WHITEPAPER

RECENT EXPERIENCE WITH COMPETITIVE TRANSMISSION PROJECTS AND SOLICITATIONS

DATA: DEVELOPERS ADVOCATING TRANSMISSION ADVANCEMENTS

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Executive Summary

This whitepaper supplements prior work of the DATA Coalition by focusing on recent experiences with competitive solicitation processes and events associated with certain competitively bid projects in early phases of development. The whitepaper presents several recent case studies that are instructive regarding not only the ineffectiveness of Order No. 1000 competitive solicitations in lowering costs and increasing innovation, but also shows how processes introduced by Order No. 1000 are creating inefficiencies, uncertainty, and undermining collaboration in a way that ultimately weakens the delivery of cost-effective and reliable transmission service. These examples span PJM Interconnection, L.L.C. ("PJM"), New England, the California Independent System Operator Corporation ("CAISO"), and the Midcontinent Independent System Operator, Inc. ("MISO") demonstrate:

- The flawed nature of competitive bids and selection processes, which can fail to consider core elements of a project like the full cost of a selection decision or the feasibility of siting and routing proposals;

- That cost caps in competitive bids and awards continue to be illusory, and how "hard" cost caps are incompatible with the development challenges and commercial realities of electric transmission, while still being susceptible to renegotiation after the fact;

- How competitive processes can lead to project selection that fails to right-size the solutions identified, to select the most cost-effective, long-term solutions, and may be unable to consider how selection decisions could adversely affect the future ability of utilities to meet load serving obligations; and

- How Order No. 1000 policy has created the incentive for developers to relentlessly argue over the right to build projects, fostering uncertainty that is to the detriment of actual infrastructure development.

Taken together, these case studies further bolster the conclusion that the benefits the Federal Energy Regulatory Commission ("FERC" or "Commission") anticipated from requiring competitive transmission solicitations have failed to materialize. Instead, the policy has created a transmission planning and development environment that is troubled by litigation and administrative challenges, protracted solicitation processes and re-scoping of projects, and that has no demonstrated countervailing benefit to consumers. There remains no evidence that FERC's competitive transmission policy has improved the process of developing needed transmission infrastructure. Instead, there is an ever-growing body of evidence that reform is needed.

I. Introduction

In 2011, as part of Order No. 1000, FERC introduced competition for certain transmission projects. This requirement was based largely on the theory that introducing competition in the development of electric transmission would lead to lower costs for customers and would foster innovation in the identification of transmission solutions. Owing to the extended timelines associated with regional compliance, process implementation, and transmission development generally, data against which to test the Commission's hypothesis was, for many years, limited. However, with well over a decade having elapsed since the issuance of Order No. 1000, more instructive evidence is available.

Much of the work done by the DATA Coalition since its inception has been oriented around informing the policy debate on Order No. 1000 competitive solicitations through the preparation of *quantitative* analysis and evidence on the topic. In particular, the evidence sponsored and/or developed by DATA has focused on scrutinizing assertions that transmission competition delivers cost savings benefits to customers. This has been done, in large part, by focusing on instances in which competitively bid projects have reached an adequately late stage of development – or have entered service – such that associated outcomes can more confidently be used to support quantitative, analytic conclusions. Given the challenges with building electric transmission, relying on early-stage cost estimates or expectations about project completion timelines can lead to misleading conclusions. As much has been shown by our work, which reveals considerable departures between winning bids and final project costs, as well as considerable delays in certain projects.

However, quantitative analysis of late-stage and in-service projects does not tell the whole story of the impact of Order No. 1000 competitive transmission requirements. This whitepaper aims to supplement the prior work of the DATA Coalition by presenting several recent case studies that are instructive regarding the ineffectiveness of competitive solicitations for transmission in lowering costs and increasing innovation. The case studies also show how processes introduced by Order No. 1000 are creating inefficiencies and undermining collaboration, as well as creating risk and cost of delay in building critical transmission infrastructure needed to reliably serve rapidly growing load and ensure the efficient delivery of energy to customers.

This work is not intended to suggest that projects developed by non-incumbents or those with cost caps (or other cost control measures) are the only projects that encounter challenges. Transmission project development is fundamentally a challenging endeavor, and projects developed by incumbents also face cost and schedule variance and may also run into regulatory or legal hurdles. However, the critical insight is that the value of Order No. 1000 competitive solicitations continues to be unsupported by current evidence, while there is a growing body of actual experience that calls into question Order No. 1000's theoretical basis for imposing competition and shows solicitations may be a detriment to transmission planning outcomes.

II. PJM Case Study: Mid-Atlantic Resilience Link

A. Background

Significant increases in load growth, particularly load growth driven by data center development, has recently become an overriding dynamic in electric system planning. This dramatic growth in demands on the power system is showing up acutely in Virginia, in the Dominion Zone of PJM, with forecasts showing as much as 5% annualized load growth through the late 2030s. This load growth, paired with the expected retirement of more than 11,000 MW of generation, led PJM in late 2022 to identify significant transmission needs to maintain reliability. To address these needs, on February 24, 2023, PJM opened the 2022 Regional Transmission Expansion Planning Window 3 – referred to hereafter as "Window Three." As part of Window Three, PJM reviewed 72 competitive submissions from 10 entities. On December 11, 2023, the PJM Board of Managers approved a set of projects, expected to cost more than $5B, from those proposed. Projects were selected such that the full set would meet the system needs identified and provide flexibility to meet future needs, make use of existing rights of way where possible, and attempt to limit risks to cost and schedule.[1]

As part of the selected suite of projects in Window Three, NextEra was selected to build one of its numerous proposed solutions in the West and Northern Virginia areas. This proposal – which had been assigned the identification no. 853 – was targeted to address a need for west-to-east transfers, would offer a third 500 kV supply to load centers in the Dominion service territory, and included significant portions of greenfield rights of way. The selected project would run a new 500 kV line from 502 Junction substation to a new substation at New Stonewall/Woodside, include substation equipment work at the new Woodside substation, and also include partial assignment to NextEra of a new 500kV transmission line from Woodside to Aspen. The total cost estimate for NextEra's selected scope was approximately $513M. Upon award, NextEra designated the project the MidAtlantic Resiliency Link, or "MARL."[2]

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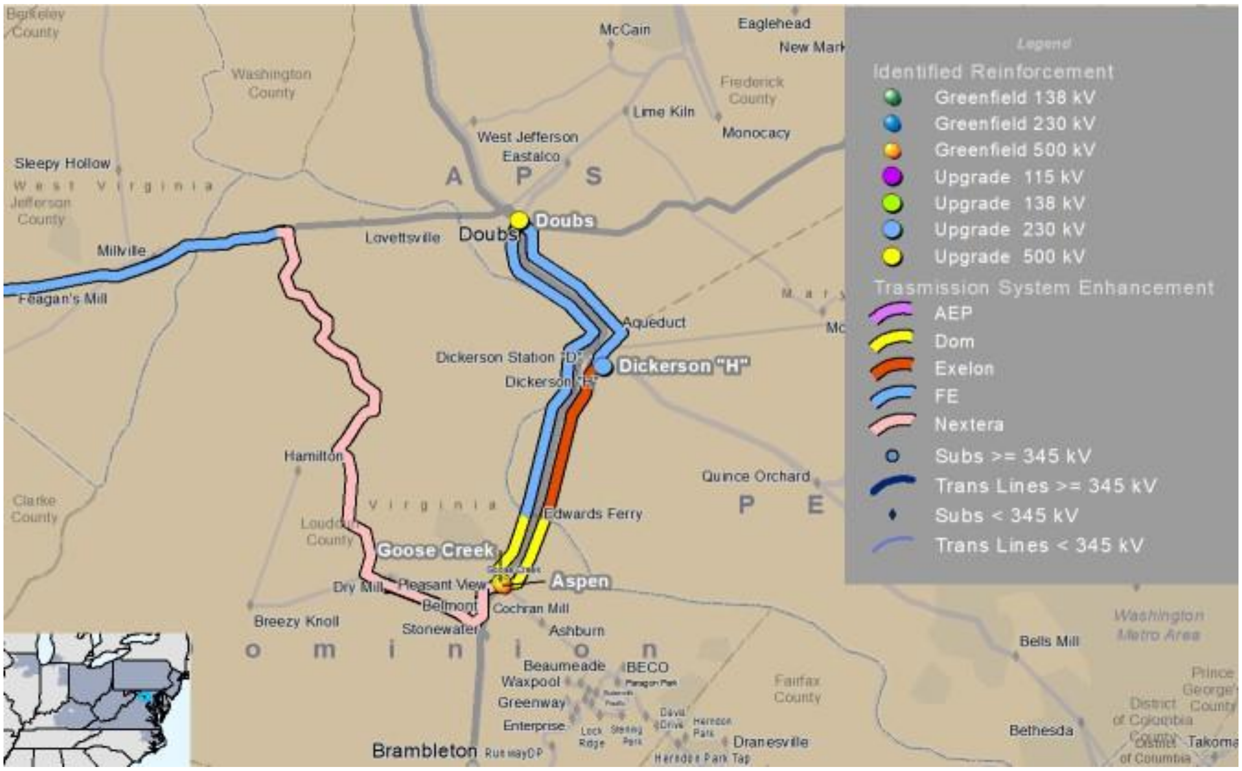
[1] *See* PJM, *PJM Board of Managers Approves Critical Grid Upgrades* (Dec. 11, 2023), https://insidelines.pjm.com/pjm-board-of-managers-approves-critical-grid-upgrades/; *see also* PJM, "Reliability Analysis Report: 2022 RTEP Window 3" (Dec. 8, 2023), https://pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx.

[2] *See* NextEra Energy Transmission MidAtlantic, Inc., *MidAtlantic Resiliency Link*, https://www.nexteraenergytransmission.com/midatlantic-resiliency-link.html.

Figure 1: Routing for MARL as Awarded (NextEra scope in peach)[3]



B. Challenges

Siting transmission in and around Loudon County, Virginia – where MARL was proposed and selected for development – is known to be especially difficult. By March 2024, less than three months after the PJM Board approved the Window Three projects, NextEra had determined that building on the proposed MARL route was likely to be infeasible. NextEra approached Dominion, Exelon (Pepco), and FirstEnergy for help, all of which have existing rights of way and existing transmission infrastructure in the area where MARL could alternatively be built. Engineering teams at the three “incumbent” utilities proceeded to review the request, ultimately determining that an alternative route could be achieved by rerouting the line to be adjacent to parallel rights of way owned by Pepco and FirstEnergy, and by only modifying FirstEnergy’s right of way.[4]

While electrically similar, the solution that was identified by the three incumbent utilities, working with NextEra and PJM, reflected practical real-world differences. NextEra maintained

[3] *See* PJM Transmission Expansion Advisory Committee, “Reliability Analysis Update,” at 42 (Jul. 9, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2024/20240709/20240709-item-10---reliability-analysis-update.pdf .

[4] FirstEnergy had future plans that would have used the available space on its existing right of way. FirstEnergy will now likely need to abandon such plans in order to accommodate the MARL redesign. Should it come to pass, future needs that could have been served by that available right of way will need to be achieved by other means, and likely with other costs that are hidden within the analysis of cost changes of the Window Three scope change.

components of the project selected through the Window Three solicitation but agreed with PJM to cancel its competitively won 500 kV transmission line in the Dominion Zone. That cancelled portion of the overall project will be rerouted and built by FirstEnergy on existing and expanded rights of way. Dominion also will experience several modified scopes to handle line crossings and to move certain substation equipment (capacitor banks). Pepco experienced no scope changes. The total net increase in expected cost estimate for the combined affected projects is $167M, which reflects the change in scope.[5] PJM's Board approved these modifications in August 2024.[6]

C. Discussion

The MARL case study is a lesson in how Order No. 1000 competitive solicitation requirements create inefficiencies and undermine collaboration, contrary to the goals the Commission set out to achieve, as well as the inherent limitations of the bidding and evaluation processes that were developed to comply with Order No. 1000.

First, the MARL experience highlights how the process leads to unsophisticated and incomplete proposals put through an artificially constrained assessment. As a general matter, competitive bidders are often unlikely to reach out to each other in the process of developing proposals to resolve the identified needs whereas, prior to Order No. 1000 competitive requirements, such collaboration would have occurred naturally among incumbent developers. In preparing their proposals, non-incumbents are unlikely to have the benefit of the knowledge of incumbent utilities that have deep local experience and extensive awareness of local systems and constraints, including the ability to assess routing feasibility. Indeed, they may not have the incentive to develop any serious routing plan at all if the goal is simply to win an award and then to address shortcomings later. In the stakeholder process associated with Window Three, NextEra acknowledged that they had simply used Google Maps to identify a *possible* corridor.[7] No rigorous siting analysis had been done to accompany the proposed route ahead of the award of MARL.[8]

[5] *See* PJM Transmission Expansion Advisory Committee, "Reliability Analysis Update," at 41-44 (Jul. 9, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2024/20240709/20240709-item-10---reliability-analysis-update.pdf. There is not a specific identified driver for the change in cost. It is possible that the difference is a result, at least in part, of differences in cost estimation protocols or may be attributed to any incentive NextEra may have had to show a lower cost estimate in the competitive process. The incumbent utilities would not have had such an incentive. There is also no incumbent project with a similar scope to MARL that could be offered as a comparison because no incumbent was willing to offer an infeasible proposal.

[6] PJM, *PJM Board Approves Updates to Regional Transmission Expansion Plan* (Aug. 8, 2024), https://insidelines.pjm.com/pjm-board-approves-updates-to-regional-transmission-expansion-plan-2/.

[7] This statement was made by a NextEra representative in a PJM Transmission Expansion Advisory Committee ("TEAC") meeting on December 5, 2023, during a discussion related to a 2022 Window 3 Reliability Update.

[8] Indeed, Order No. 1000 competitive processes impede the types of local engagement that incumbent utilities would conduct in the normal course of scoping a transmission project. It is unrealistic and unfair to ask landowners and local community officials to engage with many potential transmission developers as

PJM, owing to the need to timely advance transmission planning while complying with competitive requirements, is required to move quickly in making decisions about project evaluation and selection. Notwithstanding, it is worth emphasizing that the entire Window Three competitive solicitation added an additional year and a half of efforts by individual applicants and PJM only to result in the need for revisions within three months of the PJM Board's final project selections. Furthermore, to protect competitive interests and maintain confidentiality, PJM is limited in its ability to engage relevant parties to assess the potential challenges of a particular project or to consider the benefits of alternative configurations, and especially in its ability to engage stakeholders together and in advance of the window closing. This is not a fault of PJM's, nor should PJM have the responsibility for performing a definitive evaluation of siting and routing factors in its competitive process; PJM and its consultants may perform assessments, but such reviews have limits and do not represent a final word on siting feasibility. PJM does not have the locality-specific familiarity needed to perform detailed constructability assessments that consider the nuances of all corners of the PJM footprint. Moreover, requiring PJM to do so introduces more inefficiency and cost into a process that has not been shown to produce the intended results.

Challenges with siting transmission in Loudon County, Virginia, along the initial MARL route should not have been a surprise to NextEra, or to PJM. In the stakeholder process during which the Window Three proposals were being reviewed, numerous stakeholders – including public citizens and transmission owners – raised the considerable siting challenges that such a project was likely to face. It is widely known that prior projects in the area had run into ruinous issues (most notably the Potomac Appalachian Transmission Highline, or "PATH" project). It is also instructive that no incumbent proposed a solution on or around the problematic route, likely because of the expectation that the path was infeasible. NextEra was the only entity to suggest such a route, perhaps because they were unaware of the challenges, or were willing to overlook, at least in the early stages, the practical infeasibility of the concept.

Second, the MARL example illustrates several ways in which competitive transmission processes have led to the loss of the value brought by collaborative transmission planning. In a pre-Order No. 1000 world, PJM, FirstEnergy, Exelon, and Dominion from the outset would have worked together through an iterative process to identify projects and routes that would address the transmission needs stemming from data center-driven load growth in Virginia. They would have come with their knowledge about their service territories and ability to leverage existing rights of way and other existing assets and would have been able to consider expected future needs as well. And, in the end, they would have cooperated knowing they would have the opportunity to build the resulting projects to maintain reliability for their customers and, in doing so, fulfill their service obligations to their customers. Such outcomes are also aligned with the preference of public citizens, who shared in the stakeholder process that they expect and prefer to work with the local (incumbent) utilities they know and have worked with before, who are

well as to expect them to keep it all straight. As a result, effective early-stage landowner engagement may be non-existent at time of bid and may not be meaningful after the award depending on the structure of the bid. Furthermore, reacting to later stage landowner engagement may be constrained by bid structures with cost caps, which could limit the ability to revise a route in response to landowner input because of the financial ramifications of such a decision. Competitive bidding impedes landowner engagement.

aware of unique local restrictions and requirements, and who have a long-term incentive to maintain positive relationships with communities and in most instances are also subject to state regulation of some kind. Had such a process been in place rather than the required Order No. 1000 competitive solicitation that produced MARL, there likely would have been a much more efficient process to arrive at a better, more feasible, more timely, comprehensive solution.

For NextEra, its competitive approach paid off – it won a project with a flawed proposal, subsequently salvaged a modified project with a workable siting plan, and still ended up with an estimated $441M investment opportunity. We will never know if a project collaboratively developed by incumbent utilities in the first instance would have avoided the increased cost or identified a superior, more holistic, more robust solution. In the end, in the interest of supporting PJM and regional grid reliability, incumbent transmission owners needed to step forward to remediate the shortcomings in NextEra's infeasible proposal. Fortunately for customers, they were able to do so.[9] However, this sequence of events exposes how competitive processes create incentives and opportunities for developers to submit overly optimistic and potentially unrealistic bids. They can do so with the knowledge that, after the fact,[10] and amidst the disorder, incumbents are expected to backstop non-incumbents, effectively limiting the consequences for shortfalls of any commitments made. This is not real competition, and incumbent transmission owners (with the obligation to serve) are left in the imbalanced position of being obliged to help remedy deficient proposals by competitive developers and the deficits in the competitive process to continue to fulfill their statutory obligations to ensure reliable service.

III. New England Case Study: Cost Capping of Aroostook Renewable Gateway

A. Background

In 2021, the legislature of Maine enacted a law to facilitate renewable energy development in northern Maine. In addition to development of the renewable generation projects, the law required the development of a double-circuit 345 kV (or greater) transmission facility to connect renewable energy resources in northern Maine to the ISO-NE grid. In November 2021 the Maine Public Utility Commission ("PUC") issued a request for proposal ("RFP") for both generation and transmission proposals and received proposals for the associated transmission projects before March 2022.[11] For the transmission solicitation, on November 1, 2022, the

[9] This situation also begs the question of what would have happened, in terms of cost and reliability implications, had incumbents not been able to identify an alternative solution to remedy the failures of the competitive process that produced MARL.

[10] *See Building for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, Affidavit of Dr. Carl R. Peterson, at 20 (Sept. 19, 2022) ("Peterson Affidavit"), https://ceadvisors.com/wp-content/uploads/2022/10/Peterson-Affidavit_Final.pdf ("Yet, once the bidding process is over, the environment changes from one of large numbers to one of small numbers. The winner has an incentive to attempt to renegotiate the contract. This can be done through clever, or even not so clever, use of cost caps which allow firms to increase the contract prices after the fact.").

[11] *See Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Maine PUC Case No. 2021-00369, Order Issuing RFP

Maine PUC issued an order identifying LS Power Grid Maine ("LS Power") as the selected developer based on its term sheets from the solicitation, with a ratepayer cost for the transmission component of approximately $2.78B.[12] The selected project was called the Aroostook Renewable Gateway.[13]

Figure 2: Aroostook Renewable Gateway Routing[14]

Following the initial award, questions arose as to whether Maine ratepayers should bear the full cost of the transmission and generation projects resulting from the solicitation. Close in time,

(Item No. 2) (Nov. 29, 2021), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=112911&CaseNumber=2021-00369.

[12] *See Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Maine PUC Case No. 2021-00369, Order Approving Term Sheets (Item No. 139), at 10 (Nov. 1, 2022), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=117112&CaseNumber=2021-00369.

[13] We recognize that this is not a project technically resulting from a transmission planning process that falls under the auspices of FERC Order No. 1000, nor was the solicitation run by ISO-NE. Nonetheless, the lessons taken from the project bidding and subsequent development are informative to competitive transmission as a concept more broadly.

[14] *See* Stephen Singer, *Feds back CMP bid to build transmission line through Maine*, Portland Press Herald (Oct. 3, 2024), https://www.pressherald.com/2024/10/03/cmp-will-bid-to-build-northern-maine-transmission-line-with-425-million-boost-from-feds/.

Massachusetts passed legislation that would allow for the possibility that Massachusetts customers would pay for a portion of the line and generation, which would facilitate achievement of legally mandated greenhouse gas reduction goals in Massachusetts. Following several further procedural steps, it was determined that Massachusetts would pay for up to 40 percent of the projects. The parties were expected to file final versions of negotiated agreements to achieve this outcome by June 2023.[15]

B. Challenges

In November 2023, LS Power ultimately filed a proposed transmission agreement along with a supporting brief and studies quantifying project benefits to Maine. These were considered at a hearing on December 21, 2023. The next day, the Maine PUC issued an order terminating the original procurement of the LS Power transmission line, as well as the separately developed generation project. In its termination order, the PUC stated, "in its brief LS Power has made clear that it can no longer hold to the fixed price contained in its term sheet and that it requires a price adjustment." The PUC goes on to note that LS Power, at the time, had yet to specify a new price and that the requested change in price effectively represents a modification to "a core component of the commitments made in its approved term sheet" and that "LS Power has effectively withdrawn its original fixed-price bid."[16] In its order, the PUC observed that, while its decision is based on the failure to hold to the original fixed price in the term sheet, in its later proposed transmission agreement LS Power insisted on "pricing contingencies that would shift a substantial amount of risk and thus cost exposure to ratepayers, contravening both the RFP and LS Power's approved term sheet."[17]

In a letter following the termination order, LS Power aimed to clarify certain issues regarding the procurement. LS Power suggested that several risks introduced later in the process, and particularly the addition of Massachusetts as a participant, added delay and complication beyond those contemplated when the initial expectation was to enter into a contract by November 2022. However, it was not until late 2023 when the transmission agreement could be filed. LS Power also raised as challenges the lack of a pro forma transmission agreement associated with the RFP, as well as the unusual nature of the solicitation as considering both

[15] *See* Maine PUC, *Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Case No. 2021-00369, Order Terminating Procurement (Item No. 182), at 2 (Dec. 22, 2023), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=121809&CaseNumber=2021-00369.

[16] *See Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Maine PUC Case No. 2021-00369, Order Terminating Procurement (Item No. 182), at 3 (Dec. 22, 2023), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=121809&CaseNumber=2021-00369.

[17] *See id.* at n.4.

generation and transmission, and particularly in a manner that does not recognize the specific characteristics and challenges of providing transmission service.[18]

The Maine PUC has, in a separate docket, initiated a new administrative process to consider an alternative project and developer; however, the results of this RFI proceeding are not yet public.[19]

C. Discussion

Many of the Order No. 1000 competitive solicitations to date have received and selected proposals with cost containment mechanisms. These may take the form of cost caps or other structures designed to deliver, or give the impression of delivering, customer protections from cost escalations. Despite their prevalence, Concentric Energy Advisors have found significant challenges with cost cap implementation in practice,[20] and DATA has in prior reporting presented analysis that calls into question their efficacy.[21] In brief, cost containment provisions have suffered from poor transparency, have been structured with numerous exceptions,[22] and most projects with cost caps have ultimately exceeded their cost caps considerably but without meaningfully limiting developer cost recovery or shifting risk away from customers.

Here, the experience with the Aroostook Renewable Gateway project epitomizes the shortcomings with the concept of cost caps in the context of electric transmission development, and specifically with *binding, fixed* cost caps (i.e., caps that provide dependable assurances to

[18] *See* Maine PUC, *Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Case No. 2021-00369, Letter to Commission (Item No. 183) (Jan. 11, 2024), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122054&CaseNumber=2021-00369.

[19] *See Request for Information for Renewable Energy Generation and Transmission Projects Pursuant to the N. Me. Renewable Energy Dev. Program*, Maine PUC Case No. 2024-00099, Request for Information and Indications of Interest (Item 2) (May 10, 2024), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2024-00099. One project that could be under consideration as part of the Maine RFI process is Avangrid's Aroostook Renewable Project. This same project was selected for a $425M capacity contract through the U.S. Department of Energy's ("DOE") Transmission Facilitation Program. *See* Avangrid, *Avangrid Awarded $425M Federal Capacity Contract for Maine Transmission Project* (Oct. 3, 2024), https://www.avangrid.com/w/avangrid-awarded-425m-federal-capacity-contract-for-maine-transmission-project. If ultimately selected by the Maine PUC, the availability of the DOE capacity contract could have a considerable impact on the success of the project.

[20] *See* Concentric Energy Advisors, *An Updated Examination of FERC Order No. 1000 Projects*, at 2 (Apr. 16, 2024) ("Concentric 2024 Report"), https://ceadvisors.com/publication/an-updated-examination-of-ferc-order-no-1000-projects/.

[21] *See, e.g.*, *Building for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, DATA Coalition Supplemental Comments and Dec. 2023 Whitepaper (*Revisiting the Evidence on Cost Savings from Transmission Competition*), Whitepaper at 9-10 (Dec. 15, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231215-5048.

[22] Developers commonly propose exclusions to the cost caps for unexpected or unknown events that can occur leading up to and during construction, such as project rerouting, regulatory delays, and expected but unknown costs such as financing or interconnection. *See generally* Concentric 2024 Report.

customers with a maximum allowed recoverable cost). Such "hard" cost caps are unrealistic based on the nature of transmission development, which involves high capital costs, long lead times, regulatory hurdles, and numerous cost uncertainties driven by those and other factors. Under such conditions, paired with the regulated nature of cost recovery, efforts to fully shift recovery risk to developers may be fundamentally incompatible with cost-of-service transmission development. Were such a complete risk shift achieved, with the inevitability that significant costs would be left unrecoverable by developers, the result could be bankrupt or otherwise financially unhealthy transmission companies. Or, as in the case of the Aroostook Renewable Gateway project, developers may realize early in the development cycle that to abandon the project is the wise business decision, in turn leading to, at best, delay. Neither outcome is a recipe for delivery of high-quality, timely, reliable transmission service for customers.

The issues that we raise here regarding the expectation of binding cost caps are not new and have been widely recognized by industry stakeholders. In 2016, a PJM executive testified as to what could reasonably be expected, and not, from competitive bidding with binding cost caps.

> "*Some may urge the Commission to adopt a rule effectively saying 'developer, you live by your accepted cost cap no matter what'. But we would be kidding ourselves if we think this would be cost-free. Such a rule may just invite a cost cap proposal where the stated exceptions swallow the commitment provisions themselves. Or if they don't, they would impose a heavy risk premium on all submitted proposals --- a risk premium that may be driven as much by the regulator's insistence on making the cost cap 'binding' as anything else.*"[23]

In short, binding, fixed cost caps cannot and should not be expected to be feasible for transmission developers. And since such cost caps are unrealistic, all that is left are cost containment mechanisms that are built with exceptions and other loopholes to make them commercially acceptable to developers. Such "loose" cost caps in practice have been shown to offer, at best, limited protection to customers. For these reasons, cost capping mechanisms are left with but one purpose: for use by developers aiming to gain a competitive edge in a solicitation process by offering cost containment provisions that prove illusory in the final accounting.

While this discussion is focused on a project proposed by LS Power and technically outside of an Order No. 1000 process, its inclusion here is to highlight the challenges with the expectations of binding cost caps, and to observe that it is highly likely that any developer would refuse to accept a binding, fixed cost cap. Because hard cost capping of transmission projects is unrealistic, FERC and other regulatory bodies should be clear-eyed about what real customer

[23] *Competitive Transmission Dev. Tech. Conference*, FERC Docket No. AD16-18-000, Testimony of Craig A. Glazer, Vice President of Federal Government Policy, PJM, at 6 (Jun. 22, 2016), https://www.ferc.gov/sites/default/files/2020-08/Glazer-PJM.pdf.

protections can be gained through cost capping "innovation," which has been touted as a major innovation of competitive transmission processes.[24]

IV. CAISO Case Study: Project Re-Scoping Challenges for HVDC Projects

A. Background

Approved in 2022, CAISO's 2021-2022 transmission plan included a set of reliability projects totaling more than $1.4B. These projects were designed to ensure that load could be reliably served in the CAISO footprint given "load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation."[25] Among the projects approved were two HVDC projects in the San Francisco South Bay region that were designed to serve the San Jose-Silicon Valley Power area. These two projects were (1) Newark to Northern Receiving Station ("NRS") and (2) Metcalf to San Jose B, and at the time the plan was to eventually form a multi-terminal HVDC configuration that would, at a later point, connect the two projects by adding a line between NRS and San Jose B. Both projects were set for competitive solicitation and LS Power Grid California, LLC ("LS Power") was awarded both projects.[26] Both projects included cost caps with extensive terms, including numerous categories of costs excluded from the cost cap, described in the CAISO selection reports[27] and the resulting Approved Project Sponsor Agreements ("APSA").[28]

In its 2024-2025 transmission planning process cycle, CAISO identified that the load forecast in the San Jose Area had increased by approximately 3,400 MW in the base case and approximately 4,200 MW in the sensitivity scenario over the long term. Due to the increased load forecast, CAISO's analysis indicated that there would be considerable system overloads expected over the planning horizon, even with both San Jose HVDC projects included in the modeling. CAISO also noted, "[i]n addition, LS Power has indicated potential cost increases

[24] Prior work supported by DATA has shed light upon the challenges with effectively enforcing cost containment, owing in part to complex and subjective cost cap frameworks and a lack of transparency in their implementation. *See, e.g.*, Concentric 2024 Report at 2-3, 41.

[25] *See* CAISO, *2021-2022 Transmission Plan*, at 5 (Mar. 17, 2022), https://www.caiso.com/documents/isoboardapproved-2021-2022transmissionplan.pdf.

[26] *See* CAISO, *2021-2022 Transmission planning process*, https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2021-2022-Transmission-planning-process.

[27] *See* CAISO, *Metcalf-San Jose B HVDC Project: Project Sponsor Selection Report* (Mar. 21, 2023), https://stakeholdercenter.caiso.com/InitiativeDocuments/Metcalf-San-Jose-B-HVDC-Project-Project-Sponsor-Selection-Report.pdf; CAISO, *2021-2022 Transmission Planning Process: Project Sponsor Competitive Solicitation Newark – Northern Receiving Station HVDC Project, Summary of Accrued Project Sponsor Costs*, https://stakeholdercenter.caiso.com/InitiativeDocuments/Newark-NRS-HVDC-Project-Accrued-Final-Costs.pdf.

[28] *See* Approved Project Sponsor Agreement Between LS Power and CAISO for Newark – Northern Receiving Station HVDC Project (Aug. 28, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M531/K772/531772172.PDF; Approved Project Sponsor Agreement Between LS Power and CAISO for Metcalf – San Jose B HVDC Project (Aug. 28, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M530/K463/530463569.PDF.

related to the HVDC equipment."[29] CAISO considered multiple incremental solutions to address the expected overloads, including multi-terminal HVDC, high-capacity 230 kV AC lines, hybrid solutions, and other alternatives. Considering in-service date needs, cost effectiveness, and long-term flexibility, CAISO recommended a hybrid solution, including (1) an HVDC link from Metcalf 500 kV to San Jose B 230 kV switchyard, and (2) a high-capacity 230 kV AC circuit from Newark to NRS – instead of the HVDC project initially awarded.[30] In addition, CAISO management noted in its recommended alternative that a high-capacity 230 kV circuit between San Jose B and NRS should be considered in its 2024-2025 planning cycle.

B. Challenges

Given the considerable change in scope for the Newark to NRS line, Metcalf to San Jose B switchyard, and other additional components, CAISO was in the position of needing to determine which developer will be assigned new and modified scopes, as well as how any modified scopes would be treated relative to existing APSAs. CAISO management sought and obtained board approval (on November 12, 2024) to maintain the assignment of the Metcalf to San Jose B HVDC project to LS Power and also to assign the re-scoped Newark to NRS 230 kV AC line (formerly HVDC) to LS Power.[31] Both will have a target in-service date of June 1, 2028. The new NRS to San Jose B AC circuit is to be awarded through competitive solicitation in the second half of 2025, with a target in-service date in 2030.

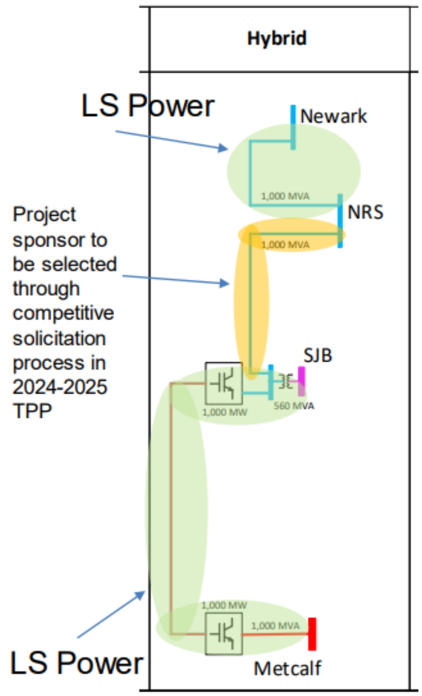
The hybrid solution also requires that, at the San Jose B substation, the HVDC line and converter connect to a new 230/115 kV substation. CAISO initially proposed to directly assign construction of this substation to LS Power. This substation component of the project is new and was never competitively solicitated. However, given the near-term reliability need, CAISO indicated that running a competitive solicitation would put the necessary in-service date at risk. If developed as initially proposed, the new substation would have been located adjacent to PG&E's San Jose B substation and, depending on its design, could have required the development of certain duplicative equipment and constrain expansion options for PG&E's substation footprint in the future. Other local upgrades to the existing 230 kV and 115 kV systems are required and will be implemented by PG&E and Silicon Valley Power.

[29] CAISO, *San Jose Area Transmission Plan: Engineering Study Report*, at 3, 5 (Nov. 5, 2024), https://www.caiso.com/documents/decision-on-modifications-to-the-2021-2022-transmission-plan-study-nov-2024.pdf.

[30] CAISO, "2024-2025 Transmission Planning Process – Reliability Assessment and Study Updates" (Sept. 23-24, 2024), https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2024-2025-Transmission-Planning-Process-Sep-23-2024.pdf.

[31] CAISO, "ISO Board of Governors General Session Meeting" (Nov. 12, 2024), https://www.youtube.com/watch?v=ocxwxGyRblQ.

Figure 3: CAISO Hybrid Solution and Assignments[32]



C. Discussion

This case study from CAISO, implicating several projects to address load growth in the San Jose area, further demonstrates failings inherent in Order No. 1000 competitive processes. First, the challenges with developing and implementing cost caps is again on display. As one rationale for the Newark to NRS re-scope, CAISO communicated that the Project Sponsor has experienced "cost increases related to the HVDC equipment."[33] This suggests that expected cost changes jeopardized the ability of the sponsor to deliver the previously identified solutions at their binding cost caps, regardless of commitments made at the time of award. Whatever customer protections were expected to be derived from the protections in the associated APSA, those become moot when competitively bid equipment costs suddenly change so considerably. Furthermore, if and when CAISO does elect to renegotiate the APSA with LS Power – as it may well do given the considerable cost difference associated with an AC rather than DC solution – that activity will take place in an environment where LS Power would have considerable leverage around favorable terms, should it agree to further cost containment at all. This is not to suggest that there is a benefit to competitive pressures when establishing the terms of project assignment, but to offer yet another data point showing how cost capping measures are illusory when it comes to implementation and enforcement, and how – consistent with observations in

[32] CAISO, "2024-2025 Transmission Planning Process Reliability Assessment and Study Updates," at 32 (Sept. 23-24, 2024), https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2024-2025-Transmission-Planning-Process-Sep-23-2024.pdf.

[33] *Id.* at 29.

other DATA work products – expectations of *ex post* contract renegotiation and opportunism following competitive solicitations are observable in practice.[34]

The San Jose B to Metcalf line, and the associated substation work, is also another example of how competitive processes lead to worse planning outcomes across multiple time horizons. At the time of approval of the initial scope of the project, and despite recommendations made by PG&E in comments, CAISO did not account for the scope of work that PG&E would need to undertake to interconnect any third-party facilities.[35] These costs were expected to reach into the tens of millions of dollars through the development of necessary but redundant facilities – 115 kV at San Jose B and 500 kV at Metcalf bus-systems to connect PG&E facilities to LS Power facilities. These costs were not considered fully in the solicitation process and were therefore not accounted for in the total expected costs to customers of the initial award.

There is also a more significant challenge that arose associated with the modifications required at San Jose B to facilitate the new lines interconnecting to that substation. The San Jose B Substation is connected to four 115 kV transmission lines and contains four distribution transformers to serve electric demand in San Jose. In 2028, with the expected tie-in of the new lines, the substation will be one of the most critical 115 kV substations in the southern portion of the San Francisco Bay Area for serving existing and emerging loads, including growth from commercial customers, industrial customers (including data centers), EV charging, and electrification. PG&E expects that this load growth will necessitate additional distribution bank capacity and new interconnections with other neighboring substations to distribute power injected by the new HVDC capacity, which in turn will require expansion of the substation's footprint. However, PG&E faces constraints with such expansion because San Jose B is surrounded by the Guadalupe River and roads to all but the south side. Now, the land on the south side of the station is held by LS Power for its portion of the project. PG&E has stated the expectation that the land currently being held by LS Power south of PG&E's San Jose B Substation has sufficient room to allow for the new CAISO-proposed scope as well as the future expansion of the distribution and 115 kV systems.[36]

This set of circumstances led PG&E, in comments, to recommend that CAISO assign the San Jose B substation work to PG&E rather than LS Power. This would have a multi-part benefit. First, it would eliminate the need to develop duplicative station facilities to support the new HVDC transmission lines, with obvious associated savings for customers. Second, it would create further efficiencies and facilitate the flexibility for future expansion of the substation to serve expected load growth, which is an especially acute concern given the fact that there is no other available land in the area to expand electric facilities in the future.[37]

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[34] *See* Peterson Affidavit at 20.

[35] *See* Pacific Gas & Electric Comments on Reliability Assessment and Study Updates, CAISO 2024-2025 Transmission Planning Process (Oct. 8, 2024), https://stakeholdercenter.caiso.com/Comments/AllComments/5e135d07-57f1-4b10-938a-143a66dc68bd#org-d73c9f15-7d74-4574-b713-0dbe95f4f09d.

[36] *See id.*

[37] *See id.*

Following its initial recommendation, CAISO management has indicated that it will change course and accept PG&E's recommendations and assign the San Jose B substation expansion scope to PG&E, rather than to LS Power.[38] This outcome resolved the aforementioned concerns about development of duplicative equipment and constraints on PG&E's flexibility to serve future load. Nonetheless, the case study demonstrates how the competitive transmission paradigm risks troublesome outcomes that are inconsistent with FERC's policy objectives.

Taken together, this example shows how the competitive process stemming from the requirements of Order No. 1000 has the potential to lead to fractured and inferior planning outcomes that (1) fail to make project selections accounting for the full costs that will be borne by customers and (2) do not maximize or "right-size" the value of solutions to meet immediate and future needs and, worse, if certain decisions are made can actually curtail the ability of the local utility – PG&E in this case – to have the flexibility to expand its system in the future when customer needs are expected to arise.

V. MISO Case Study: LRTP Tranche 1 Litigation and Uncertainty

A. Background

On July 25, 2022, MISO approved what, at the time, was the largest portfolio of regional transmission projects in Regional Transmission Organization ("RTO") history. The portfolio is referred to as Long Range Transmission Plan ("LRTP") Tranche 1 and includes 18 transmission projects in MISO's Midwest subregion. The projects will facilitate the integration of more than 50 GW of generation and storage projects and deliver tens of billions of dollars in benefits to customers. The portfolio of projects was approved following two years of collaborative planning efforts between MISO, MISO Transmission Owners, and regional stakeholders. Notably, the collaborative efforts and ultimate success in developing and approving the LRTP portfolio were underpinned by the fact that six of the nine states in the MISO North region had right of first refusal (ROFR) laws in place. These laws recognize the important role of the incumbent transmission owners and foster certainty that the incumbent transmission owners can develop the projects resulting from the regional planning process in a timely fashion, thus creating a planning environment more conducive to collaboration.

Of the LRTP Tranche 1 projects, approximately 447 miles of new 345 kV transmission circuits are planned for development in Iowa. These projects have a required in-service date of 2030 and are expected to deliver reliability, resilience, resource adequacy, and economic benefits to Iowa and the MISO region more broadly. MISO calculated that these particular projects have benefit-cost ratios in the 3.2-4.4 range, the highest projected ratios for any resource zone in MISO resulting from Tranche 1. These benefits depend on all LRTP projects working together as a portfolio. Pursuant to Iowa's state ROFR statute, in August 2022, MISO assigned ITC Midwest and MidAmerican Energy to construct the Iowa LRTP projects. The projects are estimated to cost $2.1 billion.

[38] *See* CAISO, "ISO Board of Governors General Session Meeting," at 54:00-54:30 (Nov. 12, 2024), https://www.youtube.com/watch?v=ocxwxGyRblQ.

Figure 4: Impacted MISO Tranche 1 Projects in Iowa

Note: Map is for illustrative purposes and is not indicative of proposed or suggested routes.

B. Challenges

In 2020, Iowa enacted a ROFR statute. In March 2023, in response to a challenge from LS Power, the Iowa Supreme Court issued a temporary injunction against the Iowa ROFR statute and remanded the case to the Polk County District Court. In December 2023, the Polk County District Court struck down Iowa's ROFR statute.[39] In doing so, the court issued a broad injunction against the Iowa Utilities Board, ITC Midwest, and MidAmerican Energy in relation to the LRTP Tranche 1 projects, requiring a stop to any further development activities. On December 19, 2023, ITC Midwest submitted a motion for reconsideration to the Polk County District Court seeking to reverse the injunction and allow project development to continue. MISO attempted to file an *amicus* brief to explain the reliability problems the injunction would create, the need for the projects, and how the injunction interferes with MISO's federal tariff. The Court denied MISO's participation. On March 19, 2024, the District Court issued an order denying all motions for reconsideration of its decision. ITC Midwest, MidAmerican Energy, and the Iowa Attorney General appealed these orders with respect to the scope of the injunction, and those appeals are pending.

In response to the District Court's injunction, MISO initiated Variance Analyses as authorized by the MISO Tariff to assess the impact of the District Court's injunction on the ability of ITC and MidAmerican to construct the assigned LRTP Tranche 1 projects. On August 29, 2024, MISO

[39] Neither court ruled on the merits of the ROFR legislation, but rather on the procedural issue of the constitutionality of passing the legislation as part of an appropriations bill.

publicly announced the results of these Variance Analyses and MISO's associated mitigation plans for the Iowa LRTP Tranche 1 projects. MISO's mitigation plans assigned ITC Midwest and MidAmerican Energy obligations under the MISO Tariff to construct the planned projects and directed ITC and MidAmerican to proceed.[40] Development processes are underway. LS Power, however, continues to litigate the issue of whether ITC Midwest and MidAmerican should be allowed to continue to develop and construct the LRTP projects.

C. Discussion

While MISO's Mitigation Plans assign ITC and MidAmerican the obligation to proceed with all facilities that are part of the Iowa LRTPs, the ongoing Iowa ROFR litigation could have an adverse, cascading effect on the MISO Tranche 1 projects. Transmission opponents could point to the ongoing litigation and claim other parts of the Tranche 1 portfolio should be put on hold until final resolution. If this were to ultimately result in delayed in-service dates, for customers, every day of project delay is a delay to the delivery of the reliability and economic benefits the projects will bring. For the Tranche 1 portfolio, which was studied and approved as a cohesive whole, delay to certain elements degrades the portfolio's ability to function as intended. For other related transmission projects that would connect to the Iowa lines, any delay to the Iowa projects could create "spillover" delays. For the MISO transmission system generally, state litigation that questions MISO's exclusive authority to determine ownership of transmission facilities threatens long-term system reliability and resilience and jeopardizes the ongoing energy transition across the Midwest.

The situation in Iowa is an example of the turmoil and disarray that is introduced by FERC's requirement to eliminate all federal ROFRs from jurisdictional tariffs and agreements for regionally cost allocated projects. Disputes over project ownership, and over state ROFR statutes intended to reestablish certainty following the removal of federal ROFR, threaten clarity and certainty around project development and can lead to uncertainty, delay, and their consequences.

Even in MISO, where LRTP is widely viewed as among the most successful planning processes[41] and state ROFRs have facilitated collaborative planning,[42] disputes over the right to build – which result from the requirements of Order No. 1000 – threaten a regional consensus that has led to significant regional transmission development. Particularly in the face of concerns over resource adequacy and the need for pace in grid expansion, this is very

[40] Had MISO been required, for whatever reason, to run a competitive solicitation process for these projects, the associated process to eventually return to the current stage of development would likely take years and include project cancellation, re-approval by the MISO Board, RFP development, an RFP window, RFP evaluation, and project award. Additionally, the facilities eligible for bidding amount to less than 30% of the overall project awarded to ITC Midwest due to the exclusion of upgrades under the MISO Tariff.

[41] *See, e.g.*, Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card*, at 4-7 (Jun. 2023), https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf.

[42] *See, e.g.*, Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission*, at 33-34 (Feb. 2024), https://wiresgroup.com/wp-content/uploads/2024/02/GS_WIRES-Collaborative-Planning.pdf.

troubling. The dynamic of conflict points to the incompatibility between the Order No. 1000 competitive framework and other pressing policy priorities pertaining to maintaining, strengthening, and expanding the nation's power grid. Rather than promoting cost-effective and innovative development, FERC's Order No. 1000 policy – which introduced competition for the right to build a project at cost-based rates – has led to delay, litigation, and uncertainty with no demonstration of consistent value to customers (either through meaningful new entry, reduced cost, or other innovation). Instead, it has created the incentive for competitive developers to fight a constant and multi-front battle for the opportunity to develop transmission projects, even if the result is to the detriment of actual infrastructure development.

Litigation related to Iowa's ROFR law is just one example of ongoing uncertainty stemming from the competitive requirements of Order No. 1000. Encouraged by success in Iowa, LS Power has filed suit against the state ROFR law in Indiana and that litigation is now ongoing.[43]

VI. Conclusion

This whitepaper expands upon prior work performed or sponsored by the DATA Coalition. The approach focuses on qualitative observations based on case studies of recent competitive solicitations and competitive project experiences. The projects described have not reached late stages of development, and some may never end up energized, but as examples they are all instructive as to the numerous deficits of Order No. 1000 competitive solicitations and similar regulatory frameworks. The specific issues can be summarized as follows:

- Re-scoping of NextEra's MARL project highlights how awards from Order No. 1000 solicitations often result from a flawed evaluation of incomplete transmission project concepts, which can lead to an almost immediate need for post-award fixes. Not only does this again demonstrate the flimsy nature of competitive commitments, but the resulting remedy shines a light on the strengths of the incumbent transmission owners and the value of collaboration in transmission planning.

- This policy has created an incentive for developers to relentlessly argue over the right to build projects, ultimately to the detriment of actual infrastructure development.

- Cancellation of the award of LS Power's Aroostook Renewable Gateway is emblematic of the unrealistic expectations that have sprung up regarding the value of applying a hard cost cap on competitive transmission projects. Fixed, binding cost caps are incompatible with the development challenges and commercial realities of electric transmission, while less firm cost containment mechanisms have been shown to be ineffectual for anything but gaining an advantage in the bidding process.

[43] *See generally LSP Transmission Holdings II, LLC v. Huston*, S.D. Ind. Case No. 1:24-cv-01722 (filed Oct. 2, 2024), www.pacermonitor.com/public/case/55307057/LSP_TRANSMISSION_HOLDINGS_II,_LLC_et_al_v_HUSTON_et_al.

- Litigation related to Iowa's ROFR law shows the chaos and uncertainty that has resulted from the litigation landscape that stems from the competitive requirements of Order No. 1000.

- Experience with HVDC projects in the San Jose area of California – including selecting, modifying, and expanding the projects following load growth and expected increase in the cost of equipment – shows not only how cost caps are prone to *ex post* renegotiation, but also how competitive processes have the potential to lead to project selection that does not account for the full cost to customers, fails to right-size the solutions identified, and may create future challenges for utilities to meet load serving obligations.

Overall, these examples show how Order No. 1000 competitive requirements create ongoing impediments to transmission development that are not productive, nor should they be expected to abate going forward. In fact, as regional and interregional transmission needs are expected to grow in the coming years, a reality recognized through Commission rule, things are likely to get worse. And as there is more uncertainty about a broader array of projects, the interactions are likely to produce a more chaotic, challenging, and risky development environment. Not only are competitively developed projects not likely to bring cost savings, as shown by DATA over the last half decade of work, the resulting tumult may cause costs to rise owing to delay, and likewise delay the delivery of benefits to customers. None of these outcomes are aligned with the Commission's policy objectives of advancing transmission infrastructure to ensure affordability and reliability for customers.