August 8, 2016

By Electronic Delivery

Hon. Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 14-E-0454 – In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration; State Register I.D. PSC-25-16-00012-P

Dear Secretary Burgess:

The New York Independent System Operator, Inc. ("NYISO") hereby submits the enclosed Comments in response to the Notice of Proposed Rulemaking in "Consideration of NYISO's Western New York PPTN Viability and Sufficiency Assessment" published in the June 22, 2016 edition of the New York State Register. The NYISO respectfully requests that its comments be accepted into the record of the above-captioned proceeding.

Respectfully submitted,

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 14-E-0454 **—** In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration; State Register I.D. No. PSC-25-16-00012-P

Comments of the New York Independent System Operator, Inc.

I. Introduction

The New York Independent System Operator, Inc. ("NYISO") respectfully submits these comments in the above-captioned proceeding. These comments are prepared in response to the Notice of Proposed Rulemaking in "Consideration of NYISO's Western New York PPTN Viability and Sufficiency Assessment" published in the June 22, 2016 edition of the New York State Register (I.D. No. PSC-10-15-00009-P) ("June 22 Notice").

The June 22 Notice seeks "comments on whether the proposed solutions identified in the [Western New York Public Policy Transmission Need Viability & Sufficiency] Assessment should continue to be analyzed by the NYISO, or whether there is no longer a Public Policy Requirement/PPTN driving the need for a potential transmission solution that warrants further evaluation by the NYISO." The NYISO respectfully submits that there continues to be a transmission need driven by Public Policy Requirements ("Public Policy Transmission Need" or "PPTN") in Western New York. Accordingly, the proposed solutions identified in the May 31, 2016 Western New York Public Policy Transmission Need Viability & Sufficiency Assessment ("Viability and Sufficiency Assessment") should continue to be analyzed by the NYISO for purposes of selecting the more efficient and cost effective solution that is eligible for cost allocation and recovery through the NYISO's tariffs.[1]

A. Background

In accordance with the planning process developed in compliance with Order No. 1000,[2] and the policy statement issued by the State of New York Public Service Commission ("NYPSC" or "Commission"),[3] the NYISO initiated the Public Policy Transmission Planning Process ("PPTPP")[4] by issuing a letter on August 1, 2014, inviting stakeholders and interested parties to submit proposed transmission needs driven by Public Policy Requirements to the NYISO on or before September 30, 2014.

In accordance with the Open Access Transmission Tariff ("OATT"),[5] on October 3, 2014, the NYISO filed, with the NYPSC Secretary, eight proposed transmission needs driven by Public Policy Requirements that were provided to the NYISO by: (i) H.Q. Energy Services (U.S.), Inc., (ii) Iberdrola, USA, Inc., (iii) National Grid, (iv) New York Power Authority, (v) New York Transmission Owners (not including Long Island Power Authority), (vi) NextEra Energy Transmission New York, Inc., (vii) North America Transmission, LLC, and (viii) New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation.[6]

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[1] Case No. 14-E-0454, New York Independent System Operator, *Western New York Public Policy Transmission Need Viability & Sufficiency Assessment*, (May 2016). *See* NYISO Open Access Transmission Tariff, § 31.4.8.

[2] *New York Independent System Operator, Inc.*, Order on Compliance Filing, 143 FERC ¶ 61,059 (April 18, 2013); *New York Independent System Operator, Inc.*, Order on Compliance Filing, 148 FERC ¶ 61,044 (July 17, 2014); *New York Independent System Operator, Inc.*, Order on Compliance Filing, 151 FERC ¶ 61,040 (April 16, 2015); *New York Independent System Operator, Inc.*, Order on Compliance Filing, 155 FERC ¶ 61,037 (April 18, 2016).

[3] *In the Matter of Policies and Procedures Regarding Transmission Planning for Public Policy Purposes*, Policy Statement On Transmission Planning For Public Policy Purposes, Case No. 14-E-0068 (August 15, 2014).

[4] Capitalized terms in this document are defined by Attachment Y to the NYISO Open Access Transmission Tariff and otherwise in the OATT and Market Administration and Control Area Services Tariff.

[5] OATT § 31.4.2.

[6] The NYISO posted the submittals on its website under "Planning Notices" at the following location: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

On July 20, 2015, the Commission issued an order identifying the relief of congestion in Western New York, including access to increased output from the Niagara hydroelectric facility and additional imports of renewable energy from Ontario, as a Public Policy Transmission Need ("Western NY Need") for which the NYISO must solicit and evaluate proposed solutions.[7] Throughout the months of August, September, and October 2015, the NYISO performed analysis to establish a baseline of constraints on the Western New York transmission system against which proposed projects would be measured. On November 1, 2015, the NYISO issued a solicitation for solutions of all types (transmission, generation, and demand side) to the Western NY Need.[8]

At the end of December, the NYISO received, from a total of eight developers, 15 proposals including 12 transmission-only proposals, one hybrid transmission and generation proposal, and two generation-only proposals. Through the first quarter of 2016, the NYISO assessed the viability and sufficiency of all proposed projects, and on June 1, 2016, the NYISO submitted the Viability and Sufficiency Assessment. The report informed the Commission that three of the 15 projects failed to submit a complete response to information requests within the timeframe provided by the OATT, and two projects did not meet the sufficiency criteria. Accordingly, the NYISO identified 10 viable and sufficient projects to address the Western NY Need and also recommended that the PSC determine that certain non-bulk transmission facility upgrades should be made to maximize the benefits of the upgrades to Bulk Power Transmission Facilities and fulfill the objectives of the Western NY Need.

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[7] *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration*, Order Addressing Public Policy Requirements for Transmission Planning Purposes, Case No. 14-E-0454 (July 20, 2015).

[8] The 60-day solicitation window expired on December 31, 2015, in accordance with OATT § 31.4.2.

B. The NYISO's Interest and Position in this Proceeding

The NYISO is an independent not-for-profit entity that is responsible for the reliable operation of the bulk power transmission system in New York State, for planning for that system's continued reliability, and for administering competitive wholesale electricity markets. Because of those responsibilities, the NYISO has an interest in the outcome of this proceeding. The NYISO has no financial interest in the NYPSC's rulings or in the construction of new transmission infrastructure. It has no affiliation with the NYPSC, any transmission project sponsor, or any other entity. As further discussed in these comments, the NYISO has observed constraints in the Western New York area of the New York State bulk power transmission system. As such, the NYISO believes that a solution to the Western NY Need continues to be necessary.

II. Comments

A. New York's Energy Infrastructure Is Aging and in Need of Replacement to Meet Expected Future Needs

The NYISO's 2014 Comprehensive Reliability Plan found that the New York State bulk power system is reliable, and the NYISO is currently conducting the 2016 Reliability Needs Assessment to determine whether Reliability Needs will arise during the NYISO's ten year planning horizon out to 2026.[9] The NYISO's Reliability Needs Assessment examines only violations of minimum transmission system reliability standards.[10] With New York's changing energy landscape and the aging transmission infrastructure, however, there is a clear need for transmission infrastructure to provide important reliability, economic, and public policy benefits

[9] New York Independent System Operator, *2014 Comprehensive Reliability Plan available at:* http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2014CRP_Final_20150721.pdf.

[10] *Id.*

to meet the expected electricity needs of New York consumers.

In comments filed in this proceeding on December 29, 2014 ("December 29 Comments"), the NYISO highlighted the benefits of improved transmission to Western New York, summarizing the broad range of benefits of transmission upgrades that was outlined in a July 2013 report by the Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* ("Brattle Report"). The NYISO submitted that report into the record of this proceeding, and it hereby reiterates and incorporates by reference its December 29 Comments with respect to the Western NY Need. The NYISO further submits the Brattle Group's April 2016 update to its study, highlighting that "[u]ltimately, our transmission grid is the backbone that supports all future policy changes in the electricity sector."[11]

Last month the NYISO published *Power Trends 2016: The Changing Energy Landscape*.[12] This annual publication is designed to contribute to an informed discussion of New York State energy policy. *Power Trends 2016* articulates the need to update the New York State transmission system. Over three-quarters of New York State's high voltage transmission lines are more than thirty-five years old, having gone into service before 1980. Given the age of the State's transmission infrastructure, roughly 4,700 circuit miles of the 11,000 circuit miles in the system will need to be replaced over the next three decades in order to maintain a reliable and economically feasible system.[13]

Power Trends 2016 references the *Energy Highway Blueprint ("Blueprint")* issued by Governor Andrew M. Cuomo in 2012. The *Blueprint* recommended actions and policies to

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[11] Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficient Flexible Electric Grid, Brattle Group, April 2015 (attached as Appendix A).

[12] New York Independent System Operator, *Power Trends 2016: The Changing Energy Landscape available at:* http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2016-power-trends-FINAL-070516.pdf.

[13] *Id.* at pp 17, 31.

attract significant investments in New York State's energy infrastructure. It called for 3,200 megawatts ("MW") of new generation and transmission capacity, funded by public/private investment of up to $5.7 billion. Beyond the focus of the *Blueprint* on upstate to downstate transmission paths, it is also imperative to improve the bulk power transmission system's ability to move power from the Niagara Power Project and other renewable and low- or zero-emission resources located in Ontario and Western New York to Central and Eastern New York.

Congestion, or a "constraint," occurs on the transmission system when transmission lines have inadequate capacity to carry the amount of power that is being generated ("generation") to the places where it is needed ("load"). The NYISO evaluates congestion as part of its planning processes with its biennial Congestion Assessment and Resource Integration Study ("CARIS").[14] The 2015 CARIS identified the most congested parts of the New York State bulk power system based upon historic data (2010–2014) as well as estimates of future congestion (2015–2024). Those areas include all or parts of the high-voltage transmission path in the Capital Region to the Lower Hudson Valley, as well as the 230-kilovolt system in Western New York.

The Western New York area of the transmission system continues to exhibit constraints, as described in detail in Sections B through F below, depriving New Yorkers of the full amount of clean and economic electricity that could otherwise be available to them. Additional transmission capacity continues to be needed to address these constraints.

In comments filed in this proceeding on May 21, 2015 ("May 21 Comments"), the NYISO stated that additional transmission capacity would enhance competition in the electricity

[14] New York Independent System Operator, *2015 Congestion Assessment and Resource Integration Study – Phase 1* (November 17, 2015), *available at*: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf

markets by allowing new resources to compete, thereby increasing liquidity.[15] Additional transmission capacity in New York would also make the system more resilient and able to withstand extreme weather conditions and storms. These include the traditional challenges presented by summer peaks on hot days as well as the less familiar issues that can arise during winter "polar vortex" events. Increased transmission would also give the NYISO greater operational flexibility—*e.g.*, by making it possible to dispatch more generating resources, to allow for more emergency assistance from neighboring regions, to gain access to operating reserves and ancillary services, and to remove transmission for maintenance when needed.

Increased transmission capacity may further enable the integration of renewable energy resources in New York State. Recently, New York has realized growth in wind power and hydropower. Wind power capacity in New York grew to 1,754 MW of capacity and reaching 3,984 gigawatt-hours of electricity in 2015.[16] With the NYPSC's order implementing Governor Cuomo's Clean Energy Standard, it is expected that significant additional renewable capacity will be needed to meet the goal of 50% renewable energy by 2030. Most of this renewable development is expected to take place in the northern and western portions of New York. As the NYISO has commented on in the NYPSC Clean Energy Standard proceeding, more transmission capacity would increase the NYISO's ability to dispatch renewable resources more frequently,

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[15] *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration*, Comments of the New York State Independent Operator, Inc., Case No. 14-E-0454 at pp 6-9 (May 21, 2015).

[16] New York Independent System Operator, Inc., *2016 Load & Capacity Report ("Gold Book")* at pp 62-63.

which would enable transmission of renewable energy output to load centers in the southern and eastern portions of New York State.[17]

Adding transmission would enable New York State to take better advantage of fuel diversity. The mix of fuels used to generate power affects the economics of electricity and the reliability of the power system. A balanced array of resources enables the electric system to better address issues such as price volatility, fuel availability, and the requirements of public policy.[18] Compared to other parts of the country, New York State has a relatively diverse mix of generation resources. An effective way to address statewide imbalances would be to add transmission capacity that increases the ability of hydropower and other diverse resources to serve statewide loads.

B. Transmission Constraints in Western New York

A significant and growing portion of New York State's electricity is generated by inexpensive and clean resources but, due to constrained transmission paths, much of that electricity is unavailable to the load it might otherwise serve. When constraints exist and congestion occurs, more expensive generation must run in and near the load pocket in order to serve the load, which results in wholesale electricity market prices being higher than they would be if the constraints did not exist. The additional costs created by these constraints, which are paid by those making energy purchases from or through the NYISO (and ultimately, ratepayers), is defined as "Demand$ Congestion." Demand$ Congestion for load in the western portion of New York's transmission system, or New York Control Area ("NYCA") Load Zone A (see Figure 1), has increased significantly over the last few years. That congestion is primarily

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[17] *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Supplemental Comments of the New York Independent System Operator, Inc., Case No. 15-E-0302 (July 8, 2016).

[18] *Power Trends 2016* at p 21.

reflected on the Dysinger East interface, which is the collective transmission capability from Zone A to Zones B and C to the east.

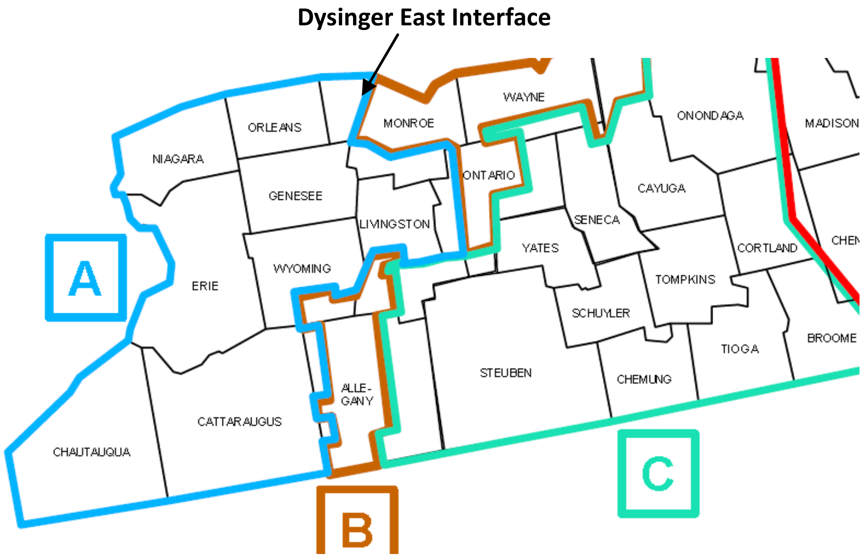
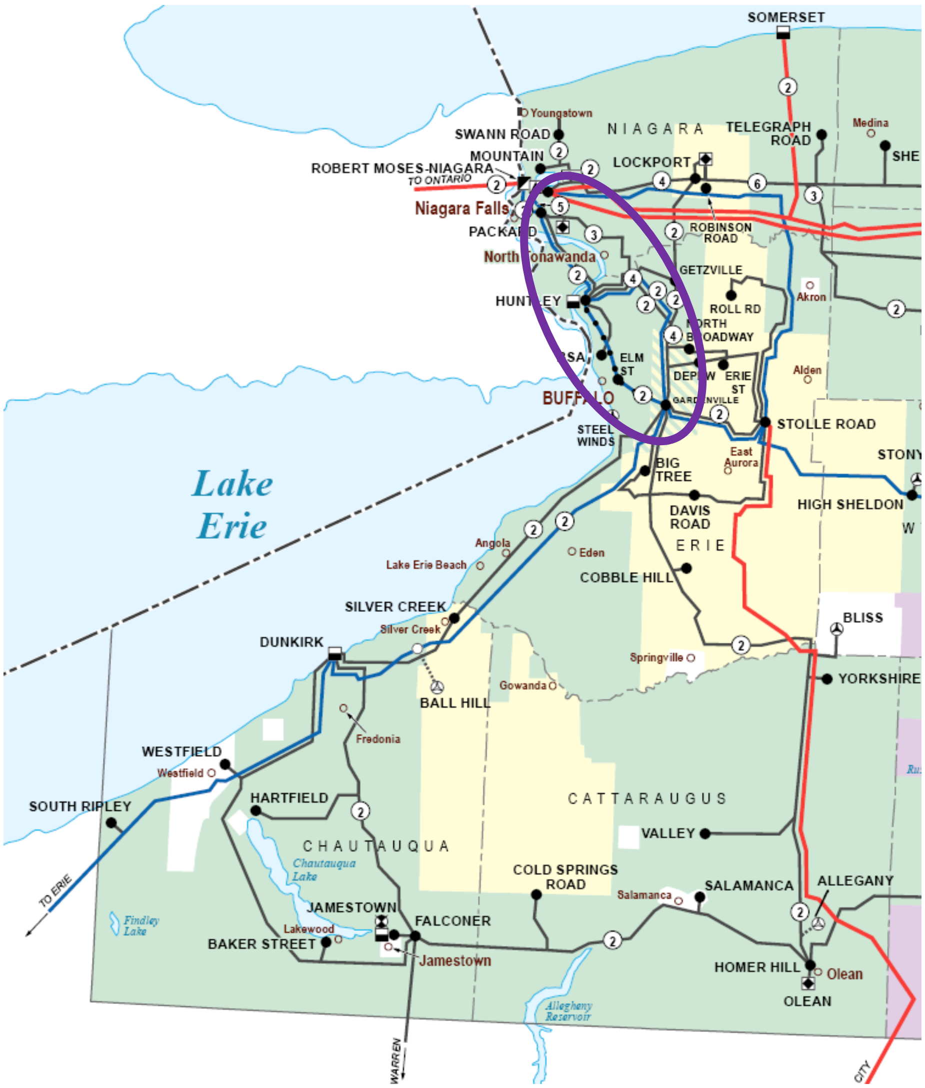


Figure 1. Western New York Area in NYCA Load Zones A, B, and C

The Niagara area is home to the largest hydroelectric generation plant—a significant source of clean and relatively inexpensive power—in New York State, and is the primary interconnection between the NYCA and Ontario, Canada. The primary transmission facilities to transfer power eastward out of the Niagara area consist of two 345 kV lines and three 230 kV lines, plus several underlying 115 kV lines. The majority of the power out of the Niagara area flows on the higher voltage, 230 kV and 345 kV lines, and the transfer of large amounts of available power in that area is constrained by the 230 kV transmission lines between the Niagara and Gardenville substations. Figure 2 depicts the transmission system in this area.



Key: red lines = 345kV; blue lines = 230kV; black lines = 115kV
Purple circle = constrained 230 kV lines

Figure 2. Western New York Transmission Lines

According to the NYISO 2016 Summer Operating Study, the import capability of the Ontario-New York tie lines to Zone A is 1,875 MW, but only 125 MW is actually able to be imported under summer peak load conditions due to the Niagara-Gardenville 230 kV constraints within New York.[19] The study also shows that the Dysinger East interface remains limited by the Niagara-Gardenville 230 kV constraints as the NYISO noted in its previous comments.

[19] New York Independent System Operator, Inc., *2016 Summer Operating Study*, *available at*: http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/operating_studies/thermal_transfers/Summer2016_Operating_Study_OC_APPROVED_5-19-2016_Report.pdf.

These transfer limits, at any given point in time, are highly sensitive to the local load level, the output of Niagara generation, and level of Ontario imports.

The constraints on the 230 kV transmission lines result in frequent, real-time congestion that limits Ontario imports and Niagara hydropower generation from flowing east. These facilities have become more congested in recent years following the mothballing of capacity at the Dunkirk generation plant and the retirement of the Huntley generation plant and several PJM units that previously helped relieve congestion on this corridor.[20]

Demand$ Congestion in Zone A rose from an annual average of $-6.8 million in 2009–2011 to an average of $29.1 million per annum in 2012–2014.[21] Consistent with the recent upward trend, Demand$ Congestion reached over $82.8 million in 2015.[22] Specifically, Demand$ Congestion associated with the Niagara-Gardenville constraints has increased from $0 in 2010 and 2011, to $2.9 million in 2012, to $20.7 million, $18.2 million, and $21.8 million in 2013, 2014, and 2015, respectively.[23]

C. Surplus MW of Import Capacity and Generating Capacity in Zone A are Unavailable Statewide

The total summer generation capability in Zone A is currently 3,994 MW and, as mentioned above, there is an import capability of 1,875 MW from Ontario. This combined total

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[20] Patton, Lee VanSchaick, Chen (Potomac Economics), *2015 State of the Market Report For The New York ISO Markets* (May 2016) ("2015 State of the Market Report"), *available at*: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf.

[21] In its May 2015 Comments, the NYISO showed the cost of congestion in Zone A through the use of Unhedged Demand$ Congestion, which is defined as Demand$ Congestion collected minus Transmission Congestion Cost ("TCC") payments. *See* May 2015 Comments at p 8. However, in 2015, as the congestion in the western New York persisted and become more certain, market participants' purchase of TCCs dramatically increased and the unhedged portion of congestion was subsequently reduced. Nevertheless, the continued increase in Demand$ Congestion demonstrates that Zone A remains congested.

[22] As reported in NYISO's annual and quarterly reports of historic congestion, which are available at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

[23] 2015 CARIS at p 52 (containing information for Niagara-Gardenville congestion for years 2010–2014, which can be found under "Niagara-Packard").

of 5,869 MW, after serving a forecasted 2016 summer peak load for Zone A of 2,680 MW, leaves a 3,189 MW surplus of power available to transfer eastward out of Zone A. However, the NYISO 2016 Summer Operating Study shows that power transfers eastward out of Zone A across the Dysinger East interface (see Figure 1) are limited to approximately 1,145 MW due to the Niagara-Gardenville 230 kV line constraints.[24] With a surplus of 3,189 MW, but an export capability of only 1,145 MW, there is as much as 2,044 MW bottled behind the 230 kV constraints with all transmission lines in-service. The construction of additional transmission out of the Niagara area would alleviate much of this bottling.

D. System Reliability

The preliminary results from the NYISO's Draft 2016 Reliability Needs Assessment have identified transmission security thermal overloads in the case of various N-1-1 contingencies in Western and Central New York under baseline load forecast conditions.[25] These overloads are due to inadequate transmission to deliver power from the Niagara area to the rest of New York State. The constraints and overloads in the Niagara area have been further exacerbated in recent years with the deactivation of downstream power plants, including Dunkirk and Huntley.

E. Elimination of Transmission Constraints

As noted above, transmission constraints can have significant negative consequences for New York electric consumers. In the 2015 State of the Market Report, Potomac Economics

[24] A Dysinger East interface limit of 950 MW is reported in the NYISO 2016 Summer Operating Study. The interface limit decreased by 725 MW from the 2015 Summer Operating Study. This interface captures flows only within New York. For power transfers across Dysinger East, typically 83% flows within New York and 17% flows on tie lines to neighboring regions. Therefore, the overall limit for power transfers out of Zone A is approximately 1,145 MW (950 / 83%).

[25] New York Independent System Operator, Inc. *2016 Reliability Needs Assessment, Focus on Preliminary RNA, Draft Report* ("Draft 2016 RNA") *available at:* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2016-07-05/2016RNA_ReliabilityNeedsReport.pdf.

reported that congestion levels in Zone A rose notably from 2014 to 2015. Those transmission constraints restricted the delivery of inexpensive power from the Niagara hydroelectric plant and inexpensive imports from Ontario and, during periods in which the Western New York system was congested, wholesale electric prices were particularly high and volatile.[26]

By comparison, elimination of transmission constraints and the associated congestion in the Western New York system will have significant economic benefits to New York State electric consumers. The specific benefits can be estimated by looking back at historic periods, simulating elimination of the transmission constraints, and analyzing how the NYISO's day-ahead commitment results are impacted. For example, in a recent simulation study, the NYISO analyzed the impacts of eliminating the 230 kV constraints in Zone A for November 2013 and September 2014 (the peak congestion months in Western New York in those respective years). The study showed that without the 230 kV constraints, average wholesale electric prices in Zone A would have been reduced by $5.47/MWh (14%) in November 2013 and $4.89/MWh (15%) in September 2014. Demand$ Congestion on the Western New York system would have decreased by $10.7 million (or 89%) in November 2013 and $8.5 million (86%) in September 2014. Finally, Niagara output and imports from Ontario would have been 12% (109 GWh) and 7% (50 GWh) higher, respectively, in November 2013; and 15% (128 GWh) and 9% (77.5 GWh) higher in September 2014.[27]

The benefits of eliminating transmission constraints can also be studied by analyzing future system conditions and market results through production cost simulations.[28] In the 2015 CARIS, the NYISO studied the addition of, among other things, a new generic 230 kV line from

[26] 2015 State of the Market Report.

[27] Internal NYISO Study performed utilizing its Congestion Reporting for Off-Line SCUC (CROS) software.

[28] These studies are performed by using GE-MAPS Software.

Niagara to Gardenville that would increase the Dysinger East normal transfer limit by approximately 630 MW. The findings indicated that a 230 kV transmission line is projected to relieve "Western 230 kV congestion" by 88% in 2019 and 96% in 2024 and results in a projected total ten-year production cost savings of $199 million (based on 2015 dollars). Reduction in the Western 230 kV congestion reduces dependence on higher-cost generation in Eastern and Central New York and allows NYCA load better access to economic imports from neighbors.[29]

F. Capacity Market Impacts

Capacity market benefits are another important way that congestion relief is good for consumers. Such capacity market savings could result from reduced statewide capacity requirements when transmission upgrades are added to the system. These upgrades would permit higher levels of flows between regions of the state and allow for increased emergency assistance from Ontario and, therefore, enable New York to meet its reliability requirements with potentially fewer capacity resources.

III. Conclusion

Expanding the bulk power transmission system, as contemplated in the Commission's AC Transmission Proceedings and the Governor's *Energy Highway Blueprint* initiative, would better position New York's bulk power transmission system to mitigate potential threats to reliability by providing greater operational flexibility and increased access to emergency assistance from neighboring regions. New transmission would alleviate congestion and, therefore, as noted above, enhance the NYISO's ability to manage the system during extreme weather and storms. The NYISO expects such improvements to lead to substantial savings for consumers. Transmission additions in Western New York would similarly improve reliability,

[29] 2015 CARIS at p 63.

make markets more efficient, and serve various public policy objectives, such as transmitting energy from more renewable resources, lowering air emissions, and making the transmission grid more resilient.

For the foregoing reasons, the NYISO respectfully submits that there continues to be a Public Policy Transmission Need in Western New York. Accordingly, the NYISO should continue to evaluate the proposed viable and sufficient transmission solutions for purposes of selecting the more efficient and cost effective solution that is eligible for cost allocation and recovery through the NYISO's tariffs.

Respectfully submitted,

/s/ Carl F. Patka

Robert E. Fernandez, General Counsel
Raymond Stalter, Director of Regulatory Affairs
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August 8, 2016

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Rensselaer, NY this 8th day of August 2016.

/s/ Joy A. Zimberlin

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Appendix A

A **WIRES** Report

TOWARD MORE EFFECTIVE TRANSMISSION PLANNING:

ADDRESSING THE COSTS AND RISKS OF AN INSUFFICIENTLY FLEXIBLE ELECTRICITY GRID

THE BRATTLE GROUP

Johannes Pfeifenberger

Judy Chang

Akarsh Sheilendranath

APRIL 2015

www.WIRESgroup.com

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WIRES Preface

Purpose of This Report

WIRES[1] is proud to submit this electric transmission analysis for consideration by policy makers, planners, regulators, and the public. Its importance cannot be overestimated, in our view, for two reasons. First, the report will help the reader grasp that, despite the positive and constructive aspects of transmission planning in the United States today, planners still depend on outmoded methodologies that are likely to cause those critical planning processes to result in suboptimal transmission solutions in the future. Second, the report reflects new issues that have arisen because our historical network of wires and substations is being modernized by federal and state regulators (for example, under FERC's Order No 1000) and by integration of distributed generation technologies, demand responsive innovations, and new digital monitoring and control mechanisms into the larger electricity marketplace – a development with enormous benefits but one that has not eroded the central role of the transmission system as the platform for innovation, security, and markets.

In a 2013 analysis, The Brattle Group[2] outlined the potential economic, operational, environmental, public policy, and reliability attributes of high voltage transmission facilities that had gone largely undefined up to that point and therefore were generally ignored in the planning processes of the regional transmission organizations ("RTOs") and in non-RTO markets as well. To understand the extent to which the full range of benefits that the transmission network provides are *not* considered in system planning processes is to understand the significance of this new analysis. Whereas the 2013 study offered important criteria for determining which

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[1] WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES' principles and other information are available on its website: www.wiresgroup.com.

[2] This new analysis builds on a 2013 report on the benefits of transmission investments to determine if the benefits of those projects exceed costs. It also provides a guide to the benefits that could be identified and measured by project planners for purposes of optimizing the deployment of those assets and assigning cost responsibility. The Brattle Group (Chang, Pfeifenberger, Hagerty), *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investment*, prepared for WIRES (July 2013). Available with other reports and papers at www.wiresgroup.com.

infrastructure solutions would be most beneficial, the following analysis takes a further step in questioning whether policy makers and transmission planners consider the costs and risks of inadequate transmission investment. Are they actively pursuing development and operation of the *most beneficial, economically efficient, and environmentally helpful* transmission infrastructure, based on the best understanding of how transmission benefits can be identified and distributed? And, if not, why not?

A great deal has already been said by the Federal Energy Regulatory Commission ("FERC") and the courts about matching cost responsibility for transmission infrastructure and the receipt of identifiable benefits from such regulated investments. But, remarkably, there has been no common standard (in theory or practice) for the range of transmission benefits by which the merits of any proposed transmission project or a portfolio of projects should be judged. The 2013 study tried to inaugurate that kind of analysis, but the planning practices it advocated have not materialized. WIRES has therefore again asked economists at The Brattle Group to enquire about this apparent problem by reporting on whether regional planning in the post-Order No. 1000 world ensures development of the most beneficial (*i.e.,* the "right") transmission projects. The new report makes clear that there are serious shortfalls in the processes by which planners assess the need for transmission and that those analytical shortfalls entail enormous potential costs and risks – to consumers, to the economy, and to society overall.

It is important to recognize that the U.S. has already amped up transmission investment, and necessarily so. The salient question is, will we invest in the projects that will deliver the greatest public benefits? The purpose of this report, in our view, is to highlight an important planning responsibility – that is, to plan for and select portfolios of investments that stand the best chance of delivering the greatest and most diverse benefits to the most ratepayers and the system over time. A robust and flexible transmission infrastructure will continue to be the key to competitive energy markets, technology deployment,[3] and investments in generation and technology that strengthen reliability, enhance the economic efficiency of regional systems, and

[3] London Economics (Frayer and Wang*), Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, prepared for WIRES (October 2014). "Transmission delivers its services and provides benefits throughout its long lifecycle. And once built, a transmission asset is a fixed element of the power system and therefore its existence is not dependent on market dynamics. In contrast, some [Market Resource Alternatives] such as generation (either utility-scale or distributed) or demand response may decide to exit the market and close operations if market conditions are not attractive. The permanent nature of transmission . . . means that system planners have reasonable certainty that transmission would provide services and benefits . . . over the transmission asset's life." (at 13-14)

promote low-carbon strategies.[4] Beyond the historical practice of patching together resources and native load or settling on lowest-common-denominator solutions among competing regional interests, today's planners need to look ahead to more optimal network structures. Such a constructive regional and interregional planning approach will require the collaboration and support of state, federal, and industry leadership.

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Report Findings

WIRES offers this as a report card on the state of transmission planning. While we had every reason to expect that regional and interregional planning processes developed pursuant to FERC's Order No. 1000 would begin to reflect consideration of the broader range of transmission benefits articulated in the 2013 report, that expectation has remained largely unfulfilled -- with notable exceptions. This new report therefore delves into the costs and risks to consumers inherent in the prevailing approach to planning. The report describes current "conservative" approaches to infrastructure expansion as those based on least cost strategies or a fear that, without absolute certainty about the electricity system's future, transmission is likely to be "overbuilt." The Brattle authors find that this approach is not prudential in the sense that the hesitancy of states, utilities, and planners to make more than incremental grid improvements will ultimately cost future consumers more and ***potentially much more*** for access to, or delivery of, power.

The authors of this new report observe that, despite the fact that most projects provide a range of benefits across relevant parts of the grid, transmission planners continue to "compartmentalize" projects mostly into projects justified by a reliability need or by narrowly defined economic benefits involving production cost savings under normalized system conditions. A more realistic determination about the potential benefits of projects, especially the economic and public policy value of interstate and interregional transmission, would ensure that the projects that are approved and built are the optimal solutions to the problems that need solutions. The result would be a net gain for the future North American energy economy,

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[4] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34830 (June 18, 2014). WIRES has argued that the Environmental Protection Agency ("EPA") dramatically underestimated the potential importance of transmission expansion and upgrades to implementation of at least two of the Clean Power Plan's 'Building Blocks'. The EPA simply assumed that, without building transmission planning into the timing or substance of the rulemaking, transmission would be available to cope with any reconfiguration of the nation's electric generation resources: "The third consideration supporting a conclusion regarding the adequacy of the infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity." 79 *Fed. Reg.* at 34864.

reliability, and jobs, in addition to enabling the industry to adapt more effectively to significant changes in technology and the public policy environment.

The new study is primarily an assessment of whether a more systematic evaluation of potential transmission benefits (1) has been the rule or the exception in the regional and interregional transmission planning processes, (2) can shine light on the costs and risks of not expanding the grid to meet the needs and challenges of the future, and (3) would resuscitate the faltering interregional planning process under Order No. 1000. The report concludes that transmission planning in the U.S. is generally deficient in all these respects.

The following analysis identifies those key deficiencies in existing planning regimes as:

- The failure of current planning processes to consider the full range of demonstrable benefits that proposed projects are capable of providing over time;
- The failure to study and calculate the costs and risks that are created by an incremental and narrow transmission planning approach; and
- The failure of interregional planning processes to lay the groundwork for actionable interregional project proposals that would be able to ensure resource diversity, reliability, and sustainable benefits of wholesale power markets.

The report concludes that, taken as a whole, today's planning techniques are not likely to optimize the benefits of transmission investment. The high voltage system that States and regions depend on must deliver, not only reliable service, but at the same time market and environmental benefits, operational cost savings across the system, congestion relief, and resilience and adaptability that provides economic and public policy returns to current and future generations of ratepayers. The solutions set forth in the report could support a substantial retooling of today's transmission planning processes.

Transmission planning could benefit from becoming, among other things, part of a "co-optimization" process of simultaneous advancement of two or more classes of investment. When only generation or only transmission investments are considered by planners, it may result in "unnecessarily higher costs and emissions, and perhaps a deterioration in reliability."[5] The solution, for example in implementing EPA's Clean Power Plan, may therefore be what has

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[5] Liu, Hobbes, et al., *Co-optimization of Transmission and Other Supply Responses*, (prepared for the Eastern Interconnection States Planning Council and the National Association of Regulatory utility Commissioners), September 2013, at 4. The authors conclude that "full co-optimization can save up to 10% or more of total generation and transmission costs compared to generation-only planning . . ." *Id.*

been called "anticipatory transmission planning."[6] Scenario planning can be used to anticipate how generation, both dispatch and investment, will perform in response to changes in transmission capacity, access, and congestion relief. A proactive planning approach that anticipates the needs of the market and applications of new technology will prove to be the most prudential in the long run. In sum, transmission planning that does not include an evaluation of all potential benefits, does not fully consider risks, and lags generation investments is becoming less and less defensible.

The authors of this report argue that, once planners and policymakers understand the tremendous risks and costs to consumers and the economy of *not* developing a transmission system capable of accommodating the multiple potential outcomes for the electricity future, they will opt for a more strategic approach to planning the grid. The uncertainties facing the industry are apparent and the temptation to plan reactively and only for operational eventualities that are already known and foreseeable is indeed great. Based on this study, however, WIRES is persuaded that there is an equally responsible and far more productive way to approach planning for investment in new transmission assets and to ensure a salutary benefit-to-cost ratio over the long haul. Incorporating real "risk mitigation"[7] into the planning process is the key to addressing the deficiencies in current transmission planning and the sub-optimal results it is likely to produce. Among other things, it necessitates consideration of a broader range of transmission benefits when calculating the benefit-to-cost ratio of a proposed project and the explicit evaluation of short- and long-term risks. It also involves a strategic vision of the electron superhighway as the foundation of the future electricity marketplace. Undeniably, there will be costs associated with such regulated investments. But, as discussed herein, the diverse benefits of a more robust and more flexible transmission system are likely to exceed those costs, sometimes exponentially.

We nevertheless recognize that changing planning practices is hard. Specious but beguiling arguments that technology will soon render the integrated grid obsolete compound the difficulty. In the end, the report makes clear that the U.S. and Canada will incur far greater

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[6] *Id.,* at 3.

[7] One prevalent worry among planners, customers, and policy makers about the risks associated with transmission investment is, for example, that ratepayers or society will end up with $90 million in benefits after spending $100 million on a project. An equally important consideration is what <u>not</u> building the project would mean; *i.e.*, how great are the chances that customers would be somewhat worse off or several multiples worse off <u>without</u> the project, as compared to the probability that they would be better off? As the Brattle report demonstrates, this type of calculus is uncommon in the transmission business, although not without precedent.

costs and risks if they fail to begin modernizing the high voltage transmission network within the foreseeable future.

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Toward More Effective Transmission Planning:

Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

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Executive Summary

This study, commissioned by WIRES,[1] is a continuation of the ongoing efforts to assess transmission planning processes in the United States, to diagnose critical deficiencies, and to recommend improvements. Our analysis focuses on the effectiveness of current and proposed planning practices in identifying the most valuable regional and interregional transmission investments. In doing so, we identify three principal deficiencies that will lead to ineffective or insufficient infrastructure investments and could leave the North American electricity markets exposed to higher risks and higher overall costs. The three principal deficiencies are:

- Planners and policy makers do not account for the high costs and risks of an insufficiently robust and insufficiently flexible transmission infrastructure on electricity consumers and the risk-mitigation value of transmission investments to reduce costs under potential future stresses.

- Planners and policy makers do not consider the full range of benefits that transmission investments can provide and thus understate the expected value of such projects.

- The interregional planning processes are ineffective and are generally unable to identify valuable transmission investments that would benefit two or more regions.

These deficiencies collectively create significant barriers to developing the most valuable and cost-effective regional and interregional transmission projects and infrastructure. If not addressed, these deficiencies will lead to: (a) underinvestment in transmission that results in higher overall costs; (b) lost opportunities to identify and select alternative infrastructure solutions that are lower-cost or higher-value in the long term than the projects proposed by planners; and (c) an insufficiently robust and flexible grid that exposes customers and other market participants to higher costs and higher risk of price spikes.

The case studies we provide in this report show that challenging and extreme conditions regularly occur on the power system and that a more robust and more flexible transmission network can help to mitigate the high-cost impacts of those conditions. A more flexible grid also reduces the cost of addressing the unprecedented long-term uncertainties faced by the industry today.

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1 WIRES is an international non-profit association of investor-, member-, and publicly-owned companies dedicated to promoting investment in a robust, well-planned, and environmentally-beneficial high-voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES principles and other information are available at www.wiresgroup.com.

From this perspective, today's planning processes are anything but "conservative"—a term often used to describe planning analyses that err on the side of discounting the benefits of transmission investments, particularly in light of the significant long-term uncertainties. We show that today's "conservative" approach actually exposes customers and other market participants to greater risks and costs because by understating the benefits of and risks addressed by transmission, valuable investments in transmission facilities are either not made or delayed. In an industry where it can take a decade to plan, permit, and build major new transmission infrastructure, ***further delaying investment by understating transmission-related benefits can easily result in a higher-cost, higher-risk outcome that is exactly the opposite of the goals of "conservative" planning.***

Policy makers, including industry regulators, play a key role in influencing the scope of regional and interregional transmission planning efforts. In an effort to improve regional and interregional planning processes, we thus recommend that state and federal policy makers encourage transmission planners to pay more attention to the transformation that our power system is undergoing, the risks and costs associated with challenging and extreme market conditions, and the ability of a more robust, flexible transmission infrastructure to reduce the costs and risks of delivering power to consumers. To do so, we recommend that policy makers:

1. Resist making the assumption that less transmission investment is always a lower-cost solution. Instead, we recommend that policy makers request that planners move from "conservatively" estimating transmission-related benefits to recognizing the full spectrum of benefits that transmission infrastructure investments can provide, including how having a more robust and flexible grid can insure customers and other market participants against the high costs and risks of unexpected events and long-term changes and uncertainties in market and policy conditions.

2. Urge planners to move from "least regrets" transmission planning that identifies only those projects that are beneficial under most circumstances to also considering the potential "regrettable circumstances" that could result in very high-cost outcomes because of inadequate infrastructure. Stating it in terms of providing insurance value: planners should move from focusing on the cost of insurance to considering the cost of not having insurance when it is needed.

3. Urge transmission planners to move from compartmentalizing projects into "reliability," "economic," and "public policy" projects to considering the multiple values provided by all transmission investments.

Regarding *interregional* planning processes, we also recommend that state and federal policy makers urge planners to:

4. Expand interregional planning processes to allow for the evaluation of projects that address different needs in different regions, recognizing that most interregional transmission projects offer a wide range of economic, reliability, and public policy benefits and that the type and magnitude of these benefits can differ across inter-connecting regions.

5. Refrain from resorting to "least common denominator" approaches to interregional planning that consider only a subset of the benefits recognized in the individual regions. Instead, require that every region, at a minimum, consider in its evaluation of interregional transmission projects all project types and all project benefits that are already considered within its regional planning process.

6. Go beyond the benefits evaluated in their individual regions to:

   a. Consider the *combined* set of benefit metrics from all interconnected regions, even if some of the benefit metrics from other regions are not yet used in some of the regions' planning processes; and

   b. Consider the unique additional values offered by interregional transmission projects, such as increased wheeling revenues or reserve sharing benefits that interregional transmission investments can provide.

7. Apply benefit-to-cost thresholds to interregional projects that are no more stringent than those applied within each region.

We also want to note the obvious: not all proposed transmission projects are justifiable economically nor should they be built. Rather than simply trying to build as much transmission as is justifiable under current planning standards, the emphasis of policy makers and planners should be to identify and invest in the most valuable, economically-beneficial bulk power infrastructure. This requires that the full benefit of transmission investments is recognized and that so-called "non-transmission alternatives" and means to more efficiently utilize existing infrastructure are evaluated as well.

Given the increased regulatory and environmental uncertainties facing the electricity industry today, the industry needs to start planning more actively in anticipation of possible future outcomes. Otherwise, time constraints on implementing solutions will leave the industry with fewer options that will make it more costly and more risky to address the challenges ahead. It is consequently important to identify the investments that provide the most benefit with the aim of reducing the overall costs and mitigating the risks faced by electricity consumers and other market participants over both the short- and long-term.

The risks and costs of inadequate infrastructure typically are not quantified but can be much greater than the costs of the necessary transmission investments. We therefore urge federal and state policy makers to ensure that planning processes include an assessment and documentation of those risks and costs. With an informed understanding and appreciation of those costs and risks, regions will be in a better position to plan a transmission infrastructure that can better protect market participants against these risks. Because leaving out or discounting the potential costs and risks of not having a sufficiently robust and flexible grid can significant increase overall electricity cost for consumers and other market participants, we hope policy makers will fully examine the issues discussed in this report and consider our recommendations for a path toward more effective transmission planning.

I. Introduction

In 2013, WIRES published a report developed by The Brattle Group to document available experience with identifying and analyzing the wide range of benefits offered by transmission investments.[2] This current report focuses on the costs and risks that an insufficiently robust and insufficiently flexible transmission infrastructure imposes on customers and society as a whole. It reviews and documents actual industry practice and the extent to which transmission-related benefits are or are not considered in the regional and interregional planning processes used by the regional transmission organizations (RTOs) and in some non-RTO regions in the U.S. We reiterate the importance of recognizing and considering all transmission-related benefits to achieve a more cost-effective power system and mitigate risks to consumers and society as a whole, and also to identify gaps, barriers, and opportunities for planning economically-efficient transmission, particularly with respect to interregional planning.

The facilities that constitute the U.S. high-voltage transmission system typically have physical lives ranging from 40 to 80 years. The existing transmission grid was developed over the past six decades, with the largest percentage of the investment made in the 1960s and 1970s.[3] The large extent to which we still rely on transmission infrastructure built in the 1960s and 1970s shows that the infrastructure, once built, is associated with long-term economic benefits of a range and magnitude far beyond those anticipated at the time when policy makers and market participants planned the system upgrades. This experience shows that a robust and flexible transmission system provides many positive externalities not typically considered by planners when they identify the specific "need" for transmission infrastructure.

While very little transmission infrastructure was added in the two decades between 1985 and 2005, the most recent decade has again seen a significant increase in transmission investments. Annual transmission investments by the Federal Energy Regulatory Commission (FERC or Commission) jurisdictional transmission owners ranged only from $2 billion to $4 billion per year in the decade ending 2005. However, since 2010, U.S. transmission investments have ranged from $10 billion to $16 billion per year and, despite year-to-year fluctuations, are forecast to remain at that level through 2030.[4] The higher recent investment levels lead to a sentiment that enough investment has been made and that further increases in transmission rates should be avoided. This sentiment has

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[2] Chang, Pfeifenberger, and Hagerty (2013) (hereinafter 2013 WIRES Report).

[3] U.S.-wide annual transmission additions at a voltage level above 132kV ranged from 4,000 to 9,000 circuit miles per year between 1960s and the early 1980s, but have been only 1,000 to 2,000 circuit miles from 1985 through 2005. In recent years, annual additions have ranged between 2,000 and 6,000 circuit miles. See Pfeifenberger, Chang, Tsoukalis (2014).

[4] *Id.*

led to a desire by some regulators and market participants to oppose any non-mandatory transmission solutions when analyzing investment options.

Although the overall policy objective of planners and regulators should be to manage the total costs and risks of our power system and its delivered costs of electricity, discussions often are focused narrowly only on transmission costs. Unfortunately, because transmission costs typically account for only 5–10% of average customer bills, a narrow focus on transmission costs tells us very little about the overall costs and risks faced by customers and other electricity market participants.

To assess the impact of transmission on the overall costs and risks faced by users of the electricity grid requires full consideration of the wide range of needs, benefits, and risk mitigation provided by transmission infrastructure investments. While "cautious" and "prudent" planning is always important when it comes to assessing the merits of individual projects, it is also important to fully consider the potential high cost of *not* making certain transmission infrastructure investments. Because such infrastructure investments can provide insurance against a multitude of high-cost outcomes in both the short- and long-term, a truly cautious and prudent planning approach requires an understanding of the risks and magnitudes of such outcomes.

As policy makers and system planners consider the future needs and benefits of our electricity grid, it is necessary to look beyond near-term needs to better understand the ability of long-lived infrastructure to manage costs and mitigate risks. Focusing only on the near-term needs of the system or resorting to "conservative" planning approaches that reject or delay valuable transmission investments may yield lower transmission rates in the short-term, but will result in a transmission system that increases the overall costs of electricity in the long-term and magnifies the many short- and long-term risks that can impose very high costs on customers and other market participants.

We want to emphasize at the outset that the overall planning objective should be to invest in the most economically-beneficial transmission infrastructure that can meet reliability, economic, and public policy needs. This perspective can differ significantly from maintaining a transmission infrastructure that only satisfies reliability needs at the lowest incremental transmission cost. Of course, it does not mean that all proposed transmission projects could be economically justified or should be built. Moreover, the best use of existing transmission capacity and rights-of-way needs to be a priority and alternative solutions must be evaluated as well. Because investing in transmission infrastructure will necessarily increase transmission rates but can reduce overall costs by a more significant amount, it is important to identify the most valuable investments in order to reduce the overall costs and mitigate risks faced by electricity customers and other market participants.

We also want to recognize that the evaluation of the merits of transmission projects is inherently linked to a broad set of important other considerations. Some of these other factors—which create additional challenges and barriers are not addressed in this report—include cost allocation, permitting and siting, allowed returns and incentives for investments, the need for better planning tools, the complications associated with the new competitive transmission processes introduced in response to Order 1000, and any potential organizational changes that might be helpful to support improved planning processes.

The remainder of this report is organized as follows:

- Section II documents the need to more systematically consider the wide range of economic, reliability, public policy, and other benefits that transmission investments can provide.
- Section III presents a discussion of the costs and risks that an insufficiently robust and inflexible transmission infrastructure imposes on customers and society as a whole and the importance of considering these costs and risks in transmission planning.
- Section IV discusses regional transmission planning practices that are currently employed within the various U.S. power-market regions. The discussion documents that most regional planning processes are deficient because they have failed to consider many transmission-related benefits and the lack of considerations for the high costs and risks that can be imposed by having an insufficiently flexible transmission infrastructure.
- Section V reviews the current practices associated with interregional transmission planning, identifies the significant gaps and barriers that prevent the identification and evaluation of beneficial interregional transmission projects, and proposes options to address the identified interregional planning deficiencies.
- And, finally, Section VI summarizes our overall conclusions and recommendations on possible ways forward.

Our report also contains three appendices. Appendix A presents a detailed case study of a probabilistic transmission planning study, Appendix B describes a framework for assessing uncertainties through improved use of scenarios and sensitivities, and Appendix C presents two case studies of proposed interregional planning processes and their limitations.

II. The Wide Range of Economic Benefits of Transmission Investments

Traditionally, the majority of transmission projects have been proposed and developed by vertically-integrated incumbent utilities whose primary focus is to serve native load and maintain a reliable transmission system for their franchised service areas. Over time, the bulk power grid has become highly integrated regionally and, to some extent, interregionally. The implementation of the FERC's Order No. 1000,[5] which requires that transmission planning regions consider reliability, economic, and public policy drivers in both regional and interregional transmission planning processes, likely will drive a continuation of this trend to more integrated regional power markets.

In the past decade, the scope of transmission planning has expanded beyond addressing reliability and load serving concerns to include consideration of economic and public-policy drivers. In that

5 FERC (2011).

context, planners and policy makers increasingly recognize that planning for economic- and public-policy-driven transmission projects requires consideration of the economic benefits and costs associated with these investments. So-called "non-transmission alternatives"— referred to as "market resource alternatives"—need to be considered as well, which means transmission-related benefits must be considered along with the benefits of alternatives.[6]

In RTO regions, where transmission planning involves multiple transmission owners within a single organized market, economic analyses have become more integral to the transmission planning process. Most of these economic analyses rely primarily on the traditional application of production cost simulations to determine whether the production cost savings associated with a transmission project—which are mostly composed of fuel cost savings—outweigh its costs. In some planning regions, the analysis of economic benefits has expanded to consider values beyond production cost savings for at least a subset of transmission projects evaluated within the regional planning process. The additional benefits considered include reduced system losses, the value of increased system reliability, access to lower-cost conventional and renewable generation, reduced reserve margin requirements, and increased market competition, among others.

While the *importance* of considering a wide range of benefits is now recognized by some policy makers, few state regulators are actively engaged in discussions concerning the need for system planners to more fully consider the potential benefits of regional and interregional transmission projects. In addition, as FERC noted in its approval of Southwest Power Pool's (SPP's) Highway-Byway transmission tariff, "relying solely on the costs and benefits identified in a quantitative study…may not accurately reflect the [benefits] of a given transmission facility, particularly because such tests do not consider any of the qualitative (*i.e.*, less tangible), regional benefits inherently provided by an [extra-high voltage] transmission network."[7]

The U.S. Department of Energy's (DOE's) August 2014 draft release of its "National Electric Transmission Congestion Study"[8] discusses the importance of considering the wide range of transmission-related benefits and the associated costs of inadequate transmission infrastructure. The following quote from the draft congestion study summarizes very well the problems associated with limiting the scope when evaluating transmission investments:

> Construction of major new transmission facilities…raises unique issues because transmission facilities have long lives—typically 40 years or more. Evaluating the merits of a proposed new facility is challenging, because common practices take into

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6 For a discussion of how market resource alternatives (such as distributed generation, storage, demand response, and smart grid technologies), can complement the need for transmission infrastructure investments, see Frayer and Wang, (2014).

7 FERC (2010), 131 FERC ¶ 61,252.

8 DOE (2014).

> account only those expected costs and benefits from a project that can be quantified with a high degree of perceived certainty. This has two effects:
>
> First, it leads to a focus on the subset of cost and benefits that can be readily quantified. Not taking into account the costs and benefits that are hard to quantify has the effect of setting their value to zero in a comparison of costs and benefits. Second, it leads to projections of costs and benefits that are generally based on extrapolations drawn from recent experiences. Projections based only on recent experiences will not value the costs and benefits a transmission project will have under very different assumptions or scenarios regarding the future because they ignore or discount the likelihood of these possibilities. Such a narrow view of the range of costs and benefits that could occur provides a false sense of precision.
>
> For example, one of the most strategically significant aspects of major new transmission projects that is seldom taken into account explicitly in the planning phase is the multiple purposes that transmission might serve. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks, in turn, create real options to use the transmission system in ways that were not originally envisioned. In the past, these unexpected uses have often proven to be highly valuable and in some cases have outweighed the original purposes the transmission enhancement was intended to serve. Past examples have included enabling grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters. The options created by a strong and flexible transmission network are real. Failure to take explicit account of these options in the planning process will severely understate the value of transmission.[9]

The North American Electric Reliability Corporation (NERC) has similarly recognized the shortcomings of current transmission planning practices in a discussion at a FERC Technical Conference on reliability in June 2014. While these comments are focused solely on the reliability planning of the Bulk Power System (BPS), they echo the need for improved transmission planning approaches and enhanced planning capabilities to address the rapid changes faced by the industry today:[10]

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9 *Id.,* pp. xiii–ix.

10 Burgess and Cauley (2014), p. 2.

> Among the key priorities identified as an emerging issue…is the important need for enhancing the planning capabilities to provide sound insights as the industry rapidly changes and adapts operations and planning. As highlighted in numerous recent long-term reliability assessments, the BPS in North America is dramatically changing in many ways.… [T]he continued wide-scale retirement of coal, petroleum, and more recently nuclear, and other baseload generation has rapidly accelerated these changes, which are being compounded by the wide-scale addition of gas-fired and variable (*e.g.*, wind, solar) resources.
>
> Understanding the reliability impacts [of these developments] will require significant changes to traditional methods used for system planning and operation. The resulting reliability behaviors within the resource supply, the transmission delivery system, and the demand characteristics will require more sophisticated analysis methods, integrated and more extensive data, probabilistic approaches, and other approaches to effectively plan and operate a reliable system. Power system planners must consider the impacts of all these changes in power system planning and design and develop the practices, tools, and methods necessary to maintain long-term BPS reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability.
>
> In support of enhancing planning approaches and assessments, [NERC] has promoted the evolution of probabilistic reliability assessment techniques…This has informed and provided a solid foundation for further risk-based approaches, which needs to be expanded on the generation resource, the load side, and the transport across transmission systems.

The need to improve planning processes in light of the industry's current uncertainties and challenges is already recognized by some state policy makers in the context of utility resource planning. For example, in a recent draft report reviewing the long-term planning efforts of the Indiana utilities, the Indiana Utility Regulatory Commission staff noted that:

> [F]ew industries are as important as the electric system, which has been called the most complex man-made system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The urgency for continual and immediate improvements are heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and new technologies. To this end, the [Commission's] IRP draft rules anticipate continual improvements in all facets of the planning processes of Indiana utilities. It

> is clear that utilities have made substantial progress but, given the importance of long-term resource planning, much work remains to be done.[11]

Although the FERC, the DOE, NERC, and state regulators increasingly recognize that the existing tools and methods need to be enhanced to properly assess the need for and value of transmission infrastructure investments, many states and transmission planning groups continue to apply a very narrow perspective of economic benefits in their transmission planning processes. To facilitate the necessary improvements in economic planning processes, state regulators will ultimately need to be among the forces-at-play behind setting the industry's direction in transmission planning. After all, state regulators and policy makers are the first to be blamed for price spikes and electricity cost increases associated with inadequate infrastructure. Even though FERC has tariff jurisdiction over transmission, without individual states' active support neither regional nor interregional transmission planning efforts will be able to reach their stated goals.

Despite the mostly narrowly-focused analyses of economic benefits in most transmission planning efforts, the industry is slowly gaining experience with evaluating the wider range of benefits offered by transmission infrastructure. Taking advantage of this growing experience, our 2013 Report compiled a comprehensive "checklist of economic benefits"—reproduced here as Table 1 below—and recommended that this checklist of benefits be considered in both project conceptualization and project evaluation efforts to help planners understand and communicate a more comprehensive and compelling "business case" for proposed transmission investments.

Starting with a comprehensive inventory of possible transmission benefits during the project conceptualization stage helps avoid narrowing the scope of benefits considered to only those for which analytical tools are readily available or that are traditionally considered. While many of these benefits were historically discussed as "intangible," "qualitative," or even "unquantifiable," there is now significant collective experience in quantifying the value of the benefits listed in Table 1. That experience shows that the economic value of a project's total benefits can be significantly greater than the traditionally-quantified production cost savings. Our 2013 WIRES Report discusses specific evaluation techniques to quantify some of the benefits listed in Table 1 and explains that even for those benefits not typically evaluated, specific methods have been developed to allow for at least a rough assessment of the additional value. The possibility of these benefits having a non-zero value should be considered for all projects, even if some of the benefits may be unique to individual transmission projects.

[11] See Borum (2015).

Table 1
Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability <u>or</u> c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

The next section of this report focuses on the need to move beyond the narrow and incremental approaches in the current regional and interregional transmission planning processes. We explain that the current approach will tend to result in underinvestment in the transmission infrastructure, investments in economically inferior projects, and lead to higher-cost, high-risk outcomes for a state's consumers and other market participants.

III. The High Costs and Risks of Inadequate Transmission Infrastructure

The risks and potential costs of inadequate transmission investments are particularly high given the significantly short- and long-term uncertainties and changing market conditions that the electricity industry currently faces. With low natural gas prices, increasing pressures to reduce carbon emissions, and more stringent federal and local environmental regulations on the horizon, the generation portfolio will be changing significantly over the next decade. Ultimately, our transmission grid is the backbone that supports all future policy changes in the electricity sector. If environmental regulations—such as a version of the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan proposal—require the future resource mix to shift more quickly from fossil-fuel-based generation to cleaner and renewable resources, developing the transmission system required to support such industry trends needs to begin now. Policy makers and industry planners should thus go beyond planning for what is already known, to considering the likely range of future policy environments to address those possible futures in their transmission and resource planning blueprints today. Given the long time it takes to develop new infrastructure, doing otherwise would eliminate many valuable options and expose customers and other market participants to the significant risks and costs of an inflexible grid that cannot keep up with the changes in the industry and therefore cannot support such changes cost effectively.

In the economic planning analyses of proposed new transmission investments today, the estimated costs of building new transmission facilities are compared to the projects' estimated economic benefits. Because the costs of planning and constructing the transmission facilities are perceived to be relatively well-known (and at times underestimated) but the benefits are perceived to be uncertain, many transmission planners and state regulators conclude that a "prudent" economic planning framework should both apply a benefit-cost ratio that is greater than 1.25 *and* rely on conservatively low estimates of transmission benefits.

We have traditionally framed the planning question: "*By how much would the estimated benefits exceed the costs of transmission?*" While requiring benefits to exceed costs is the typical criteria in economic planning, such a planning framework will lead to underinvestment if (a) the magnitudes of the benefits of the investment greatly depend on the uncertain conditions of the market in which the transmission is deployed and (b) benefits that seem to be inexact in magnitude are ignored or discounted in the name of applying a "conservative" planning perspective.

Having "conservative estimates" of economic benefits usually appears attractive to regulators and policy makers because following "conservative" planning criteria usually is perceived to protect customers by reducing transmission rate increases and reducing the likelihood that the actual benefits realized will turn out to be less than the transmission investment's costs. However, the opposite is actually the case. Comparing projected transmission costs to conservatively low estimates of projected transmission-related benefits produces results that expose customers and society as a whole to larger risks and higher overall electricity costs. This perhaps counter-intuitive conclusion results from the interaction of two factors:

- First, the economic benefits associated with proposed transmission facilities are estimated as the difference in "costs" with and without the investment. Ideally, this should be the difference in the system-wide cost of delivering electricity.[12] However, because today's transmission planning processes only consider changes in "production costs" (*i.e.*, mostly only fuel costs) based on "normal" system conditions, a potentially large portion of costs that could be affected by transmission (and thus be a source of value) is missing from the analysis.

- Second, if transmission investments are rejected based on such narrowly-defined benefits (which assumes a zero impact on any costs other than production costs) this will result in higher costs of electricity for consumers. In other words, actual costs will turn out higher than estimated because the analysis did not consider cost elements and the chance of (non-normal) high-cost conditions that the investment would have reduced.

Broadening the scope of transmission benefits analyses is sometimes opposed because some of these benefits (*i.e.*, additional costs incurred without the investment) are perceived to be uncertain. However, just because the economic benefits of a proposed transmission investment are inherently uncertain (because the actual "benefits" that will materialize could be either lower or higher than is estimated during the planning process), it does not mean they should be discounted or not even be considered (*i.e.*, assumed to be zero). This is particularly important as it relates to the analyses of challenging economic, weather, and system conditions because total costs tend to be disproportionately higher during such conditions—which will regularly be encountered over the long life of the investment. Ignoring these situations means that, *without the investment*, the costs and risks imposed on consumers and other market participants will tend to be much higher than typically estimated.

In summary, discounting transmission-related benefits and not fully evaluating short- and long-term uncertainties exposes customers and society to potentially high cost outcomes that may occur without the investment. Thus, to evaluate whether a particular investment should be made, we must understand the full range of uncertain costs that consumers and society as a whole may face *without* the proposed investment. Ignoring transmission benefits because they are uncertain simply means leaving customers and market participants exposed to these higher costs and risks when they could be mitigated through the investments.

To better address these challenges, we propose policy makers and planners ask the question "*What costs might customers and society as a whole face without the proposed transmission investments?*" as a routine part of every transmission planning effort. Asking this question would make it easier to assess and understand the total cost and risk exposure created by an insufficiently robust and flexible transmission infrastructure.

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12 In other words, an economic benefit calculation compares: (1) the cost that customers or society as a whole would incur with the transmission infrastructure investment; to (2) the costs that customers or society as a whole would incur without the investment.

A. INSUFFICIENT SYSTEM FLEXIBILITY INCREASES COSTS AND RISKS IN BOTH THE SHORT- AND LONG-TERM

The uncertainties that the industry is facing can be categorized into short-term and long-term uncertainties. An important and very tangible risk associated with not pursuing certain transmission investments is that insufficient system flexibility increases the costs of (a) operating the system under stress conditions in the short-term, and (b) adapting to policy changes and changing market conditions in the longer-term.

On a ***short-term*** basis the bulk power system is exposed to a number of uncertainties, such as fuel price fluctuations or delivery problems, plant and transmission outages, weather-related uncertainties, and combinations of these factors that can create very challenging if not extreme market conditions. Even though extreme conditions are supposed to be rare, the costs to which customers and other market participants are exposed when those conditions do occur are very high. Such high-cost outcomes should thus be considered in estimating the economic value and risk mitigation benefits of transmission investments. While reliability planning is routinely performed for "critical system conditions," most economic planning studies today analyze customer and societal costs only under "average" or "normal" system conditions. While many planners and policy makers intrinsically understand that upgrading the transmission system provides valuable insurance against both reliability event and high-cost economic outcomes, it is surprising that economic planning practices discount or entirely ignore the likelihood of high-cost outcomes and the insurance value that transmission investments can offer for reducing the cost of such outcomes.

Virtually all economic transmission planning efforts analyze system-wide costs only for average weather-related loads, normal generation outages, and a fully intact transmission system (*i.e.*, zero transmission outages). This approach to economic planning is particularly surprising when considering that many of the most challenging events recently faced by the industry—such as the price spikes associated with the "Polar Vortex," the 2011 weather events in the Electric Reliability Council of Texas (ERCOT), or even the 2000–2001 California Power Crisis—were associated primarily with very high costs but no or only modest reliability implications. Even though such high-cost events happen surprisingly regularly, we are only aware of a few planning studies (one of which we present as a case study in Appendix A of this report) that attempted to analyze the costs and risks of transmission constraints under a wide range of both typical and challenging market conditions.

On a ***longer-term*** basis, a less robust and flexible transmission grid translates to a higher cost of responding to the uncertain but increasing long-term challenges faced by the industry, particularly in terms of new environmental regulations (such as EPA's proposed rules for meeting Section 111(d) of the Clean Air Act), shifting fuel mix, distributed generation, and the integration of new technologies. Given the trend associated with the combination of these drivers, a "wait and see" approach of planning only for a "business as usual" future or of delaying planning responses until the current uncertainties resolve themselves, the traditional planning approaches need to be modified to specifically recognize the long-term challenges and uncertainties faced by the industry and increase the industry's options and flexibility to reduce the risk and costs of addressing these challenges.

For example, in a recent presentation a leading industry analyst noted that, even in the absence of final carbon regulations by the EPA, he expects every company to "come forward with a carbon compliance strategy" because the trend toward some form of carbon reduction rules "is very much real" and "companies need to be planning today with a five-year forward view and with carbon incorporated into integrated resource plans."[13] The analyst's question to the industry, "How can you possibly make an integrated resource plan in any state without incorporating carbon?," is also starting to be asked by state regulatory commissions. Similarly, in the draft report reviewing the integrated resource plans of its utilities, the Indiana commission staff noted that "it would be prudent for the utilities to consider a broad spectrum of possible implications" of the EPA's proposed Clean Power Plan and other environmental regulations. The draft report stressed that "[i]t is especially important to consider a broad range of risk associated with CO_2, in conjunction with other environmental rules" and "consider the possible impact of continued low-cost natural gas" because of their "potential for accelerating the deactivation of some power plants and other aging utility infrastructure."[14] Because transmission will be critical in constraining or enabling the industry's available low-cost compliance options but the lead time necessary to modify transmission infrastructure exceeds those of most generation or demand-side options, it is critical that regional and interregional transmission planning processes proactively consider the already-known long-term uncertainties and challenges.

As an illustration of the type of longer-term benefits of planning a robust and flexible transmission system, a study recently prepared by a consortium of 5 universities for Eastern Interconnection States' Planning Council (EISPC), National Association of Regulatory Utility Commissioners (NARUC), and the DOE documents that traditional planning approaches are no longer adequate to achieve least-cost outcomes in light of challenges such as plant retirements, renewable generation integration, and increasingly stringent environmental regulations that lead to significantly more complex and less predictable power systems.[15] The study finds that the traditional planning processes used in the industry yield suboptimal levels of transmission investments that increase the combined generation and transmission costs by 5–10%. It further estimated that improved planning processes, if applied nation-wide, would save $150 billion in total costs by spending $60 billion more on interregional transmission.

Because we rarely go back to transmission investments already built and assess what the impact of certain stress conditions would have been on consumers and the system as a whole had the project not been built, the lessons learned through actual experiences are quite limited. Likewise, if a

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13 Poszywak (2015).

14 See Borum (2015). For a summary, see Matyi (2015).

15 EISPC (2013).

project were rejected in a planning process, we hardly go back to reassess the impact of certain stress conditions experienced by consumers and society had the project been built.

We are aware of only one such *ex post* study, which was undertaken in 2001 by the California Independent System Operator (CAISO) in context of reevaluating the upgrade to "Path 15," a main transmission constraint between southern and northern California. Prior to the California power crisis in 2000–01, upgrading Path 15 had already been considered and rejected based on limited need. For example, annual congestion on Path 15 amounted to only $12 million in 1998. However, during the California Power Crisis—due to drought conditions in northern California and the Northwest, an unusually hot summer in southern California and the Southwest, and gaming of transmission constraints by certain market participants—congestion on Path 15 increased to a range of $20 million to $80 million ***per month***. The CAISO's analysis in early 2001 documented that the Path 15 upgrade, had it been in-service during the Power Crisis, would likely have reduced the energy and ancillary services costs by over $200 million through December 2000.[16] Given the project's ultimate costs of $250 million and the fact that the crisis lasted through the first quarter of 2001, we now know with the benefit of hindsight that upgrading the transmission constraint would likely have paid for itself in just one year during the Power Crisis.

In addition, the CAISO's 2004 evaluation of a second Palo Verde to Devers (PVD2) transmission line provides a good example of a forward-looking planning study that identifies the high costs and risks that can be mitigated by a more robust transmission infrastructure. It does so by using a broader and more in-depth planning approach than is traditionally used in reliability planning and the economic transmission analyses.[17] As summarized below and discussed in detail in Appendix A of this report, this example demonstrates both the short-term and the longer-term impact of planning for uncertain futures. The CAISO's PVD2 analysis also illustrates why traditional planning approaches for economically-justified investments would reject many projects even if their total benefits significantly exceed costs. As we discuss further below and in Appendix A, the case study shows that, while *forgoing* the investment may avoid some possible future outcomes in which benefits might fall slightly short of project costs, *not making the investment* will leave customers and other market participants exposed to a significant risk of cost increases that can be five to ten times higher than the annualized cost of the transmission project.

B. Understanding the Costs and Risks of Inadequate Transmission

From a risk management perspective—particularly when considering that total transmission charges tend to account for only 5% to 10% of the total cost of delivering electricity to end users—the total cost of not having enough transmission can easily be a multiple of the cost of having built too much transmission. This asymmetry in risks is precisely why under-valuing transmission

16 CAISO (2001), p. 2.

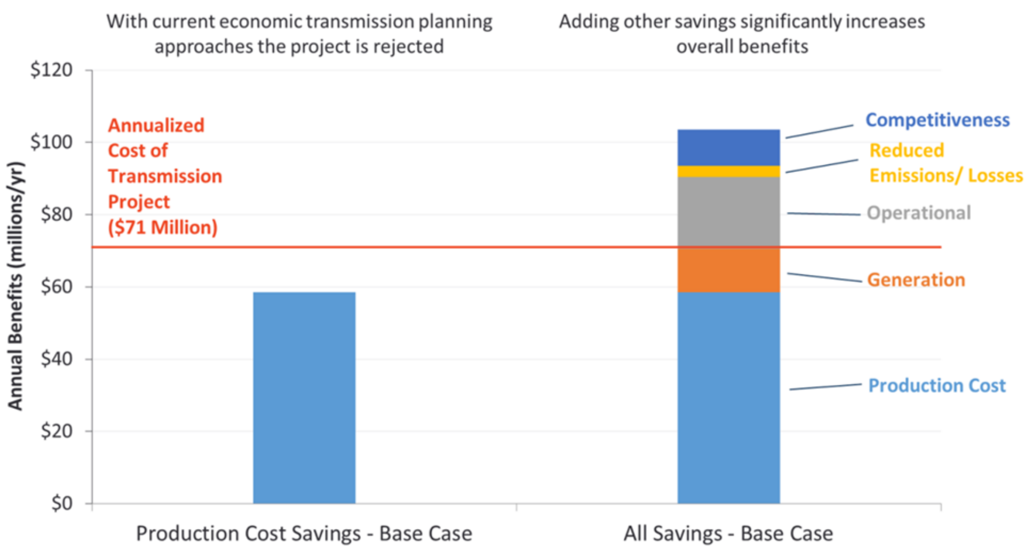
17 See Appendix A.

benefits achieves exactly the opposite of "conservative" planning. Just as the benefit-cost analysis of buying insurance would lead to unreasonably risky decisions if it understated the risk and potential cost of not buying insurance, transmission planning that ignores or understates the risks and potentially high costs of an insufficiently robust and flexible transmission infrastructure is not a "conservative" approach.

Today, almost all transmission planners and policy makers recognize reliability-related risks that arise during challenging system conditions. Few policy makers and planners would want to see the power system be exposed to even modest risks of reliability events. So why would planners and policy makers *not* want to recognize the significant risks of high-cost outcomes that are created by an insufficiently robust and flexible transmission system?

As discussed further in Appendix A, the CAISO's 2004 analysis of its PVD2 project estimated that production cost savings associated with the project were only $55 million, which is well below the $71 million estimated annualized cost of the project. However, as summarized in Figure 1 below, once other benefits such as reduced must-run generation costs, emissions reductions, reduced generation investment costs, and increased competition were taken into consideration, the total annual benefits increased from $55 million to approximately $100 million per year even under "base case" planning assumptions.

Figure 1
Estimated Annual Base-Case Benefits and Costs of CA Palo Verde-Devers 2 Line



In addition, the CAISO's analysis of seventeen plausible scenarios and a number of long-term contingencies (which could happen in any of the scenarios) showed that, even after including a more complete analysis of all benefits, these base-case results still significantly understated the overall cost-reductions and risk mitigation offered by the project. Specifically, the CAISO analysis considered 17 future scenarios with assigned probabilities. Considering the different scenarios and likelihood of those futures becoming reality, the total benefits range from $70 million annually at the low end to $550 million/year on the high end, prior to considering any long-term contingencies.

As the PVD2 analysis further shows, the estimated probability-weighted average of the project benefits across the different scenarios is approximately $120 million per year (without long-term contingencies), which exceeds the savings estimated under the base-case scenario.

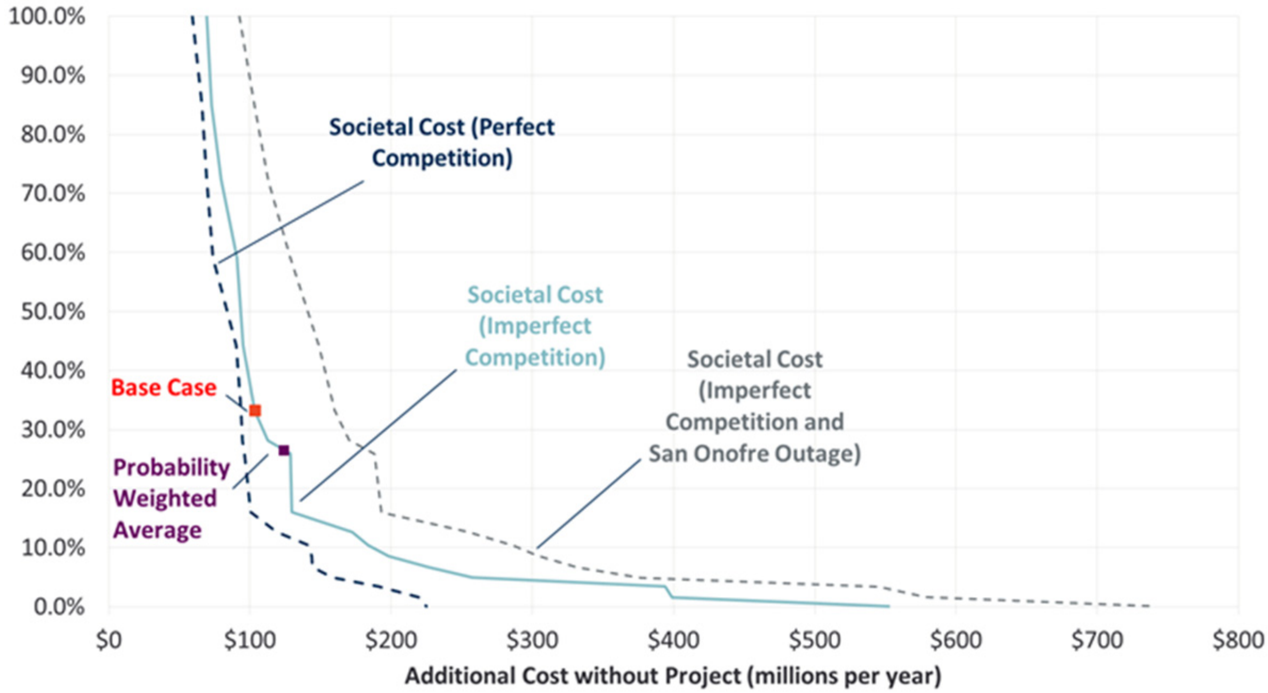
With major long-term contingencies considered, the benefits are even higher. The CAISO studied multiple long-term contingencies, one of which was a long-term San Onofre nuclear plant outage (which has now become a reality). With this outage alone total annual benefits ranged from $90 million/year in the lowest-benefit scenario to $740 million/year in the highest-benefit scenario. In other words, while the total benefits of building the line were estimated to be $100 million/year for the base case, the analysis shows that the total annual costs could be as high as $740 million/year without the project for at least one of the evaluated future scenarios. This benefit range of up to $740 million/year is over 10 times the average annual project cost of $71 million. It is also over 7 times the $100 million/year base-case benefit estimated without considering challenging futures and contingencies.

Figure 2 below provides a graphical representation of the probability distribution of estimated project-related benefits under three assumptions: (a) perfect competition between suppliers without any major long-term contingencies (dashed dark-blue line); (b) imperfect competition between suppliers without any major long-term contingencies (solid blue line); and (c) imperfect competition with the San Onofre nuclear outage (dashed grey line). The x-axis shows the range of estimated additional societal costs without the PVD2 project. In other words, the x-axis measures the cost savings or societal benefits associated with the project. The y-axis shows the probability that these cost savings are above or below a certain amount.

For example, the solid blue line of the chart shows there is 100% probability that the cost savings of the project are at least $80 million under imperfect competition without major contingencies. Moving down along this line, the graph shows that there is: (1) a 50% probability that the cost savings would be greater than $90 million; (2) a 20% probability that the savings would be greater than $125 million; and (3) a 10% chance that the savings would be between $190 and $550 million per year.

These probability-distributed values exist due to the fact that there can be operational and market conditions (such as higher loads, higher natural gas prices, or less hydro generation) that differ significantly from base case assumptions. As the analysis shows, this can dramatically increase the total benefit of (*i.e.*, the additional costs faced without) the project. The wide distribution of these results show that transmission can provide significant insurance value against the high costs of challenging conditions (such as cold snaps, heat waves, price spikes in fuel markets, or droughts) that affect power markets in the short term, as well as challenging shifts in market conditions and regulations (such as major shifts in fuel costs or unanticipated plant retirements and load growth) that can affect costs and risks in the long term.

Figure 2
Range of Projected Societal Benefits of the PVD2 Project and Probabilities that Total Benefits Exceed Certain Values



The cost of inadequate transmission infrastructure can be magnified through unusual generation and transmission outages on both a short- and long-term basis. The CAISO's PVD2 analysis simulated eight such "major contingencies," which included the long-term outage of the San Onofre nuclear plant. While this simulated long-term outage was not anticipated at the time, it became a reality in 2012. The impact of the project when additionally considering this single contingency is shown as the grey dotted line in Figure 2. As shown, this single long-term plant outage increased by approximately 50% the annual benefits offered by the project. As the chart shows, the CAISO's analysis projected a 10% probability (comparable to once in 10 years) that the annual societal cost would be at least $300 million (and possibly up to $750 million) higher without the project.[18] In

[18] As discussed in Appendix A, the figure also shows (a) total benefits assuming perfect competition (*i.e.*, without the benefit of increasing competition between generators); (b) total benefits including competitive benefits; and (c) total benefits, including competitive benefits, under long-term San Onofre outage conditions. As shown in Figure 2, there is an estimated 10% chance that the costs avoided by the project range between $140 million and $220 million per year under the assumption of perfect competition without any contingencies (left dashed line). If the possibility of imperfect competition is taken into consideration, there would be a 10% chance that annual costs would be between approximately $200 million and $550 million higher without the project. With one major contingency, the San Onofre outage, and imperfect competition, the analysis projected that there would be 10% probability that societal costs could be $300 million to $750 million higher without the project.

other words, building the project would eliminate a 10% chance of a $300 million to $750 million annual cost exposure.

Building a robust and flexible transmission system also reduces the costs of adapting to long-term changes in market conditions. Using the San Onofre outage analysis as an example for such as long-term shift in market conditions, the proposed PVD2 project would reduce the annual costs associated with dealing with the now permanent nuclear outage by between $20 million to $200 million a year (shown as the difference between the light blue line and the dotted grey line at each percentage point labeled on the y-axis.

Another example of a scenario-based transmission planning study was presented to the Public Service Commission of Wisconsin by American Transmission Company (ATC). For example, in its Planning Analysis of the Paddock-Rockdale Project, ATC evaluated the benefit that the project would provide under seven plausible futures.[19] The study, which evaluated a wide range of transmission-related benefits,[20] found that while the 40-year present value of the project's customer benefits fell short of the present value of the project's revenue requirement in the "Slow Growth" future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. The *net* benefit values in the other six futures analyzed span a wide range. With an estimated present value of a 40-year revenue requirement of $136 million, the estimated *net* benefits ranged between approximately $100 million (above cost) under the "High Environmental" future, to approximately $400 million under the "Robust Economy" and "High Wisconsin Growth" futures, and reaching up to approximately $700 million under the "Fuel Supply Disruption" and "High Plant Retirements" futures. These results show that the estimated benefits can span a wide range when different future scenarios are considered, but most importantly, not investing in the project would potentially leave customers $700 million worse off. Such an analysis also shows that understanding the potential impact of projects across plausible futures is necessary for transmission planning under uncertainties and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid.

To summarize, policy makers and regulators who support "conservative" planning should consider the potentially very high costs of inadequate transmission infrastructure during challenging market conditions and diverging future policy environments. Without considering these risks, we as an industry will be rejecting the insurance value offered by a more robust transmission infrastructure. We will reduce transmission investments based on analyses showing that little investment would be

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19 ATC (2007), p. 5.

20 For each of the seven scenarios of plausible futures, ATC presented to the Wisconsin Commission an analysis of a range of project-related benefits that included production-cost savings, reduced losses and congestion hedging costs, improved competitiveness, system-failure insurance, capacity savings due to reduced on-peak losses, access to lower-cost resources, as well as reserve-margin impacts and other reliability benefits. The magnitude of these individual benefits varied substantially across the evaluated futures, with some benefits being very high in some futures but negative in others.

needed in "business as usual" futures under "normal" system conditions, when we already know that we will very likely face uncertainties and circumstances that deviate greatly from the assumed conditions. It is consequently important to improve transmission planning processes to protect customers and other market participants from the negative consequences of both short- and long-term market conditions that are considerably more challenging than those considered in economic planning analyses today.

These costs and risks also need to be considered in any "least regret" planning approaches. Such "least regrets" transmission planning should not be focused solely on projects that are beneficial under almost any circumstances to avoid the "regret" of project costs that exceed future benefits. Rather, an effective and robust "least regrets" planning framework needs to focus on avoiding the "regrets" of the potential very-high-cost outcomes caused by an insufficiently robust and flexible transmission infrastructure.

As the above discussion showed, while *forgoing* the investment may avoid some possible future outcomes in which benefits might fall short of project costs, *not making the investment* can expose customers and other market participants to cost increases that can easily be a multiple of the annualized cost of the transmission project. This asymmetry in risk should be considered in any so-called "no regrets" planning frameworks.

C. Improved Scenario- and Sensitivity-Based Planning to Recognize Long- and Short-term Uncertainties

The PVD2 case study and the Wisconsin example are examples of how applying scenario-based analyses can be used to assess the future value of proposed transmission projects in the presence of short- and long-term uncertainties. Policy makers and system planners can utilize these types of planning tools to develop a robust transmission system that can help reduce the cost of complying with future environmental regulations, such as reducing the potential costs associated with coal plant retirements or increasing additions of renewable and natural-gas-fired generation. Planners should also consider the likelihood that developing a more robust and more flexible transmission system would reduce the long-term costs of adapting to technological changes. It is consequently important that economic transmission planning efforts consider credible future scenarios that are beyond the "current trends" or "business as usual" cases.

Such scenario-based long-term transmission planning analyzes proposed transmission investments across different future states of the world that reflect the range of long-term uncertainties. Additional sensitivity analyses are necessary to explore the potential range of values due to short-term uncertainties that will exist under any of the selected future scenarios, such as variances in fuel prices, weather- or economy-related load growth, or transmission and generation outages. This type of scenario-based long-term planning is widely used by other industries (such as the oil and gas industry)[21] and has already been employed to various degrees in transmission and resource planning efforts. For example, the Indiana commission has encouraged the utilities, in collaboration with their stakeholders, to develop scenarios and sensitivities that not only provide a likely future but also stress the system by exploring lower probability scenarios and sensitivities that have a high potential cost if realized.[22] Similarly, ERCOT developed and implemented a new stakeholder-driven long-term transmission planning process that applied a scenario-based strategic planning framework to identify the key trends, uncertainties, and drivers of long-term transmission needs in ERCOT. The process developed a range of internally-consistent scenarios covering the wide range of plausible future market conditions.[23] ERCOT converted the detailed scenario descriptions into transmission planning assumptions and generation investment and retirement projections that are consistent with each scenario's projected long-term market and regulatory conditions that reflected different projections for load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions. In its recent long-term planning effort, ERCOT performed initial planning analyses for ten scenarios—including projections of likely locations and magnitudes of generation investments and retirements—and identified four scenarios that covered the most distinct range of possible futures to carry forward for detailed long-term transmission planning analyses.

Evaluating long-term uncertainties through various distinctive future scenarios is important given the long useful life of new transmission facilities that can exceed four or five decades. Uncertainties about future regulations, industry structure, or generation technology (and associated investments and retirements) can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can be used to: (1) analyze the likely range of transmission-investment drivers such as load growth and location-specific generation investments and retirements; (2) identify "least-regrets" projects that mitigate the risk of high-cost outcomes and whose value would be robust across most futures; and (3) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. Appendix B discusses in more detail how to improve the use of scenarios and sensitivities in transmission planning to address both short- and long-term uncertainties.

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21 For example, see Royal Dutch Shell (2013). See also Wilkinson and Kupers (2013).

22 Borum (2015).

23 ERCOT (2014); see also Chang, Pfeifenberger, and Hagerty (2014).

IV. Regional Transmission Planning Practices

Our review of regional planning practices, including proposed modifications in response to FERC Order 1000, shows that with few exceptions, economic planning of transmission has not progressed much in recent years. In many planning regions, transmission planning processes are still focused mostly on reliability planning and economic evaluation processes that are narrowly concentrated on production cost savings under normal system conditions without considering the full range of potential benefits provided by transmission investments. While we recognize the substantial differences across regions, this deficiency results in economic planning processes that are largely ineffective. As a result, and with a few notable exceptions, most transmission investments are still justified solely based on reliability needs.

The failure to consider a broader set of transmission-related benefits raises concerns about missing opportunities to improve our transmission infrastructure. Without an assessment of the full set of economic benefits that transmission investments can provide beyond addressing reliability needs, the transmission solutions found and approved are likely to miss valuable options to build lower-cost or higher-value transmission projects that would reduce the overall costs of delivered electricity and mitigate risks and uncertainties in the long term.

A. The Status of Regional Transmission Planning Practices

Our review of industry practices shows that a broad range of transmission-related benefits are being considered in regional transmission planning processes only by the Southwest Power Pool (SPP),[24] by the Midcontinent ISO (MISO) when evaluating investments that qualify as Multi-Value Projects (MVPs),[25] and on occasion by the CAISO. At this point, only SPP consistently evaluates a broad range of benefits and applies benefit-cost analyses to its entire portfolio of planned transmission projects, including projects justified primarily by reliability needs.

MISO quantifies a broader range of economic benefits only when evaluating projects that qualify as Multi-Value Projects. However, since its 2010 and 2011 planning cycles when MISO approved $5.5 billion of MVP investments, not a single additional transmission project has qualified to be evaluated as a Multi-Value Project. In the last years, MISO has been focused solely on addressing reliability needs and evaluating narrowly-defined production cost savings for proposed Market Efficiency Projects (MEPs). Of the $1 billion to $1.5 billion of reliability and market efficiency projects approved by MISO *annually* in recent years, market efficiency projects accounted for only

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24 SPP (2015).

25 See MISO (2014c). In its MVP analysis MISO evaluated the following benefits: (1) congestion and fuel cost savings; (2) reduced costs of operating reserves; (3) reduced planning reserve margin requirements; (4) deferred generation investment needs due to reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; (6) reduced other future transmission investments.

$12 million.[26] This focus on reliability needs and narrowly-defined market efficiency analyses is representative of the status of transmission planning currently employed in most planning regions, including PJM, ISO New England (ISO-NE), and New York ISO (NYISO).

The CAISO has extensive experience with evaluating a broad range of benefits for transmission projects as documented in our case study of the Palo Verde to Devers No. 2 project. Nevertheless, this experience has rarely been applied in the CAISO's recent planning efforts. Rather, candidates for economically-justified transmission projects are evaluated based mostly on their impacts on wholesale market prices or their ability to reduce congestion charges based on either historically observed congestion charges or the congestion cost observed in base-case production cost simulations.[27] We are only aware of two recent transmission projects—the Harry Allen to Eldorado 500 kV line and the Delaney to Colorado River 500 kV line (the successor of the PVD2 project first evaluated in 2004)—which the CAISO justified and approved based on quantification of multiple economic benefits.[28]

Nevertheless, various regional planning groups are gradually improving their regional planning processes. For example, PJM's newly approved "Multi-Driver" transmission process recognizes that transmission projects often address a range of different needs and thus offer a range of benefits.[29] And the NYISO recently noted that "transmission upgrades would bring numerous benefits to New York State," summarized the wide range of individual benefits, and emphasized that "[m]any of these benefits are commonly overlooked in favor of an overly narrow focus on traditional production cost savings analysis."[30] However, NYISO and PJM have yet to implement and apply these new perspectives in their planning efforts.

B. The Role of Policy Makers in Regional Transmission Planning

In virtually every instance where regional planning entities have considered a broad range of benefits in their planning efforts, it was the direct result of requests from state policy makers and regulators. The CAISO's broad-based evaluation process was developed after the California power crisis, which illustrated the high cost of insufficient transmission infrastructure in 2000–2001 and made policy makers in California recognize the importance of building a more robust and flexible transmission grid. SPP's broad-based planning framework was in large part motivated by SPP's

26 MISO (2013), see, for example, 20140613 MTEP13 Appendix A Status Report.

27 See CAISO (2014a), Chapter 5

28 *Id.* For the evaluation of these projects, the CAISO has evaluated two economic benefits: production cost savings and generation capacity cost savings due to a reduction in resource adequacy requirements.

See also CAISO (2014b) (which evaluated production cost savings, estimated resource adequacy benefits, and mentioned without quantification other benefits such as reliability benefits).

29 FERC (2015b), 150 FERC ¶ 61,117.

30 NYISO (2014), pp. 7–8.

Regional State Committee's (RSC) effort in evaluating whether its Highway-Byway cost allocation methodology will result in cost allocations that are roughly commensurate with the distribution of estimated benefits. In that process, SPP and its RSC recognized the importance of considering the wide range of values that transmission is able to provide to the states and the SPP market participants. MISO's MVP process was also in large part motivated by efforts of MISO's group of state regulators, the Organization of MISO States (OMS).

Most recently, the NYISO and its transmission owners (who have traditionally employed economic planning processes that are narrowly focused on production cost savings), have also started to recognize the need to consider a broader range of transmission-related benefits in its planning process. This comes in response to state policy makers' and regulators' support for improving the state's aging transmission infrastructure. Encouraged by this new infrastructure initiative of its policy makers, the NYISO recently discussed the wide range of benefits provided by transmission infrastructure (as noted earlier), further emphasizing that increased transmission would also give the NYISO greater operational flexibility by making it easier to dispatch resources, gain access to operating reserves and ancillary services, and remove transmission for maintenance when needed. The NYISO's sentiment that a robust transmission infrastructure provides benefits beyond the production cost savings metric currently specified in the NYISO tariff is now supported by New York transmission owners who noted that: "[a] robust and well planned transmission system is necessary to have the flexibility to address contingencies that may occur in the future and to avoid cost impacts due to the need for uneconomic gap solutions as a result of generation retirements."[31]

These examples demonstrate that—while FERC sets the national regulatory policies for transmission investments—state regulators play a key role in setting the direction and pace of regional transmission planning and development. Some of the experiences show that, once the specific planning requests by state policy makers are satisfied and a broad-based planning approach is not supported and sustained through state policies, there is a tendency to regress to compartmentalized transmission planning processes for reliability and market efficiency projects that either do not consider economic costs and benefits (*i.e.*, reliability planning) or only apply a narrowly-defined set of benefits (*i.e.*, the processes used to evaluate market efficiency projects). Thus, we cannot overemphasize the important role of state policy makers and regulators in determining the scope, vision, and effectiveness of regional transmission planning and development.

To the extent transmission planning focuses on projects to support public policy goals or mandates, the influence of state policy makers is even greater. Not only will state policy makers have to specify their public policy goals or mandates, but some planning groups will initiate transmission planning for public policy needs only at the request of state policy makers or only if there is a commitment by state policy makers to cover the costs of any transmission facilities needed to support the policy objectives. Examples are the public policy transmission planning frameworks developed (but not yet tested) by PJM and ISO-NE.

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31 Powers (2015).

C. INEFFICIENCIES OF CURRENT PLANNING PROCESSES

Due to the ineffectively narrow planning frameworks for "market efficiency" and "economic" transmission projects, most routine transmission investments currently planned are justified solely based on reliability needs. This is primarily because for economically-justified transmission projects it is almost impossible to pass the benefit-cost tests associated with these project types. While a significant amount of transmission investments have been justified based on reliability need (*e.g.*, in New England), finding and approving transmission solutions solely based on reliability analyses can lead to missed opportunities to build lower-cost or higher-value transmission projects that could provide benefits beyond meeting reliability standards, and reduce the overall costs and risks to customers in the long term. Again, to identify lower-cost or higher-value transmission options will require an assessment of the full range of economic values that transmission investments can provide.

Our concern about missing opportunities to improve the infrastructure to more cost-effectively serve electricity customers is supported by experience. In the limited cases where a broader range of benefits have been considered—such as in MISO's MVP planning effort—highly valuable transmission projects have been identified, approved, and are being built—thereby reducing the overall costs for customers and the system as a whole. In fact, in 2014 MISO updated its benefit-cost analysis of the Multi-Value Projects previously approved in 2011, finding that the approved MVP portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.6 to 3.9, an increase from the 1.8 to 3.0 range calculated in 2011;
- Creates $13.1 to $49.6 billion in net benefits over the next 20 to 40 years, an increase of approximately 50 percent from 2011 estimates;
- Enables 43 million MWh of wind energy to meet renewable energy mandates and goals through year 2028, an additional 2 million MWh higher than the 2026 forecast prepared in 2011; and
- Provides additional benefits to each local resource zone relative to the benefits estimated in 2011.[32]

Unfortunately, most existing planning frameworks do not yet integrate the consideration of multiple values for all proposed transmission investment. If a project is driven by reliability needs, economic benefits are usually not considered. If a project is categorized as an economic project, but also simultaneously provides reliability benefits without addressing a clear reliability violation, that reliability benefit usually is not considered either. This particular "compartmentalized" approach of categorizing projects and then limiting the scope of benefits in each project category unnecessarily leads to an understatement of transmission-related benefits and a significant under-appreciation of

32 MISO (2014c).

the costs and risks imposed on customers by an insufficiently robust and flexible transmission infrastructure.

On the flip side, even when "multi value" or "multi-driver" planning processes exist, only certain transmission projects can qualify to be considered under these processes. For example, none of the projects evaluated by MISO in its last two planning cycles met its qualification requirements for Multi-Value Projects. Further, neither MISO nor PJM allows interregional transmission projects to be evaluated as Multi-Value or Multi-Driver Projects. (We discuss interregional planning in more detail in the next section.) Thus, while multi-value or multi-driver planning processes are a clear improvement over traditional economic planning methods, they should ideally be coupled with the acknowledgement and understanding that most transmission projects can provide a wide spectrum of the same set of multiple benefits, regardless of whether a project fits the multi-value or multi-driver categories as defined by the relevant tariffs. Without recognizing that most transmission investments provide multiple benefits, the industry will not be able to move beyond incremental solutions based on addressing reliability needs, leaving much unexplored value on the table, and increasing the risks and costs to customers and the power system as a whole.

D. Implications and Recommendations

There are substantial differences in planning approaches across regions, ranging from the SPP example of broad-based planning process that consistently considers a wide range of transmission-related benefits to regions in which economic or public policy benefits do not play a significant, actionable role in the ultimate approval of transmission infrastructure investments. This deficiency creates significant barriers to more economically-effective transmission planning. Because there is no analytical or public policy reason that would prevent consideration of the broader range of benefits provided by transmission infrastructure, we urge regions and states that are not yet considering such a broader set of benefits to do so going forward. We believe the "checklist" we outlined in our 2013 WIRES Report (and as replicated and briefly discussed earlier in this report) provides a useful starting point for considering the types of benefits that transmission investments can provide.

In most regions the majority of projects are currently justified based on reliability criteria without an assessment of economic benefits. This approach will likely continue to yield incremental transmission upgrades and will lead regions and states to miss the opportunities to identify and develop transmission infrastructure that could be lower-cost or higher value—particularly when considering both short-term market volatilities and longer-term policy and market structure uncertainties.

By "compartmentalizing" the planning process into distinctly different types of transmission projects and by narrowly defining benefits that can be considered in the evaluation of each project type, most of the current planning processes create significant barriers for identifying, evaluating, approving, and constructing the most cost effective or most valuable transmission projects. Specifically, existing tariff provisions for "market-efficiency" projects are largely ineffective in most planning regions. So far, we find that neither FERC Order 1000 nor state policy initiatives have had any discernable impact in this regard.

Nevertheless, the important role of policy makers and regulators in influencing the scope of regional (and interregional) transmission planning efforts is a reality. It means that the regional planning groups are unlikely to be motivated to improve their transmission planning processes for economic and public policy projects unless policy makers and regulators actively encourage and support such improvements. This requires policy makers to recognize the broad range of benefits and risk mitigation that a more robust transmission infrastructure can provide and encourage planning entities to consider these benefits in their planning efforts. In addition, it will be necessary for the boards and executives of the various planning entities to recognize these benefits of a more robust and flexible bulk power system, such that they can provide the appropriate guidance and encouragement to their transmission planning staff.

To mitigate risks and pursue true "least regrets" planning, we recommend that policy makers and regulators more actively encourage planning entities to improve the region's understanding and recognition of the high costs and risks that an insufficiently robust and insufficiently flexible transmission infrastructure can impose on customers and the power system as a whole under challenging market conditions, major contingencies, and changing environmental policies. We also recommend that state and federal policy makers and regulators look beyond considering each individual transmission project and the immediate need that a particular project might address. Such project-by-project assessments of individual needs tend to reinforce the compartmentalized approach of current planning processes. Instead, we encourage policy makers and regulators to consider the overall value that a portfolio of proposed transmission investments can provide and, whenever specific needs are identified, consider a wider range of solutions that can address the identified needs, including using those opportunities to identify and evaluate broader solutions that can provide benefits in addition to addressing the specific needs. As noted earlier, such assessments of broader solutions should take into consideration the transmission-related benefits given the short-term market and operational volatilities as well as the longer-term changes associated with public policies and market structure faced by the electric power industry today.

V. Interregional Transmission Planning

This section of our report first discusses the current status of interregional planning efforts and then identifies specific gaps and barriers to assessing the effectiveness of the currently used or proposed interregional planning processes. We then offer recommendations to address the identified deficiencies to improve the planning processes.

Planning of interregional transmission infrastructure for economic and public policy needs is still in its infancy. While transmission planning processes are well defined within regions, particularly to address reliability needs, planning processes for transmission upgrades across regional boundaries are largely ineffective. This is the case particularly because the potential benefits of interregional transmission infrastructure are poorly understood. Even if an intuitive understanding of these benefits exists, there are few widely-accepted analytical methods that are commonly used to document and quantify the anticipated benefits. Nevertheless, several interregional studies already point to the significant cost savings that a more robust interregional transmission infrastructure would be able to provide. Below we summarize the more relevant findings of those studies to help highlight the importance of interregional transmission planning for the U.S. and North America. We then provide an overview of current interregional planning practices and their deficiencies, including the barriers created by the "least common denominator approach" that most regional groups have chosen for their interregional planning processes. We also present recommendations to address the identified deficiencies.

A. The Value of Interregional Transmission Infrastructure

1. MISO's National HVDC Overlay Study Proposal

MISO transmission planners recently suggested that the individual transmission regions in North America could be linked through a nation-wide interregional high-voltage direct current (HVDC) network.[33] The conceptual sketch of the potential fully-developed HVDC overlay is shown in Figure 3.

Figure 3
Conceptual National HVDC Network

The preliminary analysis presented with this interregional HVDC network proposal estimates that the investment could yield at least <u>*$50 billion in cost savings not currently realized*</u> due to limited

33 See MISO (2014b).

interregional transmission capabilities. These benefits obtainable through a more robust interregional transmission interties are associated with:

1. Increased load diversity (which reduces installed generating capacity needs)
2. Increased diversification of wind and solar generation; and
3. Reduced ancillary service needs.

The MISO presentation also noted that additional benefits (not yet estimated) would likely be realized under more stringent, carbon-constrained environmental regulations, such as EPA's Clean Power Plan. While the cost of such a HVDC network has not yet been estimated, it is likely that at least several of the interregional components of this overlay would be found to be cost effective—particularly in a more carbon constrained future.

2. National Co-Optimization of Transmission and Generation Study

As briefly noted earlier, the benefits of interregional planning on a national and eastern-interconnection-wide basis have recently been analyzed by researchers from a consortium of five universities. Their research results, presented in the study, "Co-optimization of Transmission and Other Supply Resources" prepared for EISPC and NARUC with funding from the DOE,[34] shows that the traditional planning approaches for transmission and generation are no longer adequate to achieve least-cost outcomes in light of challenges such as plant retirements, renewable generation integration, and increasingly stringent environmental regulations that lead to significantly more complex and less predictable power systems. As noted earlier, the study finds that *traditional planning processes yield suboptimal levels of transmission investments that increase the combined generation and transmission costs by 5–10%*. Improved planning processes, if applied nation-wide, were estimated to *save $150 billion in total costs by spending $60 billion more on interregional transmission (yielding a benefit-cost ratio of 2.5:1)* compared to traditional approaches in which generation is planned first and transmission is then built to deliver that generation.

These cost reductions, however, can only be achieved through regional and interregional planning processes that consider a range of transmission-related benefits. In particular, the study shows that co-optimized interregional planning that explicitly considers planning uncertainties and anticipates generation investment needs, as well as generation investment responses to transmission expansion, would be able to reduce overall system-wide costs through:

1. Savings of transmission and generation investment and operating costs;
2. More efficient decisions concerning generation retirements and uprates;
3. More appropriate treatment of variable resources;

[34] EISPC (2013)

4. Efficient integration of non-traditional resources such as demand response, customer-owned generation, other distributed resources, and energy storage;
5. Fuel mix benefits;
6. Improved assessment of the ramifications of environmental regulation and compliance planning; and
7. Reduced risk and attendant effects on resource adequacy and costs.

3. Reducing the Cost of Transitioning to Low-Carbon, Clean-Energy Futures

A number of studies exploring the long-term feasibility and cost of transitioning to various forms of low-carbon, clean-energy futures found that increasing the transfer capability between regions offers significant benefits in terms of lower overall costs, increased reliability, and reduced operational challenges. For example, a long-term study by the National Renewable Energy Laboratory (NREL) looking out to 2050 found that "additional transmission infrastructure is required to deliver generation from cost-effective remote renewable resources to load centers, enable reserve sharing over greater distances, and smooth output profiles of variable resources by enabling greater geospatial diversity."[35] The study, which included a national transmission planning analysis, found that interregional transmission infrastructure enhancements would increase system flexibility, which in turn would enable the transfer of power and sharing of reserves over large areas to diversify the variability of wind and solar electricity generation in combination with variability in electricity demand. The analysis found that an 80% clean energy share would be achievable through regional and interregional transmission investments at an average annual level no higher than the recent historical range for transmission expenditures in the United States.

Similarly, the 2015 DOE "Wind Vision" report analyzing wind generation development reaching 35% of national energy production found that regional and interregional transmission investment at a level consistent with recent historical transmission investment levels would be needed to "provide access to high [quality] resource sites and facilitate grid integration reliably and cost-effectively."[36] For the analysis of necessary transmission expansion, the Wind Vision study relied on work undertaken by the Eastern Interconnect Planning Collaborative (EIPC). Phase II of the EIPC analysis identified total regional and interregional transmission needs of $60 billion to $100 billion through 2030 to facilitate least-cost resource plans for two of its scenarios, one reflecting a future with a regionally-implemented renewable portfolio standard and one with a carbon-constraint and increased energy efficiency and demand response deployment.[37] The EIPC results for the carbon constrained scenario particularly found significant interregional transmission investments as a critical enabler of cost-effectively achieving a lower-carbon power sector.

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35 NREL (2012).

36 U.S. DOE (2015)

37 U.S. DOE (2012)

These studies thus suggest that at least the recent pace of transmission investment—which has been in the range of $10-16 billion per year as discussed earlier—would be necessary for the development of a robust regional and interregional transmission system that can support achieving a range of clean-energy futures at the lowest overall cost.

4. Resource Adequacy Benefits of Interregional Transmission

In addition to lowering the cost of energy through increased trading opportunities, an expanded interregional transmission infrastructure also increases generation resource adequacy for each of the interconnected regions, which in turn can reduce the planning reserve margins needed to meet regional resource adequacy standards, and thereby reduce the cost of providing the reserve capacity necessary within each region. A recent study by The Brattle Group for FERC illustrated this benefit, showing the extent to which interconnections among neighboring regions reduce the costs of complying with resource adequacy standards.[38] An analysis of a hypothetical but realistic RTO with 50,000 MW of peak load found that the region would need an 18.5% planning reserve margin to meet a 1-event-in-10-year resource adequacy standard. The reliability simulations showed that interconnecting this RTO with three similarly-sized neighboring regions with realistic load and generation diversity substantially reduces the RTO's planning reserve margin requirement. The study found that robust interconnections between regions could reduce the reserve margin needed to achieve a 1-event-in-10-year probability of failing to serve load due to inadequate generation from 18.5% to a range of 13 to 15%, depending on the planning reserve margins in the neighboring RTOs. The lower reserve margin requirement reduced the necessary generation capacity investments by at least $2.5 billion.[39] When including economic trading opportunity created by the interregional tie-lines, the differences between the Study RTO costs in the interconnected and islanded cases were estimated at $250–350 million per year.

The study shows that interregional transmission projects offer substantial resource adequacy benefits that should be (but typically are not) considered in transmission planning. Of course, considering these benefits does not mean that an unlimited amount of interregional transmission would be justified. For example, while the above study evaluated the Study RTO with 11,000 MW of total intertie capacity to the neighboring regions, it also showed that most of the resource adequacy benefits associated with interconnecting the regions was achieved with the first 5,500 MW of intertie capacity.

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38 Pfeifenberger, Spees, Carden, and Wintermantel (2013), pp. 57–60.

39 A 5% reduction of reserve margin in a 50,000 MW system is equivalent to 2,500 MW of new generation. At an approximate overnight cost of $1000/kW, this is equivalent to $2.5 billion in reduced generation investment needs.

5. Other Benefits Unique to Interregional Transmission Projects

Most interregional planning efforts fail to recognize that interregional projects often are associated with a broader set of benefits than region-specific internal transmission investments.[40] As indicated throughout this paper (and our 2013 WIRES report), even if planners and project proponents have an intuitive understanding of the interregional benefits, the current methods for identifying, categorizing, and analyzing the projects' anticipated benefits are too limiting. First, certainly all the values of transmission we have included in Table 1 apply to interregional projects just as they do for regional projects. Moreover, benefits that accompany the diversification of load and resources can be significant.

Beyond the diversification and reliability-related benefits of expanding interregional transfer capability discussed in the previous subsection, infrastructure investments that increase the transfer capability between regions also generate wheeling revenues for one or both of the regions that tend to offset a significant portion of the transmission project costs.[41] SPP has started to recognize that interregional projects can offer unique benefits beyond those currently considered for internal transmission projects. For example, SPP recently estimated that certain regionally-funded transmission investments undertaken between 2010 and 2014 increased transfer capability between SPP and neighboring regions by approximately 1,200 MW, which supported the sale of additional long-term wheeling-out service with annual revenues of over $30 million.[42] These revenues, which offset a significant portion of the transmission projects' costs, are unique to transmission investments that increase interregional transfer capability and consequently should be considered in interregional planning processes.

The expansion of interregional transmission interties offers the prospect of significantly increasing the capacity value of intermittent renewable resources and reducing the real-time balancing cost of integrating the resources. These interregional renewable generation diversity benefits, particularly in terms of their capacity value and during often unpredictable real-time operating conditions, are rarely considered in regional or interregional planning studies.[43] In fact, when considering real-time uncertainties associated with system conditions and geographically-diverse intermittent

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40 For example, see Pfeifenberger and Hou (2012), Section VIII.C at p. 57.

41 The existence of these wheeling revenues is generally ignored in production cost simulations, even though the simulations impose a "hurdle rate" on transactions across RTO seams. This hurdle rate approach limits trade between regions to realistic levels but ignores the revenues associated with this rate.

42 SPP (2014b), pp. 85-86.

43 For further discussion, see 2013 WIRES Report, Sections VI.A.7-9 and VI.F.

generation the estimated benefit of expanding interregional interties can be a multiple of the benefits estimated with conventional planning tools that do not consider any such uncertainties.[44]

It is also important to recognize that the benefit of diversifying resources over large geographic distances goes beyond the often-analyzed short-term uncertainty of intermittent wind and solar resources. This is because the availability and cost of resources can vary significantly on seasonal and annual basis across regions. It has long been recognized that the seasonal and annual output of hydro-electric resources—such as those in northern California and the Pacific Northwest—can vary significantly across years. But these variations often are not highly correlated with resources more distant regions. Similarly, in addition to short-term intermittency, the seasonal and annual output of wind generation can vary significantly within a region. For example, wind generation in the Pacific Northwest during early 2015 has been approximately 40% below the average of the last three years due to an El Nino-related weather cycle that weakened the region's trade winds.[45] Few regional or interregional planning studies consider these potentially large seasonal and annual variations and the costs associated with them if insufficient interregional transmission infrastructure does not allow for a diversification of these variations.

B. Overview and Limitations of Current Interregional Planning Practices

As required under Order 1000, all planning regions have submitted to FERC their proposals for interregional planning processes and the Commission has now acted on some of them.[46] Unfortunately, our review of interregional transmission planning processes currently used or proposed in response to FERC's Order 1000 show that these remain largely ineffective. As we noted in our 2013 WIRES Report, the historical lack of effective interregional planning processes and lack of clarity on how benefits should be considered for interregional projects has already created what some have called a "demilitarized zone" with a lack of transmission investments near or across market seams. The currently-used or proposed interregional planning processes for the most part neither help identify valuable interregional transmission projects nor are able to produce actionable interregional plans. The most likely reason for the continued ineffectiveness of these processes is

44 See Chang, Pfeifenberger, Ruiz, and Van Horn (2014), for the finding that the benefits of interties when considering real-time uncertainties are between 2 and 20 times higher than the benefits estimated with traditional planning, depending on the overall share of renewable generation.

45 Nelson (2015).

46 See FERC (2015a) for the various regions' interregional planning processes filed in response to Order 1000 and the Commission's initial orders.

the broader challenge of addressing interregional planning needs when planners are consumed by region-internal planning efforts.[47]

Deficiencies in interregional planning had already been recognized by FERC when it issued Order 1000, in which the Commission explicitly noted that "the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential."[48] Yet, the interregional planning processes filed in response to Order 1000 continue to have a number of shortcomings that create a significant barrier to the identification and approval of valuable interregional transmission projects.[49] For example, interregional planning processes may exclude upgrades below certain voltage levels (*e.g.*, 300kV) or project size thresholds, which eliminate from consideration any lower voltage or smaller projects that could cost-effectively increase interregional transfer capabilities and provide other interregional benefits.

In addition, the planning processes generally limit interregional projects to certain *subcategories* of transmission projects. For example, MISO has initially proposed to consider and evaluate only market-efficiency projects in their interregional planning processes. While FERC did not approve this limitation, it would have created a framework that does not allow other types of projects—such as interregional reliability, public policy, or multi-value projects—to be even considered in the interregional planning process.

We use two case studies presented in Appendix C—the current interregional planning processes between SPP and MISO and that between MISO and PJM—to illustrate the challenges and limitations of the current interregional planning processes in more detail. As discussed in the Appendix, this review of planning efforts across the seams of these large RTOs shows that the interregional transmission planning processes developed to date create substantial barriers that: (1) do not allow the consideration of certain types of interregional transmission projects; (2) utilize

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47 For a detailed discussion of barriers to interregional transmission planning and cost allocation and a framework of how to address these barriers, see Pfeifenberger and Hou (2012a), and Pfeifenberger, Chang, and Hou (2012b).

48 FERC (2011) at P 350.

49 As discussed further in Appendix C, FERC has already mandated modifications as part of its review of certain interregional transmission planning proposals filed in response to Order 1000. For example, in its order on MISO-PJM's interregional transmission planning proposal it required that the two RTOs (1) need to add a process to evaluate interregional public policy projects, a category of projects that was missing from the filed proposal; (2) explain how stakeholders and transmission developers can propose interregional transmission facilities for joint evaluation; and (3) clarify how a proponent of an interregional transmission project may seek to have its interregional transmission project jointly evaluated by the MISO and PJM by submitting the interregional transmission project into MISO's and PJM's regional transmission planning processes. FERC (2014a), 149 FERC ¶ 61,250.

benefit metrics that are even narrower in scope than the metrics that the individual RTOs use for regional projects; (3) may not evaluate interregional projects for the same range of scenarios that are used for regional projects; and (4) require that projects pass multiple benefit-cost thresholds.

C. Limitations to The Type of Projects that can be Considered in Interregional Planning

With respect to the first barrier noted above, the SPP-MISO and MISO-PJM case studies document that the interregional planning processes exclude all transmission projects that fall below certain voltage levels (*e.g.*, 300kV) or project size thresholds. These artificial voltage or size definitions eliminate from consideration any lower voltage or smaller projects that may cost-effectively increase interregional transfer capabilities and provide other interregional benefits.

The interregional planning processes also generally limit the scope of interregional planning to certain *subcategories* of transmission projects. For example, MISO had proposed to consider and evaluate only market-efficiency projects in their interregional planning processes. Such a limitation to certain project categories does not allow other types of projects to be considered. Interregional transmission planning is generally limited to projects that physically cross a seam. This limitation, while consistent with the definition provided in FERC Order 1000, effectively disallows from consideration any transmission project that, while fully located in one region, can provide significant benefits to the neighboring region.

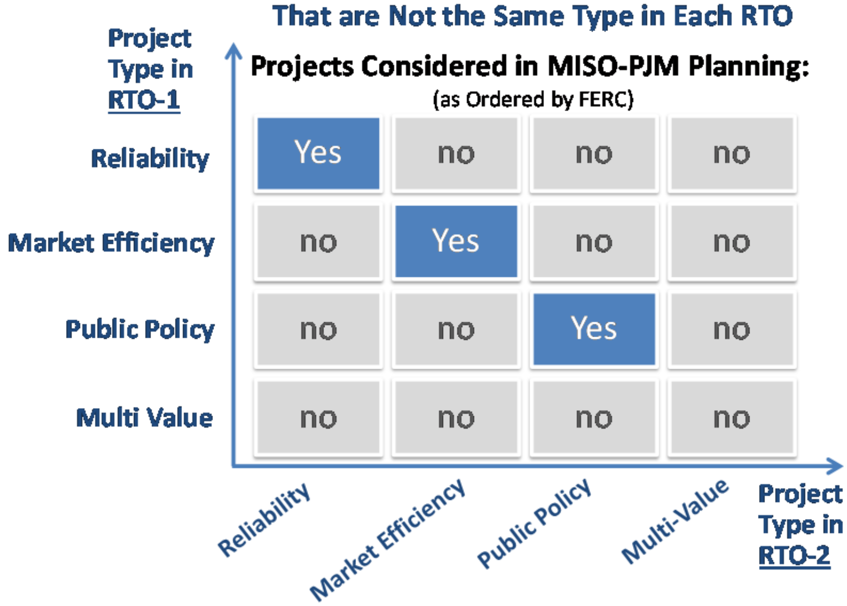
Finally, and as perhaps the least recognized but important limitation, the existing interregional planning processes tend to allow only for the evaluation of transmission projects that address the identical need in both regions. This limitation excludes any projects that, as an example, would address reliability needs in one region but address market efficiency or public policy needs in the neighboring region. Unless the two adjacent regions categorize the interregional project in exactly the same way, the regions' interregional planning rules will outright reject evaluating the project. More often than not, however, a transmission project provides multiple types of value that may differ across regions. The required categorizations of projects consequently compartmentalize projects to the detriment of planning a more effective interregional transmission system.

This categorization barrier, a more even limiting version of the compartmentalization problem discussed in the context of regional planning, is illustrated in Figure 4. As the figure shows, unless the categorizations of transmission projects proposed by adjacent regions are identical, shown across the diagonal blue boxes, the MISO-PJM planning processes will not be able to consider the projects.

This means that the MISO-PJM interregional planning process will be able to consider only those projects that: (1) address reliability needs in both RTOs; (2) are viewed as market-efficiency projects by both RTOs; or (3) address public policy requirements in both RTOs. A project that would enhance market efficiency in MISO and simultaneously address a reliability or public policy need in PJM would automatically be excluded from consideration because it would not be a market-efficiency project in both RTOs. While both MISO and PJM have started to recognize multiple benefits in their internal planning processes—referred to as Multi-Value Projects in MISO and

Multi-Driver Projects in PJM—the specified interregional planning process forecloses consideration of any interregional projects that provide such multiple benefits.

Figure 4
Interregional Planning Processes Do Not Allow for the Evaluation of Projects That are Not the Same Type in Each RTO



D. The "Least Common Denominator" Approach As a Barrier to Development of Beneficial Interregional Transmission Infrastructure

As discussed above and previously in our 2013 WIRES Report, interregional transmission planning and cost allocation is especially challenging given the tendency of neighboring regions to evaluate interregional projects based only on the subset of benefits that are common to the planning processes of each of the respective regions involved.[50] Just as in the case for regional planning processes, planning processes generally do not allow for recognizing the full set of benefits offered by interregional transmission projects. Worse, the range of benefits considered for interregional projects tends be more limited than the types of benefits considered in intra-regional planning processes, reducing the set of benefits to the least-common denominator of benefits considered in planning within each of the two regions. Similarly, interregional planning processes do not recognize the often unique benefits offered by an expanded interregional transmission infrastructure, which includes increased load and generation diversity, reduced generation-related

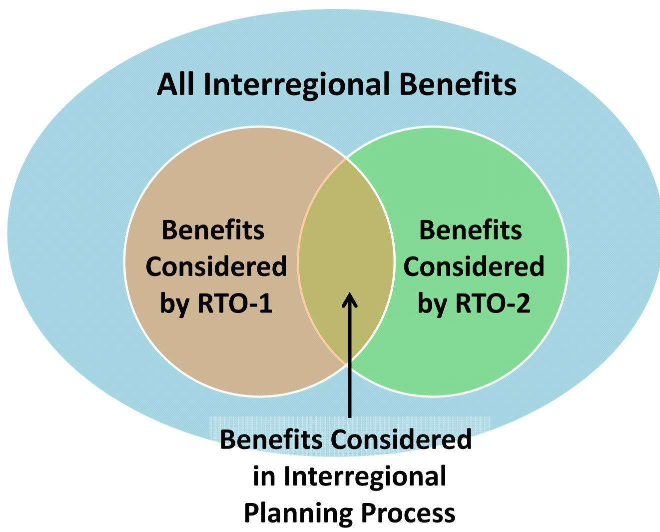
50 2013 WIRES Report, pp. 23–24.

investment costs, reduced costs of meeting renewable energy goals, and wheeling revenues that offset a portion of project costs.

As illustrated in Figure 5, this "least common denominator" approach to interregional planning will significantly disadvantage interregional projects by narrowing the scope of benefits considered and thus understating their value—even compared to the already understated values that are being estimated for intra-regional projects.

The least common denominator approach applies to the range of scenarios considered in the analysis of interregional projects and benefit-cost-thresholds applied. Market simulation analyses for interregional projects are often based on fewer scenarios (*e.g.*, only a business as usual case) than the RTOs internal planning processes, which serves to further understate the benefits of proposed interregional transmission projects. This approach does not recognize the value of transmission investments to address challenges and high-cost outcomes in futures that deviate from the business as usual case, such as under increased environmental regulations or higher natural gas and emissions prices.

Figure 5
The "Least-Common Denominator" Challenge to Interregional Transmission Planning



These understated benefits are then subjected to three separate approval thresholds—a joint interregional threshold as well as each region's individual internal planning criteria. This means, for example, that projects that pass each RTO's individual benefit-cost thresholds may fail the threshold imposed through the interregional planning process; or projects that pass the benefit-cost threshold of the interregional planning process may be rejected because they may fail one of the individual RTOs' benefit-cost thresholds. In combination with evaluating a smaller set of benefits for fewer scenarios of future market conditions, this adds an additional challenge to the approval of even very valuable projects.

E. Implications and Recommendations

In summary, interregional projects face hurdles that are considerably higher than those faced by regional projects. The limitations of the existing interregional planning processes mean that the most potentially beneficial projects will be disqualified, often during the qualifications stage before they are even evaluated. The interregional planning processes create almost insurmountable barriers to the identification and approval of valuable interregional transmission projects and, therefore, cannot be expected to lead to any significant upgrades of interregional transmission infrastructure.

To reduce the identified barriers to the identification and approval of valuable interregional transmission projects, we recommend the following improvements:

1. Relax the overly limiting qualification criteria for interregional transmission projects to allow for a wider range of interregional transmission project types. All drivers and project types considered in regional planning processes, including multi-value and multi-driver projects, should be considered in interregional planning processes. Interregional planning processes should be flexible enough to accommodate different types of interregional transmission projects (*e.g.*, reliability, economic, and public policy projects) and should explicitly recognize that a project may provide different types of benefits to each of the neighboring regions. Because cost effective interregional investments often involve upgrades to existing interties, the voltage levels of interregional projects should not be set at a level any higher than those of most existing interties between regions.
2. To avoid a "least-common-denominator" approach to interregional planning, each of the neighboring regions, at a minimum, should evaluate its share of an interregional project's benefits by considering all types of benefits that are used in the region's internal transmission planning process. Doing so will ensure that the total benefits considered in the interregional planning process are at least equal to the sum of the benefits that each entity would determine for a regional project in its own footprint. In this way, benefits and metrics considered in interregional planning would at least be consistent with the reliability, operational, public policy, and economic benefits considered in the individual regions, even if these benefits are not defined and measured the same way in each region. In addition, to the extent possible under applicable tariffs and planning processes, each region should make an effort to consider the benefits (and associated metrics) used by the other region, even if these benefits and metrics are not currently used in its internal planning process.
3. Interregional planning processes should also recognize that interregional projects might offer unique benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues that could offset some portion of the costs associated with the transmission project or benefits from increased reserve sharing capability.
4. The analytical approaches applied to interregional planning should look beyond "base cases" or "business-as-usual cases" and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments to capture the short- and

long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes.[51]

5. The benefit-to-cost thresholds to interregional projects should be no more stringent than those applied within each region. Since interregional projects are projects that regions evaluate jointly, a single joint benefit-to-cost threshold should be sufficient. If the regions jointly find that a certain interregional project or portfolio of projects offers benefits in excess of costs, the participating regions should be able to agree on a cost allocation such that each region enjoys a share of the overall benefits that exceeds its share of the costs. Having a single benefit-to-cost threshold for the participating regions would help avoid reaching different conclusions simply because the thresholds are different in the participating regions.

VI. Summary of Conclusions and Recommendations

Our review of the current state of U.S. transmission planning processes identified three principal deficiencies:

- Planners and policy makers do not account for the high costs and risks of an insufficiently robust and flexible transmission infrastructure on electricity consumers and the risk-mitigation value of transmission investments to reduce costs under potential future stresses.
- Planners and policy makers do not consider the full scope of benefits that transmission investments can provide and thus understate the expected value of such projects.
- The interregional planning processes are ineffective and are generally unable to identify valuable transmission investments that benefit two or more regions.

These deficiencies, collectively, create significant barriers to developing the most valuable and cost-effective regional and interregional transmission projects and infrastructure. If not addressed, these deficiencies would lead to: (a) underinvestment in transmission that leads to higher overall costs; (b) lost opportunities to identify and select alternative infrastructure solutions that are lower-cost or higher-value in the long term; and (c) an insufficiently robust and flexible grid that exposes customers and other market participants to higher costs and higher risk of price spikes.

A robust and flexible transmission infrastructure is valuable in that it can reduce the cost and risk of challenging and extreme conditions that regularly occur on the power system. A more flexible grid

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51 Note, however, that we do not recommend building interregional transmission for still uncertain, speculative policy requirements and future market conditions. Rather, we recommend that such futures be evaluated to identify transmission projects that address current needs but also provide the insurance and flexibility value to mitigate high-cost outcomes across a range of uncertain but not implausible futures. See our discussion of the CAISO's 2004 analysis of the PVD2 project as an example of a quantitative approach to capture this value.

reduces the cost of addressing many of the unprecedented long-term uncertainties faced by the industry today. Because it can take a decade to plan and build major new transmission infrastructure, today's "conservative" approach of delaying investments or understating transmission-related benefits exposes customers and other market participants to greater risks and costs—exactly the opposite of the goals of "conservative" planning.

In an effort to improve both regional and interregional planning processes, we recommend that state and federal policy makers encourage transmission planners to pay close attention to the transformation that our power system is undergoing, the risks and costs associated with challenging and extreme market conditions, and the ability of a more robust, flexible transmission infrastructure to reduce the costs and risks of delivering power to consumers. To do so, we recommend that policy makers:

1. Resist making the assumption that less transmission investment is always a lower-cost solution. Instead, request that planners move from "conservatively" estimating transmission-related benefits to recognizing the full spectrum of benefits that transmission infrastructure investments can provide. Because there is no analytical or public policy reason that would prevent consideration of the broader range of benefits provided by transmission infrastructure, we urge regions and states that are not yet considering such a broader set of benefits to do so going forward. The "checklist" we outlined in our 2013 WIRES Report (and as replicated and briefly discussed in this report) provides a useful starting point for considering the types of benefits that transmission investments can provide. This analysis of benefits should also include the value that a more robust and flexible grid provides by mitigating customers' and other market participants' exposure to high costs and risks of unexpected events and long-term changes and uncertainties in market and policy conditions.

2. Urge planners to move from "least regrets" transmission planning that identifies only those projects that are beneficial under most circumstances to considering the potential "regrettable circumstances" that could result in very high-cost outcomes because of inadequate infrastructure. Stating it in terms of providing insurance value: planners should move from focusing on the cost of insurance to considering the cost of not having insurance when it is needed.

3. Urge transmission planners to move from "compartmentalizing" projects into reliability, economic, and public policy projects to considering the multiple values provided by all transmission investments. This will require looking beyond the immediate need that a particular project might address. Project-by-project assessments of individual needs tend to reinforce the compartmentalized approach of current planning processes. Instead, we recommend that, whenever specific needs are identified, planners consider a wider range of solutions that, in addition to addressing the identified needs, would offer long-term benefits that go beyond the immediate need.

It is important to recognize that regional planning groups are unlikely to be motivated to improve their transmission planning processes for economic and public policy projects unless policy makers actively encourage and support such improvements. To implement these recommendations, it will be necessary for the boards and executives of the various planning entities to understand the identified challenges and recognize the benefits of a more robust and flexible bulk power system, such that they can provide the appropriate guidance and encouragement to their transmission planning staff.

Our review of planning processes finds that interregional planning processes are only in early development stages. At this point, they are mostly ineffective, particularly with respect to planning for economic and public policy projects. The limitations of the existing interregional planning processes mean that the planning processes will disqualify most potentially beneficial projects, often during the qualifications stage before they are even evaluated. These planning processes create almost insurmountable barriers to the identification and approval of valuable interregional transmission projects and, therefore, cannot be expected to lead to any significant upgrades of the nation's interregional transmission infrastructure.

To improve *interregional* planning processes we consequently offer these additional recommendations:

4. Expand interregional planning processes to allow for the evaluation of projects that address different needs in different regions, recognizing that most interregional transmission projects offer a wide range of economic, reliability, and public policy benefits and that the type and magnitude of these benefits can differ across interconnecting regions. More specifically, we recommend that planning entities relax the overly limiting qualification criteria for interregional transmission projects to allow for a wider range of interregional transmission project types, including multi-value or multi-driver projects. The planning processes should be flexible enough to accommodate projects that address different needs in different regions (*e.g.*, reliability needs in one region but public policy needs in the other).

5. Discourage planners from relying on "least common denominator" approaches to interregional planning that consider only a subset of the benefits recognized in the individual regions. Instead, require that every region, at a minimum, consider in its evaluation of interregional transmission projects all project types and all project benefits that are already considered within its regional planning process. Doing so will ensure that the total benefits considered in the interregional planning process are at least equal to the sum of the benefits that each entity would determine for the project through its regional planning process.

6. Urge planners to go beyond the benefits evaluated in their individual regions to:
    a. Consider the *combined* set of benefit metrics from all interconnected regions, even if some of the benefit metrics from other regions are not yet used in some of the regions' planning processes
    b. Consider the unique additional values offered by interregional transmission projects, such as increased wheeling revenues (which offset a portion of the project costs that need to be recovered from customers within the region) or reserve sharing benefits

that reduce the planning reserve margin and generation capacity needed to meet resource adequacy standards.

7. Apply benefit-to-cost thresholds to interregional projects that are no more stringent than those applied within each region. Since interregional projects are projects that regions evaluate jointly, a single joint benefit-to-cost threshold should be sufficient. If the regions jointly find that a certain interregional project or portfolio of projects offers benefits in excess of costs, the participating regions should be able to agree on a cost allocation such that each region enjoys a share of the overall benefits that exceeds its share of the costs.

   The analytical approaches used to determine benefit-to-cost ratios for interregional projects should look beyond "base cases" or "business-as-usual cases" and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments to capture the short- and long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes.

List of Acronyms

BPS	Bulk Power System
CAISO	California Independent System Operator
CBBRP	Cross-Border Baseline Reliability Project
CBMEP	Cross-Border Market Efficiency Project
CSP	Coordinated System Plan
DOE	U.S. Department of Energy
EISPC	Eastern Interconnection States Planning Council
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
HVDC	High-Voltage Direct Current
IPSAC	Interregional Planning Stakeholder Advisory Committee
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
JCM	Joint and Common Market Committee
JOA	Joint Operating Agreement
JPC	Joint Planning Committee
kV	Kilovolt
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
NYISO	New York Independent System Operator
OMS	Organization of MISO States
PJM	PJM Interconnection
PVD2	Palo Verde to Devers No. 2
RMR	Reliability Must Run

RSC	Regional State Committee
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TEAM	Transmission Economic Assessment Methodology

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Appendix A: Case Study of Transmission Project to Mitigate the Risk of Large Increases in Societal and Customer Costs

Traditional planning approaches would have rejected the PVD2 transmission investment despite the fact that the CAISO's more comprehensive analysis shows it offered overall costs savings in excess of the project costs including significant risk mitigation benefits.

The CAISO's 2004 analysis is instructive because it quantified project-related societal benefits and customer costs for: (1) a range of benefits beyond production costs; and (2) a range of possible future outcomes, including challenging market conditions.[52] These two aspects of the CAISO analysis showed significantly more value for the project than traditional transmission planning analyses that are focused only on production cost savings under normal system conditions. The analysis also assessed the projected impact of different levels of competition and major "contingencies," such as long-term generation outages.

Comparing Transmission Costs with "Base Case" and More Comprehensive Benefits

The CAISO analysis of PVD2 showed that the proposed transmission investment offered a reduction of 2013 "base case" power production costs of only $55 million per year while the costs were estimated at $71 million per year. Thus, with the investment made, the system was projected to incur about $71 million in annualized transmission costs while saving $55 million in production costs. Most economic transmission planning processes that focus solely on such base-case benefit and cost comparisons would have rejected the transmission project because the quantified benefits do not appear to justify the project's costs.

Even if there were an intuitive recognition that transmission projects provide many more benefits than base-case production cost savings, most economic transmission planning approaches leave out these additional benefits because they seem uncertain, difficult-to-quantify, or both. The CAISO analysis of PVD2 went beyond a base-case production cost analysis to identify a much broader range of transmission-related benefits and estimated the value associated with them more

52 For example, the total "production costs" of generating power were estimated with and without the proposed transmission investment for 17 scenarios of different combinations of load growth, gas prices, hydro generation. The analysis also assessed the projected impact of different levels of competition and major "contingencies," such as major long-term generation outages.

comprehensively than what most economic analyses of transmission projects do today. The transmission benefits quantified in the CAISO's analysis included:[53]

- Capacity benefits due to generation investment cost savings;
- Operational benefits in the form of reduced reliability-must-run costs;
- Reduced transmission losses;
- Reduced emissions costs;
- Production cost savings and reduced energy prices from both a societal (*i.e.*, economy-wide) and customer perspective;
- Increased competition to mitigation of generator market power; and
- Insurance value for high-impact, low-probability events (such as a long-term nuclear plant outage).

Even before considering competitive benefits and the impacts of low-probability events (such as nuclear outages), the total annual benefits exceeded $90 million per year, significantly above the project's $71 million of annualized costs. Including the estimated additional value provided by increased competition in wholesale power markets raised the estimated annual benefits to approximately $120 million.

As Figure A-1 also shows, the CAISO analysis found that if certain low-probability events (such as a long-term outage of the San Onofre nuclear plant) were considered, the proposed transmission investment could avoid up to $70 million of additional cost per year, significantly increasing the projected value of the project. *Ex post*, we now know that one of these high-impact, low-probability events turned out to be quite real: the San Onofre nuclear plant has been out of service since early 2012 and has now been closed permanently.[54] Such "hard-to-anticipate" events are very likely to occur over the long life of transmission facilities. Ignoring that possibility understates the value of new transmission, particularly those projects that reduce exposure to costly events.

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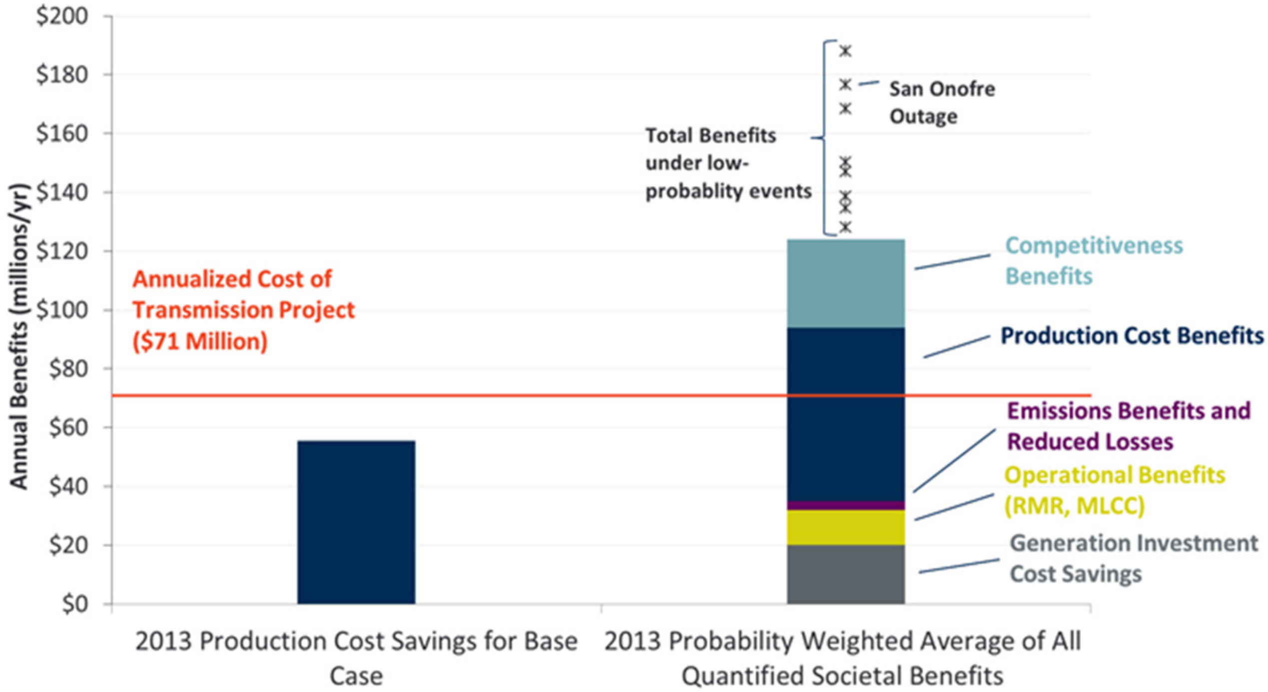
53 The CAISO also identified a number of project-related benefits that were not quantified for the purpose of comparing benefits and costs. These unquantified benefits included:
- Increased operational flexibility (providing the system operator with more options for responding to transmission and generation outages);
- Facilitation of the retirement of aging power plants;
- Encouraging fuel diversity;
- Improved reserve sharing; and
- Increased voltage support.

54 See Wald (2013).

Figure A-1
Benefits and Costs of the PVD2 Transmission Project



In summary, while not all proposed transmission investments can (or should) be justified economically, overlooking benefits because traditional tools and processes do not automatically capture these benefits can lead to the premature rejection of valuable projects and underinvestment in transmission infrastructure. Even though some of these additional benefits can be difficult to estimate in certain situations, omitting them effectively assumes these benefits are zero, which is generally not the case. Instead, estimating the approximate range of likely benefits for individual projects or a portfolio of transmission upgrades will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejecting beneficial investments.

System-Wide Costs and Risks in Absence of the Transmission Investment

When the CAISO created its transmission economic assessment methodology (TEAM) in 2004, it specifically recognized that:

> [A] significant portion of the economic value of a transmission upgrade is realized when unexpected or unusual situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The 'expected value' of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual but plausible situations. A transmission investment can be

viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.[55]

In an attempt to quantify the ability of transmission investments to mitigate the impacts of unusual and extreme events, the CAISO's analysis of PVD2 projected customer and system-wide costs with and without the project for a range of scenarios and sensitivities. This analysis provides valuable insights about the uncertainty range of production cost savings, competitive benefits, and customer and system-wide impacts of transmission investments under a wide range of projected market conditions.

The range of projected market conditions and simulated outcomes with and without the transmission investment is shown in Figure A-2, which illustrates the extent to which the investment mitigates risk for all electricity market participants.[56] For instance, Figure A-2 shows that in Scenarios 12 through 17 not having the proposed transmission project would increase system-wide costs between $200 million and $550 million each year. These scenarios include the combination of high natural gas prices, low hydro generation, higher-than-expected load growth, and some degree of generation-related market power. As shown, the sum of the probabilities that these higher costs would be incurred was estimated to be about 10% (or once in ten years). Further, the CAISO's analysis showed that, when adding in a long-term outage at the San Onofre power plant (now a reality), the lack of the transmission project would result in $300 million to $750 million of increased system-wide costs each year in these same futures.[57] Even though the anticipated probability of occurrence was low, the ability for the transmission project to avoid this magnitude of possible cost exposure compares very favorably to the $71 million annual cost of the line. The ability of the transmission project to avoid these high-cost outcomes demonstrates the transmission investment's significant insurance value.[58]

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55 CAISO (2004), p. ES-10.

56 The CAISO analysis did not analyze how benefits other than production cost savings and competitive impacts (*i.e.*, operational cost savings, generation investment cost savings, emissions benefits, and reduced losses) vary with market conditions. These benefits are charted at the bottom in Figures A-1–A-3 to allow for a better representation of the probability distribution of total transmission benefits and associated risk mitigation implications.

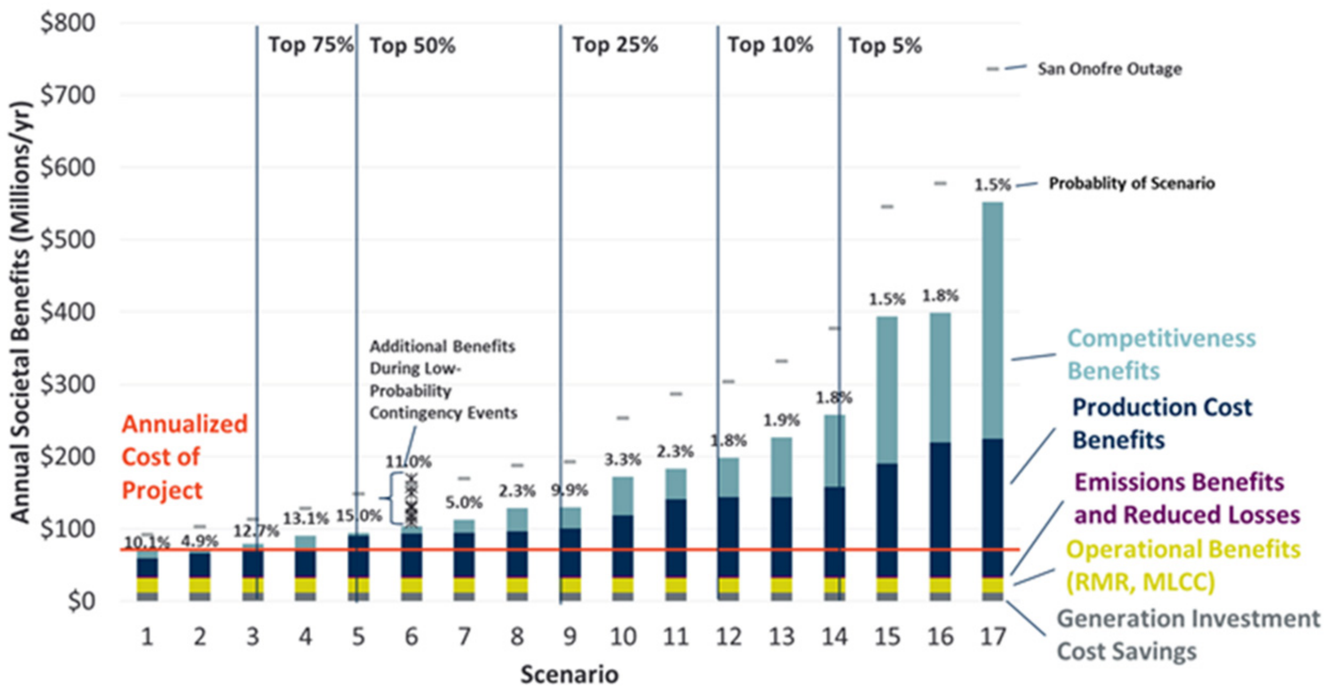
57 The CAISO has evaluated the impact of low-probability, high-cost contingency events (such as the San Onofre outage) only for base case market conditions. For the purpose of Figure A-2, we have assumed that the incremental cost savings provided the transmission project in the other scenarios for San Onofre outage conditions are proportional to the difference in production cost savings between the base case and the other scenarios (*e.g.*, the incremental benefits of the transmission project for San Onofre outage conditions are half the base case estimate if the scenario has half the base case's production cost savings).

58 Note that even assuming perfectly competitive behavior by generators (*i.e.*, assuming the light blue portion of the bars are zero) and that there would not be any possible long-term contingency (such as the

Continued on next page

Figure A-2 also documents the fact that under certain future scenarios, transmission can offer significant benefits that are not typically considered. In this analysis scenario 6 is the base case scenario. When a range of future scenarios are considered, the magnitude of societal cost avoided under certain futures (*e.g.*, the scenarios 7–17) can be significantly greater than for the base case scenario (*i.e.*, scenario 6). When all of the future scenarios are considered, the potential impact of a few high-cost scenarios can have a dramatically large impact on customers. Thus, ignoring those futures can unintentionally understate the project's value and, in particular, fail to recognize the project's risk mitigation benefit. While the probability of any of those futures emerging appears to be low, given the 40 to 60 year life of the transmission project, one can anticipate that many of these scenarios would be encountered at some point in that lifetime.

Figure A-2
Range of Projected Societal Benefits of PVD2 Project Compared to Project Costs



In this particular case, scenarios 1-5 resulted in benefits that were below the benefits in the base case scenario. However, counting all of the benefits provided by the transmission project showed that their benefits still exceeded the costs of the project. In this case one can be very confident that the project's benefits would exceed the costs over the lifetime of the transmission project—even

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San Onofre outage), the analysis projected a 10% probability that customers would be exposed to between $150 and $230 million in additional annual costs in the absence of the PVD2 project though traditional analysis that quantifies economic benefits solely based on production cost savings would have rejected the project.

As shown in Figure A-2—before even considering the potential impact of a San Onofre outage or similar other contingencies—the transmission project was estimated to provide annual benefits equal or above the $71 million in annualized project cost in every one of the 17 scenarios analyzed. Across the scenarios analyzed, there is about a 50% chance that the annual benefits exceed annual costs by less than $20 million per year. However, there is also a 50% chance that the benefits might be between $90 million and $550 million—significantly greater than the project's estimated $71 million cost. In other words, there is a 50% chance that the system-wide costs absent the transmission investment are disproportionally higher and significantly in excess of the project's costs.

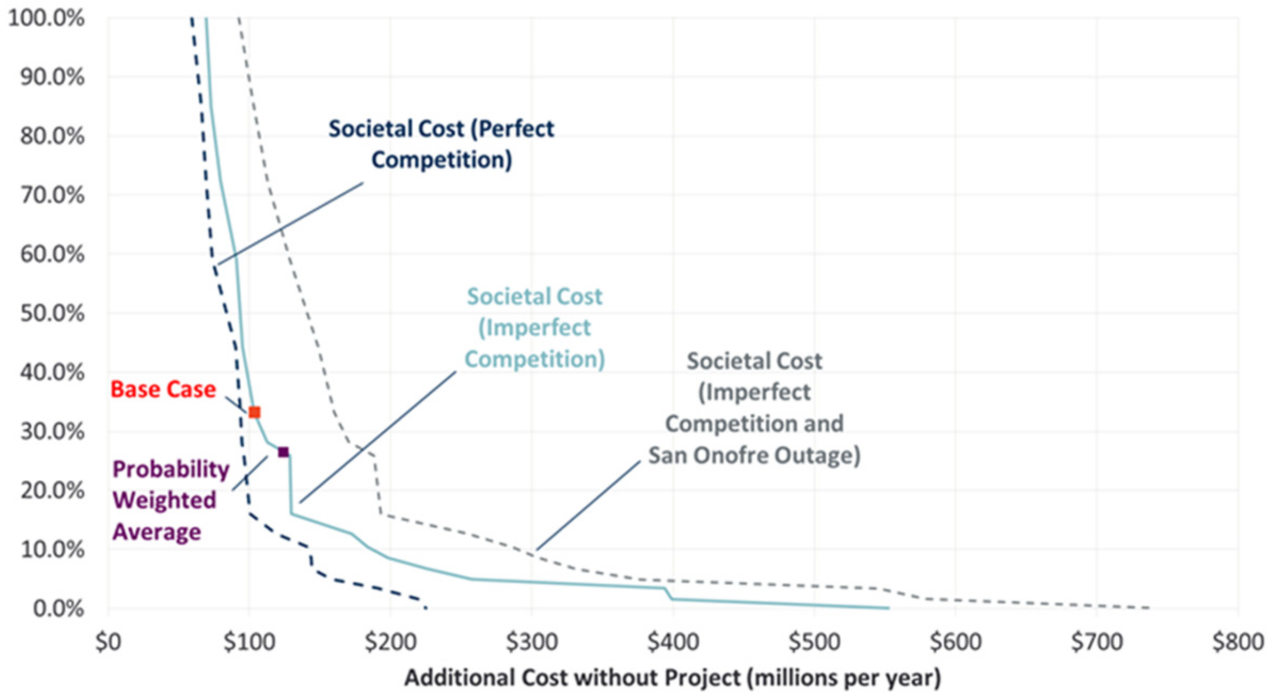
This point is even stronger when accounting for the projected potential impact of the San Onofre outage or similar other contingencies. Figure A-2 shows that society as a whole would face a 25% probability (once in four years) that annual costs would be at least $140 to $200 million higher without the project, and a 10% probability (once in 10 years) that annual costs would be between $200 and $750 million higher.

The large "tails" of these possible high-cost outcomes are also shown in Figure A-3. Rather than showing the results for each scenario, the figure organizes the data shown in Figure A-2 so it charts the probability that the additional system-wide costs incurred without the project would exceed certain values. The figure also shows: (a) total benefits assuming perfect competition (*i.e.*, without the benefit of increasing competition between generators, represented by the light blue bar in Figure A-2); (b) total benefits including competitive benefits (as represented by the total height of the bars in Figure A-2); and (c) total benefits, including competitive benefits, under long-term San Onofre outage conditions.

As shown in Figure A-3, there is an estimated 10% chance that the costs avoided by the project range between $140 million and $220 million per year under the assumption of perfect competition without any contingencies (left dashed line). If the possibility of imperfect competition is taken into consideration, there would be a 10% chance that annual costs would be between approximately $200 million and $550 million higher without the project. With one major contingency, the San Onofre outage, and imperfect competition, the analysis projected that there would be 10% probability that societal costs could be $300 million to $750 million higher without the project.

The chart also documents the asymmetric nature of transmission benefits and costs. Even if actual project costs increased from the projected $71 million to $100 million per year, total benefits would fall short of project costs by $30–40 million in some of the possible futures. However, this "downside" risk of $30–40 million is small compared to the risk of not building the project. As Figure A-3 shows, there would be an approximately 40% chance that annual costs could be between $100 million and $750 million higher without the project.

Figure A-3
Range of Projected Societal Benefits of the PVD2 Project Compared to Project Costs



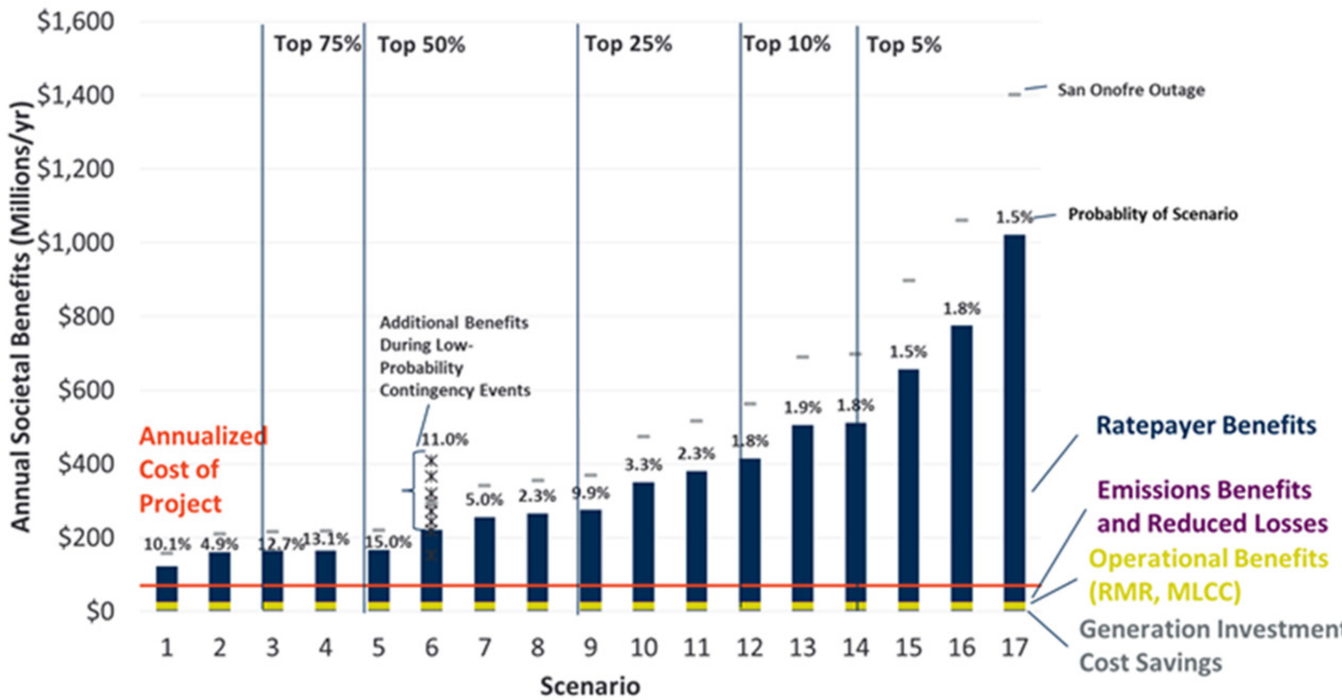
These results document the extent to which reliance on conservatively low estimates of transmission benefits can expose customers and society to disproportionately high risks if the project is rejected simply because, as previously shown in Figure A-1, base-case production costs savings of $55 million per year are less than the $71 million in annualized project cost. Rejecting the project because estimated costs exceed estimated production cost savings thus not only increases overall societal costs on average across all outcomes but, additionally, exposes society to significant risks of very high-cost outcomes. In other words, while the downside of building a project is quite limited, the costs and risks of insufficient transmission can be substantial. Understating or ignoring transmission-related benefits only magnifies the risks of high-cost outcomes.

Customer Costs and Risks Without Transmission Investments

In addition, it is important to recognize that the scope of societal costs and benefits covers the impacts on all market participants, including end-use customers and generators. Because market conditions that harm customers often will benefit generators, this means that impacts on customers can significantly exceed the societal impacts shown in Figure A-2. While we recommend that transmission projects should be evaluated from an overall societal perspective, it is nevertheless important for policy makers to understand that the cost and risk implications of inadequate transmission infrastructure on retail customers often exceed the net costs and risks to society as a whole. As illustrated in Figure A-4, the CAISO 2004 analysis of PVD2 also provides useful insights into this question.

Figure A-4 shows that the estimated higher customer costs without the project significantly exceed estimated project costs under all analyzed circumstances. Even before considering the San Onofre nuclear outage, annual customers' costs were estimated to be $150 million without the project under about 90% of all cases and would be between $400 million to $1 billion per year in approximately 10% of all possible outcomes analyzed. In other words, building the transmission project at an annualized cost of $71 million per year would be able to avoid a 1-in-10 year probability that customers could face between $400 million and $1 billion in higher-cost outcomes. With San Onofre out of service, that 1-in-10 year risk would increase customer cost exposure to a range between $700 million to $1.25 billion.

Figure A-4
Range of Additional Customer Costs without the PVD2 Project



In summary, this case study illustrates costs and risks that planning processes impose on customers and other market participants if they attempt to analyze the economic benefits of transmission investments "conservatively" by understating transmission benefits or by not considering certain benefits. Given the many uncertainties that significantly affect the cost of supplying electricity—ranging from extreme weather, unexpected generation and transmission outages, unexpected economic growth, and environmental and other regulatory risk—inadequate transmission infrastructure can expose customers and other market participants to very high-cost outcomes. Unfortunately, and as we document further below, current transmission planning processes—particularly interregional planning processes—still fail to recognize the risk of such high-cost outcomes.

Appendix B: Addressing Uncertainties Through Improved Use of Scenarios and Sensitivities

Recognizing the uncertainties about the future, particularly from a long-term perspective, we recommend that long-term transmission planning efforts improve their use of scenarios and sensitivities considered in the planning process. It is important to distinguish in market simulation efforts between (1) the short-term uncertainties that can impact the operation of the transmission network in any future year and (2) the long-term uncertainties that will define the industry in the future. The short-term uncertainties should not be used for defining long-term scenarios, but instead be captured through modeling of the uncertainties within each scenario. The long-term uncertainties on the other hand should be explored and agreed upon through the development of a range of scenarios that reasonably reflect the full range of long-term uncertainties.

Structuring the scenario development effort to create plausible and reasonable scenarios about future market conditions should involve stakeholder participation feedback because the results of planning studies will be more readily accepted by stakeholders if they understand the assumptions embodied in the scenarios and believe they reflect a reasonably complete range of plausible future market conditions. To further improve the understanding and buy-in of long-term planning efforts, this process should be defined clearly from the onset and specify concisely how scenarios will be used in transmission planning efforts. It is important for invite all potentially interested parties to participate in this process and make clear that stakeholder buy-in for the scenario assumptions and planning effort will lead to "results that matter."

To achieve these goals, we recommend that the scenario development process be a facilitated stakeholder-driven process that includes representatives from each sector within the electric power industry as well as experts from outside the region and the power industry (such as from the oil and gas sectors) to share their views on the future of the state's economy and energy industry, including their perspectives regarding electricity usages and potential growth for the industry. The scenarios should reflect a wide range of possible future outcomes in terms of region-wide and localized load growth, generation mix and locations, and fuel prices.[59]

Some stakeholders may raise concerns that transmission investment should not be based on projections of market conditions beyond several years, given the considerable long-term uncertainties faced by the industry. Planners may want to stay away from such investment decisions, fearing that uncertain futures could dramatically change the value of those investments and result in regrets. We believe, however, that the likelihood of inefficient investments or

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59 For an example of a facilitated stakeholder-driven scenario planning effort applied to long-term transmission planning, see ERCOT (2014); see also 2013 WIRES Report.

"regrets" is just as high when decisions about long-lived assets are made solely based on near-term considerations. Shying away from making investment decisions because of difficulties in predicting the future could lead to a perpetual focus on transmission upgrades that address only the most urgent near-term needs, such as reliability violations, and thereby forego opportunities to capture higher values by making investments that could address longer-term needs much more effectively. It is also likely to lead to inefficient use of scarce resources, such as available transmission corridors and rights-of-way. To address this challenge, we recommend that transmission planners evaluate long-term uncertainties through scenario-based analyses. Such scenario-based long-term planning approaches are widely used by other industries (such as the oil and gas industry)[60] and have also been employed in most transmission planning efforts. However, the scenarios specified in transmission planning processes take into account only a very limited degree of divergent assumptions about renewable energy additions, load levels, and a few other factors.

Evaluating long-term uncertainties through various distinctive future scenarios is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can be used to: (1) identify "least-regrets" projects who mitigate the risk of high-cost outcomes and whose value would be robust across most futures; and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values of economic transmission projects under the various scenarios should be used both to assess the robustness of a project's cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

In addition to a scenario-based consideration of long-term uncertainties, we recommend that short-term uncertainties be considered separately. Short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive scenario definitions. These uncertainties should be simulated probabilistically or through sensitivity analyses for each of the chosen scenarios to capture the full range of the societal value of transmission investments.[61]

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60 For example, see Royal Dutch Shell (2013). See also Wilkinson and Kupers (2013).

61 For simplified frameworks taking into account both long-term and short-term uncertainties for transmission planning in the context of renewable generation expansion, see Munoz, *et al.* (2013); Van Der Weijde and Hobbs (2012); and Park and Baldick (2013).

The simulation of short-term uncertainties can be particularly important because the value of transmission projects is disproportionately higher during more challenging market conditions that are created by such uncertainties. Not analyzing the projects under challenging, but realistic, market conditions risks underestimating their values. The impact of near-term uncertainties can be analyzed by specifying probabilities and correlations for key variables, importance sampling, and undertaking Monte Carlo simulations for the selected set of cases. However, such complex and time-consuming probabilistic simulations are not always necessary. Often, a limited set of sensitivity cases (*e.g.*, 90/10, 50/50, 10/90 load forecasts) and case studies (*e.g.*, simulating past extreme contingencies, outages, weather patterns) can serve as an important step toward capturing the actual values of projects, which can help planners better understand how these near-term uncertainties can affect the expected value of projects in any particular future year.

For example, to address how uncertainties affect the value of transmission projects, the California Energy Commission developed a framework for assessing the expected value of new transmission facilities under a range of uncertain variables. Their recommended approach identifies the key variables that are expected to have a significant impact on economic benefits, establishes a range of values to be analyzed for each variable, and creates cases that focus on the most relevant sets of values for further analysis, including the probabilities for each case.[62] ERCOT also previously performed simulations for normal, higher-than-normal, and lower-than-normal levels of loads and natural gas prices in its evaluation of the Houston Import Project. The simulations showed that a $45.3 million annual consumer benefit for the Base Case simulation (normal load and gas prices) compared to a $52.8 million probability-weighted average of benefits for all simulated load and gas price conditions,[63] illustrating the extent to which the value of transmission projects can depend on the consideration of key uncertainties. A more comprehensive analysis of how uncertainties affect the value of a transmission project was undertaken by the CAISO in 2004 as summarized in Appendix A.

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62 Toolsen (2005).

63 ERCOT (2011), p. 10.

Appendix C: Case Studies of Proposed Interregional Planning Processes

This appendix presents two case studies of recently-proposed interregional transmission planning processes that are currently being implemented. The first case study summarizes the interregional planning processes proposed by SPP and MISO. The second case study documents the interregional planning process proposed by MISO and PJM.

Case Study 1: SPP-MISO Interregional Planning

The SPP-MISO interregional planning process is an example of significant disagreements between the neighboring regions, which greatly reduces the scope and effectiveness of the interregional planning effort. SPP has attempted to approach interregional planning broadly and include reliability, economic, and public policy projects at all voltage levels. In contrast, MISO applied a much more narrow perspective and proposed limiting interregional planning solely to "market efficiency projects" at a voltage level of primarily 345 kV or above. As SPP explained to FERC, MISO's approach excludes interregional transmission projects with voltages primarily less than 345 kV and projects that are primarily needed to resolve reliability concerns or provide public policy benefits.[64] As SPP notes, approximately 80% of the interconnections between SPP and MISO are at a voltage level less than 345 kV, so it is reasonable to expect that many opportunities for more efficient or cost-effective resolution of issues near the SPP-MISO seam would be precluded from being considered using MISO's proposed criteria.[65] SPP also pointed out that excluding interregional reliability and public policy projects would limit the opportunity and ability to identify interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities.

While this disagreement is still pending before FERC, SPP and MISO have continued their interregional planning efforts by exchanging planning data, building joint planning models, soliciting stakeholder input on seams-related concerns and opportunities, and defining the scope and timeline of the two organization's first interregional study process. This SPP-MISO interregional planning process is specified in the two organizations' Joint Operating Agreement ("JOA") and implemented by the Joint Planning Committee ("JPC"), the decision-making body consisting of representatives from the staff of SPP and MISO. The JPC considers stakeholder inputs, as facilitated by the Interregional Planning Stakeholder Advisory Committee ("IPSAC"). The IPSAC can make recommendations to the JPC concerning both the need to study

64 SPP (2013), p. 21.

65 SPP (2013), p. 22.

transmission issues and solutions and the appropriate action on any solutions identified by the draft of the JPC's report on the results of a study.

The first SPP-MISO effort to develop a Coordinated System Plan ("CSP") formally started in early 2014. The study scope, as approved by the JCP, includes possible transmission solutions to seams-related reliability concerns and possible market efficiency improvements, but excludes interregional transmission projects that would be needed to address public policy objectives. To identify such seams-related reliability concerns and market efficiency opportunities and study them through the CSP effort, SPP, MISO, and individual stakeholders submitted descriptions of interregional transmission issues.[66] Transmission owners have been participating actively in the CSP study process and have submitted information on existing challenges along the SPP-MISO seam. SPP, MISO, and their stakeholders also developed planning models and study assumptions for use in the CSP. However, due to a lack of SPP and MISO stakeholder support to study a broader range of possible futures (such as a Clean Power Plan scenario), this first round of CSP analyses will only reflect "business as usual" study assumptions. As is the case for most traditional transmission analyses, the analysis considers only production cost savings and study cases are based only on weather-normalized peak loads and a fully intact transmission system.[67]

The joint study effort is currently under way and a draft CSP report is expected in June 2015. At the completion of this first MISO-SPP CSP study, the JPC may recommend interregional transmission projects for further evaluation. Any recommended interregional transmission solutions would then be considered by SPP's and MISO's respective regional transmission planning processes, which means each proposed interregional project also needs to be approved by both regional processes, including through SPP and MISO boards, before it can be implemented as an interregional project as part of a Coordinated System Plan.[68] The fact that interregional projects need to pass three separate approval thresholds—the joint interregional thresholds as well as each RTOs' individual regional planning criteria—adds an additional challenge to the approval of any interregional transmission projects.

As the above discussion should make clear, this interregional planning process is unlikely to "find" beneficial interregional projects even if they exist. This barrier to identify beneficial projects is created by the combination of several factors. First, the very limited scope of how interregional projects are defined will exclude from consideration many potentially beneficial projects simply because they will not meet the interregional planning criteria. Second,

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66 MISO and SPP (2014a).

67 Traditional market simulations for the evaluation of production cost savings are based on transmission constraint definitions under first-contingency conditions. As explained in WIRES 2011, this approach does not consider the additional congestions and more stringent constraints created by transmission outages.

68 See SPP (2014a) and MISO (2014a).

considering only a narrow set of benefits in interregional planning processes—a set that is often even narrower than the benefits considered in regional planning efforts—will make it difficult for even very valuable projects to meet the applicable benefit-cost thresholds. Third, analyzing only "business as usual" futures (and, as is usually the case, under normalized weather conditions without considering transmission outages) will fail to identify valuable transmission projects that would shield customers from high-cost outcomes under market conditions and in futures that are more challenging than the case analyzed. Fourth, the "mechanics" of the interregional planning process that requires individual projects to pass all three planning thresholds will invariably mean that even projects that are beneficial from an overall perspective will often be rejected because they fail one of the individual RTO's regional planning criteria.

CASE STUDY 2: MISO-PJM INTERREGIONAL PLANNING

Another example that highlights the challenges created by planning of interregional transmission infrastructure is the process currently used by MISO and PJM under their Joint Operating Agreement (JOA), which specifies requirements and evaluation criteria for cross-border baseline reliability projects (CBBRPs) and cross-border market efficiency projects (CBMEPs).

FERC has already mandated as part of its review of the MISO-PJM interregional transmission planning proposal filed in response to Order 1000 that the two RTOs need to add a process to evaluate interregional public policy projects, a category of projects that was missing from the filed proposal.[69] The MISO-PJM interregional planning process is currently evaluated further by FERC in response to a complaint filed by Northern Indiana Public Service Company (NIPSCO).[70] As NIPSCO explains in its complaint, the criteria for the evaluation of interregional transmission projects set out in the MISO-PJM JOA require projects to pass three separate tests before they can even qualify as potential interregional transmission projects. This process, as discussed below, is likely to reject valuable projects that could cost-effectively solve inefficiencies along the heavily intertwined MISO-PJM seam.

For example, under the criteria proposed in MISO's and PJM's compliance filing with the interregional planning provisions of Order 1000, cross-border market efficiency projects must: (1) qualify as market efficiency projects ("MEPs") under the MISO Transmission Expansion Plan ("MTEP") process; (2) qualify as an market efficiency projects under PJM's Regional Transmission

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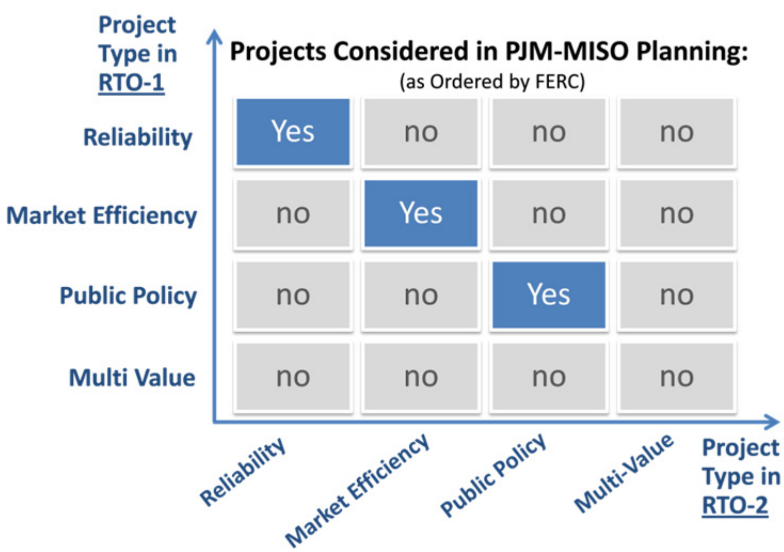
69 FERC (2014a), 149 FERC ¶ 61,250 at 89. FERC also ordered the RTOs to address other deficiencies, such as explaining (1) how stakeholders and transmission developers can propose interregional transmission facilities for joint evaluation and (2) how a proponent of an interregional transmission project may seek to have its interregional transmission project jointly evaluated by the MISO and PJM by submitting the interregional transmission project into MISO's and PJM's regional transmission planning processes.

70 FERC (2014b), 149 FERC ¶ 61,248.

Expansion Plan (RTEP) criteria; and (3) qualify under the joint planning criteria set out by the JOA.

As illustrated in Figure C-1, these criteria mean many types of projects will automatically be excluded from consideration. Examples of such exclusions are any interregional projects that satisfy market-efficiency project criteria in one RTO but that would address reliability, public-policy, or multi-value project needs in the other. In other words, a project that would enhance market efficiency in MISO and simultaneously address a reliability or public policy need in PJM would automatically be excluded from consideration because it would not be a market-efficiency project in both RTOs. Thus, the proposed MISO-PJM JOA fails to recognize that many interregional projects that provide a particular benefit in one RTO may provide other types of benefits (public policy or reliability) in the other RTO. This interregional planning process also fails to recognize that projects may provide multiple types of transmission-related benefits. While both MISO and PJM have started to recognize multiple benefits in their internal planning processes—referred to as multi-value projects in MISO and multi-driver projects in PJM—the specified interregional planning process forecloses consideration of projects that provide such multiple benefits.

Figure C-1. Interregional Planning Processes Do Not Allow for the Evaluation of Projects That are Not the Same Type in Each RTO



As shown in Figure C-1, interregional projects that the MISO-PJM interregional planning process will be able to consider are only those that: (1) address reliability needs in both RTOs; (2) are viewed as market-efficiency projects by both RTOs; or (3) address public policy requirements in both RTOs.[71] As the figure shows, that includes only 3 out of 16 different types of interregional projects.

The selection criteria for interregional and regional projects also impose different qualification requirements by applying differing minimum capital investment and project voltage thresholds. For example, the joint criteria require a minimum project size of $20 million to qualify a potential CBMEP, while the two regions' individual requirements have lower capital thresholds: $5 million within MISO and none within PJM. This means that a $15 million interregional market efficiency project that would qualify under both MISO and PJM regional planning criteria would fail the joint qualification criteria. In fact, the most recent MISO-PJM planning effort has rejected interregional projects based on this size threshold, despite the fact that analyses had estimated the projects' benefit-cost ratio to range from 5.0 to 36.[72]

Differing voltage threshold requirements for each of the three sets of criteria additionally create a similar potential barrier for enhancing interregional transmission investments across the MISO-PJM seam. As currently proposed, MISO's criteria for interregional projects require projects to be rated at 345 kV or higher,[73] while the PJM criteria and the joint qualification criteria would accommodate projects with a rated voltage as low as 100 kV. This effectively means that interregional projects operating at less than 345kV that would qualify under PJM and the joint criteria, will simply fail to qualify because it does not meet MISO's voltage threshold.

Additional hurdles are created by the benefit-cost thresholds that apply to economically-justified interregional projects that qualify for evaluation as cross-border market efficiency projects. To be approved as a CBMEP, a proposed project must: (1) pass the joint benefit-to-cost test based on a single benefit metric (adjusted production costs) prescribed in the JOA (which considers only 10 years of benefits); (2) pass MISO's benefit-to-cost test based on the adjusted production cost metric for MEPs specified in MISO's MTEP process (which considers 20 years of benefits); and, additionally, (3) also pass PJM's benefit-to-cost test based on the different benefit metric (a blend between adjusted production costs and load LMP payments) specified in PJM's RTEP process (which considers 15 years of benefits).

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71 MISO proposed in its Order 1000 filing to consider only projects that address market-efficiency needs in both RTOs. PJM proposed to consider interregional projects that address either reliability needs in both RTOs or market efficiency needs in both RTOs. As noted earlier, in response to these compliance filings, FERC has ordered that the RTOs' interregional planning process needs to be expanded to also consider public policy needs.

72 MISO and PJM (2014a).

73 Lower voltage facilities of 100kV or above that collectively constitute less than 50% of the combined estimated project costs are acceptable. See MISO-PJM (2014c), p. 21.

Requiring projects to pass the joint benefit-cost test as well as both RTO's individual benefit-cost criteria, all of which consider only a narrow set of transmission-related benefits will very likely eliminate even highly valuable interregional projects. This is illustrated in the most recent MISO-PJM's effort to evaluate cross-border transmission opportunities utilizing the enhanced joint interregional study process the RTOs' filed in response to Order 1000. MISO and PJM solicited from market participants specific proposals to address identified seams-related challenges and received 76 interregional transmission proposals from 12 transmission companies.[74] RTO staff, with input from the Joint and Common Market Committee (JCM) and the IPSAC, conducted a joint study to evaluate the received proposals. Only two projects of the nearly 76 project proposals passed all three benefit-to-cost thresholds required by the MISO-PJM interregional planning process. The two projects that qualified turned out to be projects that were previously proposed as regional projects.[75]

As NIPSCO explained in its complaint, a single set of qualification criteria and benefit-cost thresholds for cross-border projects would improve the interregional planning process and avoid introducing unintended barriers to the RTOs' ability to identify and evaluate valuable interregional transmission investments.

Broadening the range of benefits evaluated for cross border projects would be important as well. Currently the benefits allowed to be considered (*i.e.*, adjusted production cost and load payment savings) are simply too narrowly defined to be able to identify valuable projects.[76] Both RTOs' pre-specified benefit metrics as well as the benefit metrics specified for the joint interregional planning process do not allow for the consideration of other quantifiable (and often significant) economic benefits such as savings from reduced reserve margins, lower transmission losses, or the cost of avoided reliability projects. The fact that benefits are compared with costs for only the first 10 years of a project's useful life will further serve to eliminate some beneficial projects simply because benefits tend to start low and increase over time while regulated costs start high and decrease over time. Ignoring many types of benefits and those that are realized over the long-term artificially understates the projects' actual benefit-to-cost ratios and, thus, results in the rejection of interregional projects even if they were able to pass the qualification criteria. Not surprisingly and despite the significant transmission congestion along the MISO-PJM seam, no cross-border market efficiency project has been able to get approved based on the RTOs' interregional planning process.

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74 For example, see FERC (2013), 145 FERC ¶ 61,256, at P 13.

75 MISO-PJM (2014c).

76 Production cost and load payment savings are based on market simulations that reflect only weather-normalized peak load conditions, fully intact transmission system (*i.e.*, no transmission outages), and for only a very limited number of alternative futures. Deviations from such normalized assumptions can disproportionately increase the benefits of transmission projects, and thus the projects' benefits-to-cost ratios.

As in the case of SPP-MISO Interregional Planning process discussed above, the MISO-PJM interregional planning process creates significant barriers to interregional planning. It will, at the outset, disqualify many potentially valuable projects from consideration as an interregional project, and the projects that qualify will likely be rejected through multiple benefit-cost tests that limit benefits to narrowly-defined metrics that will understate the overall value of any proposed interregional transmission projects.