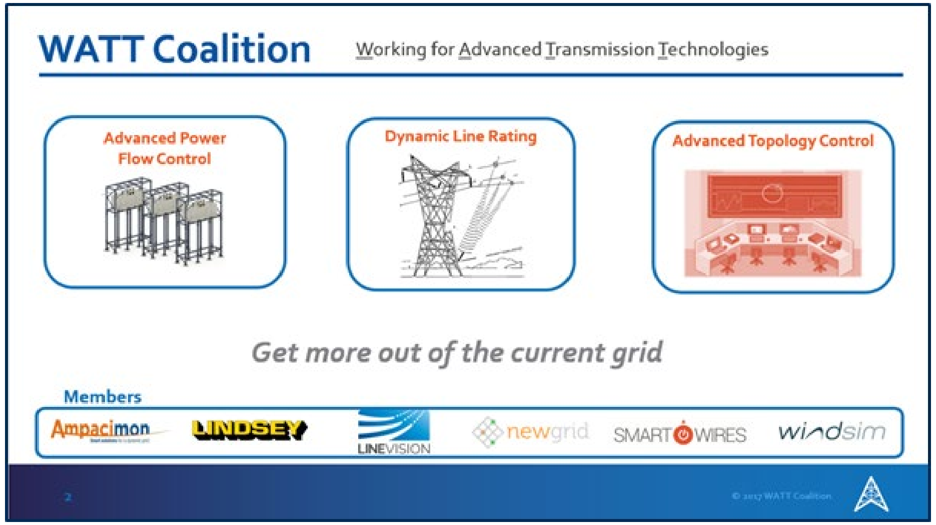
Can Grid-Enhancing Technologies (GETs) help integrate more renewables?

- GETs quickly and cost-effectively help maximize the capability of the existing transmission system

Study Overview - 1/2

Goal: Analyze how much additional renewables can be added to the grid using Grid-Enhancing Technologies (GETs):

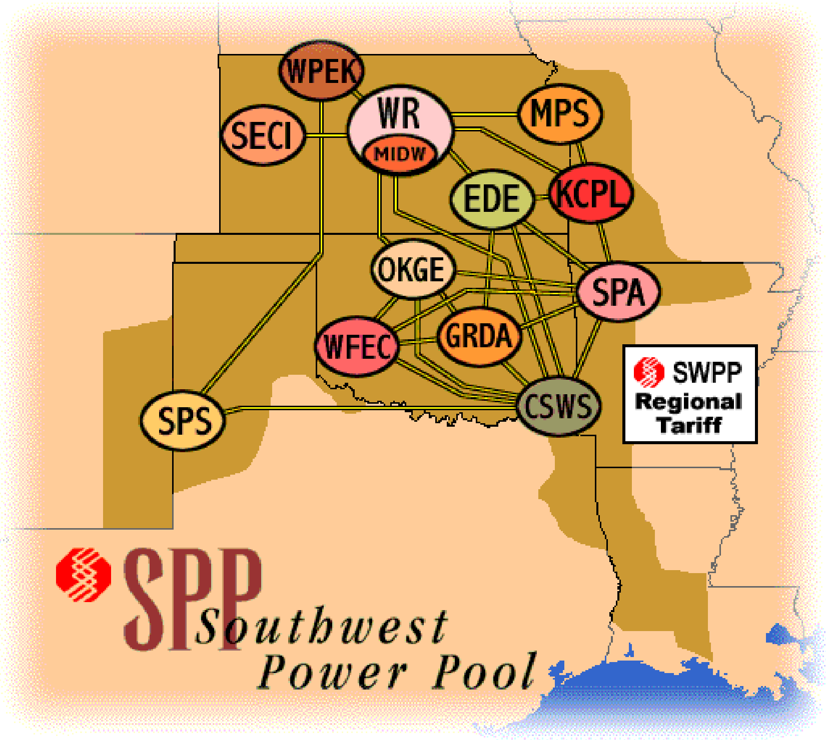
- GETs enhance transmission operations and planning.
- GETs complement building new transmission—they can bridge the timing gap until permanent expansion solutions can be put in place.
- While there are various types of GETs, this study focuses on the combined impact of the following three technologies:
  - **Advanced Power Flow Control**: Injects voltage in series with a facility to increase or decrease effective reactance, thereby pushing power off overloaded facilities or pulling power on to under-utilized facilities.
  - **Dynamic Line Ratings (DLR)**: Adjusts thermal ratings based on actual weather conditions including, at a minimum, ambient temperature and wind, in conjunction with real-time monitoring of resulting line behavior.
  - **Topology Optimization**: Automatically finds reconfiguration to re-route flow around congested or overloaded facilities while meeting reliability criteria.



Study Overview - 2/2

Goal: Analyze how much additional renewables can be added to the grid using Grid-Enhancing Technologies (GETs):

- Use the Southwest Power Pool (SPP) grid (focused on Kansas and Oklahoma, looking at 2025) as an illustrative case study.
  - SPP Generation Interconnection Queue* (GI Queue) shows ~9 GW of renewable resources with an Interconnection Agreement (IA) executed in Kansas and Oklahoma.
  - SPP Integrated Transmission Planning (ITP) Reports** show high congestion.
- Results metrics for the combined (not for individual) three GETs include:
  - Renewables added (capacity [GW] and energy [GWh]).
  - Economic benefits (production costs, investments, jobs, etc.)
  - Carbon emissions reduction.



SPP figure from http://opsportal.spp.org/Images/SPPMap.gif
* SPP GI Queue as of September 28, 2020
** 2019 Integrated Transmission Planning (available at: https://spp.org/Documents/60937/2019%20ITP%20Report_v1.0.pdf) and Q3 2020 Quarterly Project Tracking Report (available at: https://www.spp.org/documents/62710/q3%202020%20qpt%20report%20draft.pdf)

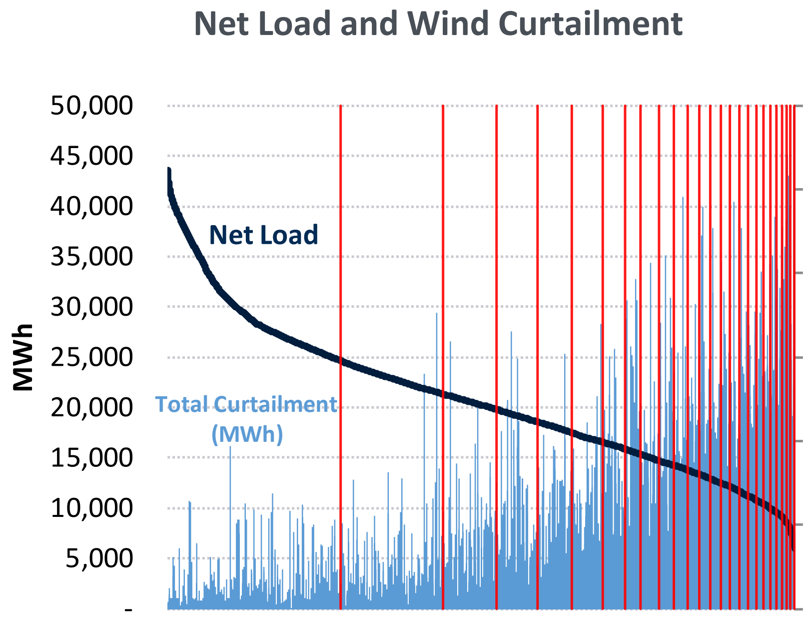
Study Approach - 1/2

Study purpose

- Quantify the benefits of **the three GETs combined** for integrating renewable resources (largely wind) using SPP as a test bed.

Analysis approach

- Select 24 representative historical power flow snapshots of SPP operations (2019 – 2020) that together reasonably represent a full year.
- Modify the snapshots to reflect new transmission upgrades, renewable projects from the GI queue, announced retirements, load change, etc.
- Find the maximum renewables amount (GW and GWh) that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case), sequentially in the order of DLR, Topology Optimization, and Advanced Power Flow Control, by simulating the entire SPP system using the 24 power flow cases.
- Assess benefits of GETs including economic values (production costs, jobs, local benefits etc.) and carbon emissions reduction.



Areas between red line indicates the bins from which snapshots were selected, blue bars indicate curtailment of renewables. Each bin contains equal amounts of curtailment.

Study Approach - 2/2

Study purpose

- Quantify the benefits of **the three GETs combined** for integrating renewable resources (largely wind) using SPP as a test bed.

Finding the maximum amount of renewables that can be integrated

- Analysis is performed separately for the Base Case and With GETs Case for all 24 snapshots.
- Analysis is done using an iterative process:
  - Determine feasible reduction in thermal unit generation to accommodate additional renewable resources.
  - Dispatch wind and solar to their max output by running Security Constrained Optimal Power Flow (SCOPF).
  - Iteratively solve SCOPF (i.e., solve SCOPF, take out renewable projects with high curtailments, then resolve SCOPF, and repeat).
- Analysis assumes a 5% curtailment threshold for viability assessment (i.e., projects are viable if analysis indicates annual curtailments to be less than 5%).
  - Curtailment occurs largely for two reasons—transmission congestion (which the GETs will help solve) and minimum generation constraints of other generation resources.

Study Results - 1/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Potential Renewables Considered: 9,430 MW
  - Based on queue projects with IA executed.
- Integrated Renewables (without further transmission upgrades)
  - Base Case: 2,580 MW
  - With GETs Case: 5,250 MW
  - Delta (With GETs Case – Base Case): 2,670 MW

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

~1.5 times the amount of wind SPP integrated in 2019 (1.8 GW).

ADDITIONAL RENEWABLES INTEGRATED

State	Base Case			With GETs Case			Delta (GETs - Base)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	1,710	0	1,710	1,910	0	1,910	200	0	200
Oklahoma	770	100	870	3,200	140	3,340	2,430	40	2,470
Total	2,480	100	2,580	5,110	140	5,250	2,630	40	2,670

X2

[Rounded to the nearest 10 MW]

Study Results - 2/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Additional renewables enabled by GETs: **2,670 MW / 8,776 GWh**.
  - 2,630 MW of **new wind** is assumed to produce over 8,640 GWh of energy per year.
  - 40 MW of **new solar** is assumed to produce about 60 GWh of energy per year.
  - GETs lower curtailment of **existing wind** by over 76,000 MWh per year.
- GETs installation cost is about $90 million.
  - Annual O&M costs is estimated to be around $10 million.
- GETs benefits (other than the value of additional renewables) include:

ANNUAL PRODUCTION COST SAVINGS

$175 million

ANNUAL REDUCED CARBON EMISSIONS

3 million tons

LOCAL JOBS

650 long-term jobs and
11,300 short-term jobs

OTHER LOCAL BENEFITS

$15 million land lease and
$32 million tax revenues per year

Study Results - 3/5

GETs enable more than twice the amount of additional new renewables to be integrated.

- Estimated annual production cost savings: **$175 million**.
  - Pay-back for GETs investment (~$90 million) is about half a year.
  - $175 million conservatively assumes $20/MWh savings for 8,776 GWh of energy.
  - $20/MWh is at the lower end of the generation cost of a new natural gas-fueled combined cycle plant or coal plant and lower than average 2019 LMP (both day-ahead and real-time).
- Estimated job benefits associated with the increased renewables (2,670 MW):
  - Over 11,300 direct short-term jobs (largely construction of renewables).
  - Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
- Estimated carbon emissions reduction: **Over 3 million tons per year.**
  - Conservatively assumes the renewables replace carbon emissions from natural gas-fueled combined cycle plants.
  - Less efficient resources with higher heat rates and emission rates are more likely to be replaced.
- Other estimated benefits include:
  - Local benefits estimated to be over $32 million annual tax revenues and $15 million land lease revenues (based on literature research).

Study Results - 4/5

Key benefits of GETs for Kansas and Oklahoma

- Enable more than **twice** the amount of additional new renewables to be integrated.
  - This is 1.5x the amount of wind SPP integrated in 2019.
- Estimated annual production cost savings: $175 million.
  - Payback for GETs investment is about 0.5 years.
- Estimated carbon emissions reduction: Over 3 million tons per year.
- Over 11,300 direct short-term and 650 direct long-term jobs.
- Over $32 million annual tax revenues and $15 million land lease revenues.

Potential Nation-Wide Benefits

Extrapolating these results to a nation-wide level* indicate GETs to provide **annual benefits** in the range of:

- Over **$5 billion** (~$5.3 billion) in production cost savings.
- **$90 million tons** of reduced carbon emission (more than enough to offset **ALL NEW** automobiles sold in the U.S. a year).
- About **$1.5 billion** in local benefits (local taxes and land lease revenues).
- More than 330,000 short-term (only for first year) and nearly 20,000 long-term jobs.
- Investment cost is $2.7 billion (only for first year). Ongoing costs would be around $300 million per year.

https://www.eia.gov/electricity/state/kansas/, https://www.eia.gov/electricity/state/oklahoma/, and https://www.eia.gov/electricity/annual/html/epa_01_01.html

Study Results - 5/5

GETs utilized in this study include:

- **Hardware solutions**: DLR on 56 lines and Advanced Power Flow Control on 8 locations.
- **Software solutions**: 204 unique Topology Optimization reconfigurations, averaging 13 per snapshot.**

Hardware Solutions by Voltage Level	345	230	161	138	115	69	Total
DLR*	10	3	11	22	3	7	56
Advanced Power Flow Control	3	0	4	1	0	0	8

Software Solutions by Voltage Level	345	230	161	138	115	69	Total
Lines	20	10	31	75	4	30	170
Substations	4	0	1	1	0	0	6
Transformers (high voltage terminal)	10	1	4	13	0	0	28

- Estimated costs for implementing the above GETs: ~$90 million.
  - Initial investment costs is estimated to be around $90 million.***
  - Ongoing costs of around $10 million per year.***

* Every DLR installation requires 15 to 30 sensors.

** Average actions represent the average number of actions that remain per case, not actions per hour. Based on other studies the average number of actions per hour is expected to be smaller, typically less than the number of topology changes due to planned outages.

*** Costs can vary project by project, and also on how the GETs service is provided—for example, Topology Optimization can be provided as a software subscription service to reduce the initial cost. We also assume utilities can incorporate these technologies without large costs.

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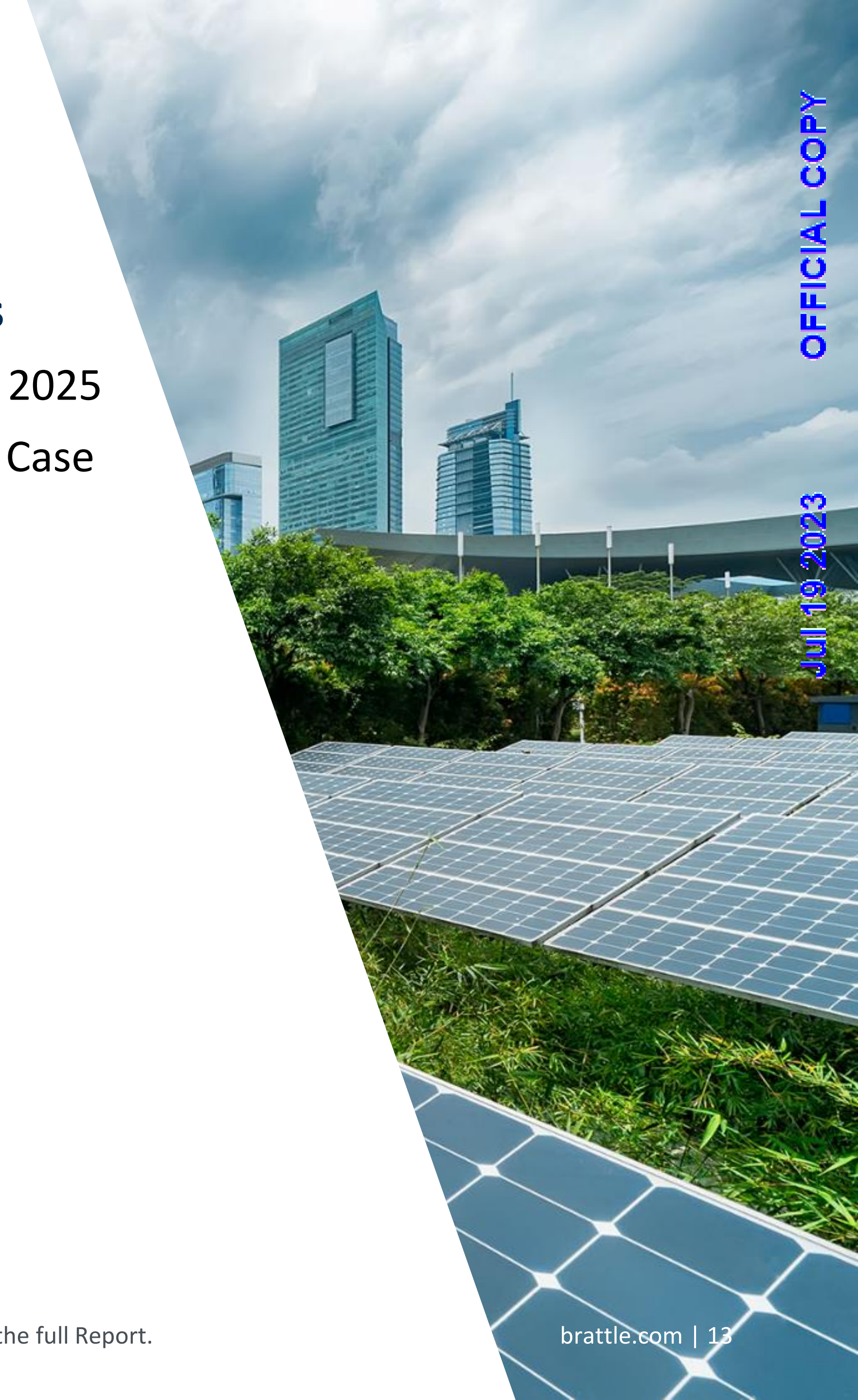

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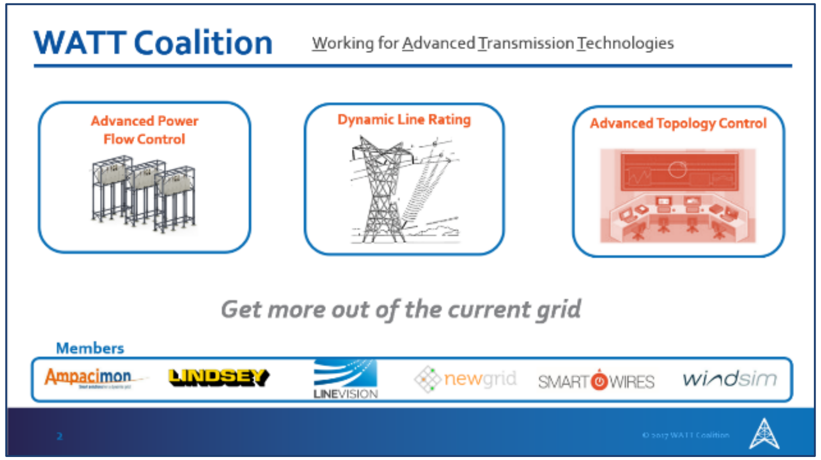
Study Scope and Purpose

Study purpose

- Analyze how much additional renewables can be added to the grid using three GETs:
  - Advanced Power Flow Control
  - Dynamic Line Ratings (DLR)
  - Topology Optimization



Study scope

- Use the Southwest Power Pool (SPP) grid with the focus on **Kansas and Oklahoma** looking at 2025 as an illustrative case study.
  - SPP Generation Interconnection Queue* shows ~9 GW of renewable resources with Interconnection Agreements executed.
  - SPP Integrated Transmission Planning (ITP) reports** shows high congestion.
- Results metrics for the **combined** (not for individual)*** GETs include:
  - Renewables added (capacity [GW] and energy [GWh]).
  - Economic benefits (production costs, jobs, local benefits, etc.)
  - Carbon emissions reduction.

* SPP GI Queue as of September 28, 2020.

** 2019 Integrated Transmission Planning (available at: https://spp.org/Documents/60937/2019%20ITP%20Report_v1.0.pdf) and Q3 2020 Quarterly Project Tracking Report (available at: https://www.spp.org/documents/62710/q3%202020%20qpt%20report%20draft.pdf)

*** This is because the order of analysis matters—being the first GETs to be analyzed will likely show more benefits than being the last.

GETs – Introduction

Traditional thinking treated transmission as if it is fixed and **cannot be operated dynamically**.

- Transmission has a fixed capacity, much like roads or railways do (e.g., the number of cars or trains that can go through at any given time).
- Advancements in maps and GPS technology have allowed for safer, easier and more efficient driving on the same roads and railways.
- Are there similar technologies that allow for such innovation in transmission **operations** (and planning)?

GETs enhance transmission operations and planning.

- GETs considered in this study: DLR, Topology Optimization, and Advanced Power Flow Control.
- These technologies have matured over the past several decades, are commercially proven and **actively operating** on grids around the world.
- They **focus on operational improvements** and have a much lower cost and faster implementation than traditional transmission technologies.
  - Similar to the comparison between building a road to reduce congestion (long-term investment) and having a good map/GPS system to avoid congested roads (operational improvements).

Dynamic Line Ratings - 1/2

Historical practice was largely based on Static Line Ratings (SLR).

- Maximum operating temperature for a given line is pre-determined.
  - Uses conservative assumptions, such as low wind, high temperature, high solar irradiance, etc., to accommodate most conditions.
  - It is similar to setting highway speed limit based on snowy road conditions.
  - Recently more transmission operators have adopted ambient adjusted rating (AAR).

DLR enhances AAR further and utilize real-time data.

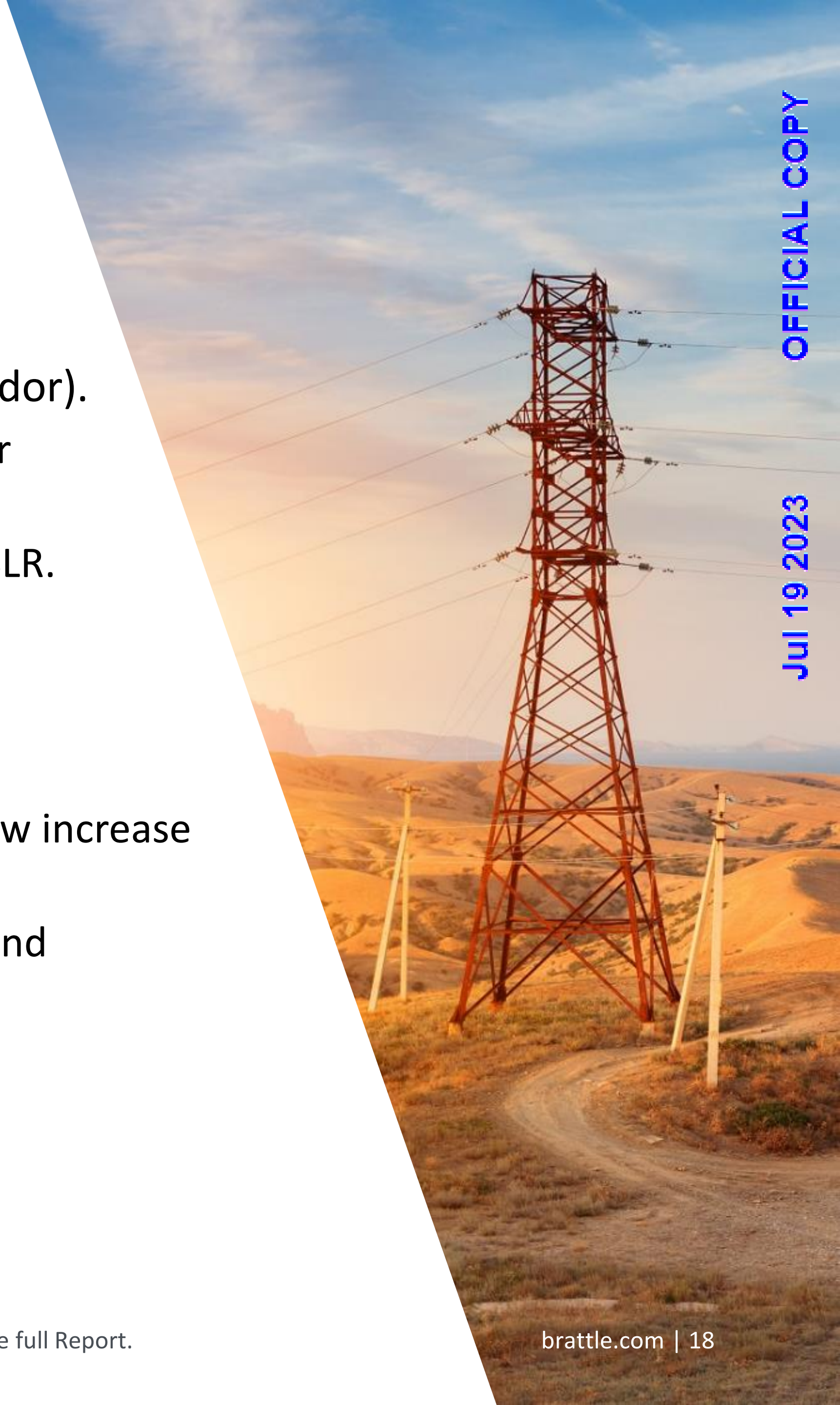
- Commonalities between SLR, AAR, and DLR.
  - Minimum allowable electrical clearance is the same.
- Differences between SLR, AAR, and DLR.
  - SLR applies uniform weather conditions to all lines and is generally lower than AAR and DLR that applies line-specific conditions.
  - AAR requires line-specific data and ambient temperature, but has a ≥ 15% risk of exceeding electrical clearance limitations (as commonly implemented in the U.S.)*
  - DLR requires line-specific data in conjunction with real-time monitoring of ambient temperature, wind and conductor position, and can provide forecasts for operations planning.*

* Post-Technical Conference Comments of the WATT Coalition, November 2019, available at: https://watttransmission.files.wordpress.com/2019/11/post-technical-conference-of-the-watt-coalition.pdf, pp 2-5.

Dynamic Line Ratings - 2/2

DLR adjust limits based on ambient conditions.

- Thermal ratings use real-time measurements the line location (along line corridor).
  - Line temperature, line sagging, ambient conditions (temperature, humidity, solar irradiance, wind, precipitation etc.).
  - DOE/ONCOR study indicates DLR transfer capability to be 5 to 25% higher than SLR.
- Accumulation of real-time data can be used for future calibration.
  - DLR is variable and requires a forecast for operations planning.
- High wind leads to higher cooling and allows for increased flow.
  - High degree of overlap between wind production and DLR-induced allowable flow increase has been observed.
  - European studies indicate DLR contributes to approximately 15% reduction in wind curtailments in some areas.



Advanced Power Flow Control - 1/2

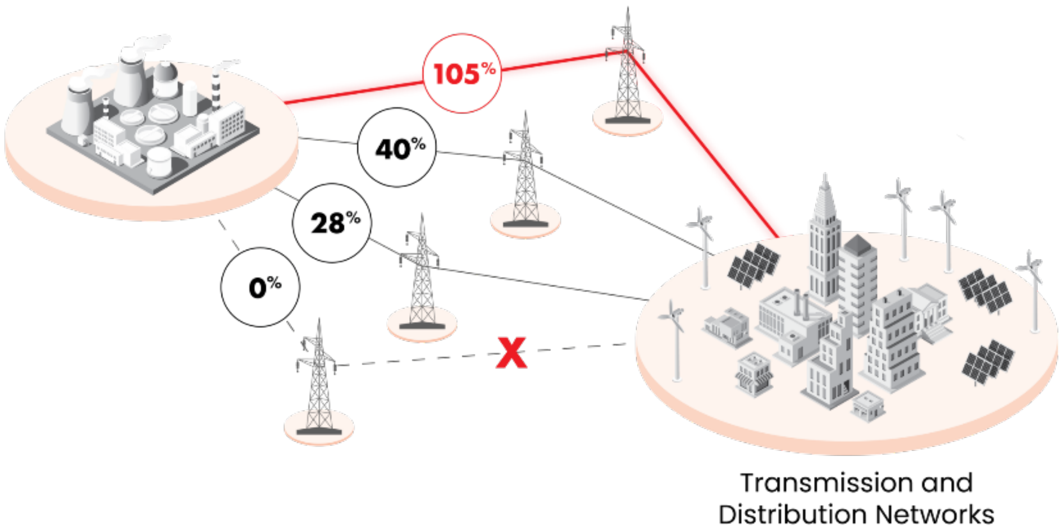
Phase Shifting Transformers (PSTs)* and Flexible Alternating Current Transmission Systems (FACTS) devices help the operator control flow through a given path.

- These devices are widely accepted in the industry.
  - The largest drawback is the cost—for example, a recently-installed PAR* between Michigan and Ontario has an annual carrying cost of over $10 million.
- FACTS devices are power-electronic-based static devices that allow for flexible and dynamic control of flow on transmission lines or the voltage of the system.
  - Some FACTS devices alter the reactance of a line to control the flow (i.e., increasing the reactance will push away flows while decreasing the reactance will pull in more flow to the line).
  - FACTs devices typically cost less than PARs, can be manufactured and installed in a shorter time, are scalable, and in many cases, are available in mobile form that can be easily deployed (or redeployed, as needed) while providing flexible layout options.

* Phase Shifting Transformers are also called Phase Angle Regulators (PARs).

Advanced Power Flow Control - 2/2

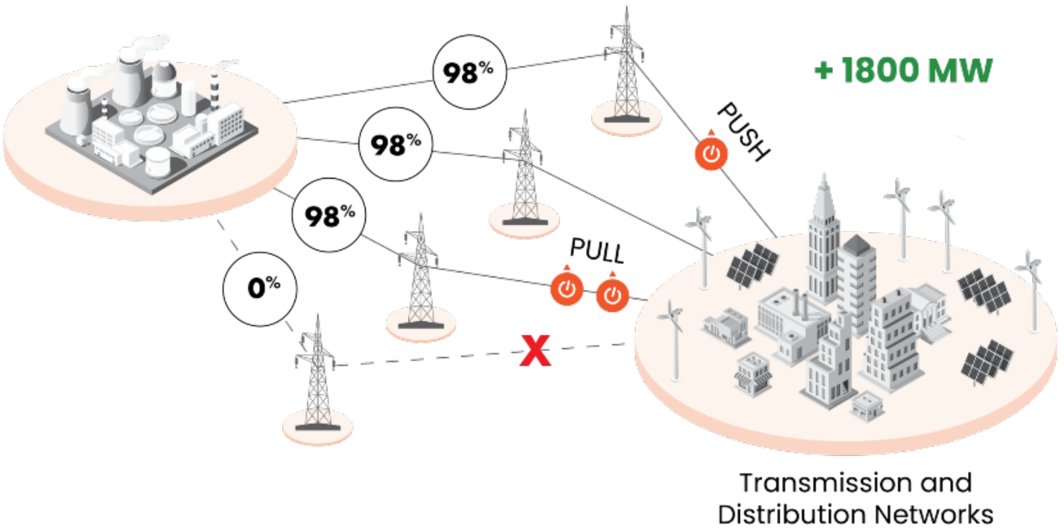
Before FACTS Device*



Traditional solutions include:

1. Redispatch generation
2. Reconductor constraining element
3. Install PSTs/Series Capacitor/Series Reactor
4. Construct a new parallel circuit

After FACTS Device



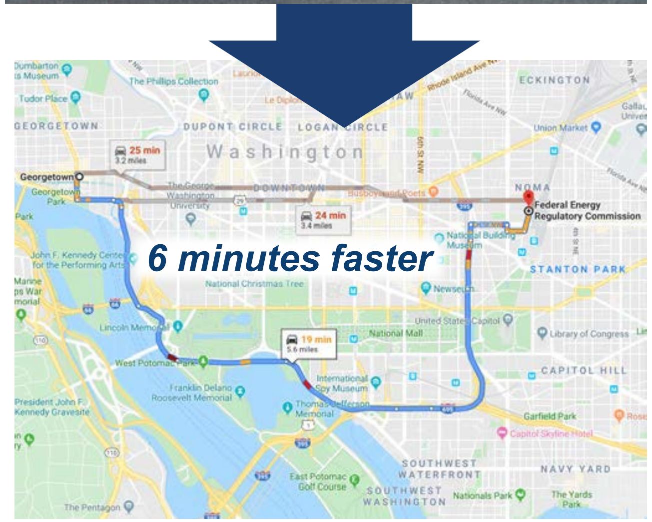
Power can be **PUSHED** and **PULLED** to alternate lines with spare capacity—leading to maximum utilization (typically obtained by a number of small applications on more than one circuit.)

* Illustrative example from Smart Wires, https://www.smartwires.com/smartvalve/

Topology Optimization - 1/2

Topology Optimization is analogous to Waze: “Arrive to destination reliably, with minimum delay even when there are events on the road” by re-routing.

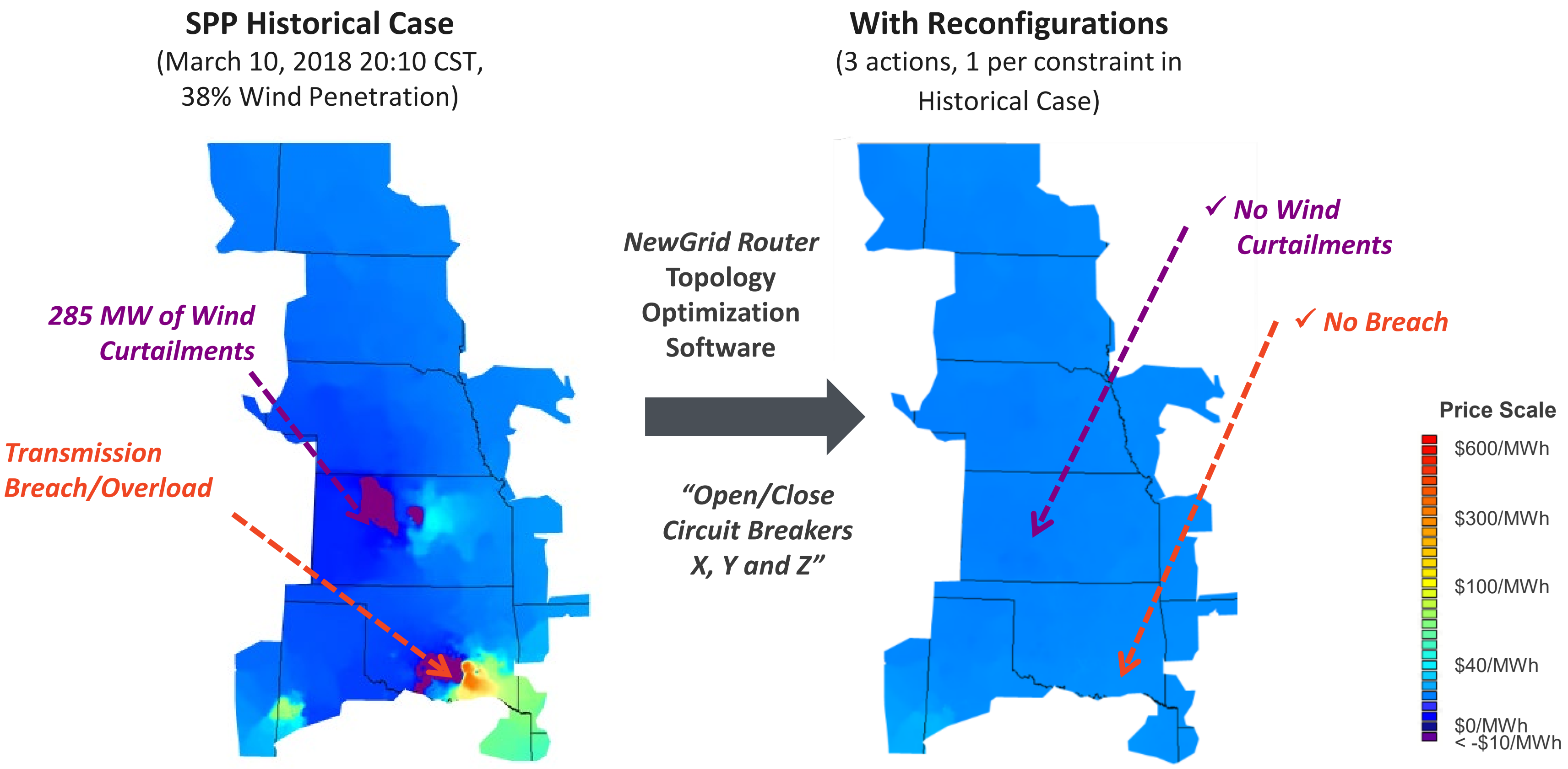
- Re-routing is achieved by grid reconfigurations: switching circuit breakers open or close.
  - Analogous to temporarily diverting traffic away from congested roads to make traffic smoother.
  - Similar effect as advanced flow control devices, using existing equipment.
- Reconfiguring the grid in operations is feasible today.
  - Circuit breakers are capable of high duty cycles and extremely reliable—some breakers are switched very frequently today, e.g., those connecting generating units with daily start and stop operations.
  - Switching infrastructure is already in place—most breakers are controlled remotely over SCADA by the TO.
  - Low cost: usually $10-$100 per switching cycle.



Road closure picture from https://www.islandecho.co.uk/plea-motorists-heed-road

Topology Optimization - 2/2

Topology Optimization software technology automatically finds reconfigurations to route flow around congested elements ("Waze for the transmission grid").

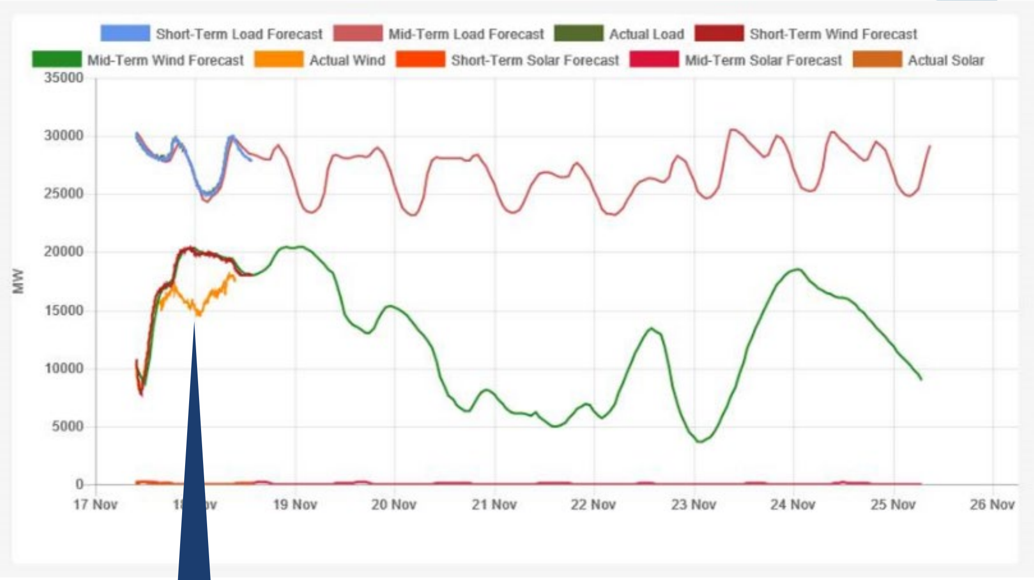


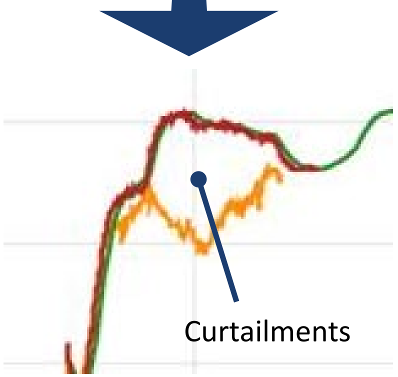
Why GETs?

GETs enhance transmission operations and planning.

- GETs **focus on operational improvements** and can be implemented quicker and at a lower cost than traditional transmission technologies.
  - Similar to the comparison between building a road to reduce congestion (long-term investment) and having a good map/GPS system to avoid congested roads (operational improvements).
- SPP operations data shows renewable curtailments likely caused by transmission congestion (indicated by transmission shadow prices).

SPP REAL-TIME MARKET DATA SNAPSHOT FROM NOVEMBER 18, 2020





Actual wind production (shown in yellow) is lower than forecasts. Wind (and load) forecasts for both the short- and mid-term trend are over each other, indicating that the reduced wind production is likely due to curtailments.

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Study Objective, Approach, and Steps

Overall study objective

- Quantify the combined benefits of three GETs for integrating renewables:
  - For a future year 2025.
  - For a select area within SPP.
  - Using 24 representative snapshots (power flow cases) to represent a full year.

Analysis approach and steps

Step 1: **Identify preferred area** for analysis.

Step 2: **Select 24 representative snapshots** from SPP operational power flow cases.

Step 3: **Modify the snapshots** to reflect new transmission upgrades, renewable plants from the generation interconnection queue, announced retirements, etc.

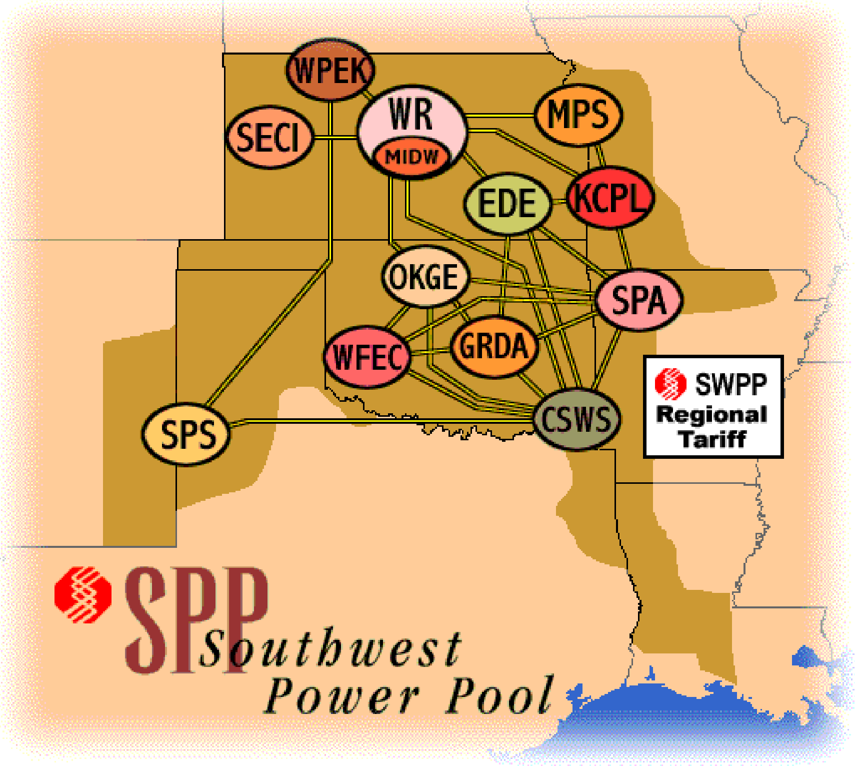
Step 4: **Find the maximum amount of renewables** that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case) in the order of DLR, Topology Optimization, Advanced Power Flow Control. This will be done by solving the power flow cases (for the entire SPP footprint) prepared in Step 3, with and without GETs.

Step 5: **Assess benefits** including economic values (production cost savings, job creation, local benefits, etc.) and carbon emissions reduction.

Step 1: Identify Preferred Areas - 1/4

Step 1: Identify preferred area for analysis.

- GETs focuses on transmission operation.
  - These technology options are particularly helpful in increasing renewable penetration when transmission congestion is curtailing renewables (or preventing interconnection).
  - More renewables (largely wind in SPP) will likely to higher transmission congestion.
- Therefore, the preferred areas would be:
  - Areas with transmission constraints identified in SPP transmission studies.
    - Preferred areas to be identified by studying the SPP Integrated Transmission Planning (ITP) Assessment Report and quarterly updates.
  - Areas with significant generation resource changes (large amounts of new renewable projects and retirements of existing resources).
    - Preferred areas to be identified by studying the SPP GI Queue.



SPP figure from http://opsportal.spp.org/Images/SPPMap.gif

Step 1: Identify Preferred Areas - 2/4

Based on the observations from the ITP report and GI queue, **Kansas and Oklahoma** are selected as the focus areas.

- Selection criteria for new renewables projects are set to those where Interconnection agreement has been fully executed.*
  - GI queue status of IA Fully Executed/On Schedule or IA Fully Executed/Suspended.
- This approach will include over 9,400 MW of renewable projects:

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

WIND SITING PLANS FROM 2019 ITP

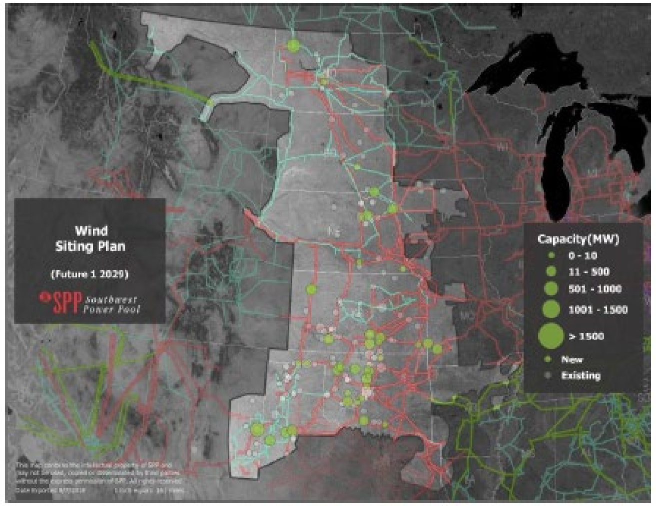


Figure 2.19: 2029 Future 1 Wind Siting Plan

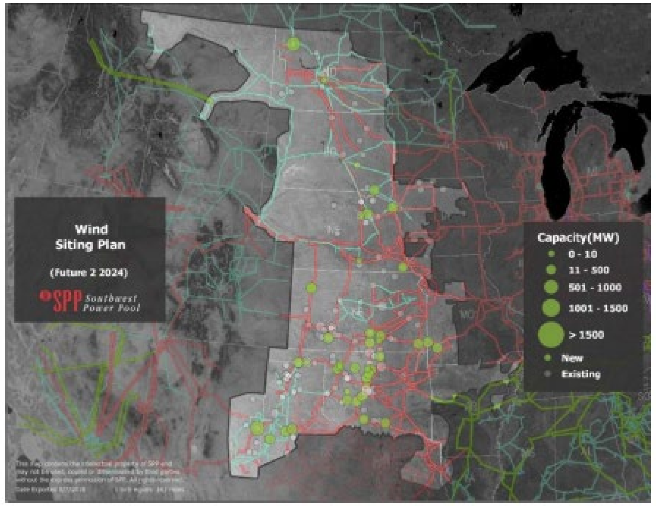


Figure 2.20: 2024 Future 2 Wind Siting Plan

* The 2010 SPP Wind Integration Study uses a similar approach.

Step 1: Identify Preferred Areas - 3/4

SPP identifies two target areas in its 2019 Integrated Transmission Planning (ITP) Assessment Report as areas that needed additional analysis and could benefit from closer attention.

4.1.1.1 Southeast Kansas/Southwest Missouri Target Area (Target Area 1)

Southeast Kansas/Southwest Missouri was identified as Target Area 1, requiring additional analysis for several reasons. The area has been the site of historic and projected congestion on the EHV system and has had unresolved transmission limits identified in multiple studies, most recently in the 2018 ITPNT. By defining this corridor as a target area in the 2019 ITP, SPP is able to address the TWG's direction to provide a path forward for the area to properly evaluate and resolve the issues present in day-to-day operations and in the planning horizon.

4.1.1.2 Central/Eastern Oklahoma Target Area (Target Area 2)

Central/Eastern Oklahoma was identified as Target Area 2 due to heavy congestion and parallel system correlation with Target Area 1. Additional analysis was unnecessary for Target Area 2 because system issues in this area were only related to congestion and underlying voltage stability concerns. The main point of congestion in Target Area 2 is related to the Cleveland 345/138 kV station west of Tulsa, Oklahoma. The renewable forecast in the 2019 ITP drives increased bulk transfers across central Oklahoma. EHV contingencies in the area shift congestion mostly to the lower-voltage system.

Step 1: Identify Preferred Areas - 4/4

SPP's GI Queue shows significant renewable additions and material retirements of existing generation resources for Kansas and Oklahoma.

KS/OK

Planned Capacity and Retirement 2020-2025

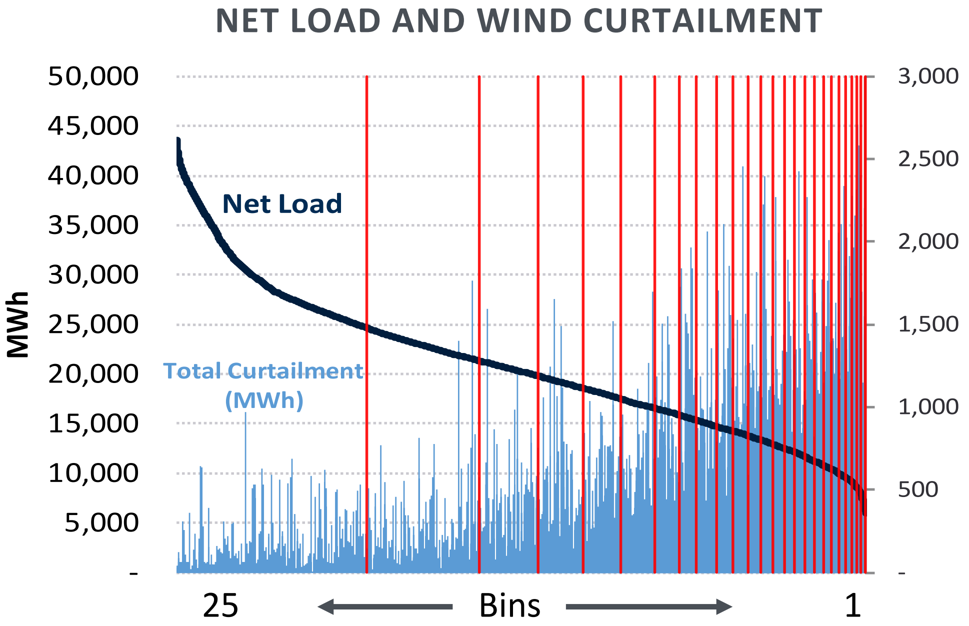
Control Area	Entity	Planned Capacity (MW) Total	Solar	Wind	Battery	Planned Retirement (MW) Total	Fuel Oil	Coal	Natural Gas
OKGE	**Oklahoma Gas & Electric Co**	**10,837**	**2,036**	**7,623**	**1,178**	**339**	**28**		**312**
Evergy	**Evergy**	**10,276**	**1,812**	**8,148**	**316**	**1,223**	**410**		**813**
KCPL	Kansas City Power & Light	2,911	550	2,361	-	727	297		431
WERE	Westar Energy	7,365	1,262	5,787	316	893	114		382
SPS	**Southwestern Public Service Co**	**13,122**	**6,985**	**5,088**	**1,049**	**920**			**920**
AEPW	American Electric Power West	**9,335**	**3,249**	**5,344**	**742**	**474**	**12**	-	**462**
BEPC	Basin Electric Power Coop	2,740	700	2,040	-				
LES	Lincoln Electric System	1,065	306	659	100	99			99
MIDW	Midwest	948	50	878	20				
NPPD	Nebraska Public Power District	6,806	2,025	4,707	74	354	178		176
OPPD	Omaha Public Power District	1,808	1,027	135	646	605	136	199	270
SUNC	Sunflower Electric Power Corp	4,163	1,110	3,003	50	431	84		346
WAPA	WAPA Upper Great Plains West	3,441	388	3,053	-				
WFEC	Western Farmers Electric Coop	2,265	1,404	677	184	130			130
AR	Other AR Utilities	126	126	-	-	5	5		
IA	Other IA Utilities	300	-	300	-	6	6		
KS	Other KS Utilities	7,465	5,041	1,729	695	166	66		100
LA	Other LA Utilities	440	330	-	110				
MN	Other MN Utilities	-	-	-	-	43	43		
MO	Other MO Utilities	5,176	3,031	1,642	503	427	74	165	188
MT	Other MT Utilities	510	75	385	50				
ND	Other ND Utilities	1,033	72	887	74	4	4		
NE	Other NE Utilities	3,497	2,026	1,171	300				
NM	Other NM Utilities	500	500	-	-				
OK	Other OK Utilities	3,396	2,001	1,143	252	540		540	
SD	Other SD Utilities	1,832	63	1,705	63	34	10		24
TX	Other TX Utilities	2,482	920	852	710				
Total		**94,920**	**36,092**	**51,712**	**7,116**	**6,197**	**1,097**	**904**	**4,197**

Planned Capacity Source: SPP GI Queue accessed September 28, 2020

Step 2: Identify 24 Snapshots - 1/5

Step 2: Select 24 representative snapshots from SPP operational power flow cases.

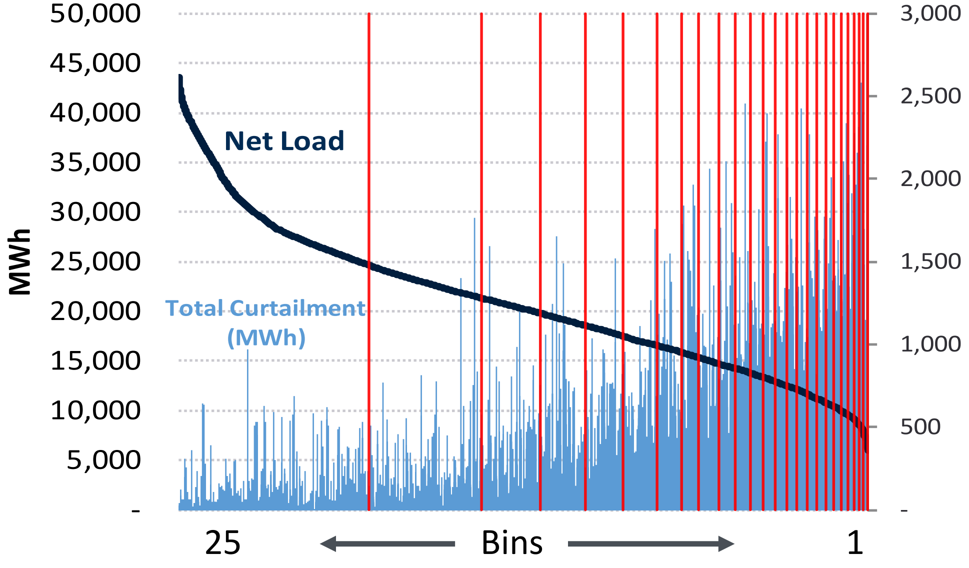
- The 24 snapshots should represent varying conditions over a full year.
  - This is an alternative approach to performing production simulation type analyses.
  - This approach may reflect historical operational conditions better than production simulations.
- Create 25 bins (numbered 1 through 25) using historical data (one full year).
  - Sort all hours in the year by decreasing net load.
  - Create 25 bins (separated by red lines in the chart to contain about 1/25th of the total (annual) curtailment observed.
  - Curtailment is higher in hours where net load (shown as the thick black line in the chart to the right) is lower.
  - Analysis will be for 24 bins, excluding the first bin (bin 25) with minimal average curtailment.
- Select appropriate snapshots to represent each bin.



Step 2: Identify 24 Snapshots - 2/5

25 bins (numbered 1 through 25) created using historical data (one full year).

- Each bin (separated by red lines in the chart to the below) contains approximately 1/25th of the total (annual) curtailment observed.



Areas between red line indicates the bins from which snapshots were selected, blue bars indicate curtailment of renewables. Each bin contains equal amounts of curtailment.

To be analyzed

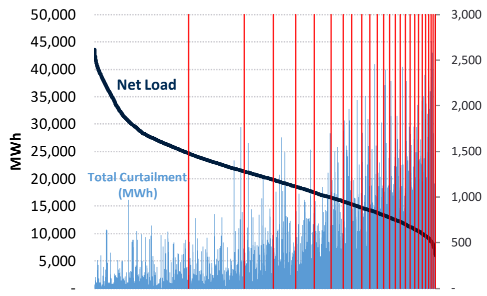
BIN INFORMATION

Bin	Wind Production Potential [MWh]	Wind Curtailment [MWh]	Average Curtailment [%]	Average Curtailment [MWh]	No of Hours
1	930,179	56,420	6%	973	58
2	801,517	57,229	7%	1,122	51
3	995,079	55,534	6%	868	64
4	1,190,204	56,178	5%	711	79
5	1,272,130	56,782	4%	668	85
6	1,418,124	56,184	4%	579	97
7	1,454,767	56,198	4%	573	98
8	1,690,406	57,186	3%	485	118
9	1,734,496	55,497	3%	455	122
10	1,916,544	56,104	3%	422	133
11	1,743,862	56,538	3%	449	126
12	2,054,919	55,794	3%	374	149
13	2,111,623	56,131	3%	364	154
14	2,154,600	56,823	3%	351	162
15	2,569,128	56,044	2%	289	194
16	2,698,718	56,007	2%	269	208
17	3,225,928	56,365	2%	217	260
18	2,680,982	56,487	2%	262	216
19	3,792,959	56,089	1%	179	313
20	4,647,197	56,480	1%	130	434
21	4,940,542	56,082	1%	117	480
22	5,436,156	56,237	1%	98	575
23	6,560,518	56,340	1%	75	750
24	10,239,766	56,239	1%	39	1436
25	13,951,550	56,266	0%	23	2421

Step 2: Identify 24 Snapshots - 3/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Maintain daily and seasonal spread.
  - No same day.
  - More than 4 per season (4 Winter, 6 Spring, 6 Summer, 8 Fall).



To be analyzed

BIN Information

Bin	Wind Production Potential [MWh]	Wind Curtailment [MWh]	Average Curtailment [%]	Average Curtailment [MWh]	No of Hours
1	930,179	56,420	6%	973	58
2	801,517	57,229	7%	1,122	51
3	995,079	55,534	6%	868	64
4	1,190,204	56,178	5%	711	79
5	1,272,130	56,782	4%	668	85
6	1,418,124	56,184	4%	579	97
7	1,454,767	56,198	4%	573	98
8	1,690,406	57,186	3%	485	118
9	1,734,496	55,497	3%	455	122
10	1,916,544	56,104	3%	422	133
11	1,743,862	56,538	3%	449	126
12	2,054,919	55,794	3%	374	149
13	2,111,623	56,131	3%	364	154
14	2,154,600	56,823	3%	351	162
15	2,569,128	56,044	2%	289	194
16	2,698,718	56,007	2%	269	208
17	3,225,928	56,365	2%	217	260
18	2,680,982	56,487	2%	262	216
19	3,792,959	56,089	1%	179	313
20	4,647,197	56,480	1%	130	434
21	4,940,542	56,082	1%	117	480
22	5,436,156	56,237	1%	98	575
23	6,560,518	56,340	1%	75	750
24	10,239,766	56,239	1%	39	1436
25	13,951,550	56,266	0%	23	2421

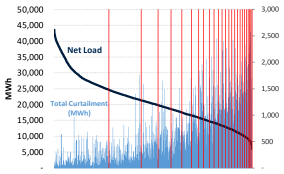
Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
4	September 21, 2020	Early Morning
5	June 13, 2020	Early Morning
6	September 9, 2020	Early Morning
7	March 8, 2020	Mid Day
8	January 9, 2020	Early Morning
9	November 11, 2019	Late Afternoon
10	January 8, 2020	Late Afternoon
11	April 18, 2020	Early Morning
12	September 10, 2020	Early Morning
13	December 7, 2019	Late Afternoon
14	April 16, 2020	Late Afternoon
15	March 4, 2020	Late Night
16	December 19, 2019	Late Afternoon
17	May 10, 2020	Late Night
18	November 15, 2019	Late Afternoon
19	December 11, 2019	Late Afternoon
20	November 16, 2019	Mid Day
21	August 13, 2020	Early Morning
22	September 6, 2020	Mid Day
23	August 20, 2020	Late Night
24	June 26, 2020	Late Night

* SPP provides limited snapshots (Early Morning: 0500, Mid Day: 1100, Late Afternoon: 1700 Late Night: 2300)

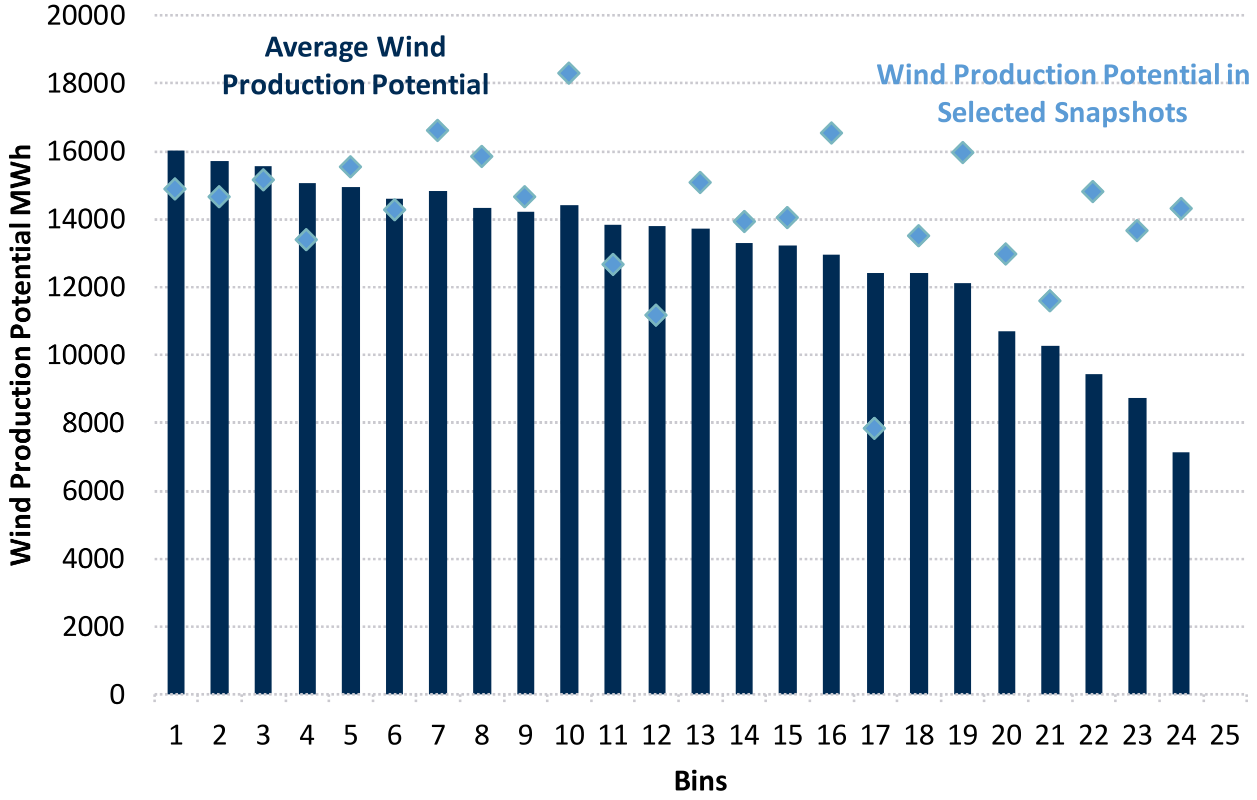
Step 2: Identify 24 Snapshots - 4/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Average wind production potential in sample: 14.3 GW.
  - Sample wind production potential ranges from 7.9 GW to 18.3 GW.



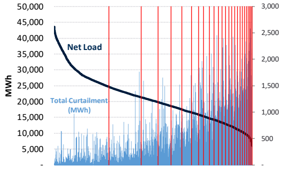
Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
4	September 21, 2020	Early Morning
5	June 13, 2020	Early Morning
6	September 9, 2020	Early Morning
7	March 8, 2020	Mid Day
8	January 9, 2020	Early Morning
9	November 11, 2019	Late Afternoon
10	January 8, 2020	Late Afternoon
11	April 18, 2020	Early Morning
12	September 10, 2020	Early Morning
13	December 7, 2019	Late Afternoon
14	April 16, 2020	Late Afternoon
15	March 4, 2020	Late Night
16	December 19, 2019	Late Afternoon
17	May 10, 2020	Late Night
18	November 15, 2019	Late Afternoon
19	December 11, 2019	Late Afternoon
20	November 16, 2019	Mid Day
21	August 13, 2020	Early Morning
22	September 6, 2020	Mid Day
23	August 20, 2020	Late Night
24	June 26, 2020	Late Night



Step 2: Identify 24 Snapshots - 5/5

Select a representative hour from each bin to obtain 24 snapshots that span the conditions where wind curtailment occurs.

- Average capacity factor: 63.2% (annual SPP CF 41.5%).
- Average curtailment in sample: 2.8%.



Bin	Date	Time*
1	April 12, 2020	Early Morning
2	September 28, 2020	Early Morning
3	June 1, 2020	Early Morning
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5	June 13, 2020	Early Morning
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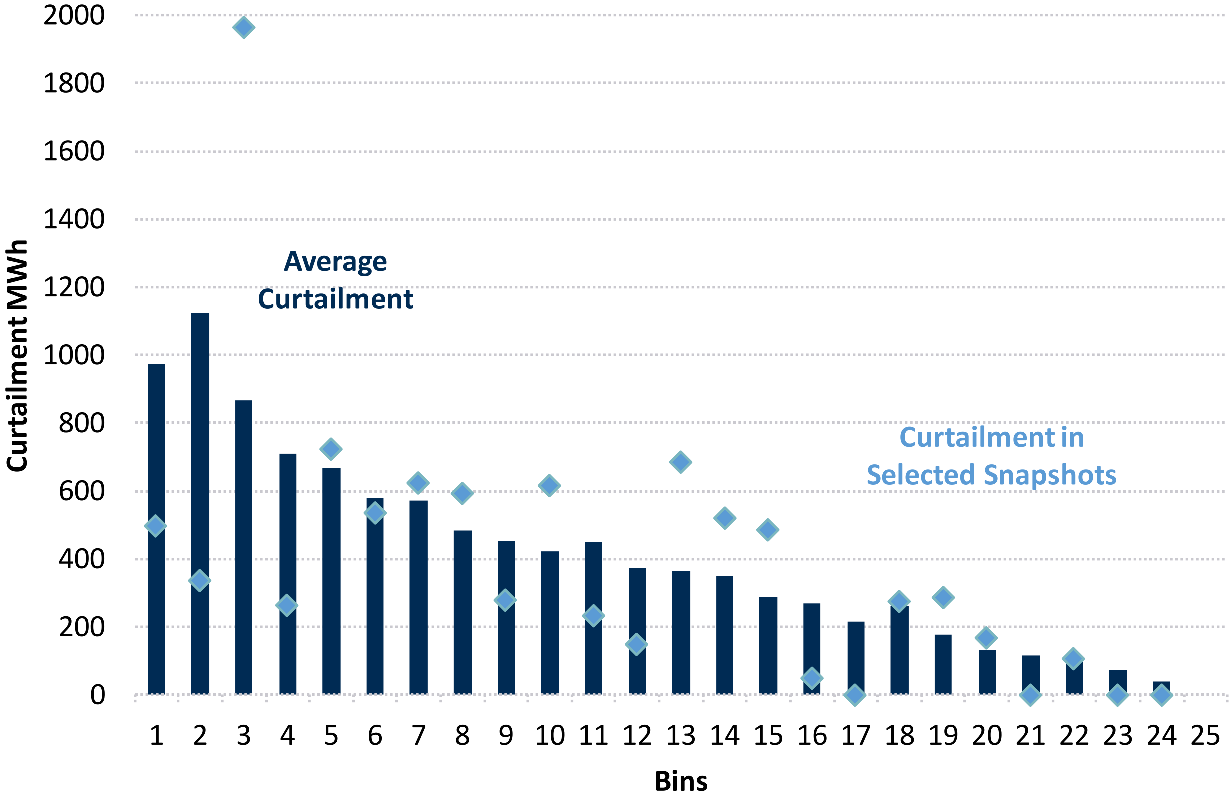
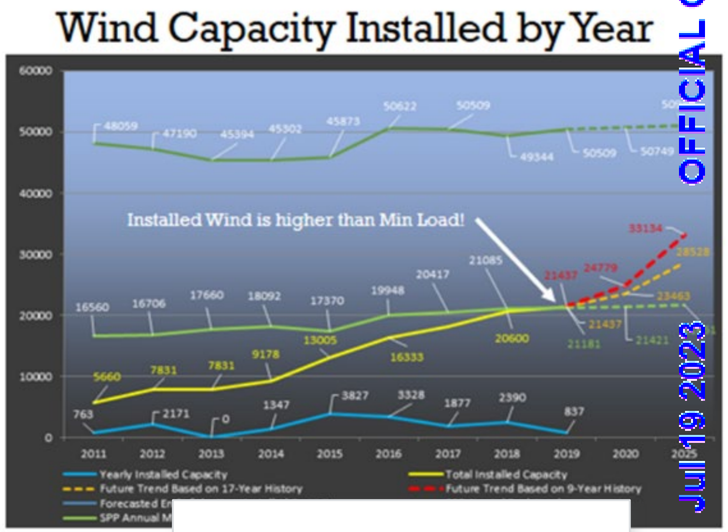
24	June 26, 2020	Late Night

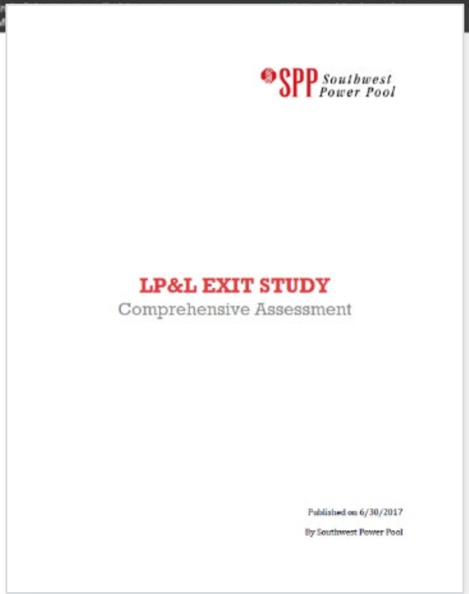


Step 3: Modify the 24 Snapshots - 1/2

Step 3: Modify the snapshots from SPP to reflect new transmission upgrades, wind and solar units from the generation interconnection queue, announced retirements, load changes, etc., to model 2025.

- Generation
  - Add/retire announced thermal generation.
  - Add new wind and solar units from interconnection queue. Assume added units' max potential output based on capacity factor from nearby units of the same type (this will be done by snapshot).
  - Adjust wind/solar dispatch to reverse curtailment by observing historical data on LMPs to identify units that may have been be curtailed (e.g., LMP less than -$20/MWh).
  - For assumed curtailments, estimate what the non-curtailed dispatch might have been using nearby wind/solar units.
- Load
  - Adjust load to 2025 level.
  - Remove portion of Lubbock load that is scheduled to transfer to ERCOT.*
  - Keep imports/exports with neighboring areas constant.



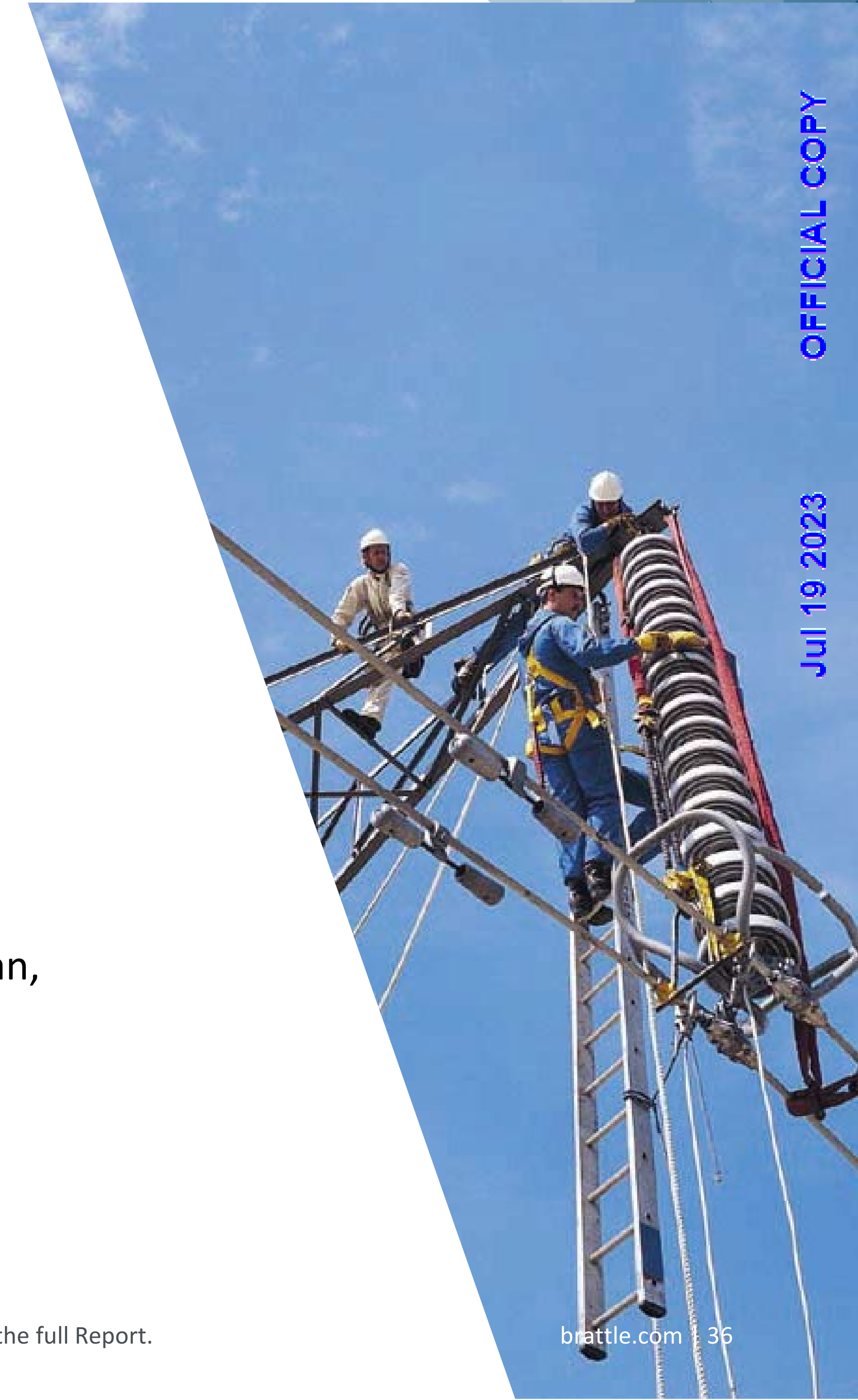


* LP&L Exit Study, available at https://www.spp.org/documents/52338/2017-lpl%20exit%20study%20-%2020170630_final.pdf

Step 3: Modify the 24 Snapshots - 2/2

Step 3: Modify the snapshots from SPP to reflect new transmission upgrades, wind and solar units from the generation interconnection queue, announced retirements, load changes, etc., to model 2025.

- Transmission
  - Adjust transmission constraint limits by comparing binding constraints against historical data (and adjust as necessary.)
  - Add new transmission projects. Transmission projects that are planned to be in service by 2025 are selected from SPP's Integrated Transmission Planning (ITP) reports (See appendix for the list of projects.)
  - Identify outages in snapshots that correspond to capital projects, and put them back in service.
  - Setup single-element contingencies in SPP and neighboring areas (Mid-American, Associated Electric, Entergy etc.).



Step 4: Find Max Renewables - 1/3

Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario (Base Case) and then with GETs.

- Dispatch wind and solar to their max output by running Security Constrained Optimal Power Flow (SCOPF).
  - Adjust output of non-renewable units. For fossil-fuel thermal units:
    - If capacity is < 100 MW, allow the unit to shut down.
    - If capacity is >= 100 MW, assume the unit's min-gen is 30% of max-capacity.
    - For night time snapshots, allow natural gas-fueled combined cycle units and simple cycle units to shut down as needed.
    - Leave nuclear units and units outside of SPP operating as is (i.e., no redispatch).
  - Set priority order for different generator units by unit type.
    - Prioritize wind and solar over other units, and prioritize existing wind/solar over new wind/solar.

Step 4: Find Max Renewables - 2/3

Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario (Base Case) and then with GETs (With GETs Case). This will be performed by solving the power flow cases for the entire SPP footprint.

- Without GETs implemented (Business as Usual).
  - Assess curtailment without GETs.
  - Solve SCOPF (i.e., run contingency analysis to get violations, add interfaces to represent violations and re-run OPF, repeat these steps until no new violations are identified.) In doing so, enforce 69 kV and higher constraints within SPP, and 100 kV and higher constraints for external regions.
  - Save power flow case as Base Case.
  - Tally curtailment by comparing dispatch with limits for all wind and solar units. For new renewable projects (9,430 MW-worth from GI Queue), assume 5% curtailment thresholds for viability assessment (i.e., projects are considered viable if analysis indicates annual curtailments to be less than 5%). This will be an iterative process (i.e., run SCOPF, take out renewable projects with high curtailments, then resolve SCOPF, and repeat).

Step 4: Find Max Renewables - 3/3

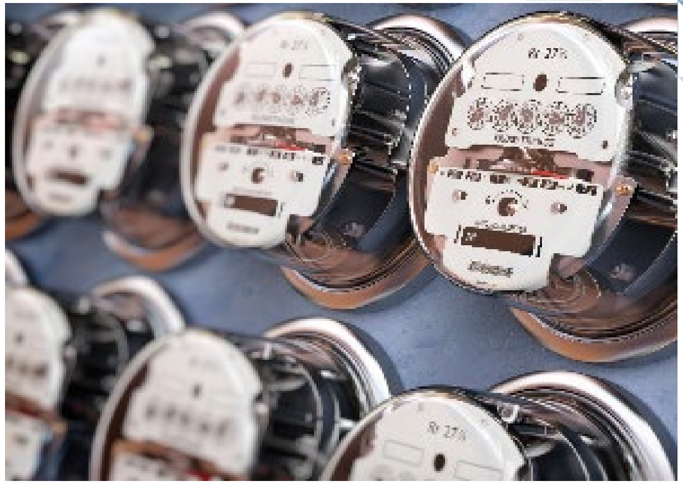
Step 4: Find the maximum amount of renewables that can be integrated under a business as usual scenario and then with GETs (in the order of DLR, Topology Optimization, and Advanced Power Flow Control). This will be performed by solving the power flow cases for the entire SPP footprint.

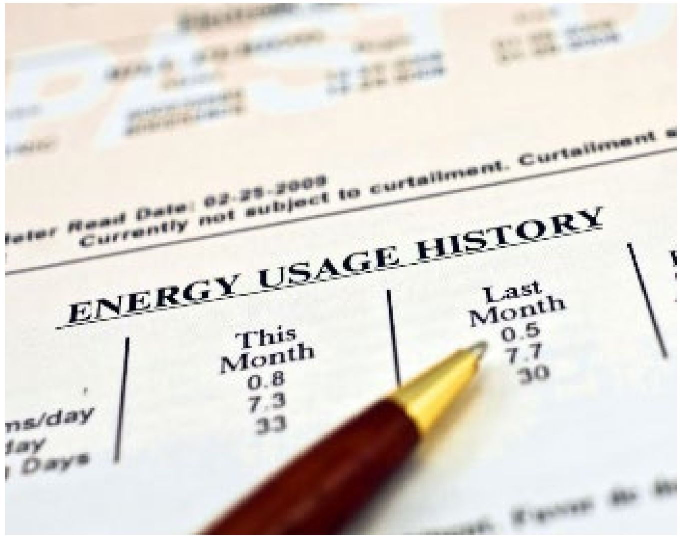
- With GETs implemented (repeat the analysis from the previous slide).
  - Perform DLR analysis on Base Case and save power flow case as DLR Case.
  - Perform Topology Optimization analysis on DLR Case, save power flow case as TC Case.
  - Perform Flow Control analysis on TC Case, save power flow case as FC Case.
  - Revisit FC Case to identify additional DLR and/or Topology Optimization opportunities.
  - Tally curtailment by comparing dispatch with limits for all wind and solar units. Apply the same 5% threshold to assess project viability.
- Results will be for the combined benefits, rather than individual GETs.
  - The order of GETs implemented in the analysis will likely change the benefits reaped by the individual technologies (i.e., being the first technology to be added would likely show larger benefits than being last).

Step 5: Assess Benefits - 1/3

Step 5: Assess benefits including economic values (production cost savings, job creation, local benefits, etc.) and carbon emissions reduction.

- Calculate production costs benefits and carbon emission benefits utilizing SPP market data where applicable.
- Review public studies on the economic impacts to estimate "per unit" benefits, and apply to the findings.
- GETs Vendors provide economic impacts associated with their respective technology installments.
  - Cost data for both initial investment, and ongoing operational costs once installed, provided by GETs vendors.



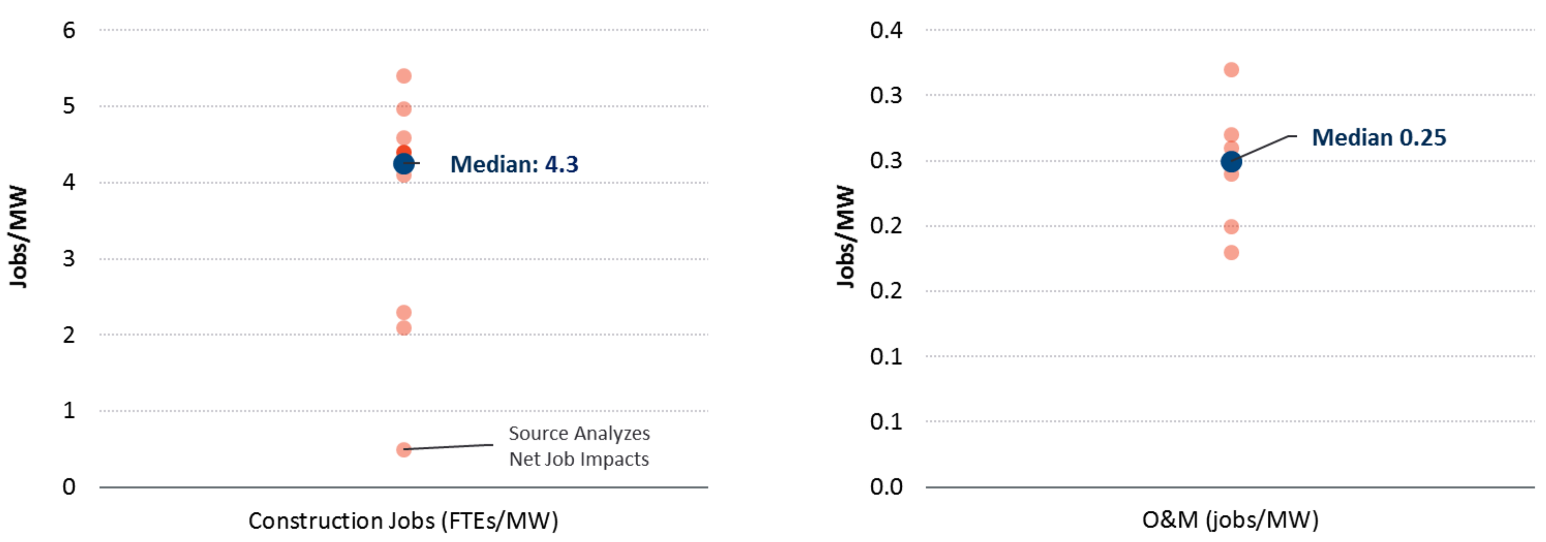


Step 5: Assess Benefits - 2/3

Adding more renewables produces jobs.

- Review of various public reports (14)* to assess job impacts through wind investments.
  - Direct, indirect, and induced jobs are included.
  - Data generally reflects short term jobs (e.g., construction jobs) rather than long term O&M jobs.
  - Impacts are at the state level (or smaller geographical areas).

COMPARISON OF JOB IMPACTS ACROSS STUDIES



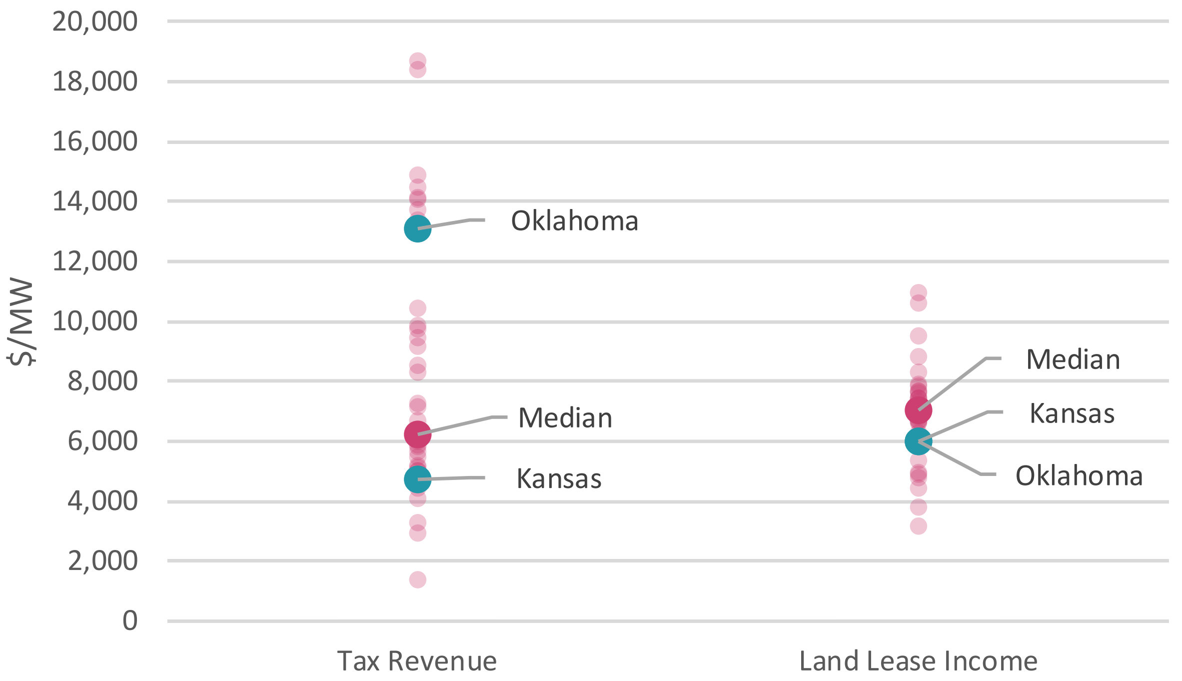
* See Appendix-B for list of reports reviewed.

Step 5: Assess Benefits - 3/3

Adding more renewables produces additional local benefits.

- Review of various public reports (7)* to assess land lease and tax revenues from wind development.

COMPARISON OF LEASE AND TAX REVENUES ACROSS STUDIES AND STATES



* See Appendix-B for list of reports reviewed.

Table of Contents

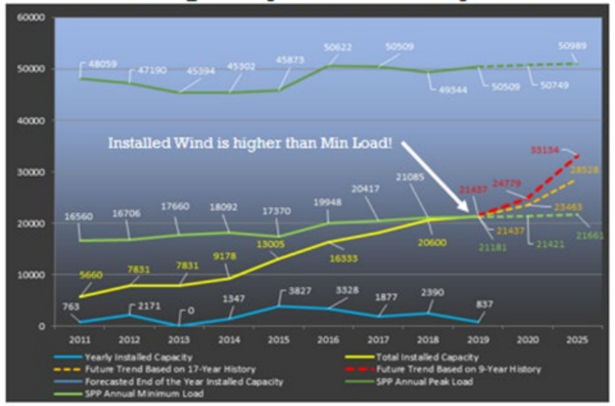
System Assumptions for 2025

Study focus area: Kansas and Oklahoma.

- Load Change
  - SPP estimates 240 MW load growth between 2020 and 2025.
  - Approximately 470 MW (summer peak) of Lubbock load estimated to transfer to ERCOT in 2021.
    - Load connected to the Xcel Energy system by four 230 kV nodes (LP-Milwakee, LP-Southeast, LP-Holly, and LP-Wadswrth) is scheduled to transfer. Roughly 180 MW will remain in SPP.
- Over 9,400 MW of potential renewable projects.
  - Projects in the SPP GI queue projects with IA executed.
- Over 70 new transmission projects added.
  - Based on status from ITP Assessment reports.

Detail data are included in the Appendix.

Wind Capacity Installed by Year



POTENTIAL RENEWABLE PROJECTS

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

TRANSMISSION PROJECTS

Voltage Level	Project Counts
230 KV and Above	16
169 kV and 138 kV	27
115 kV	16
69 kV	14
Total	73

Renewables Under Base Case

Study focus area: Kansas and Oklahoma.

- Base Case (business as usual) allows for over 2,500 MW of new renewables to be integrated.
  - Retirements of existing thermal resources contribute.
  - While limited, load growth also contributes.
  - Lubbock load departure works against integrating more renewables.

ADDITIONAL RENEWABLES INTEGRATED – BASE CASE

State	Potential (MW)			Base Case (MW)			Realization (%)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	3,410	120	3,530	1,710	0	1,710	50%	0%	48%
Oklahoma	5,760	140	5,900	770	100	870	13%	71%	15%
Total	9,170	260	9,430	2,480	100	2,580	27%	38%	27%

[Rounded to the nearest 10 MW]

Renewables Under With GETs Case - 1/3

GETs utilized in this study include:

- **Hardware solutions**: DLR on 56 lines and Advanced Power Flow Control on 8 locations.

Hardware Solutions by Voltage Level	345	230	161	138	115	69	Total
DLR*	10	3	11	22	3	7	56
Advanced Power Flow Control	3	0	4	1	0	0	8

- **Software solutions**: 204 unique Topology Optimization reconfigurations, averaging 13 per snapshot.**

Software Solutions by Voltage Level	345	230	161	138	115	69	Total
Lines	20	10	31	75	4	30	170
Substations	4	0	1	1	0	0	6
Transformers (high voltage terminal)	10	1	4	13	0	0	28

- Estimated costs for implementing the above GETs: ~$90 million.
  - Initial investment costs is estimated to be around $90 million.***
  - Ongoing costs of around $10 million per year.***

* Every DLR installation requires 15 to 30 sensors.

** Average actions represent the average number of actions that remain per case, not actions per hour. Based on other studies the average number of actions per hour is expected to be smaller, typically less than the number of topology changes due to planned outages.

*** Costs can vary project by project, and also on how the GETs service is provided—for example, Topology Optimization can be provided as a software subscription service to reduce the initial cost. We also assume utilities can incorporate these technologies without large costs.

Renewables Under With GETs Case - 2/3

Study focus area: Kansas and Oklahoma.

- GETs allow for **over 5,200 MW** of new renewables to be integrated.
  - This is **more than twice the amount** of renewables integrated in the Base Case.

ADDITIONAL RENEWABLES INTEGRATED – WITH GETS CASE

State	Potential (MW)			With GETs Case (MW)			Realization (%)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	3,410	120	3,530	1,910	0	1,910	56%	0%	54%
Oklahoma	5,760	140	5,900	3,200	140	3,340	56%	100%	57%
Total	9,170	260	9,430	5,110	140	5,250	56%	54%	56%

[Rounded to the nearest 10 MW]

- Curtailment levels of existing renewables (wind) are also reduced.
  - Existing wind curtailment reduced by over 76,000 MWh.
  - No change for solar.

Renewables Under With GETs Case - 3/3

GETs enable more than twice the amount of additional new renewables to be integrated.

- Potential Renewables Considered: 9,430 MW
  - Based on queue projects with IA executed.
- Integrated Renewables (without further transmission upgrades)
  - Base Case: 2,580 MW
  - With GETs Case: 5,250 MW
  - Delta (With GETs Case – Base Case): 2,670 MW

RENEWABLE POTENTIAL ASSUMED FOR KANSAS AND OKLAHOMA

State	Wind	Solar	Total
Kansas	3,410	120	3,530
Oklahoma	5,760	140	5,900
Total	9,170	260	9,430

[Rounded to the nearest 10 MW]

~1.5 times the amount of wind SPP integrated in 2019 (1.8 GW).

ADDITIONAL RENEWABLES INTEGRATED

State	Base Case			With GETs Case			Delta (GETs - Base)		
	Wind	Solar	Total	Wind	Solar	Total	Wind	Solar	Total
Kansas	1,710	0	1,710	1,910	0	1,910	200	0	200
Oklahoma	770	100	870	3,200	140	3,340	2,430	40	2,470
Total	2,480	100	2,580	5,110	140	5,250	2,630	40	2,670

X2

[Rounded to the nearest 10 MW]

Benefits of Increased Renewables - 1/7

GETs enable more than twice the amount of additional renewables to be integrated.

- 2,670 MW = 5,250 MW (With GETs Case) – 2,580 MW (Base Case)
- 2,670 MW = 2,630 MW (Wind) + 40 MW (Solar)
- GETs investment cost is around $90 million.

SUMMARY OF BENEFITS OF INCREMENTAL 2,670 MW OF RENEWABLES - 1/2

Annual Renewables Benefits			Notes
Additional Generation	New Wind	8,640 GWh	Wind assumes 37.5% capacity factor, solar assumes 18.0% capacity facto, see slide 51.
	New Solar	60 GWh	
	Total	8,700 GWh	
Reduction in Curtailment from Existing Wind		76 GWh	
Total Increase in Renewable Generation		8,776 GWh	
Annual Production Costs Savings		$175 million	Assumes $20/MWh is avoided, see slide 52.
Annual Carbon Reduction		3 million tons	Assumes Combined Cycle Plant (350g per kWh), see slides 53 & 54.

Benefits of Increased Renewables - 2/7

GETs enable more than twice the amount of additional renewables to be integrated.

- 2,670 MW = 5,250 MW (With GETs Case) – 2,580 MW (Base Case)
- 2,670 MW = 2,630 MW (Wind) + 40 MW (Solar)
- GETs investment cost is around $90 million.

SUMMARY OF BENEFITS OF INCREMENTAL 2,670 MW OF RENEWABLES - 2/2

Renewables Benefits			Notes
Direct Jobs from Renewables	Short-term (Construction etc)	Over 11,300 person-year	See slide 55.
	Long-term (O&M etc)	Over 650 person-year	
Estimated Local Tax Revenues (Annual)		$32 million	
Estimated Land Lease Revenues (Annual)		$15 million	

- There are additional job benefits associated with the installation and operations of GETs.
  - 50 to 60 long-term jobs.
  - 20 to 30 short-term jobs (for installation).

Benefits of Increased Renewables - 3/7

GETs enable additional new renewables by: 2,670 MW / 8,776 GWh.

- 2,630 MW of Wind is assumed to produce over 8,640 GWh of energy per year.
  - Assumes 37.5% capacity factor for wind.
  - 2019 SPP State of the Market Report* shows wind producing roughly 74,000 GWh of power and SPP having 22,482 MW of wind at the end of 2019.
  - These figures conservatively suggest the realized average capacity factor of wind is 37.5% (after accounting for outages and curtailments).
  - In reality newer wind plants show higher capacity factors. SPP State of the Market Report shows real time capacity factors for wind in 2019 to be 39.4%.
- 40 MW of Solar is assumed to produce about 60 GWh of energy per year.
  - Assuming 18% capacity factor for solar.
- Curtailment of existing wind is reduced by more than 76 GWh a year.
  - Total increase in renewables generation enabled by GETs is 8,776 GWh.

* 2019 SPP State of the Market Report, available at: https://www.spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf

Benefits of Increased Renewables - 4/7

GETs enable additional 8,776 GWh of generation from renewables.

- Estimated annual production cost savings: **Over $175 million**.
  - Conservatively assumes $20/MWh savings for 8,776 GWh of energy.
  - Generation cost of a new natural gas-fueled combined cycle plants would be in the $20/MWh to $25/MWh range (assuming $2.5-3.0/MMBtu fuel cost and 7,000 Btu/kWh heat rate plus VOM).
  - Generation cost of coal plants would be in the $20/MWh to $25/MWh range (assuming $2/MMBtu fuel cost and 10,000 Btu/kWh heat rate plus VOM).
  - LMPs can be used as an indicator for the marginal cost of power. The SPP State of the Market Report shows 2019 day-ahead prices averaged around $22/MWh and real-time prices averaged around $21/MWh. 2018 average was $25/MWh for both.
  - This value does **NOT** include any Production Tax Credit-driven savings.
  - Pay-back for GETs investment ($90 million) is about half a year.

Benefits of Increased Renewables - 5/7

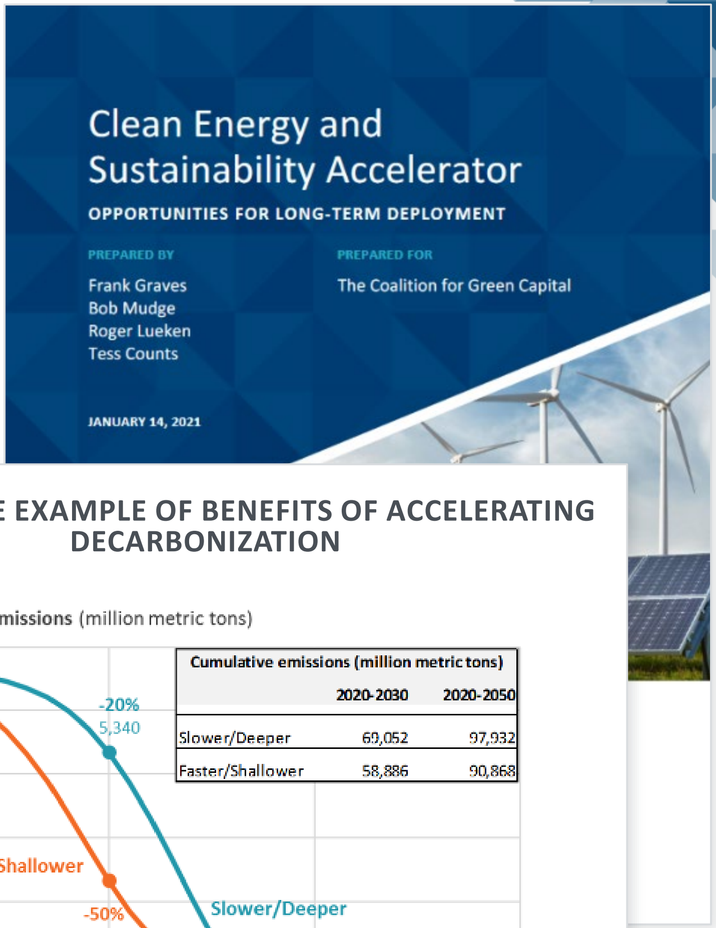
GETs enable additional 8,776 GWh of generation from renewables.

- Estimated carbon emissions reduction: **Over 3 million tons per year**.
  - Conservatively assumes the additional new renewables replace carbon emissions from natural gas-fueled combined cycle plants (with emission estimated to be 350g per kWh, or 0.8 pound per kWh).
  - Less efficient resources with higher heat rates and emission rates are more likely to be replaced. The average coal plant produces approximately twice the amount of carbon emissions, compared to a combined cycle plant. An average natural gas-fueled simple cycle gas turbine (a.k.a. peakers) produces approximately 20% to 30% more carbon emissions, compared to a combined cycle plant.
  - Additional benefits include **reduced water usage**. By enabling twice the amount of renewables to be integrated, reduction in water usage for power production is doubled.

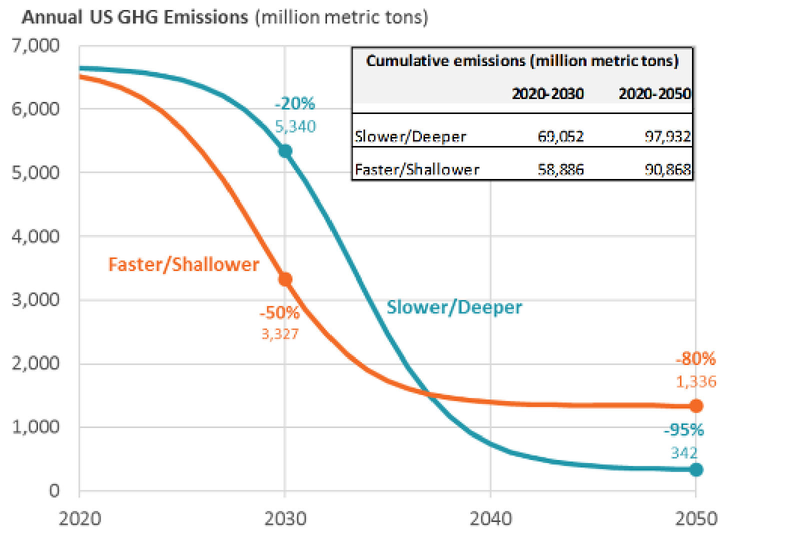
Benefits of Increased Renewables - 6/7

GETs, through enabling more renewables, is estimated to reduce carbon emission by over 3 million tons per year.

- Cumulative greenhouse gas (GHG) in the atmosphere is what causes warming, not the rate at which they are emitted in any given year (and they persist in the atmosphere for decades or longer).
  - Therefore, early reductions in GHG emissions are in many ways more important than eventual depth of reductions, because of the cumulative and persistent nature of GHGs in the atmosphere.
  - A recent whitepaper published by Brattle* illustrates how earlier adoption can lead to lower cumulative GHG emission (through 2050).
- Utilizing GETs could set an example for early adoption of existing technology to curb GHG emission.



ILLUSTRATIVE EXAMPLE OF BENEFITS OF ACCELERATING DECARBONIZATION

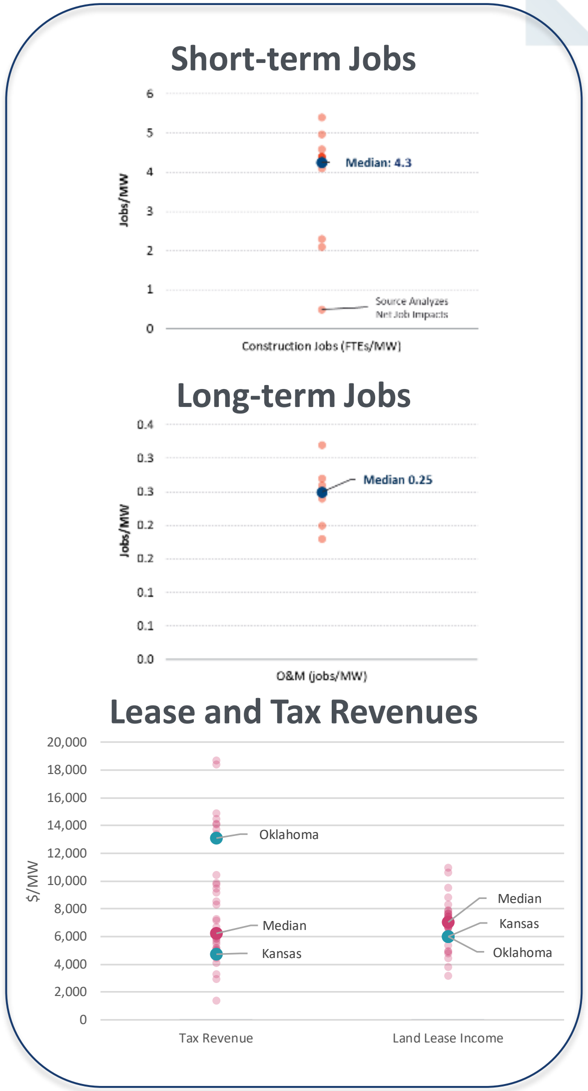


* Clean Energy and Sustainability Accelerator, available at: https://brattlefiles.blob.core.windows.net/files/20809_clean_energy_and_sustainability_accelerator.pdf

Benefits of Increased Renewables - 7/7

The additional 2,670 MW (2,430 in Oklahoma and 200 MW in Kansas) of renewables enabled by GETs will provide jobs and other local benefits.

- Over 11,300 direct short-term jobs (largely construction of renewables).
  - Assumes 4.3 jobs (person-year) / MW for wind and 1.3 jobs (person-year) / MW for solar.
- Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
  - Assumes 0.25 jobs (person-year) / MW for wind and 0.005 jobs (person-year) / MW for solar.
- Other estimated local benefits include over $32 million annual tax revenues and $15 million land lease revenues.
  - Tax revenues assumes $13,000/MW for the 2,430 MW in Oklahoma and $4,700/MW for the 200 MW in Kansas.
  - Land lease revenues assumes $5,900/MW for both Kansas and Oklahoma.



Summary of Benefits - 1/2

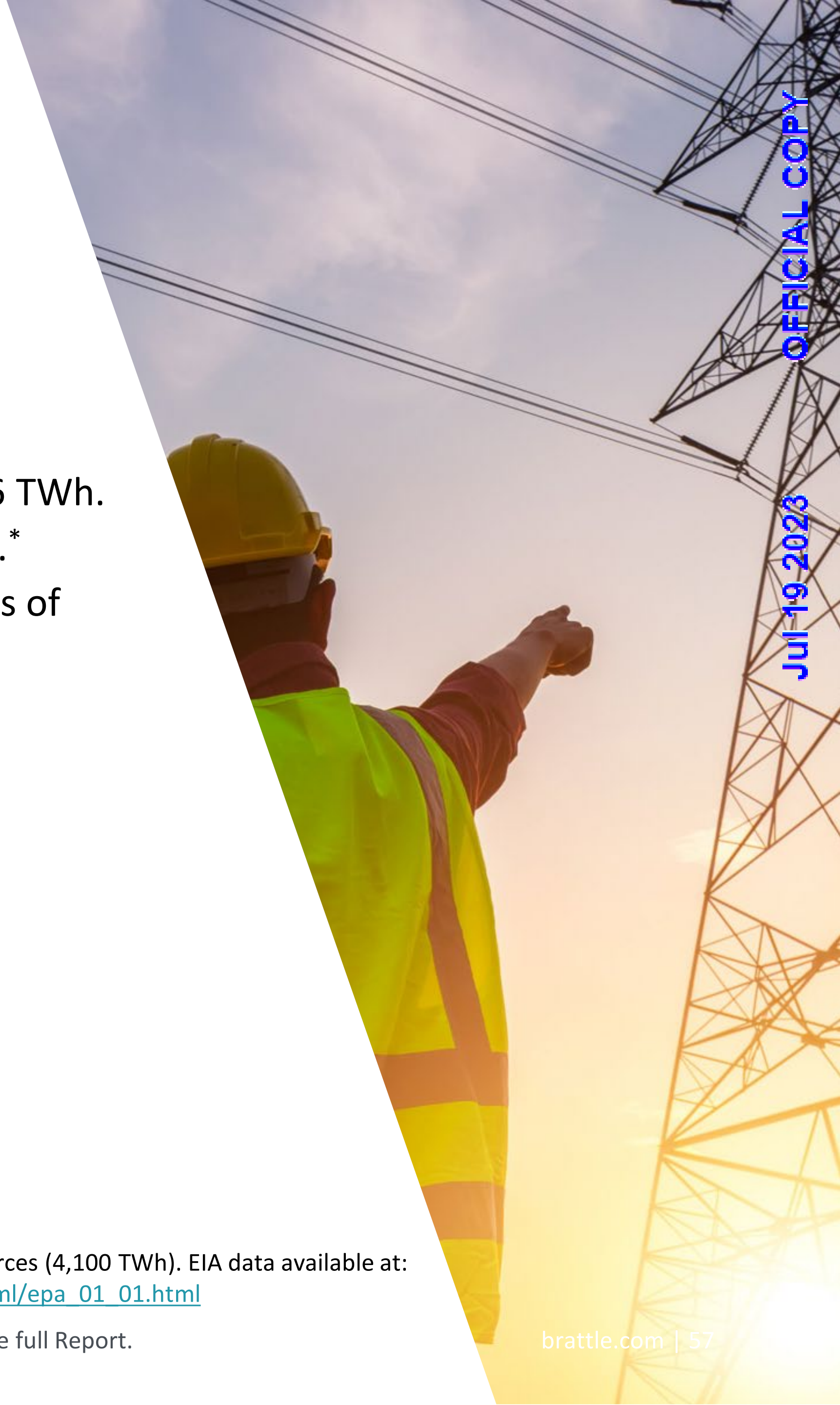
Key benefits of GETs for Kansas and Oklahoma

- Enable more than **twice** the amount of additional new renewables to be integrated.
  - This is 1.5x the amount of wind SPP integrated in 2019.
- Estimated annual production cost savings: **$175 million**.
  - This suggests the payback for GETs investment is about 0.5 years.
- Estimated carbon emissions reduction: **Over 3 million tons per year**.
- Other benefits include:
  - Over 11,300 direct short-term jobs (largely construction of renewables).
  - Over 650 direct long-term jobs for operation and maintenance of the renewable resources.
  - Over $32 million annual tax revenues.
  - Over $15 million land lease revenues.

Summary of Benefits - 2/2

- 2019 generation in Kansas and Oklahoma combined was about 136 TWh.*
- 8,700 GWh from the GETs enabled new renewable generation equates to 6.4% of 136 TWh.
- The nationwide generation from utility-scale resources in 2019 was about 4,100 TWh.*
- 6.4% of 4,100 TWh would equate to 260 TWh worth of clean power, or 90 million tons of carbon reduction assuming wind replaces natural gas burning CCs – the most clean conventional fossil-fuel based power generation technology.

- Over **$5 billion** (~$5.3 billion) in production cost savings.
- **$90 million tons** of reduced carbon emission.
  - More than enough to offset **all new automobiles** sold in the U.S. in a year.
- About **$1.5 billion** in local benefits (local taxes and land lease revenues).
- More than 330,000 short-term (only for first year) and nearly 20,000 long-term jobs.
- Investment cost is $2.7 billion (only for first year).
- Ongoing costs would be around $300 million per year.



* EIA shows 2019 generation in Kansas and Oklahoma combined (136 TWh) was about 1/30 of the nationwide generation from utility-scale resources (4,100 TWh). EIA data available at: https://www.eia.gov/electricity/state/kansas/, https://www.eia.gov/electricity/state/oklahoma/, and https://www.eia.gov/electricity/annual/html/epa_01_01.html

APPENDIX

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Glossary

AAR	Ambient Adjusted Ratings
DLR	Dynamic Line Ratings
FACTS	Flexible Alternating Current Transmission Systems
GETs	Grid-Enhancing Technologies
GHG	Greenhouse Gas
GI Queue	Generation Interconnection Queue
IA	Interconnection Agreement
ITP	Integrated Transmission Planning
LMP	Locational Marginal Price
PARs	Phase Angle Regulators
PSTs	Phase Shifting Transformers
SCOPF	Security Constrained Optimal Power Flow
SLR	Static Line Ratings
SPP	Southwest Power Pool

Potential Renewables from SPP GI Queue

Potential renewable generation projects selected from SPP's GI Queue.

Generation Interconnection Number	IFS Queue Number	Nearest Town or County	State	CA	Commercial Operation Date	Capacity	Generation Type	Substation or Line	Status
GEN-2010-005	0	Harper County	KS	WERE	12/31/2020	299.2	Wind	Viola 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-019	0	Woodward County	OK	OKGE	12/31/2020	175	Wind	Woodward EHV 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-020	0	Ellis	OK	OKGE	12/31/2020	165.6	Wind	Woodward EHV 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-013	IFS-2015-001-18	Kiowa County	OK	WFEC	12/1/2022	120	Solar	Snyder 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-029	IFS-2015-001-12	Dewey & Blaine County	OK	OKGE	12/1/2020	161	Wind	Tatonga 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-048	IFS-2015-002-11	Major County	OK	OKGE	10/1/2020	200	Wind	Cleo Corner 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-055	IFS-2015-002-25	Beckham County	OK	WFEC	12/1/2022	40	Solar	Erick 138kV Substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-062	IFS-2015-002-15	Garfield County	OK	OKGE	12/31/2021	4.5	Wind	Breckinridge 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-092	IFS-2015-002-36	Grady	OK	AEPW	12/31/2020	250	Wind	Lawton East Side-Sunnyside (Terry Road) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-093	IFS-2015-002-37	Caddo	OK	OKGE	12/31/2022	250	Wind	Gracemont 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-095	IFS-2016-001-20	Woods County	OK	OKGE	6/1/2020	176	Wind	Tap Mooreland - Knob Hill 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-003	IFS-2016-001-45	Ellis	OK	OKGE	8/31/2021	248.4	Wind	Badger-Woodward EHV Dbl Ckt 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-016	IFS-2016-001-07	Edwards	KS	MIDW	11/1/2021	78.2	Wind	North Kinsley 115 kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-030	IFS-2016-001-26	Johnston County	OK	OKGE	12/1/2021	100	Solar	Brown 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-032	IFS-2016-001-11	Kingfisher County	OK	OKGE	12/31/2023	200	Wind	Crescent Substation 138 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-045	IFS-2016-001-34	Cimarron, Texas County	OK	OKGE	12/31/2021	499.1	Wind	Mathewson 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-057	IFS-2016-001-35	Cimarron, Texas County	OK	OKGE	12/31/2021	499.1	Wind	Mathewson 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-071	IFS-2016-001-19	Kay	OK	OKGE	11/30/2021	200.1	Wind	Middleton Tap 138kV Substation	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-073	IFS-2016-001-48	Kingman County	KS	WERE	10/30/2022	220	Wind	Thistle-Wichita Dbl Ckt (Buffalo Flats) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-102	IFS-2016-002-01	Pontotoc	OK	OKGE	12/1/2023	150.9	Wind	Blue River 138kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-118	IFS-2016-002-05	Kingfisher	OK	WFEC	10/1/2021	288	Wind	Dover Switchyard 138 kV Line	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-126	IFS-2016-002-06	Murray	OK	OKGE	10/15/2021	172.5	Wind	Arbuckle 138kV substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-131	IFS-2016-002-37	Grady	OK	OKGE	10/31/2020	2.5	Wind	Minco 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-132	IFS-2016-002-61	Roger Mills	OK	AEPW	5/6/2020	6.1	Wind	Sweetwater 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-150	IFS-2016-002-15	Nemaha	KS	WERE	12/30/2022	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-157	IFS-2016-002-20	Allen County	KS	KCPL	12/31/2022	252	Wind	West Gardner 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-158	IFS-2016-002-17	Allen County	KS	KCPL	12/31/2022	252	Wind	West Gardner 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-174	IFS-2016-002-19	Nemaha	KS	WERE	11/6/2020	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-176	IFS-2016-002-67	Nemaha County	KS	WERE	11/30/2021	302	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-001	IFS-2014-001-08	Marion	KS	WERE	7/28/2020	200.6	Wind	Tap Wichita - Emporia Energy Center 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-034	IFS-2015-002-08	Kay County	OK	OKGE	10/31/2020	200	Wind	Rose Hill (Open Sky)-Sooner (Ranch Road) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-052	IFS-2015-002-03	Sumner	KS	WERE	12/1/2019	300	Wind	Open Sky-Rose Hill 345kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2015-066	IFS-2015-002-38	Roosevelt County	OK	OKGE	12/31/2022	248.4	Wind	Sooner - Cleveland 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-046	IFS-2016-001-12	Ford County	KS	SUNC	11/15/2021	299	Wind	Clark County-Ironwood 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-051	IFS-2016-001-13	Custer	OK	AEPW	12/31/2020	9.8	Wind	Clinton Junction-Weatherford Southeast 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-063	IFS-2016-001-17	Johnston	OK	OKGE	9/1/2021	200	Wind	Hugo-Sunnyside 345 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-091	IFS-2016-002-22	Caddo	OK	AEP	12/31/2021	303.6	Wind	Gracemont-Lawton East Side 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-036	IFS-2016-001-44	Johnston County	OK	OKGE	8/30/2020	303	Wind	Johnston County 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-082	IFS-2016-001-28	Beaver	OK	OKGE	12/1/2020	198	Wind	Beaver County - Woodward EHV Dbl Ckt (Badger) 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-020	IFS-2016-001-27	Woodward County	OK	WFEC	12/15/2020	148.4	Wind	Moreland 138kV Substation	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-068	IFS-2016-001-40	Garfield	OK	OKGE	10/21/2020	250	Wind	Woodring 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-149	IFS-2016-002-14	Washington	KS	WERE	12/31/2022	300	Wind	Stranger Creek 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-061	IFS-2016-001-15	Garfield/Noble	OK	OKGE	8/1/2020	248.16	Wind	Sooner-Woodring 345 kV line	IA FULLY EXECUTED/ON SCHEDULE
GEN-2017-009	0	Neoshoe County	KS	WERE	10/31/2020	302.5	Wind	Neosho - Caney River 345 kV	DISIS STAGE

List of Transmission Projects - 1/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (230 KV AND HIGHER)

Project Name	Project Type	Owner	Project Status	In-Service Date
Multi - Gentleman - Cherry Co. - Holt Co. 345 kV	Regional Reliability	NPPD	Delay - Mitigation	6/1/2022
XFR - Thedford 345/115 kV	High Priority	NPPD	Delay - Mitigation	5/1/2021
XFR - Wolfforth 230/115 kV Ckt 1 Transformer	Regional Reliability	SPS	On Schedule < 4	4/15/2021
Sub - Amarillo South 230 kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	4/1/2020
XFR - Sundown 230/115 kV Transformer	Regional Reliability	SPS	Delay - Mitigation	12/15/2020
Multi - Tuco - Yoakum 345/230 kV Ckt 1	Regional Reliability	SPS	Delay - Mitigation	6/1/2020
Sub - Nichols - 230 kV	Regional Reliability	SPS	Delay - Mitigation	5/15/2020
Multi - Sheldon - Monolith 115 kV	Regional Reliability	NPPD	Delay - Mitigation	1/1/2021
XFR - Lawrence Hill 230/115kV	Regional Reliability	WR	Delay - Mitigation	6/1/2021
XFR - McDowell 230/115 kV Ckt 1	Regional Reliability	SPS	Delay - Mitigation	5/28/2021
Multi - China Draw - Road Runner 345 kV	Regional Reliability	SPS	Delay - Mitigation	11/15/2021
Line - Eddy County - Kiowa 345 kV New Line	Regional Reliability	SPS	On Schedule < 4	11/15/2020
Multi - S1361	Regional Reliability	OPPD	On Schedule < 4	6/1/2021
Multi - Cimarron - Northwest - Mathewson 345kV	Economic	OGE	On Schedule < 4	7/1/2020
Multi - Neset - New Town 230 kV	Regional Reliability	BEPC	Re-evaluation	12/31/2022
Sub - Neosho 345 kV	Sponsored Upgrade	WR	On Schedule < 4	7/1/2020

List of Transmission Projects - 2/4

Transmission projects that are planned to be in service by 2025 are selected from SPP's 2019 Integrated Transmission Planning (ITP) Assessment Report.

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (138 KV AND 169 KV)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Cedar Grove - South Shreveport 138 kV	Transmission Service	AEP	On Schedule < 4	6/1/2020
Line - Keystone Dam - Wekiwa 138 kV Ckt 1 Rebuild	Regional Reliability	AEP	On Schedule < 4	6/1/2021
Line - Lincoln - Meeker 138 kV Ckt 1 New Line	Regional Reliability	OGE	Delay - Mitigation	7/31/2020
Multi - Driftwood 138/69 kV Substation and Transformer	Regional Reliability	WFEC	Delay - Mitigation	4/1/2022
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV	Regional Reliability	WFEC	Delay - Mitigation	12/1/2024
Sub - Cleo Junction 138 kV Terminal Upgrades	Regional Reliability	WFEC	Delay - Mitigation	5/31/2023
Line - Crosstown - Blue Valley 161 kV New Line	Regional Reliability	KCPL	Re-evaluation	6/30/2023
Sub - Tupelo - Tupelo Tap 138 kV Terminal Upgrades	Economic	WFEC	Delay - Mitigation	12/31/2020
XFR - Creswell 138/69/13.2 kV Transformers	Regional Reliability	WR	On Schedule < 4	6/1/2021
Multi - Park Community - Sunshine 138 kV	Regional Reliability	WFEC	Delay - Mitigation	5/31/2021
Line - Cogar - OU SW 138 kV	Regional Reliability	WFEC	Delay - Mitigation	3/1/2024
Sub - Westmoore 138 kV	Regional Reliability	OGE	On Schedule < 4	12/31/2020
Sub - Santa Fe 138 kV	Regional Reliability	OGE	Re-evaluation	6/1/2021
Sub - Riverside Station 138 kV	Regional Reliability	AEP	Delay - Mitigation	11/1/2022
Sub - Southwestern Station 138 kV	Regional Reliability	AEP	Delay - Mitigation	11/1/2022
Sub - Moore 13.8 kV Breaker	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Sub - Craig 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2021
Sub - Leeds 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2020
Sub - Southtown 161 kV	Regional Reliability	KCPL	On Schedule < 4	12/31/2021
Sub - Mooreland 138/69 kV Breakers	Regional Reliability	WFEC	On Schedule < 4	5/1/2022
Line - Tulsa SE - S Hudson 138kV Ckt 1	Regional Reliability	AEP	Delay - Mitigation	11/1/2021
Line - Tulsa SE - 21st Street Tap 138kV Ckt 1	Regional Reliability	AEP	Delay - Mitigation	11/1/2021
Line - East Kingfisher - Kingfisher 138kV	Economic	WFEC	On Schedule < 4	1/1/2021
Line - Neosho - Riverton 161 kV	Transmission Service	EDE	NTC-C Project Estimate	10/1/2023
XFR - Pryor Junction 138/115	Regional Reliability	AEP	Delay - Mitigation	11/30/2021
Line - Anadarko - Gracemont 138kV	Economic	WFEC	On Schedule < 4	1/1/2021
Jayhawk Wind 161/69kV Transformer	Sponsored Upgrade	Apex		12/31/2021

List of Transmission Projects - 3/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (115 KV)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Northwest - Rolling Hills 115 kV Ckt 1	Regional Reliability	SPS	On Schedule < 4	5/15/2021
Line - Ainsworth - Ainsworth Wind 115 kV Ckt 1 Rebuild	Regional Reliability	NPPD	On Schedule < 4	6/1/2020
Sub - Carlsbad - Pecos 115 kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Carlisle - Murphy 115kV Terminal Upgrades	Regional Reliability	SPS	On Schedule < 4	6/1/2022
Sub - Carlsbad Interchange 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Hale Cty Interchange 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Denver City Interchange 115 kV North	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Sub - Canaday 115 kV	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Sub - Hastings 115 kV	Regional Reliability	NPPD	On Schedule < 4	6/1/2021
Multi - Marshall County - Smittyville - Baileyville - South Seneca 115 kV	Regional Reliability	WR	Delay - Mitigation	6/1/2023
Sub - Firth 115kV	Regional Reliability	NPPD	Delay - Mitigation	6/1/2023
Sub - Amoco - Sundown 115 kV	Economic	SPS	On Schedule < 4	6/1/2020
Line - Hansford - Spearman 115kV	Economic	SPS	On Schedule < 4	1/1/2021
Multi-Hobbs Interchange-Millen 115kV	Regional Reliability	SPS	On Schedule < 4	6/1/2022
Sub - Denver City Interchange South 115 kV	Regional Reliability	SPS	On Schedule < 4	6/1/2021
Line - Aberdeen City - Aberdeen Industrial Park 115 kV	Sponsored Upgrade	NWE	On Schedule < 4	12/31/2021

List of Transmission Projects - 4/4

PLANNED TRANSMISSION PROJECTS FROM 2019 ITP FOR 2020-2025 (69 KV AND LOWER)

Project Name	Project Type	Owner	Project Status	In-Service Date
Line - Elmore - Paoli 69 kV Rebuild	Regional Reliability	WFEC	Delay - Mitigation	3/1/2022
Line - Sara Road - Sunshine Canyon 69 kV Ckt 1 Rebuild	Regional Reliability	WFEC	Delay - Mitigation	12/31/2019
Device - S964 69 kV Cap Bank	Regional Reliability	OPPD	On Schedule < 4	6/1/2020
Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City	Zonal Reliability	AEP	Delay - Mitigation	11/20/2020
Line - City of Winfield - Oak 69 kV Reconductor	Regional Reliability	KPP	On Schedule < 4	12/30/2020
Device - Dover SW 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	9/1/2023
Device - Cherokee SW 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	8/1/2023
Device - Clear Creek Tap 69 kV Cap Bank	Regional Reliability	WFEC	Delay - Mitigation	12/1/2020
Sub - Washita 69 kV	Regional Reliability	WFEC	On Schedule < 4	6/1/2021
Device- Gypsum 69 kV Capacitor Bank	Regional Reliability	WFEC	On Schedule < 4	6/1/2021
Sub - Cleo Corner - Cleo Junction 69kV	Regional Reliability	OGE	On Schedule < 4	6/1/2022
SUB - Marietta - Rocky Point 69 kV	Regional Reliability	WFEC	On Schedule < 4	12/1/2021
SUB - Forest Hill 69 kV Terminal Upgrades	Regional Reliability	OGE	On Schedule < 4	1/1/2021
DPNS-2019-March-1011 Shell Rock and Bauman Substation	Regional Reliability	CBPC	NTC - Commitment	6/1/2020

Review of Public Reports - 1/2

Adding more renewables produces jobs.

- Various (14) public reports were reviewed to estimating the jobs and other economic benefits of wind development (out of 11 had useful information).

11 STUDIES ON THE ECONOMIC BENEFITS OF WIND DEVELOPMENT

Study	Region
Aldieri et. al, Wind Power and Job Creation, 2019	U.S. and other countries
AWEA, Wind Powers America Annual Report, 2019	Nationwide
Brattle, Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region, 2010	SPP
EIG, Statewide Economic Impact of Wind Energy Development in Oklahoma, 2014	Oklahoma
NREL, Economic Impacts from Wind Energy in Colorado Case Study, 2019	Rush Creek Wind Farm, Colorado
NREL, Economic Development Impact of 1,000 MW of Wind Energy in Texas, 2011	Texas
NREL, Economic Impacts from Indiana's First 1,000 MW of Wind Power, 2014	Indiana
NREL, Estimated Economic Impacts of Utility Scale Win Power in Iowa, 2013	Iowa
NREL, Jobs and Economic Development from New Transmission and Generation in Wyoming, 2011	Wyoming
UC Berkeley, Job Impacts of California's Existing and Proposed RPS, 2015	California
USDA, Ex-Post Analysis of Economic Impacts from Wind Power Development in U.S. Counties, 2012	Great Plains and Rocky Mountains

Note: Three additional studies reviewed (whose data was not directly applicable to the analysis) are: NREL, Analysis of the Renewable Energy Projects Supported by 1603 Treasury Grant Program, 2012; NYSERDA, New York Clean Energy Industry Report, 2019; and NREL, Counting Jobs and Economic Impacts From Distributed Wind in the United States, 2014.

Review of Public Reports - 2/2

Adding more renewables produces additional local benefits.

- Various (7) public reports were reviewed specifically to estimate the other economic benefits (tax and lease revenue) of wind development.

7 STUDIES ON THE ECONOMIC BENEFITS OF WIND DEVELOPMENT

Study	Region
EIG, Statewide Economic Impact of Wind Energy Development in Oklahoma, 2014	Oklahoma
NREL, Economic Impacts from Wind Energy in Colorado Case Study, 2019	Rush Creek Wind Farm, Colorado
NREL, Economic Development Impact of 1,000 MW of Wind Energy in Texas, 2011	Texas
NREL, Economic Impacts from Indiana’s First 1,000 MW of Wind Power, 2014	Indiana
NREL, Estimated Economic Impacts of Utility Scale Win Power in Iowa, 2013	Iowa
NREL, Jobs and Economic Development from New Transmission and Generation in Wyoming, 2011	Wyoming
Wind Powers America Annual Report, 2019	USA state-level data

Note: The WPA annual report contained data for each state. All other sources report values from a single project.

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Clarity in the face of complexity

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AGO Burgess Exhibit 3

UTILITY DIVE

OPINION

Tapping into DOE's $250B of loan authority for projects that reinvest in US clean energy infrastructure

DOE recently released program guidance for its Title 17 Clean Energy Financing Program, including how it will support projects that reinvest in U.S. energy infrastructure for the clean energy future.

Published July 6, 2023

By Jigar Shah

bombermoon via Getty Images

Jigar Shah is the director of the Loan Programs Office at the U.S. Department of Energy.

The United States has a massive fleet of existing and legacy energy infrastructure. To meet the nation's climate goals and support communities with energy-based economies, we must reinvest in that infrastructure and skilled workforce to build our clean energy future. Now, the federal government has up to $250 billion to do just that.

Through the Energy Infrastructure Reinvestment (EIR) category of the Title 17 Clean Energy Financing Program, the Department of Energy Loan Programs Office (LPO) can provide low-cost debt financing for large-scale energy infrastructure projects that retool, repower, repurpose or replace existing or legacy infrastructure, or that help operating energy infrastructure prepare for a cleaner future by making new investments to avoid, reduce, utilize or sequester air pollutants, including greenhouse gas emissions.

EIR is as vast as utilities' needs and domains and includes financing for investments in operating systems as well as retired assets. The program is technology-agnostic, meaning LPO can finance entire Integrated Resource Plans as long as they relate to existing or legacy infrastructure.

Potential projects are wide-ranging. They may include replacing retired infrastructure with nuclear energy or renewables with or without storage, leveraging existing interconnections, repurposing pipelines, retrofitting power plants, reconductoring transmission lines, repowering legacy nuclear or hydro plants, and more. The program may also finance environmental remediation at brownfield sites to accompany site redevelopment.

Here are just a few examples of projects that could be eligible for EIR financing.

- **Fossil replacement with solar and storage:** An independent power producer owns the site of a 300-MW coal-fired power plant that has ceased operations. The plant has been demolished, but the interconnection and road infrastructure remain. The company plans to reuse the site and repurpose the existing interconnection to build 30 MW of solar and 250 MW of 4-hour battery storage. The project is eligible for, and the company is exploring, relevant federal Investment Tax Credits. The company has developed a plan to retrain and provide new employment opportunities for plant employees. The company is seeking a loan guaranteed by LPO to support construction of the solar and storage, which will be repaid through a combination of tax credits and revenue from the new solar-plus-storage facility. A portion of the loan will also be used to finance the remediation of several on-site coal ash ponds.

- **Transition to nuclear:** A utility plans to install a small modular reactor on the site of a retired coal-fired power plant. The SMR's 300-MW electric generation capacity is similar to that of the retired coal plant, therefore making it well-suited for reusing the existing grid interconnection. Several balance-of-plant systems, such as the plant makeup water and water storage systems, cooling towers, and chemical stores from the coal plant can be repurposed for use with an SMR. The SMR has the potential to benefit from the existing pool of skilled workers able to transition from their prior employment at the coal plant. Further cost savings include avoiding land acquisition costs for the SMR, utilizing rail and road infrastructure, and having an existing water source. The SMR design has been certified by the U.S. Nuclear Regulatory Commission, and the utility's plans have received state regulatory approval. The utility is seeking a loan guaranteed by LPO to finance the construction of the SMR, with repayment assured through a long-term power purchase agreement and the regulatory approval for cost recovery via customer rate base.

- **Power plant replacement with an energy-related industrial facility:** A private developer has purchased the site of a retired gas-fired power plant and plans to repurpose the site through the construction of several large, clean energy manufacturing facilities. The developer has identified the existing electrical, pipeline, rail and road infrastructure as attractive assets that will accelerate and simplify site conversion. The manufacturing facilities will create numerous construction and permanent jobs. The developer is working closely with the local community and labor organizations.

- **Transmission reconductoring:** A utility plans to upgrade several high-voltage transmission lines through reconductoring. The utility estimates that replacing the conductive core of older

> transmission lines will double the electricity carrying capacity compared to the existing conductors, while reducing line losses by up to 50%. The reconductoring plan will retool the existing towers and utilize established rights-of-way. This investment will significantly increase the utility's ability to interconnect new clean energy generation without requiring the time and expense associated with the permitting and construction of new transmission lines. The reconductoring plan has received regulatory approval for cost recovery, which LPO considers sufficient to ensure reasonable prospect of repayment on the loan.

LPO looks forward discussing whether our low-cost debt can support your organization's reinvestment in energy infrastructure. We'll need to begin these conversations soon. Conditional commitments (agreed upon term sheets with stipulations the borrower must meet before financial close) must be made by Sept. 30, 2026, for loan disbursements available through Sept. 30, 2031.

If you'd like to learn more about how LPO can support some or all of your IRP, please request a pre-application consultation to get connected with a member of our team.

AGO Burgess Exhibit 4

Duke Energy Carolinas
Response to
Attorney General's Office
Data Request No. 2

Docket No. E-7, Sub 1276

Date of Request: June 6, 2023
Date of Response: June 16, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to AGO Data Request No. 2-1, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to AGO under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolina

Request:

1. Refer to the Direct Testimony of Daniel Maley (Maley Direct).
    a. Please explain whether Duke Energy Carolinas (DEC) considered including any investments in Grid Enhancing Technologies (GETs) in the transmission portion of its MYRP. This includes technologies such as Dynamic Line Ratings, Advanced Power Flow Control, Topology Optimization, or other approaches (outside of traditional equipment) that can increase the real-time transfer capacity of the transmission network.
    b. Please provide any studies or analyses (including cost-benefit analyses) Duke performed to determine whether GETs investments should be included in the MYRP to improve the performance of existing lines or new projects planned for the MYRP period.
    c. If such studies were not performed, please explain why not.

Response:

Duke Energy considers a variety of investment alternatives when developing solutions to reliability concerns. Generally, investments that add to system resiliency and have well understood as low reliability risks are preferred in meeting expectations to achieve least cost planning objectives. Alternative investments to new transmission infrastructure (line, transformer, station) that are local impact in nature are preferred to avoid concerns with mis-operation or failure resulting in widespread impacts as well. Traditional solutions include:

- Line upgrade
- Redispatch
- Additional transformer capacity
- Ancillary equipment upgrade
- Capacitor addition
- Topology configuration change
- Improve line clearance
- Allowable Load shed – DCC (distribution control center)
- Allowable Load shed – ECC (transmission control center)
- Relay scheme – non-RAS (e.g., additional overcurrent)
- Redundant bus differential protection
- Redundant transformer differential protection
- Generator Runback
- Series bus junction (bus tie) breaker
- Series station
- Shift load on transmission or distribution

GETs that Duke Energy has utilized and/or considers when evaluating potential investments include:

- Phase shifting transformers
- High Temperature Wire
- Variable/Switched/fixed reactors
- Automated topology management/automated power flow controls (may be considered similar to RAS or phase shifters but broader applications)
- Remedial Action Schemes (RAS)
- Battery Energy Storage Systems
- Dynamic Line Rating Monitoring
- Synchronous Condenser
- Static Var Compensator
- Static Synchronous Compensator

DEC considered but did not formally study GETs for the projects included in the MYRP. In most instances, the nature of the system concerns, such as frequency of contingent events, risk to the system, and cost allows for use of engineering judgment to eliminate many of the alternatives. For instance, FERC Order 881 directs utilities to implement Ambient Adjusted Ratings, for which DEC is working on reaching compliance by the FERC deadline. DEC may consider Dynamic Line Ratings in the future but considers their use as a short-term corrective action to allow time for permanent infrastructure improvements. DLRs are difficult to implement accurately as it is impossible to predict future ambient conditions at all points along a transmission line.

Advanced Power Flow Control devices attempt to force power flows from one transmission path to another. These devices are typically expensive, complex, and delay, but don’t eliminate, traditional upgrades. Topology Optimization is still in its infancy and is currently focused on real-time or short-term planning applications. It generally involves radializing network lines, which exposes more customers to outage risk. Their widespread use may impose additional unknown risk to the system by placing it more often in conditions outside those previously studied and well understood by operators.

Duke Energy Carolinas
Response to
Attorney General's Office
Data Request No. 2

Docket No. E-7, Sub 1276

Date of Request: June 6, 2023
Date of Response: June 16, 2023

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☒ **NOT CONFIDENTIAL**

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The attached response to AGO Data Request No. 2-3, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to AGO under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolina

Request:

3. Refer to the transmission projects identified in Maley Direct, Exhibit 2.
   a. Please identify which, if any, of the projects in Exhibit 2 are designed to increase import/export capability with neighboring balancing areas (BAs).
      i. Please provide the costs associated with the projects identified to improve the import/export capability.
   b. Please provide any studies or analyses DEC has conducted to identify specific elements on DEC's transmission system that are binding in terms of the import/export limits for each interchange with neighboring BAs. Please provide a list of the limiting elements for each interchange.
   c. Please provide any analysis Duke has performed to determine how much the import/export constraints could be increased if the limiting elements were upgraded.
      1) Please explain whether any of these interchange limits was a factor contributing to the loss of imports from PJM to DEC during the December 2022 outages.

Response:

a. None of the Capacity & Customer Planning projects in Exhibit 2 are designed to increase import/export capability with neighboring balancing areas (BAs). The projects in Exhibit 2 are those necessary to meet new and existing customer needs, NERC TPL requirements, and generation resources assumed in the Carbon Plan to reliably serve DEC BA load.
i. NA

b. DEC evaluates long-term Transmission Service Requests (TSRs) as they are received. No limits to requested DEC imports or exports have been identified in recent requests.

c. N/A - DEC's transmission planning practice is to initiate transmission upgrades in response to firm Transmission Service Requests but not proactively to increase available transfer capability.
1. No interchange limits or other transmission issues contributed to the loss of imports from PJM to DEC during the December 2022 outages. Curtailment of DEC/DEP imports from PJM were the result of PJM generation failures and associated emergency procedures, not transmission issues. Reference PJM presentation PJM Winter Storm Elliott Overview for OC (https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230112/item-02---overview-of-winter-storm-elliott-weather-event.ashx) .

CERTIFICATE OF SERVICE

The undersigned certifies that they have served a copy of the foregoing DIRECT TESTIMONY OF EDWARD BURGESS ON BEHALF OF THE ATTORNEY GENERAL'S OFFICE upon the parties of record in this proceeding by email.

This the 19th day of July, 2023.

/s/ Tirrill Moore
Tirrill Moore
Assistant Attorney General

/s/ Derrick C. Mertz
Derrick C. Mertz
Special Deputy Attorney General