Informing the **Transmission Discussion**

A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States

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WIRES

Challenges and Policy Implications

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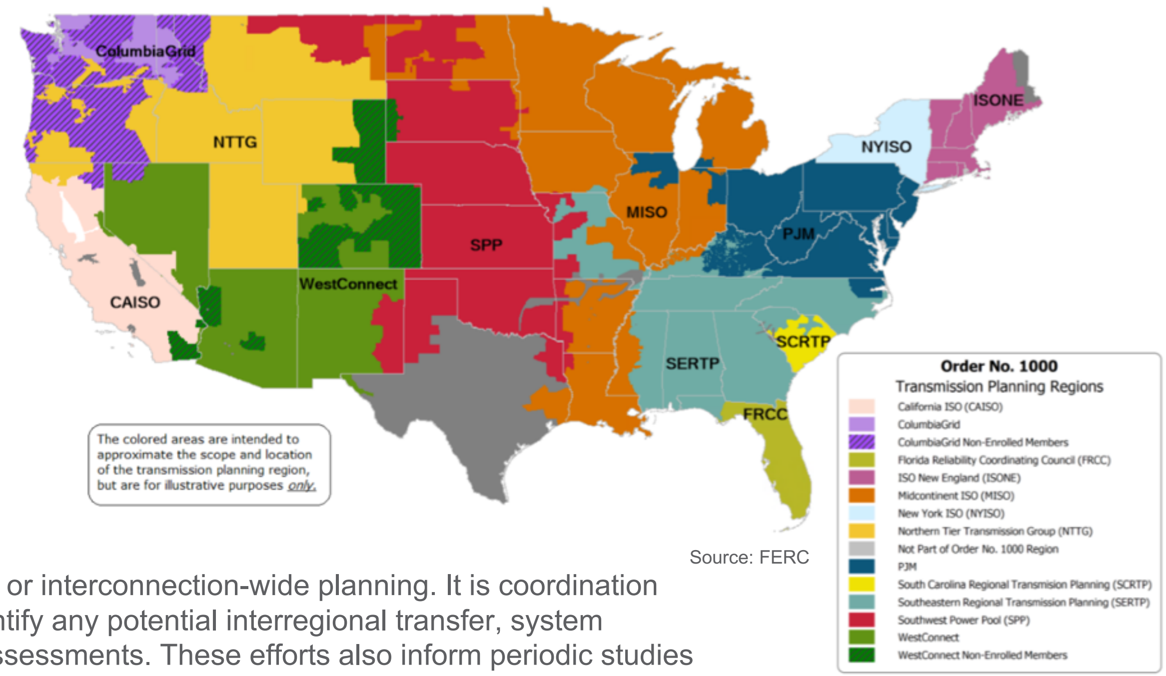
Interregional Planning and Cost Allocation

- **Balkanization**: The balkanized history of the North American grid has historically been accompanied by coordinated but independent planning of the transmission system. Regions can have very different industry structures, with some dominated by vertically integrated utility systems which seek to optimize transmission investment while serving customers with their own generation resources. Other regions, specifically RTOs and ISOs, have planning processes that yield periodic, multi-year transmission expansion plans, with significant amounts of stakeholder involvement.
- **Role of Order 1000**: Order 1000, promulgated in 2011, provided specific requirements for (1) regional transmission planning; (2) consideration of transmission needs driven by public policy requirements; (3) non-incumbent transmission development; (4) interregional transmission coordination; and (5) cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation. Interregional coordination occurs on an interconnection-wide basis, through each of the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee and the Eastern Interconnection Planning Collaborative (DOE Transmission Data Review, at p. 79).

FERC Order 1000 Transmission Planning Regions



Source: FERC

- **Interregional planning approach:** Interregional planning is not integrated multi-regional or interconnection-wide planning. It is coordination focused on stitching together regional transmission plans into “roll-up reports,” which identify any potential interregional transfer, system overload, or other issues that could impact reliability, supplementing regional reliability assessments. These efforts also inform periodic studies of interregional seams. The horizon for these reviews is over a planning horizon of 5 to 10 years (see EIPC State of the Eastern Interconnection). While these coordination efforts consider long-term changes in the resource mix, they are not focused on optimizing the cost-effectiveness of public policy requirements (e.g., renewable and clean energy mandates) or deliverability of those resources. Planning for those priorities is left to the regions.

Sources: FERC Order 1000; DOE Transmission Data Review; EIPC State of the Eastern Interconnection

Interregional Planning and Cost Allocation (Cont'd)

- **Shortcomings of current interregional planning construct:** When compared to implementation of the regional planning processes under Order No. 1000, interregional planning processes are in their infancy and remain incomplete. Order 1000 was intended to resolve a number of transmission development issues, including improving interregional planning. But challenges remain to achieving the investment in large-scale transmission envisioned by the FERC when it promulgated that order. The general view across the industry is that interregional planning processes are at best, stalled, and at worst, ineffective in identifying valuable projects. Some of this can be attributed to the level of effort that has been required of planners to implement transmission planning and cost allocation within their own regions, leaving limited time to focus on addressing issues with interregional processes. As recently noted by AWEA, "FERC Order 1000 was a well-intentioned attempt to fix two of the main obstacles holding back transmission investment, barriers to planning and paying for regional and inter-regional transmission. However, unintended consequences and lackluster implementation, particularly for inter-regional transmission, have left all sides unhappy" (Grid Vision, at p. 71).
- **Some planning issues:** Several of the issues that have limited the effectiveness of interregional planning include:
  - Voltage level or project size restrictions: Some interregional planning processes exclude upgrades below a specific project size or voltage-level threshold, resulting in some beneficial projects not being considered. For instance, the MISO and SPP interregional planning process does not include projects under 345 kV. MISO recently noted that of the 300 current interconnections between these two RTOs, only 12 are at or above 345 kV.
  - Project type restrictions: Interregional planning processes allow only for the evaluation of projects that address an identical need in both regions. For example, an interregional project meeting a reliability need in MISO but not meeting a reliability need in PJM cannot be considered, even if providing some other benefit (e.g., public policy, market effectiveness) in PJM.
  - Multiple benefit-to-cost ratios: In some interregional planning processes, projects have faced a "triple hurdle" in that they have to meet an interregional benefit-to-cost ratio and meet internal benefit-to-cost standards of each of the two regions involved. Some of those (SPP/MISO; MISO/PJM) hurdles have been relieved, although different planning parameters and cost-benefit approaches between regions remain.
- **Possible scale mismatches:** Not peculiar to, but relevant to, interregional planning for increasing amounts of utility-scale wind and solar resources is the difference in scale between those projects and investment in the transmission system. Historically, resource development occurred in relatively large increments—hundreds or thousands of megawatts—near load centers. Wind and solar resources are location specific based upon the resource. In addition, as noted earlier, the increment of addition in capacity terms of solar and wind farms are most often in the tens to hundreds of megawatts, while high-voltage transmission lines are "often most efficiently constructed at scales designed to serve a gigawatt of capacity or more" (MIT Future of the Grid, at p. 96). This can mean that large-scale projects may be deferred until a critical mass of renewable facilities can cost-effectively interconnect.

Sources: Grid Vision; ScottMadden; "FERC Order 1000: Five Years On" (June 2016); MIT Future of the Grid; WIRES/Brattle Planning Paper

Interregional Planning and Cost Allocation (Cont'd)

- **Cost allocation principles:** Cost allocation is an issue for interregional transmission projects. The cost of the lines crossing regional borders are typically divided between regions on a project by project basis. However, as most of the cost is recovered from network usage charges, the efficiency and fairness of transmission cost allocation become critical issues. Order 1000 requires that costs should be allocated in a way that is roughly commensurate with estimated benefits. This contrasts with cost "socialization" where all transmission users cover total costs on a pro rata basis. Order 1000 goes further, noting that a planning process may consider benefits including "the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestions relief, and/or meeting Public Policy Requirements [such as renewable portfolio standards]...." (FERC Order 1000, at p. 421)
- **Challenges in identifying and allocating benefits:** However, effective implementation of these principles has proven challenging. As one analysis has noted, "[I]dentifying who benefits from transmission services and by how much is an analytically complex task in power systems planning and operation. The expansion of interregional transmission capacity and subsequent exchange of energy produce differentiated distributional effects in each region, independently of whether a new tie line creates an aggregated net benefit. These distributional effects create winners and losers at each side of the transmission tie lines, which may create opposition to the projects or simply threaten their sustainability, as each region needs to balance their own benefits and costs." (Prada & Ilic, at pp. 4–5) Further, the benefits of, for example, congestion relief may result in cost improvements or have positive resilience impacts that are difficult to disentangle and allocate between regions and beneficiaries.

When integrating renewables across long distances, issues of equity across states and regions, economic development. and political complications exacerbate an already difficult problem.

Sources: FERC Order 1000; Prada & Ilic

Resilience Planning and Cost

- **Traditional planning approach focuses on reliability, not resilience:** Traditional transmission planning processes are rightly focused on delivering an adequate level of reliability, that is, so the bulk electric system does not experience instability, uncontrolled separation, cascading, and collapse under normal operating conditions, and/or voltage when subject to predefined disturbances, and frequency and voltage are maintained within defined parameters under normal operating conditions and when subject to predefined disturbances. Typical planning accounts for N-1 contingencies and increasingly N-2+ parameters—the loss of one or more critical system components.
- **Ill-suited for resilience planning:** But as major weather disturbances, cyber-events, and other low-frequency, high-impact events threaten the electric grid, existing planning approaches show gaps. As NERC has noted, for less probable severe events, “bulk electric system owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the bulk electric system even if these events can result in cascading, uncontrolled separation, or voltage collapse. Less probable severe events would include, for example, losing an entire right of way due to a tornado, simultaneous or near simultaneous multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena.” (2019 State of Reliability, at p. 2)

Resilience vs. Reliability: Different Stakeholders, Cost-Bearers, Responsibilities, and Levels of Planning Maturity

Planning criteria	Well-established N-2 planning	Unspecified or incipient “black swan” planning
Scenarios considered	Stated contingencies	Unlikely/unknown contingencies beyond reliability planning
Primary focus	Prevention, protection, and risk mitigation	Critical infrastructure recovery; social stability
Potential value of event “insurance”	Estimable through system modeling	Difficult to ascertain; policy-driven
Costs borne by	Ratepayers	Taxpayers
Funded by	Utility capital expenditures	• Federal emergency funds • State infrastructure • Municipal, county government
First response responsibility	Utility	Government, community response
Stakeholder coordination	Utility, ISO led	Government led

There remains a planning gap between reliability and resilience. Transmission planners, operators, and owners continue to focus on reliability, including weather and fuel dependency, as those are most clearly actionable and related to electric infrastructure investment. Resilience has broader societal implications involving more stakeholders with government as a key facilitator. And its costs are more properly a societal decision. While transmission has an important role to play, it is only one piece of resilience preparation.

Sources: ScottMadden analysis; 2019 State of Reliability

Resilience Planning and Cost (Cont'd)

- **One approach to updating planning:** As WIRES and The Brattle Group noted in comments to FERC's resilience docket in May 2018, transmission planning should incorporate resilience considerations. Resilience can be a part of the evaluation of multi-value transmission projects (MVPs) as part of the transmission planning process as a complementary benefit. It touches upon each of the reliability, economic, and public policy objectives of MVPs. Resilience benefits could be quantified, expanding the range of potential outcomes or scenarios to incorporate more extreme scenarios (see WIRES/Brattle Resilience, at pp. 16–19).
- **North American Energy Resilience Model under development:** DOE is now engaged in an effort to develop a first-of-its-kind comprehensive resilience-modeling system to assess threats and consequences for the North American electric power systems, as well as associated dependencies on natural gas and other critical energy infrastructures (see NAERM, at p. 2). Threats to be considered include extreme weather and cyber, as well as next unknown "worst-case" threats, such as those potentially inflicted by nation-state actors. Planning objectives, potential investments, and cost-benefit trade-offs will be important outputs.
- **Some issues to address:** Some key issues for incorporating resilience into planning include the following:
  - Design criteria: How to design a resilient system—what are key design criteria and what level of resilience is needed—are important considerations. According to NIAC, there is no common agreement on the level of redundancy or resilience that should be built into critical utilities to lessen risks and impacts of a long-term catastrophic power outage. The council notes that without design basis guidance, "it is difficult for owners and operators to justify investments, receive regulatory approval, or even know what standards are realistic and sensible to build to." (NIAC, at p. 11) Scenario identification and testing may to be augmented to consider "black sky" or other events not envisioned for standard reliability planning. A related issue is the degree of uniformity those design criteria should have. Regional risks may differ, and so may design criteria.
  - Cost: Cost-effectiveness is also a consideration. Designing a system against any threat will be cost-prohibitive and unlikely to be supported by regulators and customers. How to balance cost against potential impacts and possible benefits remains a challenge. Indeed, planning and designing for graceful degradation and rapid recovery may be appropriate instead of hardening against all risks. Benefits will need to be considered; transmission enhancements to alleviate congestion or increase deliverability of resources may have resilience benefits and vice versa.
  - Cost Allocation: Who should pay is a critical question to answer in securing resilience for the transmission system. Resilience can be considered a "social good" given the reliance of key sectors on the power system for ongoing operations. Those include governmental agencies, critical infrastructure (communications, water, wastewater and sewage, natural gas, fuel processing and distribution), and financial institutions. All of these provide essential services necessary to sustain communities during a long-lived outage. While transmission capital investment is, with proper regulatory oversight, an important factor in fostering resilience, there is the question of whether transmission customers are the sole beneficiaries of resilience benefits or whether government or other sectors should pay some of the costs of resilience efforts.

Sources: WIRES/Brattle Resilience; NAERM; NIAC

Resilience Planning and Cost (Cont'd)

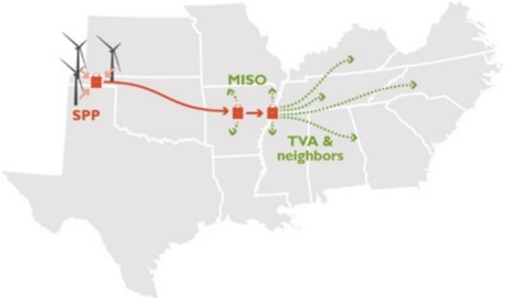
- **Some issues to address (cont'd)**
  - Incentives: How to provide incentives, or to de-risk resilience investments, is another important consideration for transmission owners. In its comments on FERC's Notice of Inquiry Regarding the Commission's Electric Transmission Incentives Policy, American Electric Power recommended that FERC establish an incentive for FERC-approved company-specific resilience and action plans. This, in its view, would encourage proactive grid resilience efforts that go beyond minimum reliability standards (AEP Filing, at pp. 13–20). This is one approach, but other approaches may be appropriate. Given the challenges of transmission development under normal planning assumptions, adding resilience, a much more diffuse and difficult to quantify benefit, to planning may require additional support.

In resilience planning, the balance between utility versus other infrastructure—government or non-utility—needs to be assessed and consideration given to "where the line should be" between those investments. Regional entities (utilities, ISOs/RTOs) should guide policymakers to discern between what utilities can do (and what it will cost) and what other entities should do. These questions will require mostly regional answers, based upon the nature of resilience threats.

Source: AEP Filing

Local Siting and Permitting Issues

- **Local opposition:** Large-capacity interregional projects are subject to federal, state, and local siting and permitting requirements before construction of facilities can commence. For some, intervenors in these processes are not satisfied with any project for any reason, even those which might improve regional access to lower emitting resources. Objections range from aesthetic or environmental impacts to lack of local benefits from a project to hostility to any eminent domain.
- **Multiple required approvals:** State authorizations for transmission projects largely hinge on determination of need, and state regulators often focus on in-state cost and benefits in approving projects and may be required to do so under state law. Determination of those costs and benefits may be subject to varying legal interpretations. There is a compounding effect with larger, longer proposed lines, as increasing numbers of state governmental and regulatory authorities and individual landowners become involved. In recent years, some large projects aimed at moving large-scale renewable resources between regions have been slowed or stopped due to state or local action (see right). Those projects were participant funded, that is, a proposed line was independently funded and not part of a regional transmission expansion plan.



**Example of Interregional Project Hurdles:
Plains & Eastern Clean Line Project**

- Clean Line Energy Partners proposed a large 700 mile, $2.2 billion, 3.5 GWs high-voltage DC line to extend from the Oklahoma and Texas panhandles eastward across Arkansas and into Tennessee. The Plains & Eastern project would have brought low-cost wind power eastward. The project was proposed in 2010.
- The DOE partnered with Clean Line on the project in March 2016, specifically in using federal powers of eminent domain to obtain rights of way for the line's route. The Trump administration in January 2018 included the line on its priority list for infrastructure projects.
- However, many local and tribal interests, especially in Arkansas, opposed the project.
- The DOE withdrew from its partnership in 2018, hampering further development. Clean Line has sold the Oklahoma portion of the project to renewables developer NextEra Energy.

This project illustrates that despite meaningful federal support, local issues remain significant barriers to large-scale interregional transmission development.

Sources: MIT Future of the Grid; QER2; Clean Line Energy Partners; industry news; RTO Insider

Local Siting and Permitting Issues (Cont'd)

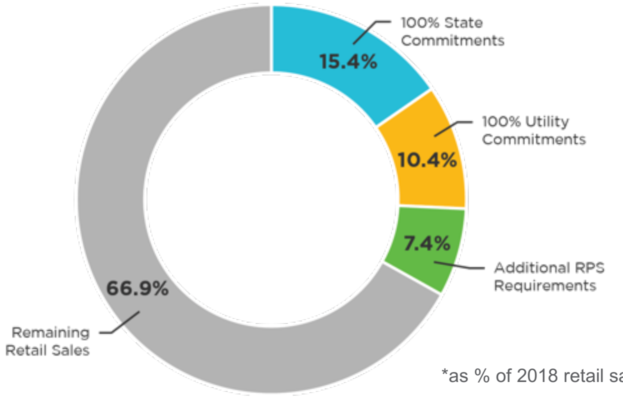
- **Strong policy support helps:** Successful projects have been characterized by strong policy support in the states that the facilities traverse. For example, Central Maine Power has proposed a $1.1 billion, 1,200 MWs high-voltage DC line, called New England Clean Energy Connect. The project is aimed at bringing hydro power from Quebec into New England, and particularly Massachusetts, which has ambitious clean energy goals. The project has been supported by Maine's governor and the Conservation Law Foundation and traverses only Maine, where it interconnects with existing 345 kV facilities.
- **FERC's backstop siting authority:** FERC's authority to overcome these local issues has not been exercised. Section 216 of the Energy Policy Act of 2005 contemplated the development of FERC's backstop siting authority, allowing for FERC to approve siting if a state "withheld approval" of a file application for more than a year. This authority could be invoked only if a proposed line was in a DOE-designated "corridor" facing transmission congestion "that adversely affects consumers." However, this authority has been challenged—both in what constitutes "withheld approval" as well as corridor designation—effectively neutralizing this authority. The DOE continues to assess congestion on a periodic basis, but it has yet to identify or reaffirm any corridors.

Sources: Industry news

Policy Implications

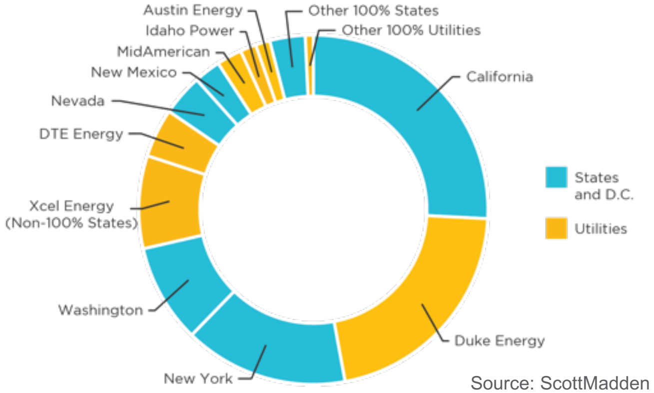
- **Historical issues persist:** The fact that transmission is needed across the country to support both reliability and integration of renewable resources is well-documented; the evolution of policy has not supported this basic understanding. Incentive policy, which drove significant investments through the 2000s is changing, and returns on equity and adders are being reduced. Order 1000 interregional processes have not materialized to facilitate broader integration across markets. The same cost-allocation challenges, which were once discussed at the regional level, have now moved to the interregional level, identifying beneficiaries and allocating costs appropriately, particularly across regions with different methodologies is challenging.
- **Need for forcing function:** Until a forcing function requires these regions to develop a methodology that facilitates largely public policy projects, the hope of interregional transmission meeting national needs for transmission (to serve any purpose, let alone clean energy) will remain elusive.
  - State and local policy continues to stymie transmission development through siting and permitting processes that are poorly aligned.
  - Environmental interests stack up on both sides of the transmission development debate. Some organizations acknowledge the degree to which transmission is needed to facilitate renewables integration. Others focus on the environmental impacts of specific corridors, slowing or stopping permitting and construction. There is also a view that DERs can offset the need for central station (utility-scale) generation and transmission.
  - Economic development always points to local resources serving local load; states are focusing on in-state resources to meet RPS and clean energy targets making the case for interregional collaboration more difficult.
- **Ground-up developments:** What has changed in the last two years or so is the degree to which states, utilities, and other companies are committing to 100% carbon free portfolios (see graphs at right). It is not possible to meet these goals without intraregional, and in some cases interregional, transmission connecting these resources to load. Myriad studies support the notion that higher penetrations of renewables are possible with significant transmission development; however, the balkanized nature of the grid makes the "highway" system approach to transmission unworkable.

100% Clean Energy Commitments and RPS Requirements*



*as % of 2018 retail sales

100% Clean Energy Commitments by State and Utility**



Source: ScottMadden analysis

Notes: 100% clean energy commitments often include renewable resources plus carbon free generation (e.g., nuclear, carbon capture, etc.). Only the state commitment is counted if both the state and an electric utility have 100% clean energy commitments. Data as of July 2019. *As % of 2018 retail sales. **Based on 2018 retail electricity sales.

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Policy Implications (Cont'd)

- **Intraregional for now:** This means that the regions are left to attempt to meet their own renewables goals with intraregional resources or to find a way to collaborate with their neighbors to further integrate resources and needs. Absent a framework, this is unlikely to happen.
- **Possible actions until a national framework emerges:** It is unclear whether the current political and policy environment will provide some kind of national framework for optimal clean, affordable, and resilient transmission grid. Assuming a national framework is not forthcoming in the near term, the following are some potential actions to advance needed investment:
  - FERC should step forward and begin to assess more proactive approaches to creating the framework for interregional collaboration in light of company, state, and regional goals related to clean energy. Cooperation between regions exists, especially where there are significant cross-seam flows (e.g., MISO/SPP, MISO/PJM). Building on those seams, processes may be an easier path to improving interregional processes.
  - There is an opportunity to reconsider the current trend in transmission incentives if there is a desire to have companies undertake these large interregional projects.
  - The myriad stakeholders focused on clean energy—market operators, labor, states, and clean energy advocates, among others—need to further articulate the critical role of transmission in facilitating company, state, and regional goals for clean energy. While environmental concerns about critical habitats and siting need to be acknowledged and managed, the role of high-voltage transmission in facilitating a transition to a cleaner fuel mix needs to be communicated, again and again. This communication can't come from utilities or transmission owners; this needs to originate with those advocating for aggressive carbon goals. The idea that DERs will either solve the clean energy challenge or ameliorate the need for more transmission needs to be revisited; while DERs may provide local benefits, they cannot replace utility-scale renewables in meeting clean energy objectives.
  - As utilities (like Xcel Energy) put forward clean energy and carbon free goals, they should also highlight the role that transmission plays in facilitating this transition.
- **Articulating network effects:** The network and other positive effects of transmission need to be more broadly understood and communicated. The current cost/benefit methodology for defining needs or articulating the benefits of transmission do not adequately account for the future uses of these facilities.
  - The network effects of previous projects should be communicated. For example, AEP's 765 kV transmission overlay, including its proposed Pioneer Transmission project, relieves congested lower-voltage lines, enhances reliability of the regional transmission system, improves operational and maintenance flexibility, offsets the need for smaller, incremental upgrades on lower-voltage lines, lowers costs by reducing congestion and system losses, and enables further development of new generation resources. Today's project built for reliability will facilitate transfers of "greener" power, but we can't necessarily articulate when and how much. Transmission should be viewed as a "no regrets" investment because it facilitates myriad future scenarios.

Policy Implications (Cont'd)

- **Aligning system needs with clean energy goals:** As regions and states develop and communicate clean energy goals, they should work with the RTO/ISO to understand the degree to which these goals must be facilitated by transmission. In its original announcement of its 50/30 clean energy goals, New York did not acknowledge this dependence on transmission causing a public debate between New York officials and the NYISO. This requires education and commitment to a collaborative process, even at the state level. Clean energy advocates, in addition to utilities, must also play a role in educating the needs to enhance grid capacity to facilitate large-scale development required by some state policies.

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