STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY AND ITC MIDWEST LLC FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345 KV TRANSMISSION LINE PROJECT	DOCKET NO. E002, ET6675/CN-17-184 OAH Docket No. 82-2500-35157
IN THE MATTER OF THE APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A ROUTE PERMIT FOR THE HUNTLEY-WILMARTH 345 KV TRANSMISSION LINE PROJECT	Docket No. E002, ET6675/RP-17-185 OAH Docket No. 82-2500-35157

DIRECT TESTIMONY OF

ANDREW W. SIEBENALER

On Behalf of

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

and

ITC MIDWEST LLC

September 6, 2018

Exhibit ___(AWS-1)

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Andrew Siebenaler, and my business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

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

A. I am employed as a Senior Engineer in Regional Transmission Planning by Xcel Energy Services Inc. In that capacity, I provide transmission planning support for Northern States Power Company, a Minnesota corporation doing business as Xcel Energy (Xcel Energy). I am one of the transmission planning engineers assigned to the Huntley – Wilmarth 345 kilovolt (kV) Transmission Line Project (Huntley – Wilmarth Project or Project).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I earned a Bachelor of Science degree in Electrical and Computer Engineering from the University of Minnesota – Duluth in 2012. From December 2012 through March 2015, I was employed by the Midcontinent Area Power Pool Corporation (MAPPCOR or MAPP) in the position of Transmission Planning Engineer, where I was tasked with the reliability analysis of the transmission system for the MAPP member companies for the purpose of compliance with North American Electric Reliability Corporation transmission planning standards. Since transitioning to Xcel Energy, I have maintained the position of Regional Transmission Planning Engineer. In this role, I am responsible for the representation of Xcel Energy in regional, state, and local technical discussions related to transmission planning efforts and policy development, primarily for the Xcel Energy service territory within the Midcontinent Independent System Operator, Inc.'s (MISO) footprint. My role also includes the economic planning and analytical efforts of the MISO transmission system. My resume is attached as Exhibit___(AWS-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy and ITC Midwest LLC (ITC Midwest) (collectively, Applicants) for a Certificate of Need and Route Permit for the Huntley – Wilmarth Project.

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

A. The purpose of my testimony is to discuss the need for the Project and the alternatives to the Project that Applicants considered. I will provide an overview of the MISO regional transmission planning process as well as information regarding MISO's approval of the Project as a Market Efficiency Project (MEP) as part of its 2016 Transmission Expansion Plan (MTEP16). I will also discuss Applicants' additional analysis of the Project under MTEP17 modeling assumptions (presented in the Certificate of Need Application) as well as our most recent analysis of the Project under MTEP18 modeling assumptions. I will provide the benefit-to-cost ratios under the MTEP18 Futures for route alternatives proposed during the scoping process for the Environmental Impact Statement (EIS). Finally, I will discuss the system alternatives that the Applicants evaluated to the proposed Project.

Q. What schedules are attached to your testimony?

A. Schedule 1: Resume of Andrew Siebenaler;

Schedule 2: "EDF Renewables to develop up to 200 MW of Iowa's Golden Plains Wind Project" dated June 13, 2018;

Schedule 3: Revised Table 17 and Appendix K from Certificate of Need Application;

Schedule 4: "Exploration of Transmission Outages Modeling in Economic Planning" presentation dated June 12, 2018;

Schedule 5: Brattle Group Report;

Schedule 6: Applicants' Response to Minnesota Department of Commerce Information Request No. 23;

Schedule 7: Excerpts from Attachment FF of the MISO Tariff;

Schedule 8: Applicants' Supplemental Response to Minnesota Department of Commerce Information Request No. 10; and

Schedule 9: Applicants' MTEP18 Curtailment Results.

Q. Are you available to provide testimony in support of particular sections of the Certificate of Need Application?

A. Yes. I am testifying in support of the following sections of the Certificate of Need Application: Section 3.3 (Minnesota's Changing Generation Portfolio); Chapter 4 (Need Analysis); and Chapter 5 (Alternatives Analysis).

II. NEED OVERVIEW

Q. WHY IS THE HUNTLEY – WILMARTH PROJECT NEEDED?

A. Yes. The Huntley – Wilmarth Project is primarily designed to reduce transmission system congestion which in turn improves the efficiency of the MISO energy market resulting in lower wholesale energy costs.

Q. WHAT IS TRANSMISSION SYSTEM CONGESTION?

A. Congestion, in its most basic form, simply means that there is insufficient transmission capacity to deliver all of the lowest cost power to customers and, as a result, the electrical system is not operating as efficiently as it could be. Transmission system congestion is similar to a traffic jam on the highway in that when generators and consumers want to produce and consume more energy than the system has the ability to accommodate at that time, the result is that most cost effective energy is unable to travel along the congested path. The Minnesota/Iowa border is one of the most congested areas in the region's electric transmission system due to the large number of wind generators in place and planned for this area and the lack of adequate transmission capacity to transport this power to customers.

Q. HOW WILL THE HUNTLEY – WILMARTH PROJECT ADDRESS THIS CONGESTION PROBLEM?

A. In examining the congestion problem in more detail, MISO determined that the congestion along the border concentrated on the Huntley (Winnebago) – Blue Earth – South Bend – Wilmarth 161 kV line during the loss of the Lakefield Junction – Wilmarth 345 kV line. To address this issue, additional transfer capacity in the form of a new 345 kV transmission line between the Huntley and Wilmarth substations was identified as necessary to alleviate the congestion and increase market access to lower cost generation. The increased access to lower cost generation provides economic benefits through reduced wholesale energy costs.

Q. ARE THERE OTHER BENEFITS OF THE PROJECT?

A. Yes. The Project will also strengthen the resilience of the regional grid and improve the deliverability of energy by reducing curtailments of wind generators. In addition, the Project will make the Minnesota transmission system more robust and allow the transmission system to better respond to different outages on the system. A more robust transmission system also enables access to a diverse mix of generation resources that allow customers the ability to access the least expensive power available at any given time. Finally, as discussed by Applicants' witness Mr. Ben Abing, the Project will provide environmental benefits by providing reductions in CO_2 and NO_x emissions.

III. CHANGING GENERATION PORTFOLIO

Q. HOW HAS THE MINNESOTA GENERATION PORTFOLIO CHANGED OVER THE PAST 20 YEARS?

A. The generation mix in Minnesota and surrounding states has dramatically shifted from relying primarily on coal and nuclear generation resources to a more diverse generation mix that includes increasing amounts of renewable energy, in particular, wind generation. For instance, wind generation in

Minnesota has increased from approximately one percent of the generation mix in 2000 to 18 percent in 2016. During the same timeframe, Minnesota's generation from coal-fired resources has dropped from approximately 66 percent to 39 percent and natural gas generation has increased from approximately three percent to 15 percent.

Q. WHAT ARE THE MAIN REASONS FOR THE CONSIDERABLE GROWTH IN WIND GENERATION?

A. The expansion of wind generation in Minnesota has been the result of various overlapping factors: local, state, and federal policies, favorable geographic conditions, technological improvements, and economics. In 2007, Minnesota established mandatory Renewable Energy Standards (RES), which set a renewable generation target of 30 percent by 2020 for Xcel Energy and 25 percent by 2025 for other load-serving utilities in Minnesota.

Federal Production Tax Credits (PTC) and Investment Tax Credits (ITC) have also spurred growth by providing meaningful tax incentives for qualified wind projects and expenditures.

The unique geographic conditions in southwestern and southern Minnesota as well as most of Iowa, North Dakota, and South Dakota have further promoted growth of new wind generators. These areas are ideal locations for wind generation as they have higher-than-average wind speeds combined with vast areas of land suitable for accommodating new wind turbines. Advancements in wind generation technology have significantly improved the cost and performance of today's wind turbines. Together, these factors have made wind power one of the most economical options to generate electricity in Minnesota today.

Q. DOES THE MISO INTERCONNECTION QUEUE REFLECT THE ACCELERATED EXPANSION IN WIND DEVELOPMENT?

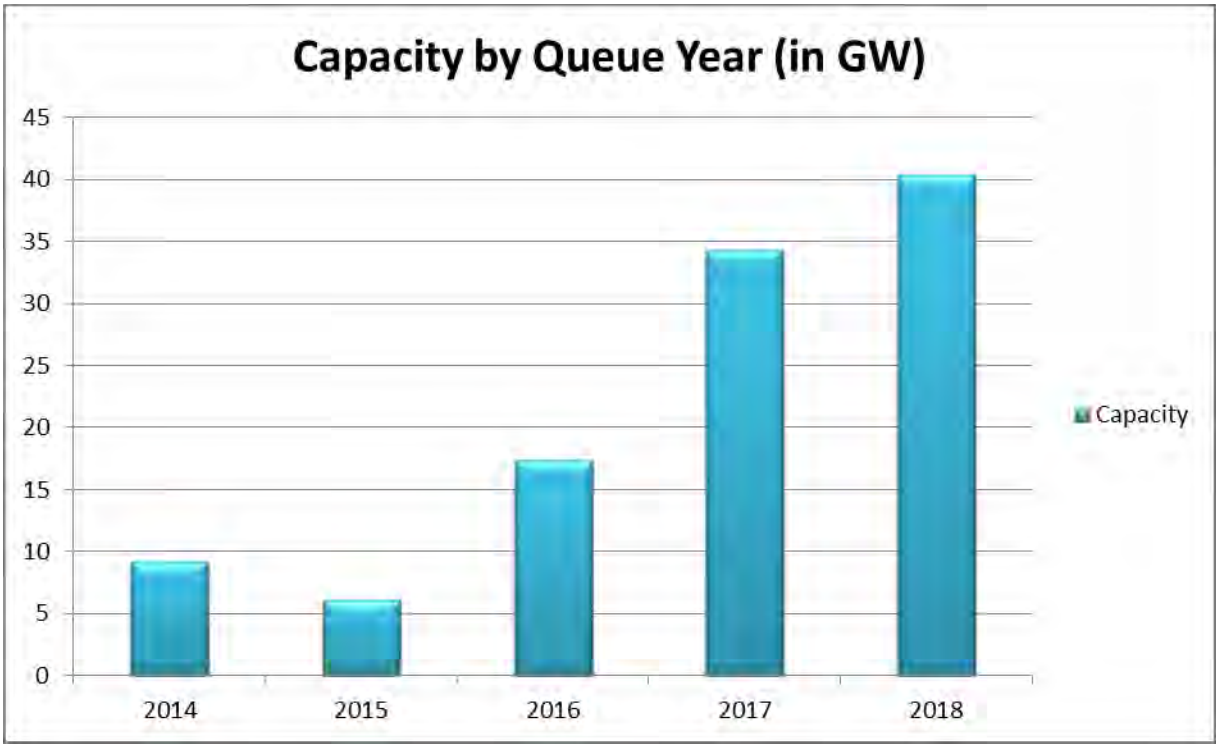
A. Yes. As of August 1, 2018, the MISO interconnection queue contains 536 interconnection requests with a combined capacity of 91.3 gigawatts (GW). All projects in the current queue are proposed to be in-service on or before April 1, 2023. Over 85 percent of these 536 requests are for renewable generation projects.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. This is consistent with the rapid rate of expansion of renewable generation projects that MISO has experienced in the past couple of years. **Figure 1** summarizes the GW of active and completed projects in MISO's Definitive Planning Phase (DPP) process from 2014 to 2018. As shown by this figure, the number of active generation projects in 2017 and 2018 were markedly higher than prior years. The current interconnection queue demonstrates that this trend is likely to continue.

Figure 1

Active and Completed Projects in MISO's DPP Process, 2014 – 2018 (in GW)



Q. HOW MANY OF THESE PROJECTS ARE LOCATED IN MINNESOTA AND IOWA?

A. MISO categorizes projects by five different areas. One of those areas, the "West Area," includes Minnesota, Iowa, and portions of Wisconsin and the Dakotas. As of June 2018, the West Area had 198 active interconnection requests totaling 32 GW. Of those requests, 131 are for wind generators totaling 25 GW.

Q. ARE ANY OF THESE NEW GENERATION RESOURCES PROPOSED TO BE LOCATED NEAR THE HUNTLEY – WILMARTH PROJECT?

A. Yes. In June 2018, Alliant Energy announced plans to build a new 200 megawatt (MW) wind project called the Golden Plains Wind Project in Winnebago and Kossuth counties in Iowa. Winnebago and Kossuth counties are located along the Minnesota/Iowa border directly south of Mankato, Minnesota. The Golden Plains Wind Project is expected to come online in early 2020 and is part of Alliant Energy's plan to add 1,000 MW of new wind generation in Iowa by the end of 2020. Attached to my testimony as Exhibit___(AWS-1), Schedule 2 is a news article related to this wind project.

Q. HAVE OTHER UTILITIES ANNOUNCED PLANS TO EXPAND THEIR WIND GENERATION RESOURCES?

A. Yes. In August 2016, the Iowa Utilities Board approved MidAmerican Energy's Wind XI Project. The Wind XI Project will add more than 2,000 MW of wind generation in Iowa by the end of 2019. Xcel Energy has also announced plans to add 1,850 MW of wind generation in the Upper Midwest by 2022. I have summarized other utility wind generation announcements in **Table 1** below.

Table 1

Announced Wind Additions in the Upper Midwest

Utility	Wind Addition	Timing of In-service
MidAmerican Energy	2,000 MW	2019
Xcel Energy	1,850 MW	2022
Alliant Energy	1,000 MW	2020
Great River Energy	400 MW	2020
Minnesota Power	300 MW	2020
Otter Tail Power	400 MW	2021

These announced wind resource additions amount to approximately 6,000 MW of new wind coming online in the Upper Midwest by 2022.

Q. WHAT ARE THE CONSEQUENCES OF THE PAST AND CONTINUED EXPANSION OF WIND GENERATION ON THE TRANSMISSION SYSTEM?

A. The exceptional growth of wind generation in Minnesota and the surrounding states has put unprecedented pressure on the transmission system to deliver the low cost wind power to customers. As more wind generation facilities have been constructed along the Minnesota and Iowa border over the past decade, transmission congestion in this area has increased.

IV. MISO'S AND APPLICANTS' ANALYSIS OF NEED

Q. CAN YOU PROVIDE A SUMMARY OF THE NEED ANALYSES THAT HAS BEEN CONDUCTED TO DATE FOR THE HUNTLEY – WILMARTH PROJECT?

A. Yes. The Huntley – Wilmarth Project has undergone extensive review and analysis by both MISO and the Applicants. MISO analyzed and approved the Project in December 2016 as part of MTEP16 and Applicants further analyzed the Project under the models developed by MISO for MTEP17 and MTEP18.

As part of MTEP16, MISO analyzed the Project compared to 23 different transmission alternatives under five different future scenarios or "Futures." The Huntley – Wilmarth 345 kV Project outperformed all other transmission alternatives and was found to provide $210 million in present value (PV) economic benefits and had a benefit-to-cost ratio of 1.51 to 1.86, using MISO's cost estimates of $88 to $108 million (2016$). MISO further analyzed the Project and two other transmission alternatives under a Queue Wind Sensitivity that incorporated future wind generation additions into the MTEP16 Futures. Under the Queue Wind Sensitivity, the Project outperformed the two other alternatives and had a PV benefit of $251 million and had a benefit-to-cost ratio of 1.86 to 2.28, using MISO's cost estimates of $88 to $108 million (2016$).

The Applicants further analyzed the Project under MTEP17 and MTEP18 models and concluded that under these more recent models that the Project continued to provide economic benefits. Under the MTEP17 models, the

Huntley – Wilmarth Project had a PV benefit of $276 million and had a benefit-to-cost ratio of 1.66 to 2.16 using the cost estimates for the routes proposed by the Applicants in the Route Permit Application of $105.8 million to $138.0 million (2016$). Similarly, under MTEP18, the Applicants determined that the Project has a PV benefit of $218 million and had a benefit-to-cost ratio of 1.30 to 1.69 using the cost estimates for the routes proposed by the Applicants in the Route Permit Application.

In sum, while the Project provides different levels of economic benefits under the three different MTEP model years, under each MTEP analysis the Project has repeatedly been shown to provide economic benefits that exceed its costs. This extensive analysis demonstrates that the Huntley – Wilmarth 345 kV Project is a robust solution that is able to provide wholesale energy cost benefits across multiple Future scenarios.

A. MISO's Analysis of Need for the Project – MTEP16

Q. WHAT IS MISO?

A. MISO is a regional transmission organization (RTO), which operates the transmission system and an energy market in parts of 15 U.S. states and the Canadian province of Manitoba. As an RTO, MISO is responsible for planning and operating the transmission system within its footprint in a reliable manner.

Q. HOW DOES MISO FACILITATE THE DEVELOPMENT OF A RELIABLE AND EFFICIENT TRANSMISSION SYSTEM?

A. Each year, MISO develops its transmission expansion plan or MTEP in collaboration with transmission owners and other stakeholders. The MTEP is used to evaluate different transmission projects to meet local and regional reliability standards, support the achievement of state and federal energy policy requirements, and enable a competitive and efficient electricity market.

Q. HOW IS THE MTEP DEVELOPED?

A. The development process involves an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. A diverse group of MISO stakeholders[1] participate in the MTEP process by proposing potential candidate projects; suggesting model updates; providing input on appropriate modeling assumptions; developing scenarios of future electrical systems and energy policies; and reviewing results and drafts of the MTEP report.

Q. HOW DOES XCEL ENERGY PARTICIPATE IN THE MTEP PROCESS?

A. Xcel Energy participates in the development of the annual MTEP by actively engaging in all aspects of the MTEP process from the initial model creation through approval of the MTEP each December. Xcel Energy's involvement

[1] MISO's stakeholders include representatives from transmission-owning MISO members, independent power producers and exempt wholesale generators, power marketers and brokers, municipal utilities, cooperatives, transmission dependent utilities, public consumer advocates, state regulators, environmental organizations, competitive transmission developers, eligible end-use customers, and coordinating members.

includes providing feedback and input on the creation of different future scenarios and model development as well as providing information about Xcel Energy's transmission system that may be pertinent to the MTEP.

Q. HOW DOES THE MTEP ADDRESS CONGESTION?

A. The Market Congestion Planning Study (MCPS) is conducted as part of the annual MTEP. This study focuses exclusively on identifying where congestion on the transmission system may limit access to the lowest-cost generation resources. The MCPS evaluates transmission improvements that may relieve this congestion and increase market efficiency under a variety of future system scenarios or "Futures." This is the study MISO undertook as part of MTEP16 to develop and evaluate the Huntley – Wilmarth Project.

Q. CAN YOU BRIEFLY DESCRIBE THE FIVE FUTURES THAT WERE USED IN THE MTEP16 ANALYSIS?

A. Yes. The five MTEP16 Futures are:

(1) *Business as Usual*: captures all current policies and trends in place at the time of Futures development and assumes they continue, unchanged, throughout the duration of the study period.

(2) *High Demand*: captures the effects of increased economic growth resulting in higher energy costs and medium gas prices.

(3) *Low Demand*: captures the effects of reduced economic growth resulting in low energy costs and medium to low gas prices.

(4) *Regional Clean Power Plan (CPP) Compliance*: assumes a MISO footprint-wide plan to comply with the CPP that will result in a significant reduction in carbon emissions.

(5) *Sub-regional CPP Compliance*: assumes zonal or state-level compliance with the CPP that will result in significant reductions in carbon emissions.

Q. WHAT WERE THE WEIGHTINGS THAT MISO ASSIGNED TO THESE FIVE FUTURES?

A. The Regional CPP Compliance Future was the highest weighted Future at 30%, with the Sub-Regional CPP Compliance Future weighted slightly lower at 25%. The remaining three Futures, Business As Usual, Low Demand and High Demand, received lower weights at 19%, 16%, and 10%, respectively.

Q. WHAT DID MTEP16 CONCLUDE REGARDING CONGESTION IN THE MANKATO/BLUE EARTH AREA?

A. MTEP16 identified the transmission system in this area as having significant congestion, including the Huntley – Blue Earth – South Bend – Wilmarth 161 kV line. MTEP16 concluded that congestion on this flowgate had increased to a level that warranted further analysis and identification of potential cost-effective solutions to resolve this congestion.

Q. WHAT PROJECT ALTERNATIVES DID MISO CONSIDER TO RELIEVE CONGESTION IN THE MANKATO/BLUE EARTH AREA?

A. MISO first screened 23 transmission project alternatives, which were submitted by stakeholders or developed by MISO staff. Projects that showed a one-year benefit-to-cost ratio equal to 0.9 or greater were carried forward for further analysis. The initial screening was passed by 16 projects – 12 of these projects involved different 345 kV configurations and four projects were different 161 kV configurations.

Q. WHAT WERE THE RESULTS OF MISO'S MORE COMPREHENSIVE ANALYSIS OF THE 16 PROJECTS?

A. MISO grouped the 16 alternatives into four groups of solutions based on voltage level and design approach. Four solutions, one from each group, were selected due to their high screening performance. These transmission solutions were: (1) new Huntley – Wilmarth 345 kV transmission line; (2) new Huntley – North Rochester 345 kV transmission lines; (3) Huntley – South Bend 161 kV reconductor, new South Bend – Wilmarth 161 kV line, and Wilmarth Substation expansion; and (4) new Freeborn – West Owatonna 161 kV line.

Q. WHICH OF THESE FOUR ALTERNATIVES PERFORMED THE BEST UNDER MISO'S MTEP16 ANALYSIS?

A. MISO's analysis showed that the Huntley – Wilmarth Project outperformed the other alternatives on all critical metrics. Specifically, the Huntley – Wilmarth 345 kV line relieved 100 percent of the congestion through the end of the study period (2031), had the highest benefit-to-cost ratio, and provided the largest 20-year present value benefit.

Q. DID MISO CONDUCT ADDITIONAL ANALYSES TO TEST THE ROBUSTNESS OF THE PROJECT?

A. Yes. MISO considered two additional options that modified the Huntley – Wilmarth Project and conducted economic sensitivity and reliability analyses of the top three project alternatives. The economic sensitivity analyses confirmed that the Project maintains high benefit-to-cost ratios when

Futures are modified to reflect announced coal generation retirements (i.e., Sherco Units 1 and 2) and the physical location of future wind units. The analyses (shown in **Table 2** below) indicated increased economic benefits for the Project in the Sherco replacement sensitivity as well as when more precise forecasted wind generator locations were included in the modeling.

Table 2

MTEP16 Base Case and Wind Sensitivity Results

ID	Transmission Solution	MTEP16 Model	MISO Cost Estimate (2016$) (Millions)	Weighted Benefit-to-Cost Ratio	20-yr Present Value Benefit (2016$) (Millions)
I-2	Huntley – Wilmarth 345 kV new circuit	Base	$88-108	1.51-1.86	$210
		Queue Wind Sensitivity		1.86-2.28	$251

Q. DID MISO EVALUATE WHETHER THE PROJECT WOULD RESULT IN ANY RELIABILITY CONCERNS ON THE TRANSMISSION SYSTEM?

A. Yes. MISO conducted a "No-Harm" reliability test. MISO found that there were no additional reliability needs created by the inclusion of the Huntley – Wilmarth Project in the MISO transmission system.

Q. PLEASE SUMMARIZE MISO'S FINAL MTEP16 RESULTS REGARDING THE PROJECT.

A. MISO's MTEP16 analysis concluded that the Project will relieve 100 percent of the identified congestion and provide an anticipated $210 million (2016$) in PV benefits over 20 years with a weighted benefit-to-cost ratio between

1.51 and 1.86 based on MISO's estimated costs of $88 to $108 million (2016$).

Q. BASED ON THIS ANALYSIS, DID MISO DESIGNATE THE HUNTLEY – WILMARTH PROJECT AS AN MEP?

A. Yes. To qualify as an MEP, a project candidate must meet all of the following criteria:

1. Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;
2. The benefit-to-cost ratio of the candidate project must meet or exceed 1.25; and
3. The total project costs must exceed $5 million.

In December 2016, MISO's Board of Directors determined that the Huntley – Wilmarth Project met all three criteria and approved the Huntley – Wilmarth Project as an MEP and for inclusion in Appendix A of MTEP16.

Q. WHY DOES MISO UTILIZE THE BENEFIT-TO-COST RATIO OF 1.25 AS THE BENCHMARK FOR AN MEP?

A. While any transmission line project that has a greater than 1.0 benefit-to-cost ratio has Adjusted Production Cost (APC) savings that exceed its costs, MISO utilizes the 1.25 benchmark to account for uncertainty as to both the benefits and costs of a particular project. MISO analyzes projects under a set of Future models that attempt to provide reasonable bookends of the future but these are still assumptions and, ultimately, may not entirely match reality. Likewise, the costs of a Project may increase from the time it is approved given that MISO does not perform a detailed cost estimation process as part of the MTEP analysis. As a result, a 1.25 benefit-to-cost benchmark appropriately accounts for these uncertainties on both the benefit and cost side of the equation.

B. Applicants' Analysis of Need for the Project – MTEP17 Futures

Q. DID APPLICANTS CONDUCT ADDITIONAL ANALYSES OF NEED FOR THE PROJECT?

A. Yes. For purposes of the Certificate of Need Application, the Applicants conducted an analysis of the Project using the most recent MISO models which, at that time, were those developed for MTEP17.

Q. WHAT FUTURES WERE DEVELOPED FOR MTEP17?

A. For MTEP17, the number of futures was narrowed from the five Futures used in MTEP16 to three Futures—Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT). The EF Future assumes all current policies and trends in place at the time of the Futures development continue, unchanged, throughout the duration of the study period. The PR Future is designed to model the effects of current economic growth with average energy costs and medium gas prices. In addition, all current state-level renewable portfolio standards and energy efficiency resource standards are modeled in the PR Future. The AAT Future models a robust economy that drives technological advancement and economies of scale resulting in a greater potential for demand response, energy efficiency, and distributed generation as well as expanded renewable generation.

Q. WHAT WEIGHTING DID MISO ASSIGN TO EACH OF THESE THREE FUTURES?

A. The assigned weights were 31 percent for EF, 43 percent for PR, and 26 percent for AAT.

Q. PLEASE SUMMARIZE THE RESULTS OF APPLICANTS' MTEP17 ANALYSIS.

A. During the discovery process, Applicants determined that the MTEP17 analysis contained in the Certificate of Need Application was not based on the final June 2017 MTEP17 models but rather an earlier version of these models. Applicants also determined that there was a minor error in the present value calculator used by the Applicants to calculate the benefit-to-cost ratios. As part of discovery, Applicants provided revised MTEP17 results based on the final MTEP17 models, which were released on June 6, 2017. Additionally, Applicants corrected for the error in the present value calculator. These results are summarized in **Table 3** below, which is a revised version of Table 17 from the Certificate of Need Application:

Table 3

Revised Table 17, MTEP17 Analysis with Current Project Cost Estimates

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	816.04	13.92	138.01	275.83	4.90-6.39	0.08-0.11	0.83-1.08	1.66-2.16

These revised MTEP17 results are slightly higher than the results reported in the Certificate of Need Application. The Certificate of Need Application results had a weighted benefit-to-cost ratio of 1.64 to 2.14. The updated results show a weighted benefit-to-cost ratio of 1.66 to 2.16.

Q. ARE THERE ANY OTHER NEEDED CORRECTIONS TO THE MTEP17 DATA IN THE APPLICATION?

A. Yes. Attached as part of Exhibit___(AWS-1), Schedule 3 are revised versions of Table 21 and Appendix K with the updated MTEP17 data.

Q. DO ANY OF THESE CORRECTIONS CHANGE APPLICANTS' ANALYSIS OF THE NEED FOR THE PROJECT?

A. No. Each of these corrections is very minor and does not impact the Applicants' conclusion that the economic benefits of the Huntley – Wilmarth Project outweigh its costs.

Q. DID THE APPLICANTS MAKE ANY CHANGES TO THE MISO MTEP17 MODELS THAT WERE RELEASED IN JUNE 2017?

A. No. Applicants did not make any adjustments to the MISO models for purposes of their MTEP17 analysis.

Q. PLEASE SUMMARIZE THE RESULTS OF APPLICANTS' MTEP17 ANALYSIS.

A. Applicants' analysis using the MTEP17 Futures confirmed that the Project will relieve 100 percent of the identified congestion and will provide an anticipated $275.8 million (2016$) in PV benefits over 20 years. The Project has a weighted benefit-to-cost ratio of 1.66 to 2.16 using the Project costs for the range of route and design alternatives proposed by Applicants (ranging from $105.8 million to $138.0 million).

Q. HOW DO THE MTEP17 RESULTS COMPARE TO THE MTEP16 RESULTS?

A. The weighted 20-year present value for the Project was even higher under the MTEP17 Futures as compared to the MTEP16 Futures ($275.8 million compared to $210 million). In addition, the MTEP17 benefit-to-cost ratios are higher than those from the MTEP16 base case (1.66 to 2.16 compared to 1.51 to 1.86) and slightly lower than the MTEP16 Queue Wind Sensitivity case (1.66 to 2.16 to 1.86 to 2.28). I note that the benefit-to-cost numbers in these MTEP17 results include the Applicants' updated cost estimates for the routes and designs presented in the Route Permit Application.

Q. WHY DID THE ECONOMIC BENEFITS OF THE PROJECT INCREASE UNDER THE MTEP17 MODELS AS COMPARED TO THE MTEP16 BASE CASE?

A. The increase in the economic benefit of the Project under the MTEP17 models is likely due to the increased reliance on wind generation in the MTEP17 Futures, as well as the increased weight placed on the two Futures (PR and AAT) with higher wind penetration levels. There are increased congestion costs in the MTEP17 Futures due to the higher average cost of natural gas present in the MTEP17 assumptions as compared to MTEP16. In turn, the increased congestion costs present in the MTEP17 Futures increases the economic benefits of the proposed Project because the 345 kV line has sufficient capacity to transport additional low cost wind generation to customers resulting in lower energy costs. Due to natural gas-fired generation being the most flexible resource type available in the MISO footprint, it is the natural balance to variations in intermittent resources, such as wind generation. Because of this balance between the two resource types, congestion costs increase as natural gas prices increase.

Q. DID APPLICANTS ALSO ANALYZE THE PROJECT'S IMPACTS ON WIND RESOURCE CURTAILMENTS USING THE MTEP17 MODELS?

A. Yes, Applicants analyzed the curtailments of wind resources in the MTEP17 model with the Huntley – Wilmarth line "in" and "out-of-service." The results showed, depending on the Future, that the Project will reduce wind curtailments by 9 to 23 percent in year 2031 within Minnesota, Iowa, North Dakota, and South Dakota.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH THIS REDUCTION IN CURTAILMENTS?

A. Fundamentally, a reduction in curtailments means that the electrical system is operating more efficiently and allowing low cost wind energy to reach customers. A reduction in wind curtailments also means that there is a reduction in thermal generation as wind generation is able to meet a greater portion of the energy demand.

C. Applicants' Analysis of Need for the Project – MTEP18 Futures

Q. DID APPLICANTS CONDUCT AN ANALYSIS OF THE PROJECT UNDER THE MTEP18 FUTURES?

A. Yes. Following submission of the Certificate of Need Application, MISO issued its models for MTEP18. The MTEP18 models have four Futures: (1) Limited Fleet Change (LFC); (2) Continued Fleet Change (CFC); (3) Accelerated Fleet Change (AFC); and (4) Distributed & Emerging

Technologies (DET). **Table 4** summarizes the key assumptions in these four Futures:

Table 4

MTEP18 Futures Comparisons: Key Assumptions

MTEP18 Future	Limited Fleet Change	Continued Fleet Change	Accelerated Fleet Change	Distributed & Emerging Technologies
Demand and Energy	Low (10/90) High LRZ9 Industrial	Base (50/50)	High (90/10) Low LRZ9 Industrial	Base + EV *Energy: 1.1%* *Demand: 0.6%*
Fuel Prices	Gas: Base -30% Coal: Base -3%	Base	Gas: Base +30% Coal: Base	Base
Demand Side Additions ***By Year 2032***	EE: - GW DR: 2 GW	EE: - GW DR: 3 GW	EE: 5 GW DR: 4 GW	EE: 2 GW DR: 3 GW Storage: 2 GW
Renewable Additions ***By Year 2032*** ***(% Wind and Solar Energy)***	10%	15%	30%	20%
Generation Retirements[1] ***By Year 2032***	Coal: 9 GW Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW	Coal: 17 GW+ Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW Nuclear: 2 GW
CO_2 Reduction Constraint ***From Current Levels by 2032***	None	None	20%	None
Siting Methodology[2]	MTEP Standard	MTEP Standard	MTEP Standard	"Localized"

Q. HOW DO THESE FOUR FUTURES COMPARE IN TERMS OF RENEWABLE GENERATION ADDITIONS?

A. The LFC Future predicts few changes to the current generation fleet with only a slight increase in renewable generation. The CFC Future predicts continued additions of renewable generators and coal generation retirements at the same pace as the past decade. The AFC Future predicts renewable additions and coal retirements at a rate above historical trends with renewables accounting for 30 percent of the generation fleet by 2032. The DET Future predicts that new renewable additions will largely by distributed and storage resources that are co-located at the substation serving the most load. **Figure 2** below summarizes the generation additions and retirements by Future and **Figure 3** summarizes the same information in pie chart form.

Figure 2

MTEP18 Nameplate Capacity Additions for 2017-2032

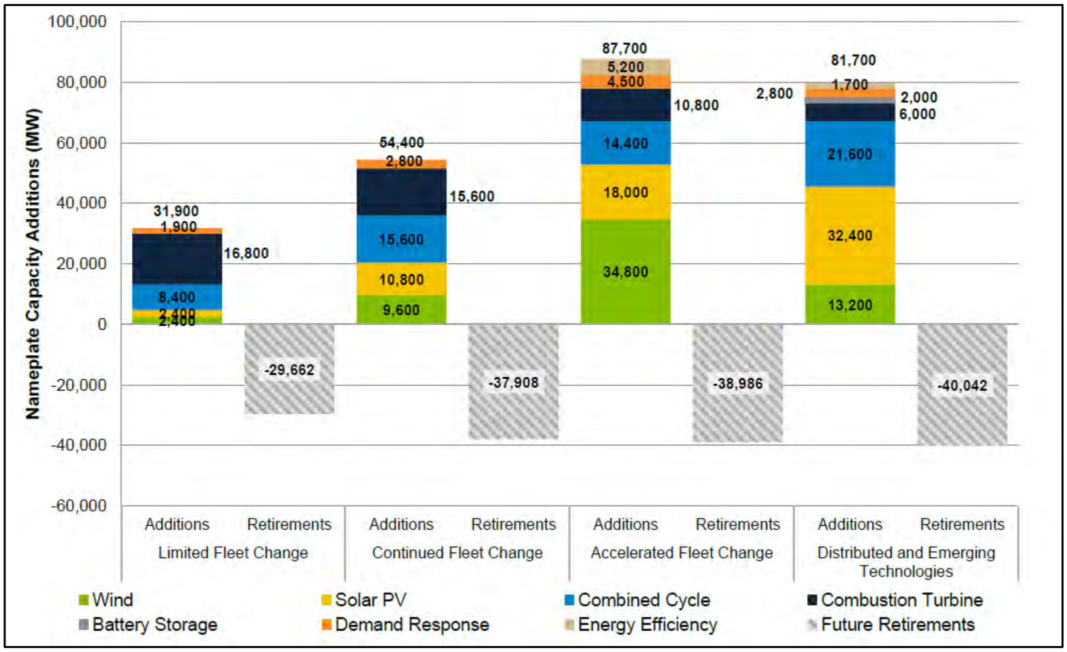
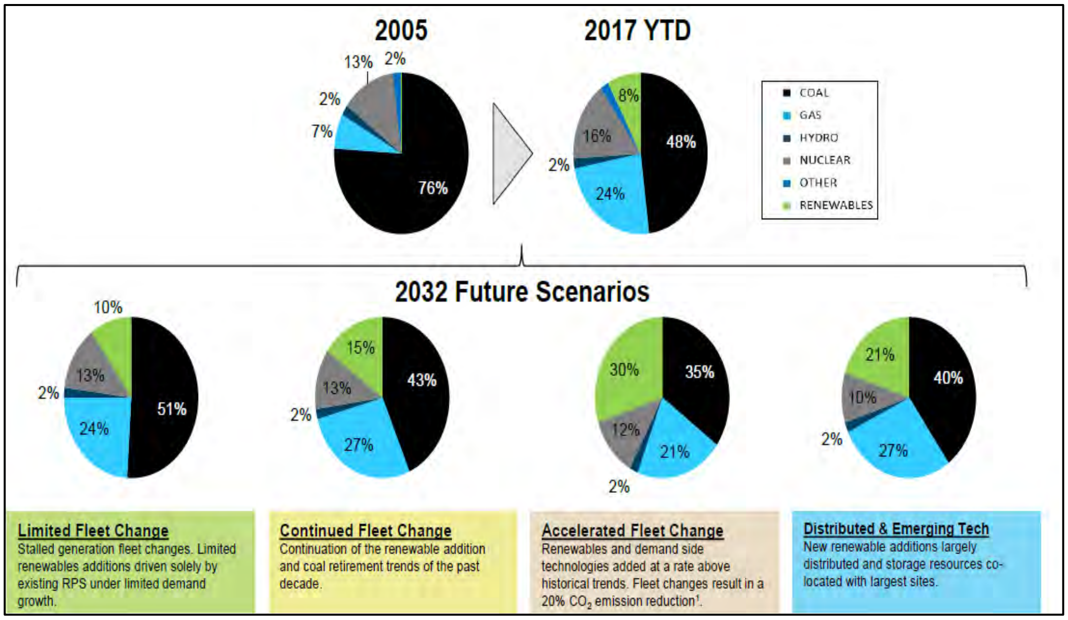


Figure 3

Energy Projections by Future (2017-2032)



Q. WHAT ARE THE MISO WEIGHTINGS FOR THESE FOUR FUTURES?

A. Each of the four Futures has a different weighting which are summarized in **Table 5** below:

Table 5

MTEP18 Future Weightings

Future	Weighting
Limited Fleet Change (LFC)	25%
Continued Fleet Change (CFC)	30%
Accelerated Fleet Change (AFC)	20%
Distributed & Emerging Technologies (DET)	25%

Q. HOW DID THE PROJECT PERFORM UNDER THE MTEP18 MODELS AND ASSUMPTIONS?

A. As shown in **Table 6** below, the 20-year PV for the Project was $217.97 (2016$) under the MTEP18 analysis and the Project has a weighted benefit-to-cost ratio was 1.30 to 1.69.

Table 6

MTEP18 Analysis with Current Project Cost Estimates

Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service Date	PV Benefit (Million 2016$)					Benefit-to-Cost Ratios (Millions, 2016$)				
		LFC	CFC	AFC	DET	Weighted	LFC	CFC	AFC	DET	Weighted
$105.8-$138.0	2022	$23.56	$106.72	$665.77	$187.63	$217.97	0.15-0.20	0.60-0.78	4.03-5.25	1.10-1.43	1.30-1.69

Q. ARE YOU CONCERNED THAT THE APC BENEFITS OF THE PROJECT ARE LOWER UNDER MTEP18 THAN THEY WERE UNDER MTEP17 AND MTEP16?

A. No. There are several reasons for this slight decline in MTEP18 which I will describe in more detail, but it is important to note that none of these reasons calls into question the need for this Project. Even for the highest cost route/design included in the Route Permit Application (Red Route, double-circuit monopole), the benefit-to-cost ratio remains well above 1.0 under MTEP18. This demonstrates that the benefits of the Project exceed its costs and the Project remains a needed facility to address the transmission congestion in the Mankato area and to allow low-cost renewable generation along the Minnesota/Iowa border to reach customers.

Q. WHY DID THE APC BENEFITS OF THE PROJECT DECLINE UNDER THE MTEP18 ANALYSIS?

A. The APC benefits of the Project declined slightly in MTEP18 due to changes to the number and type of Futures as well as the weightings of the Futures.

Q. CAN YOU DESCRIBE THESE CHANGES IN MORE DETAIL?

A. Yes. Unlike MTEP17 that included only three different Futures, two of which assumed high wind penetration across the MISO footprint, the MTEP18 models expanded to four Futures. Of these four Futures, only one assumed high wind penetration (Accelerated Fleet Change) and this Future received the lowest weighting (20 percent) of the four Futures. The other Future in MTEP18 that assumed increased reliance on renewable generation was the Distributed and Emerging Technologies Future but this Future assumed this additional renewable generation would be in the form of distributed solar generation added near load centers. The two remaining Futures, with a combined weight of 55 percent, are the Limited Fleet Change and the Continued Fleet Change. These two heavily weighted Futures assume that wind and solar will only serve between 10 to 15 percent of MISO's energy needs by 2032.

Q. DO YOU AGREE THAT IT IS APPROPRIATE TO PLACE THE HIGHEST COMBINED WEIGHT ON THE TWO MTEP18 FUTURES WITH LIMITED WIND GENERATION DEVELOPMENT?

A. The goal of the MTEP Futures is to provide adequate bookends that include a broad range of different policy and economic outcomes. This allows

MISO to develop plans for the transmission system that account for a wide variety of different generation assumptions. This broad array of Futures is also important considering MISO's large footprint that reaches from Louisiana to Canada. The MISO footprint includes a variety of topology as well as varying amounts of renewable generation development. The southern region of MISO has experienced considerably less wind generation development in recent years than the MISO North Central region. Thus, while I understand that the purpose of the Futures is to account for a broad range of possible future generation mixes, I do not believe that the two Futures with limited wind generation expansion represent realistic views of the future of renewable generation in Minnesota, Iowa, North Dakota, and South Dakota.

Q. PLEASE DESCRIBE THE WIND GENERATION DEVELOPMENT THAT IS TAKING PLACE IN THE MINNESOTA, IOWA, NORTH DAKOTA, AND SOUTH DAKOTA AREAS.

A. As shown in **Figure 4** below, the amount of installed wind capacity in Minnesota, Iowa, North Dakota, and South Dakota has increased dramatically since 2006 and continues to climb. In addition, as noted above, utilities have announced plans to add nearly 6,000 MW of new wind generation in the Upper Midwest by 2022 and the MISO West Generator Interconnection Queue has 34,800 MW of generation that has requested to be placed in-service by 2021.[2] These facts demonstrate that the assumptions

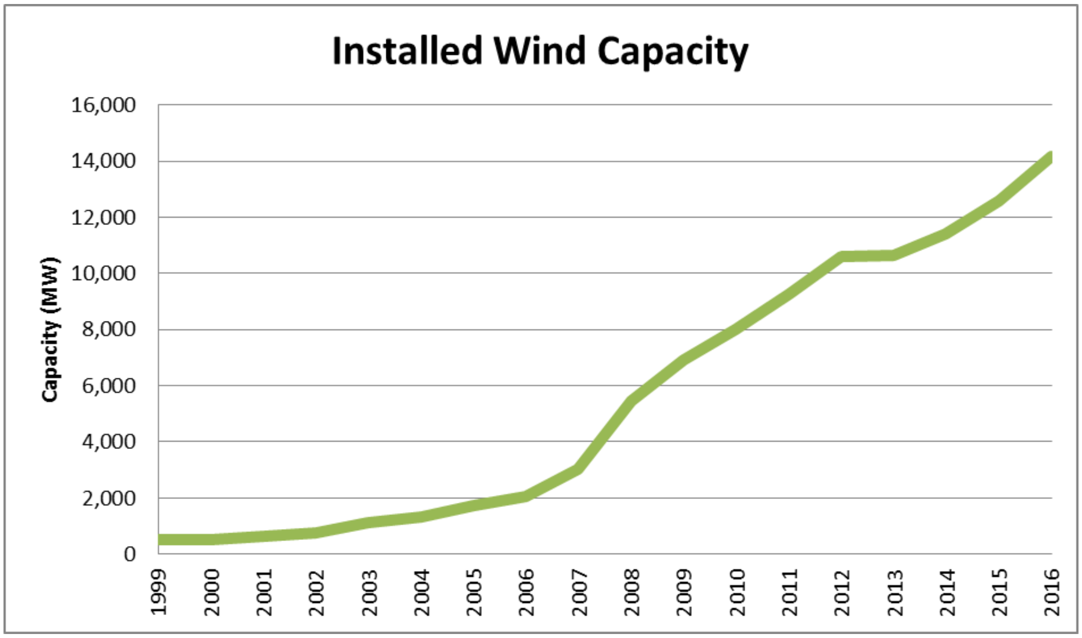
[2] This 34,800 MW includes projects that will be placed in-service by 2021 and have completed MISO's interconnection process. The 198 active interconnection requests that I noted above in my testimony refers to the

related to renewable generation additions contained in the MTEP18 Futures are likely too conservative. For instance, the Limited Fleet Change Future assumes only 2,400 MW of wind generation will be added across the entire MISO footprint by 2032. The 6,000 MW of utility announcements alone will surpass this figure by 2022. Likewise, the Continued Fleet Change Future assumes only 9,600 MW of additional wind generation will be added by 2032. Again, given the 6,000 MW of wind expansion announced to date, this figure is likely too low, particularly when you consider that it projects out 15 years.

number of interconnection projects that, as of June 1, 2018, are being reviewed by MISO in the interconnection process.

Figure 4

Installed Wind Capacity in Minnesota, Iowa, North Dakota, and South Dakota[3]



Q. Do you anticipate that the economic benefits of this Project will continue to decline in the MTEP19 analyses?

A. No. The MTEP19 models are still undergoing review and this review will not be complete until early 2019. However, MISO has determined that for MTEP19, each of the four Futures will receive an equal 25 percent weighting rather than placing greater weight on Futures that assume minimal renewable generation expansion. The wind generation assumptions for each of the four MTEP18 Futures are summarized below:

- Limited Fleet Change: 2,400 MW of additional wind generation by 2032;

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[3] *See* https://windexchange.energy.gov/maps-data/321.

- Continued Fleet Change: 9,600 MW of additional wind generation by 2032;
- Accelerated Fleet Change: 34,800 MW of additional wind generation by 2032; and
- Distributed & Emerging Technologies: 13,200 MW of additional wind generation by 2032.

Even assuming that the wind generation assumptions for the four MTEP19 Futures remain the same as MTEP18, this equal weighting approach will increase the weighted benefit-to-cost ratio for the Project because the Accelerated Fleet Change will be weighted the same as the Continued Fleet Change—rather than 10 percent lower.

Q. ARE THERE OTHER ECONOMIC BENEFITS OF THE PROJECT THAT ARE NOT CAPTURED BY THE APC SAVINGS CALCULATED UNDER THE MTEP MODELS?

A. Yes. MISO's calculation of the APC savings is a conservative estimate and does not take into account all of the potential economic benefits of a transmission project. For instance, the current MTEP analysis does not consider the impact of transmission line outages, either planned or unplanned, on the costs of congestion on the transmission system. Rather, MISO currently assumes a system-intact scenario (i.e., all lines are in-service), which does not account for increases in system congestion due to transmission line outages. In June 2018, MISO started the process of exploring how to potentially account for the impact of transmission outages on congestion. A copy of MISO's presentation from this exploratory meeting is attached as Exhibit___(AWS-1), Schedule 4. In this presentation, MISO noted that the MISO Independent Market Monitor (IMM) reported that congestion costs due to transmission line outages can increase congestion costs up to 40 percent in the Day-Ahead and Real-Time markets.[4] A MISO PROMOD benchmark study in 2014 supported the IMM's assertion; this analysis showed transmission outages could increase system congestion by approximately 66 percent.[5] Because this additional congestion cost due to transmission line outages is not captured in the MISO benefit calculations for the Project, it is reasonable to assume that the benefit values calculated under the current MTEP models represent a conservative estimate of the Project's economic benefits. In June 2018, MISO started the process of exploring how to potentially account for the impact of transmission outages on congestion.

In addition, according to a report developed in 2013 by the Brattle Group on behalf of the WIRES Group, there are other benefits that go beyond those accounted for in the MISO APC savings calculation, including increased system reliability, lower generation capacity costs, reduction of overall environmental impacts, achievement of public policy objectives, and increased localized employment and tax revenues. A copy of this report is attached as Exhibit___(AWS-1), Schedule 5 to my testimony. As noted in this report, these other types of benefits are often difficult to monetize on a comparable basis to APC savings and, as a result, are not accounted for in analyzing the potential economic benefits of a transmission line project. For

[4] Exhibit___(AWS-1), Schedule 4 at 4.

[5] Exhibit___(AWS-1), Schedule 4 at 4.

example, increased property tax revenues can be easily monetized, but are extremely difficult to accurately determine beneficiaries. The area in which new generation may be developed can be served by several different utilities and may be subject to several different tax rates which are all completely dependent on the actual location of those facilities which have not yet been permitted. While this can be a real benefit that can be directly attributed to increased transmission capacity in an area, the beneficiaries of this increased tax revenue are extremely sensitive to several different factors and may change significantly over time when compared to the original calculation of those benefits.

V. BENEFIT-TO-COST RATIOS OF SCOPING ROUTES

Q. DID THE APPLICANTS CALCULATE THE BENEFIT-TO-COST RATIOS UNDER MTEP18 FOR THE ROUTE AND SEGMENT ALTERNATIVES PROPOSED DURING THE SCOPING PROCESS FOR THE EIS?

A. Yes. As discussed in the Direct Testimony of Applicants' witness Mr. Stevenson, the alternative route and the segment alternatives proposed during scoping change the current bandwidth for the Project's estimated costs from $105.8 to $138.0 million (2016$) to $104.8 to $160.7 million (2016$). The lowest cost alternative ($104.8 million) is the Purple Route with Segment Alternatives F and J and a single-circuit, H-frame design. The highest cost alternative is the Purple-E-Red Route ($160.7 million) with a monopole design. The Applicants calculated the benefit-to-cost ratios for these alternatives under MTEP18 and these results are summarized in **Table 7** below.

Table 7

MTEP18 Analysis with Scoping Route Cost Estimates

Scoping Route Cost Estimates (2016$ Millions)	Expected In-Service Date	PV Benefit (Million 2016$)					Benefit-to-Cost Ratios (Millions, 2016$)				
		LFC	CFC	AFC	DET	Weighted	LFC	CFC	AFC	DET	Weighted
$104.8-$160.7	2022	$23.56	$106.72	$665.77	$187.63	$217.97	0.13-0.20	0.51-0.79	3.46-5.30	0.94-1.44	1.11-1.71

In addition, in response to Minnesota Department of Commerce Information Request No. 23, the Applicants provided a summary of the costs for the scoping routes along with the benefit-to-cost ratio for those routes under MTEP17. A copy of this response is attached as Exhibit___(AWS-1), Schedule 6.

VI. MISO VARIANCE ANALYSIS

Q. IN ADDITION TO THE BENEFIT-TO-COST RATIO, ARE THERE OTHER COST CONSIDERATIONS THAT ARE RELEVANT TO THIS DOCKET?

A. Yes. Applicants are required to provide regular updates to MISO regarding the cost of the Project. Under Attachment FF of the MISO Tariff, if the cost of this Project exceeds or is projected to exceed 25 percent or more of the Project's baseline cost estimate, MISO is required to initiate a new process called a "variance analysis." A variance analysis for a project may also be triggered by a schedule delay or inability to complete project construction. A copy of the relevant sections of the MISO Tariff is attached as Exhibit___(AWS-1), Schedule 7.

Q. PLEASE GIVE AN EXAMPLE OF HOW A VARIANCE ANALYSIS COULD BE TRIGGERED BY THE OUTCOME OF THIS DOCKET.

A. The Project's baseline cost estimate is $108 million (2016$). Cost estimates for routes currently under consideration in the Route Permit process range from $104.8 million to $160.7 million. The Applicants will update the Project's cost estimate provided to MISO after a route is determined by the Commission. Assuming that the current cost estimates do not change, any final route with a cost estimate of $135 million (2016$) or greater would trigger a MISO variance analysis once Applicants submit a cost update to MISO.

Q. WHAT ARE THE STEPS IN THE MISO VARIANCE ANALYSIS?

A. To date, MISO has not used this process before, but the general procedures for a variance analysis are set forth in the MISO Tariff. After a variance analysis has been triggered, MISO will notify the transmission owner – here, the Applicants. The Applicants would then discuss with MISO whether a variance event exists and what outcome the Applicants believe is appropriate, along with supporting facts and documentation. Based on this information, MISO may continue the variance analysis process or terminate it. If MISO continues the variance analysis process, MISO will further investigate the variance event and the surrounding facts. MISO will determine an appropriate outcome based on an examination of several factors including the cause or reason for the variance, the degree of fault of the transmission owner for the increased costs, impacts to the MISO Transmission System, and a comparison of the costs of different outcomes. After this evaluation, MISO can decide to: (1) take no action; (2) institute a mitigation plan to alleviate grounds for a variance; or (3) cancel the project.

Q. WHY IS MISO'S VARIANCE ANALYSIS A CONSIDERATION IN THIS DOCKET?

A. Because this Project is an MEP, the new MISO variance analysis process applies. Because some routes under consideration already have projected costs more than 25 percent greater than the baseline cost estimate, selection of such a route could trigger a variance analysis.

Q: HOW WOULD THE APPLICANTS RESPOND IF THE PROJECT REQUIRES A VARIANCE ANALYSIS?

A: Other than requiring a variance analysis, the MISO Tariff does not dictate a particular action MISO must take when the Project's costs exceed $135 million. As discussed elsewhere in my testimony, the Applicants believe that based on Applicants' analysis of this Project under MTEP17 and MTEP18, the Project's expected economic benefits have increased as compared to MTEP16, such that all routes under consideration would provide positive economic benefits. Applicants would provide this information to MISO along with information regarding the factors the Commission took into account in making their route determination. Based on this information, Applicants would recommend that the Project move forward. However, it is reasonable to assume that those routes with costs that are substantially higher than $135 million present a greater risk that MISO may choose to take some action at the conclusion of its variance analysis.

VII. ALTERNATIVES ANALYSIS

Q. WHAT ALTERNATIVES TO THE PROJECT DID THE APPLICANTS EVALUATE?

A. Minnesota Certificate of Need statutes and rules require an analysis of alternatives to a proposed project. To comply with this requirement in the Certificate of Need Application, the Applicants analyzed:

(1) *Size Alternatives*: higher and lower voltage transmission line options as well as double circuiting the 345 kV line with another 345 kV line to increase Project capacity;

(2) *Type Alternatives*: other endpoints for terminals/substations, upgrading existing transmission lines, double circuiting proposed line with existing transmission lines, direct current (DC) line instead of the proposed alternating current (AC) line, different type of conductors, new generation resources, and underground transmission lines; and

(3) *No-Build Alternatives:* load growth as well as conservation and Demand Side Management.

Q. WHAT DID THE APPLICANTS CONCLUDE WITH REGARD TO ALL OF THESE ALTERNATIVES?

A. As explained in the Certificate of Need Application, the Applicants determined none of these alternatives was a more reasonable and prudent alternative to the proposed Project.

Q. DID THE APPLICANTS PERFORM ANY ADDITIONAL ANALYSES OF ALTERNATIVES FOLLOWING THE FILING OF THE CERTIFICATE OF NEED APPLICATION?

A. Yes. Just as the Applicants analyzed the Project under the MTEP18 models, the Applicants also analyzed the Huntley – Wilmarth 161 kV transmission line under the MTEP18 models. Similar to the Project, the APC saving benefits of the 161 kV alternative decreased under the MTEP18 models. However, the decrease for the 161 kV alternative was much more pronounced. This can be seen in the comparisons provided below in **Table 8**. I note that the data for MTEP17 for the 161 kV alternative have been updated from the data in the Application to correct for the minor errors in the present value calculator and MTEP17 models noted above.

Table 8

MTEP17 and MTEP18 PROMOD Comparison

Transmission Alternative	Cost Estimate (2016$)	MTEP17 Weighted Benefit-to-Cost Ratio	MTEP18 Weighted Benefit-to-Cost Ratio	MTEP17 20-year Present Value Benefit ($millions)	MTEP18 20-year Present Value Benefit ($millions)
Huntley – Wilmarth new 345 kV transmission line (Green Route, monopole design)	$121.3	1.88	1.47	$275.83	$212.61
Huntley – Wilmarth new 161 kV transmission line (Green Route, monopole design)	$80.9	2.05	1.24	$200.7	$119.43

Indeed, due to the significant decrease in the economic benefits of the 161 kV alternative, the 345 kV line outperforms this alternative in the 20-year PV benefit in both model years as well as the weighted benefit-to-cost ratio in MTEP18. This is noteworthy because the weighted benefit-to-cost ratio metric was the only metric where the 161 kV alternative slightly outperformed the 345 kV Project under MTEP17 due to its lower cost.

Q. HOW DOES THE 161 KV ALTERNATIVE PERFORM WITH REGARD TO RELIEVING THE IDENTIFIED CONGESTION UNDER MTEP18 MODELS?

A. Similar to its performance under MTEP17, the Huntley – Wilmarth 161 kV line initially reduces 99 percent of the congestion in 2022, but only provides 94 percent and then 85 percent congestion relief by 2027 and 2032, respectively, as more wind is added to the system. In contrast, the 345 kV line relieves 100 percent of the identified congestion throughout the entire study period. I note that in calculating the congestion results for MTEP18, Applicants determined that we incorrectly applied the weighting formula for the MTEP17 analysis. This correction to the MTEP17 congestion results is described and provided in Applicants' Supplemental Response to Minnesota Department of Commerce Information Request No. 10, which is attached as Exhibit___(AWS-1), Schedule 8.

Q. HOW DOES THE 161 KV LINE PERFORM COMPARED TO THE 345 KV LINE IN TERMS OF REDUCING CURTAILMENTS UNDER MTEP18?

A. Like the MTEP17 results, the 345 kV line is more effective than the 161 kV line at reducing curtailments in each of the four MTEP18 Futures. The 345 kV transmission line reduces curtailments by between 2.6 percent and 18.4 percent while the 161 kV line only reduces curtailments by between 1.4 percent and 12.1 percent. These results, provided in detail in

Exhibit___(AWS-1), Schedule 9, show that the 345 kV line is better equipped to enable wind generation to be delivered across the transmission system.

Q. DO ANY OF THESE UPDATES TO THE ANALYSIS OF THE 161 KV ALTERNATIVE CHANGE YOUR ASSESSMENT OF THIS ALTERNATIVE?

A. No. Fundamentally, a 161 kV transmission line simply does not have sufficient capacity necessary to relieve all of the identified congestion along the Minnesota and Iowa border. As more and more wind generation is added to the system in the later study years, the inadequacy of this lower voltage alternative becomes even more apparent as demonstrated by the declining congestion relief of the 161 kV alternative throughout the 20-year study period.

Q. CAN YOU SUMMARIZE THE PERFORMANCE OF THE 161 KV ALTERNATIVE COMPARED TO THE 345 KV LINE?

A. Yes. As noted in the Application, under MTEP17, the 345 kV line between the Huntley and Wilmarth substations outperformed the 161 kV alternative in all but one of the metrics:

- 100 percent congestion relief through the end of the study period;
- higher 20-year present value APC benefits;
- greater reduction in curtailments; and
- greater reduction in system losses.

The only metric where the 161 kV alternative performed better was in terms of the weighted benefit-to-cost ratio due to its lower cost. Under MTEP18, the 345 kV line continued to outperform the 161 kV line under these same metrics but also outperformed the 161 kV line in terms of its weighted benefit-to-cost ratios.

Q. BASED ON THE PERFORMANCE OF THE 161 KV ALTERNATIVE, IS THIS ALTERNATIVE A REASONABLE AND PRUDENT ALTERNATIVE TO THE 345 KV LINE?

A. No. Given the current and anticipated expansion of wind generation in the Upper Midwest, a 161 kV alternative simply does not provide the necessary capacity to transport this energy to customers. Rather, the capacity of a 345 kV line is needed to enable this generation to reach customers and thus realize all of the benefits of this low cost renewable wind generation.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Andrew Siebenaler

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Andrew.W.Siebenaler@xcelenergy.com

Experience

Apprentice Electrician

Electric, Fire & Security, Inver Grove Heights, MN

June 2005 –August 2008

Installation and Maintenance of electrical appliances and fixtures, ensuring compliance with all federal, state and local electrical requirements

Assisting Journeyman and Master electrician in the installation of complex electrical equipment

Locate and repair aging or malfunctioning electrical equipment

Plant Maintenance Engineer Intern

Hormel Foods, Osceola, IA

May 2012 – August 2012

Supervise plant maintenance staff and coordinate maintenance project efforts

Assist senior engineering staff in development and implementation of plant improvement projects

Develop and implement leak monitoring process for liquid ammonia piping and control valves

Transmission Planning Engineer II

MAPPCOR, Roseville, MN

December 2012 – March 2015

Analyze the transmission system in compliance with federal, state and local transmission planning standards

Ensure the compliance with NERC transmission planning standards

Develop automated processes to reduce the time required for processing and review of transmission planning studies

Senior Engineer – Regional Transmission Planning

Xcel Energy, Minneapolis, MN

March 2015 – Present

Participation in all aspects of Regional Transmission Organization planning processes

Develop policies and procedures to be implemented in Regional Transmission Organization processes

Provide transmission expertise in development of long term plans

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Education

Bachelor of Science, Electrical and Computer Engineering

University of Minnesota - Duluth, Duluth, MN

December 2012

Electrical Construction and Maintenance Diploma

Dunwoody College of Technology, Minneapolis, MN

June 2007

EDF Renewables to develop up to 200 MW of Iowa's Golden Plains Wind Project

By Michelle Froese | June 13, 2018

EDF Renewables and Alliant Energy's Iowa energy company announced the signing of contracts by which EDF Renewables will develop and construct up to 200 MW of the Golden Plains Wind Project.

Golden Plains Wind Project is located in Winnebago and Kossuth counties in the north central portion of Iowa. The project is expected to create 150+ construction jobs as well as inject millions of dollars in economic benefits to the local area. The project will be completed by early 2020 and is expected to produce enough clean energy to power 87,000 average homes a year.

Golden Plains wind farm is part of Alliant Energy's plan to add 1,000 MW of new wind generation to Iowa by the end of 2020.

"We are pleased to partner with Alliant Energy to deliver competitively-priced, clean energy to its customers through the Golden Plains Wind Project," said Kate O'Hair, vice president development, North Region at EDF Renewables. "The Project will also provide an economic boost to the Iowa economy, through new construction and operations jobs, expanded tax base, and recurring, long-term income for participating landowners."

Golden Plains wind farm is part of Alliant Energy's plan to add 1,000 MW of new wind generation to Iowa by the end of 2020.

"Wind energy is a win for Iowans," said Doug Kopp, president of Alliant Energy's Iowa energy company. "The benefits of this project help customers through reductions in emissions and fuel cost. It gives landowners lease payments to help on the farm and it helps communities through increased local tax revenue for schools and community services."

Table 17-Revised
MTEP17 Analysis with Current Project Cost Estimates (2016$)

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	**EF**	**PR**	**Weighted**	**AAT**	**EF**	**PR**	**Weighted**
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	816.04	13.92	138.01	275.83	4.90-6.39	0.08-0.11	0.83-1.08	1.66-2.16

Appendix K-Revised

Benefit-to-Cost Ratios for Applicants' Proposed Routes/Designs

Assumptions:

Present Value Benfit (MTEP17): $273.11 Million

In-Service Date: 2022

Discount Rate: 7.10%

Inflation Rate: 2.50%

ARR: ITC and NSP Average

Benefit to Cost Ratios under MTEP17 for Applicants' Proposed Route/Designs

	Purple Route (West Route)			Green Route (Middle Route)		Red Route (Middle Route)		Blue Route (East Route)	
	Single-Circuit Parallel H-Frame	Single-Circuit Parallel Monopole	Double-Circuit Monopole and Single-Circuit Monopole	Single-Circuit H-Frame	Single-Circuit Monopole	Double-Circuit Monopole and Single-Circuit H-Frame	Double-Circuit Monopole and Single-Circuit Monopole	Double-Circuit Monopole and Single-Circuit H-Frame	Double-Circuit Monopole and Single-Circuit Monopole
Total Line, ROW, AFUDC ($2016)	$ 100,600,000	$ 116,500,000	$ 132,700,000	$ 103,800,000	$ 116,100,000	$ 130,000,000	$ 132,800,000	$ 118,500,000	$ 130,600,000
Wilmarth Substation ($2016)	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000
Huntley Substation ($2016)	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000
Total Project Costs including AFUDC ($2016)	**$ 105,800,000**	**$ 121,700,000**	**$ 137,900,000**	**$ 109,000,000**	**$ 121,300,000**	**$ 135,200,000**	**$ 138,000,000**	**$ 123,700,000**	**$ 135,800,000**
Benefit-to-Cost Ratio MTEP17	**2.16**	**1.88**	**1.66**	**2.10**	**1.88**	**1.69**	**1.66**	**1.85**	**1.68**

Year	MISO Gross-Plant Weighted Average - OLD*	MISO Gross-Plant Weighted Average - MTEP17**	ITCM	NSP	ITC NSP AVG***
1	16.44%	15.93%	17.42%	14.40%	15.91%
2	16.18%	15.68%	17.12%	14.17%	15.64%
3	15.93%	15.43%	16.82%	13.94%	15.38%
4	15.67%	15.18%	16.51%	13.70%	15.11%
5	15.42%	14.94%	16.21%	13.47%	14.84%
6	15.16%	14.69%	15.91%	13.24%	14.58%
7	14.91%	14.44%	15.61%	13.01%	14.31%
8	14.65%	14.19%	15.31%	12.77%	14.04%
9	14.40%	13.94%	15.01%	12.54%	13.77%
10	14.14%	13.69%	14.71%	12.31%	13.51%
11	13.89%	13.44%	14.40%	12.08%	13.24%
12	13.63%	13.20%	14.10%	11.85%	12.97%
13	13.38%	12.95%	13.80%	11.61%	12.71%
14	13.12%	12.70%	13.50%	11.38%	12.44%
15	12.87%	12.45%	13.20%	11.15%	12.17%
16	12.62%	12.20%	12.90%	10.92%	11.91%
17	12.36%	11.95%	12.60%	10.68%	11.64%
18	12.11%	11.71%	12.29%	10.45%	11.37%
19	11.85%	11.46%	11.99%	10.22%	11.11%
20	11.60%	11.21%	11.69%	9.99%	10.84%

* Used in initial PV calcs

** Provided by MISO engineers on 12-11-2017 (not used in any PV calcs)

*** Used in updated ARR calcs

MISO

Exploration of Transmission Outages Modeling in Economic Planning

Planning Subcommittee

June 12, 2018

Key Takeaways

- Transmission outages have a significant impact on congestion and system economics, but currently no concurrent transmission outages are modeled in PROMOD.

- MISO performed a conceptual economic study to test four modeling options of transmission outages. Study showed there are ways to implement the 4 options in PROMOD, and each of them has trade-offs.

- MISO continues the information gathering and exploration. Stakeholders are welcomed to provide feedback on the current options and provide additional options for evaluation.

2018 Tentative Work Schedule

Schedule /Meeting	Task
June PSC	Review conceptual study initial observations and discuss option trade-offs
Aug PSC	Continue information gathering; update on additional analysis
Oct PSC	Review stakeholder feedback and discuss additional study analysis and findings
Dec PSC	Survey preferred option

Drivers for Investigating Transmission Outages in Economic Modeling

- A major contributing factor of market price volatility is transmission and generation outages
- MISO IMM reported 40% of the higher price is contributed by transmission/generation outages
- Concurrent generation outages are modeled in PROMOD, but not concurrent transmission outages
- MISO PROMOD benchmark study in 2014 showed transmission outages could increase system congestion by about 66%
- Transmission outages, planned or forced, can cause re-dispatch of the generation. They have economic consequences.

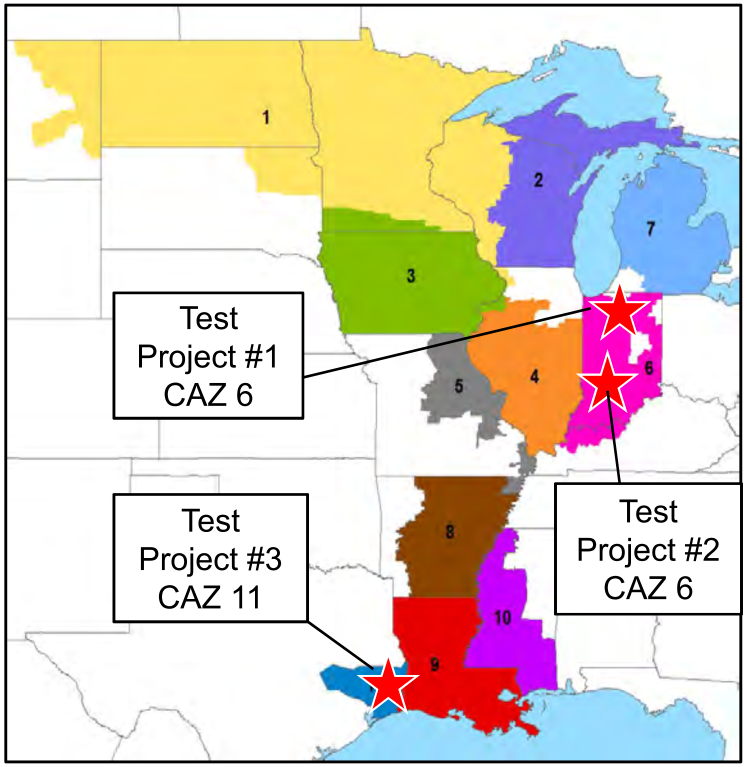
Modeling Options and Trade-offs

Trade-offs	Explicit Modeling	Implicit Modeling
	• **Option 1:** Historical Outage Modeling • **Option 2:** Monte Carlo Outage Modeling	• **Option 3:** System-Wide De-rate • **Option 4:** APC Adder from PROMOD Results or External Dataset/Resource
⇧	• Historical outages present real outages happened in the past • Monte Carlo uses historical statistics for future predictions • Monte Carlo statistical approach capture a range of potential impact • Capture more locational effect	• Less impact on run time • Capture system wide average impact: o Similar to using hurdle rate to simulate the effect of market hurdles and interchange
⇩	• Increased run-time • Limited snapshots • Locational effect may change as snapshots change	• No locational variation • Individual project impact may vary

MISO

Overview of the Conceptual Study

- **Study designed to determine:**
  - If PROMOD can model transmission outages
  - Impact of transmission outages on congestion and APC
  - Implementation of the four current options
  - Feasibility of options – impact on run time
- **Models used:**
  - MTEP17 Policy Regulation Future 5-year out (2021) and 10-year out (2026)
- **Testing Scenarios:**
  - MISO Copper Sheet – All MISO flowgates assumed to have infinite rating
  - 3 test projects



Option 1 – Historical Outage Modeling

Option 1 – Overview

- Used 2016 MISO outage data from Control Room Operations Window (CROW)
- Modeled transmission outages (planned and forced) longer than 5 days with a minimum voltage level of 115kV

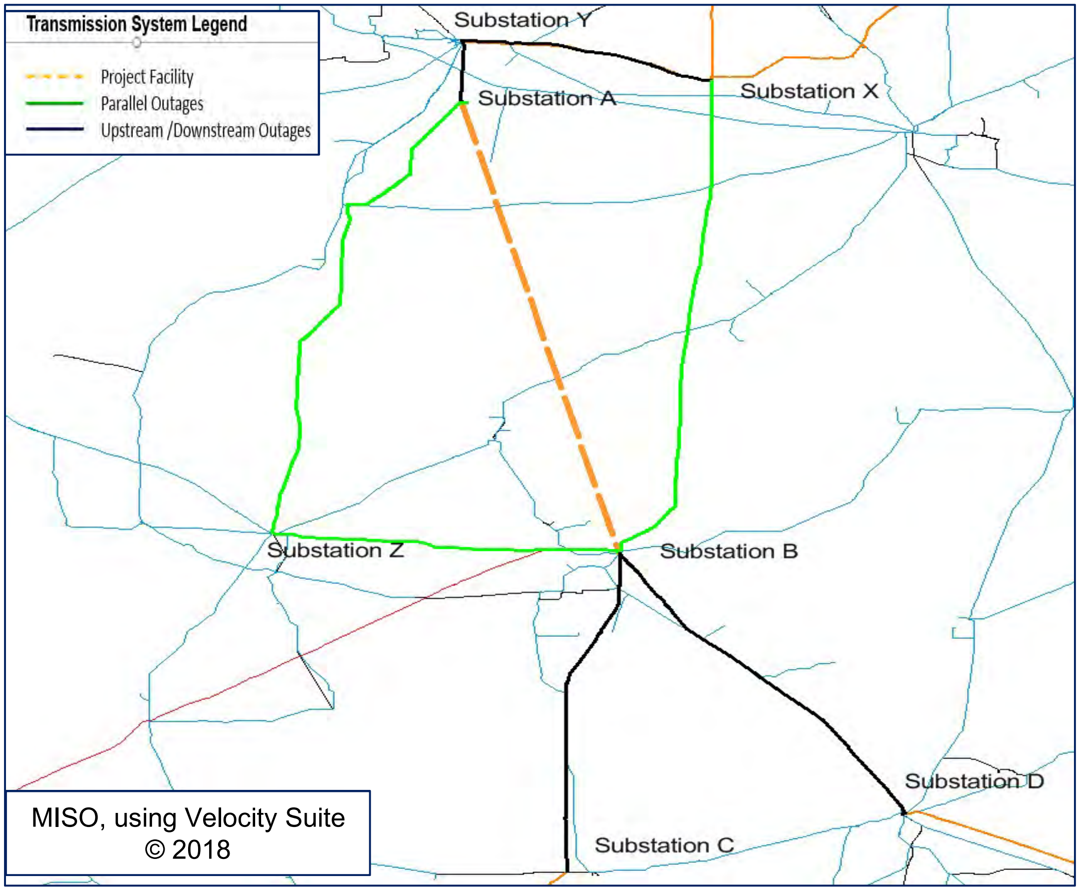
	# of Transmission Outages
Initial dataset from CROW – Greater than 5 days and greater than 115kV	~2,000
After branch outages mapped to MTEP17 – PR 2021/2026 PROMOD models and removing islanding issues	1,460*

* Modeled a conservative amount of transmission outages in this study

Option 1- Historical Outage Modeling Preliminary Observations

Test Project	No Outages APC Savings ($M)	With Outages APC Savings ($M)	Option 1 Outages APC Savings Change (%)
Copper Sheet	89.6	147	64%
Test Project 1	7.5	11	50%
Test Project 2	1.1	2	80%
Test Project 3	9.2	27	200%

- Have a significant impact – individual project benefits vary based on if outages are in series or parallel with the project line
- Single snapshot of the past
- 3 times Increase in model run-time when explicitly modeling
- CROW outage data is confidential



- More outages in parallel with the project line tend to increase congestion in basecase, increasing APC savings due to the study project
- More outages upstream or downstream of the project line tend to decrease congestion in basecase, decreasing APC savings due to the study project

Option 2 – Monte Carlo Outage Modeling

Option 2 – Overview

- Worked with Power Analytics Software Inc. extensively to implement a Monte Carlo algorithm tool PDTR to create random transmission outages. A detailed description of the tool is attached with this presentation material.
- Created 20 random outage "draws" for each testing scenario based on historical outage statistics
- Draws were based on the outage set statistics modeled in Option 1 for better comparison
- Main parameters for generating the draws are:
  - The probability of transmission outages for each voltage category
  - Seasonal variation of outage probability for each voltage category
  - Average Outage Duration

Option 2 – Monte Carlo Modeling Preliminary Observations

Test Project	No Outages APC Savings ($M)	With Outages Avg. APC Savings ($M) (20 Draws)	Average APC Savings Change (%)	Sample 95% Confidence Interval (CI) and standard deviation σ
Copper Sheet	141.8	246.7	74%	CI = [58%, 90%], σ = 36%
Test Project 1	11	10.5	-6%	CI = [-12%, 0%], σ = 14%
Test Project 2	1.7	2.6	55%	CI = [27%, 84%], σ = 63%
Test Project 3	15	32	113%	CI = [48%, 179%], σ = 146%

*MTEP17 PR 2026 basecase used

- Have a significant impact – copper sheet system wide impact on APC is in similar scale as historical outage modeling
- Individual project benefits vary based on if outages are in series or parallel with the project line
- Statistical approach; capture a range of possibilities
- Complexity is high and involves creation of several draws
- 3 times Increase in model run-time + each project needs to be run with many outage draws

Option 3 – System-Wide De-rate

Option 3 – Overview

- MISO FTR process de-rate the transmission facility rating 10% - 15% to maintain revenue sufficiency

- Study simulated de-rating all Eastern Interconnection flowgates in model event files by 5 and 10%

Option 3 – De-rate Option Preliminary Observations

Test Project	Basecase APC Savings ($M)	5%De-rate APC Savings ($M)	5% De-rate APC Savings Change (%)	10%De-rate APC Savings ($M)	10% De-rate APC Savings Change (%)
Copper Sheet	89.6	128	43%	180.5	102%
Test Project 1	7.5	6.1	-18%	7.7	2%
Test Project 2	1.1	0.91	-17%	0.95	-14%
Test Project 3	9.2	16.8	82%	26	182%

- Copper sheet system wide impact on APC saving range (copper sheet saving) is in similar scale as those of Option 1 and Option 2 – capturing the decreased network flow capacity due to outages
- De-rate would increase or decrease APC saving for individual projects due to congestion pattern shifting
- Complexity is low
- No computational burden

Option 4 – APC Adder

Option 4 – APC Adder

- Derive one or a range APC saving changing percentage adder due to transmission outages' impact from a conceptual study or external data source.
- Benchmark every few years use latest information
  - Calculate a conservative MISO system-wide APC saving change average from previous options?
  - Calculate a conservative portfolio project APC saving change average from previous options? E.g. SPP uses 11% APC adder based on a portfolio project study
  - Calculate 95% confidence interval of the APC saving change multiple samples of Monte Carlo draws for individual projects?
  - Other

Option Trade-off Summary

Option	Attribute	Complexity	Computation Time
(1) Historical Outage Modeling	• Modeled outages are realistic and locational specific; • One snapshot in the past	Medium	High
(2) Monte Carlo Outage Modeling	• Statistical approach • Capture a range of possibilities	High	High
(3) System-Wide De-rate	• System wide impact is consistent with those of explicit outage modeling – capturing the decreased network flow capacity due to outages • Individual project level impact vary due to congestion pattern shifting	Low	Low
(4) APC Adder	• Aim to have system wide impact consistent with those of explicit outage modeling • No locational effect	Low	Low

Next Steps

- Stakeholder feedback request (please submit by July 9th):
  - What additional options should MISO consider to model transmission outages
  - What additional information can be provided to help inform both if and how transmission outages should be modeled in PROMOD
  - What sources of information should MISO consider to derive a fixed percentage in Option 4 – implicit outage modeling through an APC adder

  All feedback publically posted unless otherwise specified

- Next steps
  - Continue work with Transmission Outage PSC PROMOD Work Team
  - August PSC to provided additional and refined results from conceptual study analysis

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Appendix – APC Change Calculations

- Copper Sheet APC Savings Change (%)
  - Compares benefit of relieving all congestion in system between models with and without transmission outages

$$\frac{[Copper\ Sheet\ APC\ Savings\ with\ Outages] - [Copper\ Sheet\ APC\ Savings\ without\ Outages]}{ABS(\ [Copper\ Sheet\ APC\ Savings\ Without\ Outages])}$$

- Project APC Savings Change (%)
  - Compares benefit of a project in models with and without transmission outages

$$\frac{[Project\ APC\ Savings\ with\ Outages] - [Project\ APC\ Savings\ without\ Outages]}{ABS(\ [Project\ APC\ Savings\ Without\ Outages])}$$

A WIRES Report

on

The Benefits of Electric Transmission:

Identifying and Analyzing the Value of Investments

The Brattle Group

Judy W. Chang

Johannes P. Pfeifenberger

J. Michael Hagerty

WIRES

The Brattle Group

July 2013

www.WIRESgroup.com

http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

Contents

WIRES Preface and Commentary

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

Summary of Peer Review of *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*

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WIRES

(Working group for Investment in Reliable and Economic electric Systems)

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WIRES Preface and Commentary

WIRES[1] commissioned this report to address an emerging practical and theoretical question tied to the effective planning and construction of the electric transmission system: What are the potential benefits of a transmission project or portfolio of projects and can those benefits be ascertained and measured for purposes of planning and cost responsibility? To summarize, this report is designed to accomplish three objectives:

(1) To catalogue all the potential benefits[2] of transmission that can, and arguably should, be identified, considered, and estimated in planning the expansion or upgrade of the grid, based on the growing experience of transmission planners across the country;

(2) To document the evolving experience and practice of regional transmission organizations (RTOs) and non-RTO regions in determining the economic, reliability, operational, and public policy benefits of transmission investments based on their physical and operational characteristics, location,

[1] WIRES is a national 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] "Benefits" are anything "advantageous or for the good of" individuals or groups of people ("beneficiaries"). The Brattle report addresses a variety of benefits in the energy delivery environment that range from those which immediately result from costs incurred for a specific service (*e.g.*, interconnection) to benefits with broader or long-term impacts from improvements or extensions of a shared system (*e.g.*, competitive access to markets or resources, congestion relief, or increased reliability).

technology, surrounding markets, prevailing regulation, and environmental and economic impacts; and

(3) To evaluate how planners and policy makers may employ transmission benefit determinations and calculations to support needed transmission investment across the country. Many of these benefits have not been considered or well understood until fairly recently.

This report is therefore a unique, and we expect uniquely valuable, compilation of transmission's value for, and effects on, the electric system, its customers, and the economy as a whole. But the report's impact and its significance ultimately rests with how the industry and the Commission utilize its ideas in implementation of Order No. 1000 within and between RTO and non-RTO regions, where important differences in planning and cost allocation approaches exist. We offer this study as a basic analytical resource upon which such decision making processes will go forward.

* * * * * *

Today's wholesale or "bulk" electric power system, and the electricity markets it supports, rests upon an increasingly integrated high-voltage network of lines, substations, and control facilities that are planned and constructed by often-diverse entities, serve multiple purposes, and in effect operate across utility system and state, regional, and even international boundaries. The bulk electric power system provides numerous economic, security, environmental, public policy, and reliability benefits to ratepayers across regions and interconnections. Yet some integrated electric utilities continue to build transmission primarily to serve only the reliability needs of customers within their service territories. Either way, decisions about which transmission facilities to build or upgrade (or which non-transmission solutions may be preferable) and how to recover the costs of that new capacity are more complicated today than ever before.[3] Before investing in new infrastructure in any situation, an evaluation of the near- and long-term benefits that additional transmission capacity can provide, and to whom, is fundamental to a rational deployment and allocation of society's resources, good environmental stewardship, fairness to customers (including future generations of customers), and fulfillment of public policies such as fuel diversity, clean energy, economic development, and market competition. Well-planned and timely-built transmission has a decisive and positive impact in all these areas.

Nevertheless, it would be rash to assume that policy makers, transmission planners, and regulators already share a common understanding of transmission's potential benefits or an agreed-upon approach to planning that ensures fair consideration of all the ways these assets could serve the public and the economy during their long, useful lives. Instead, the widespread differences in planning processes and experience suggest that many, or even most, potential benefits are eliminated from consideration at the very outset of the planning process. This outcome is often attributable to the assumption that transmission is generally planned and built for a single discreet purpose or market and that its purpose and usage change very little over the life of the asset. In addition, the prospect of assigning or accepting cost responsibility may profoundly affect judgments about a project and prejudice views of its value. Moreover, measuring all the widespread and diverse impacts of new transmission capacity on an integrated network presents new analytical challenges, and planners may be unfamiliar with ways to estimate or model benefits that heretofore were regarded as remote, speculative, unquantifiable, or simply too difficult to estimate. And finally, regions have very different approaches to identifying and measuring the benefits of transmission.

[3] Modern transmission, like other integrated infrastructure networks, poses novel challenges to planners and policy makers, including how to deploy capital for the maximum benefit of electricity customers sharing the network and whether (and how) particular additions to the grid can be said to benefit specific groups of customers, including those who may not directly "use" the facilities at points in time. *See Midwest ISO Transmission Owners v. Federal Energy Regulatory Commission*, 373 F 3d 1361 (D.C. Circuit, 2004); *Illinois Commerce Commission et al. v. Federal Energy Regulatory Commission*, 576 F 3d 470 (7th Circuit, 2009*); Illinois Commerce Commission et al. v. FERC*, No. 11-3421 (7th Cir., June 7, 2013).

These differences in assumptions and approaches to transmission planning and cost allocation among the regions could devolve into a "lowest common denominator" approach to selecting inter-regional projects, a concern identified in the report. This report offers an alternative and less expedient approach to inter-regional planning agreements that will lead to more economically-efficient investment decisions.

Whether assessing a utility, regional, or inter-regional transmission project, a failure to fully consider all *potential* benefits of a transmission project will lead to uneconomic results. For example, traditional methods of evaluating the need for, or benefits of, transmission projects based primarily on meeting applicable reliability standards will not consider economic benefits. Even when evaluating economically-justified transmission projects, methods that focus on production cost simulations that assume normal weather, no transmission outages, and no change in transmission losses provide an inherently limited economic analysis for new or upgraded transmission. Consideration of other transmission-related benefits (*e.g.*, storm hardening, increased competition in wholesale power markets, congestion relief, deferral of new generation or other upgrades, and numerous other attributes discussed in this report) that could accrue over time provides greater opportunity for implementing the best projects. The narrower or more restrictive the analysis, the greater the likelihood that highly beneficial projects may be rejected and that sub-optimal projects may be accepted in the planning process.

In sum, we think the report constitutes a strong message and recommendation that planners must plan for the highest value first, in response to the industry's extensive and evolving experience developed in recent years and the demands placed on planners by FERC policies. Only then should the question of identifying all beneficiaries and addressing the question of who pays be undertaken. In the final analysis, policy makers, planners, and customers deserve to have confidence that they are realizing the greatest level of transmission benefits for which customers are paying.[4]

We hasten to add that not all transmission projects that are proposed can also be economically justified or should be built and that better use of existing transmission capacity and rights-of-way should be a priority. Non-transmission solutions must be fairly evaluated as well. The tariffs of individual regions approved under Order No. 1000[5] will govern whether a benefits calculus drives or simply informs the planning process and whether all potential benefits are fairly evaluated. So far, the Commission has not been specific about what will be required in those tariffs, but the Commission's ongoing review of the compliance filings may help fill the gaps. As we read Order No. 1000, however, both the transmission planning and cost allocation analyses will in the future take place at the regional and inter-regional levels and will thereby reflect the operation of modern wholesale power markets.[6] For those reasons, WIRES believes that this report will be of special interest to the Commission, system operators, and industry experts who are currently implementing Order No. 1000. The issues raised and the approach suggested herein should also persuade investors and public policy makers of the importance of encouraging investment in stronger electric infrastructure, given the

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[4] The Seventh Circuit Court of Appeals has opined on the role of transmission benefits in public utility ratemaking: "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." *ICC v. FERC*, 576 F 3d *at* 476. For a discussion of the relevance of benefits to setting returns on investment, *see* WIRES June 26, 2013 *Petition for Statement of Policy*, Docket No. RM13-18-000. Recognizing that transmission benefits and beneficiaries may not be precisely quantifiable in every case, the court also stated: "We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." Instead the court instructed regulators to ensure that transmission benefits and cost responsibility are at least "roughly commensurate" with one another. *Id*. at 477.

[5] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

[6] We recognize that certain vertically integrated markets consider transmission benefits in the context of integrated resource planning. It is not the purpose of this report to suggest whether any limitations inherent in such analysis can be, or need to be, reconciled with Order No. 1000. Consideration of all of the benefits of transmission in such markets would still be important to any determination of the public interest and achieving optimal use of resources on the power system.

broad range of benefits transmission is capable of providing to a region, an interconnection, or the nation.

* * * * *

This report is aimed at two distinctly different readerships. First, the lay person or policy maker who comes to the benefits issue without a grounding in public utility operations or economics will find a clear explanation of transmission benefits and their role in the transmission planning process. The Executive Summary will be particularly helpful to them. Its purpose is to make clear that supporting or opposing transmission infrastructure development in the 21st Century has to be about more than opting for what appears to be the cheapest solutions to immediate problems. Second, we believe transmission planners, engineers, and economists will find practical, technical support in these pages for a more efficient and thorough way to identify, consider, and evaluate the multiple benefits of transmission in the planning process. The Brattle Group report thus provides both clarity and depth in its analysis – a difficult challenge to meet.

Finally, WIRES has instituted an important innovation in this report. Appended to the report is an independent evaluation of the work product by four well-known expert economists – one each from academe, an integrated utility, an RTO, and an economic consultancy. These peer reviewers have familiarized themselves with The Brattle Group's analysis and articulated a collective "second opinion" about it. Their review, appended to the report, provides important additional insight into the context and methodologies of transmission benefits determinations. Looking beyond benefits analysis to the increased use of optimization tools in the planning process, the peer reviewers also suggest that transmission planners should institute more "decisional support methodologies" that will help improve planning in response to the grid's growing complexity and the options planners must consider. However, we do not understand these experts to be suggesting that constructing a business case for a transmission project in light of all its potential benefits should be deferred during the continuing search for more perfect analytical tools.

The Brattle Group authors and the peer reviewers would hasten to emphasize, and we therefore repeat here, that the views they express are their own and not necessarily those of their organizations.

* * * * * *

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The Brattle Group

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagerty

Prepared for

WIRES

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THE BENEFITS OF ELECTRIC TRANSMISSION: IDENTIFYING AND ANALYZING THE VALUE OF INVESTMENTS

EXECUTIVE SUMMARY

A. SCOPE OF THIS REPORT

WIRES, also known as the **W**orking Group for **I**nvestment in **R**eliable and **E**conomic Electric **S**ystems, engaged *The Brattle Group* to assemble available experience with identifying and analyzing the wide range of potential benefits offered by transmission investments. WIRES has asked *Brattle* to focus on how various benefits can be identified and estimated, and to discuss the experiences of regional transmission organizations (RTOs) and non-RTO regions in analyzing the economic, reliability, public policy, and other benefits that new or upgraded transmission can provide.

Because the recognition and understanding of many of the transmission-related benefits by system planners and regulators has been evolving, there is currently no standard menu of benefit metrics that can be applied in the evaluation of transmission investments. The lack of standard benefit metrics is a critical gap in advancing the planning of an improved power grid. This report attempts to fill that gap.

While we recognize that the evaluation of the merits of transmission projects is inherently linked to a broad set of important and challenging topics, our report is focused on the identification and evaluation of transmission-related costs and benefits. The report is organized as follows:

- Section I provides background, including the purpose and scope of our report.
- For both policy makers and practitioners, Section II discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. Compiled from a detailed review of industry practices and our own experience, we then present a "checklist of economic benefits" that can be used to help identify the potential benefits of transmission investments. We recommend policy makers and planners use this checklist to document, evaluate, and communicate a comprehensive "business case" for transmission projects.
- To further explain how benefit-cost analyses can be used in the planning process, Section III focuses on a proposed improvement to the current planning and cost allocation processes through a four-step framework for identifying and evaluating valuable transmission projects and their potential benefits. These four steps will be followed by a discussion of how the benefits of transmission should be analyzed in light of considerable near-term and long-term uncertainties
- Next, Section IV raises and provides solutions to several methodological challenges associated with the identification and evaluation of transmission projects. We discuss: (a) how the costs of transmission investments should be compared with the investments'

benefits over the various time horizons; (b) the difference between overall benefits (often referred to as "societal" or economy-wide benefits) and electricity-customer impacts; (c) how estimates for the distribution of benefits should be used to inform cost allocation; and (d) how transmission-related benefits should be considered and analyzed in interregional planning.

- Section V then summarizes the extent to which transmission planning efforts in Regional Transmission Organizations (RTOs) and non-RTO regions have addressed and estimated various economic, reliability, public policy, and other benefits that transmission investment can provide.

- And finally, for the practitioners, Section VI provides a detailed technical discussion to document available approaches, best practices, and metrics that allow for a more comprehensive evaluation and estimation of benefits associated with transmission infrastructure investment. This section of our report is targeted to industry executives, managers, and planning staff charged with evaluating transmission investments and developing the business case for potential projects.

Transmission planning faces many other challenges today. While we are tempted to comment on all of them, this report focuses on the identification and evaluation of transmission benefits. Some of the topics that we are *not* addressing include the complexities associated with: (1) the permitting and siting of new transmission facilities; (2) the processes and available options for the allocation and recovery of transmission costs; (3) the differences between cost-of-service-regulated and market-based (or "merchant") transmission investments; (4) the differences between the transmission planning and integrated resource planning (IRP) processes of vertically-integrated utilities; (5) the detailed step-by-step and iterative transmission planning process itself, including the comparisons of different transmission options and non-transmission alternatives and how one selects the most valuable projects and configurations; (6) the development of decision-analysis tools or frameworks that may be able to streamline the planning decision based on comprehensive analyses of transmission and non-transmission investment options; (7) the institutional and organizational barriers to creating a credible, unbiased, and comprehensive planning process; (8) the implications of setting different allowed rates of return on transmission investments and regulatory incentives for such investments; and (9) the broader political economy associated with building transmission, cost allocation, permitting, and regulation.

Even though these topics are not directly addressed in this report, we feel that the main topic—identifying, understanding, and evaluating transmission-related benefits—is a critical component of transmission planning and therefore serves as a foundation upon which these other topics can be addressed. It is our overarching recommendation that policy makers and planners consider the full set of potential benefits in all planning efforts going forward. To support this recommendation, we also suggest supplementing existing planning processes with a four-step framework under which the broad set of benefits would first be identified and then analyzed for public interest determinations.

B. Benefits of Transmission Investments and Their Relevance to Industry Planning and Cost Allocations

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 will become even more so in the future with the implementation of the Federal Energy Regulatory Commission's (FERC's) Order No. 1000, which requires that both RTO and non-RTO regions consider reliability, economic, and public policy drivers in their regional and interregional transmission planning processes.

In the last decade, the most visible trend away from the traditional approach to planning has occurred in RTOs that operate organized markets. In those regions, transmission planning has gradually expanded beyond addressing reliability and load serving concerns to include economic and public-policy drivers. In that context, planners and regulators increasingly recognize that planning for economic- and public-policy-driven transmission projects requires consideration of the wide range of benefits and costs associated with these investments. Non-transmission alternatives also need to be considered, which means the transmission benefits must be weighed against the benefits associated with those alternatives as well. To the extent that this trend is also occurring in non-RTO regions, it seems less apparent primarily because the evaluation of at least some of the economic or public-policy benefits of transmission expansion is incorporated within the utilities' state-regulated integrated resource planning.

In RTO regions where planning involves multiple utility transmission owners within a single organized market, economic analyses have become more integral to the transmission planning process. Some RTOs—such as the PJM Interconnection (PJM), the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), and the Energy Reliability Council of Texas (ERCOT)—rely primarily on the traditional application of production cost simulations to determine whether the economic value of building a transmission project outweighs its costs. Other regional system operators—in particular the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), and the California Independent System Operator (CAISO)—have expanded the scope of analyzing economic transmission projects to consider an increasingly broader range of benefits, including reduced system losses, increased system reliability, access to lower-cost renewable generation, and increased market competition. In non-RTO regions—such as the Southeastern U.S. and ColumbiaGrid—individual utilities identify their local transmission needs through their transmission and integrated resource planning efforts. The regional plans are then based on an aggregation of the local projects of individual utilities and an assessment of whether larger regional projects would provide more cost-effective solutions to the aggregated local needs.

Despite the differences among regions in how they consider transmission benefits in planning, the same set of potential transmission benefits applies regardless of the specific market or geographic location. The magnitudes of benefits associated with transmission investments depend on the market conditions and the physics of electric power flows, and not on the regulatory framework under which the investments are made.

Recent developments in transmission planning around the country show that the industry and regulators have reached a point where a more comprehensive and standardized catalogue of benefits and methodologies for estimating benefits should be articulated and considered. Based on the industry experience and our own, we have assembled a comprehensive list of potential economic benefits that transmission investments can provide (in Table ES-1). In addition to production cost savings as traditionally estimated in the industry, the table lists eight categories of additional economic benefits that often are not estimated or overlooked. We address each of these potential benefits, explain why they often have not been captured in the traditional metrics, and present examples of instances where these benefits have been already analyzed and used to guide transmission investment decisions. A solid understanding and appreciation of the full range of costs and benefits will help avoid making premature decisions about valuable projects whose wide spectrum of benefits relative to proposed alternatives might be overlooked. Assembling this experience will hopefully provide a common understanding of the range of potential transmission benefits, inform the planning processes that different regions are developing in compliance with Order 1000, and guide planners and policy makers in making transmission investment decisions across different regions going forward.

Above all else, we recommend that the catalogue of benefits in Table ES-1 be used as a "checklist" during initial transmission project conceptualization efforts to help planners identify a comprehensive inventory of the projects' potential costs and benefits. Starting with an inventory of possible transmission benefits during the initial project conceptualization effort would help avoid limiting the scope of benefits considered to those for which analytical tools are readily available or only to those that have been evaluated traditionally.

As we discuss in Section V of this report, all of these benefits have been considered by some planning entities for at least some transmission projects. Some of these benefits can be measured readily through standard benefit metrics while others may be unique to specific transmission projects and require additional analyses. Examples of the approaches and tools utilized to estimate these benefits are discussed in Section VI of our report.

C. USE OF BENEFITS METRICS: RECOMMENDED APPROACHES FOR PLANNING

In addition to the advantages of starting project evaluations with a comprehensive list of potential costs and benefits, we also offer the following suggestions to planners and policy makers when evaluating the merits of transmission projects:

- *Consider all Benefits*. Production cost simulations have become a standard tool for many transmission planners, and such a shift represents a significant progress in evaluating the economic benefits of transmission. However, the results only provide estimates of the short-term dispatch-cost savings under a singular set of generally simplified system conditions. Traditionally, these simplified simulations yield benefit estimates that reflect just a portion of total production cost savings and an even smaller portion of the overall economy-wide benefits provided by transmission investments. Other important benefits are often more difficult to estimate and are often overlooked. While not all proposed transmission projects can (or should) be justified economically, overlooking benefits because the traditional tools do not automatically capture these benefits often leads to the rejection of otherwise desirable projects. Benefits that are potentially significant but difficult to estimate should be analyzed by calculating their likely range and magnitude. Omitting consideration of such difficult-to-estimate benefits inherently assigns a zero value and thereby results in an understatement of total project benefits. Some benefits are long-term in nature and others materialize immediately. Some are policy-driven or policy-dependent, necessitating a clear understanding of the goals policy makers are trying to achieve. The long-term benefits of a physical asset with a useful life of at least 40 years should be considered as well—they are tangible and attainable even if they are difficult to estimate given the long time horizon.

Table ES-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 or 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

- *Define the Scope of Transmission Benefits and the Perspective Taken.* The process for identifying transmission benefits is often limited to the impacts of new projects on customer rates within a utility's system or a planning region. Such perspective is important because those who pay for the transmission facilities should also obtain benefits that are "commensurate" with their share of costs. However, a benefit analysis limited to the direct rate impact on customers, especially customers in a single utility footprint or in the planning region, could miss benefits to a region or a larger portion of the economy. Overly narrow benefits evaluations of economic or public policy-driven projects can also miss increased customer value from improved reliability and ignore benefits that accrue to other market participants or regions. In some cases, applying an electricity-customer perspective can overstate benefits relative to true efficiency gains by ignoring costs imposed on other market participants or regions. To avoid under- or overstating the total benefits of transmission investments, we recommend that benefit-cost analyses of transmission projects be derived from a perspective that considers the overall benefits (often referred to as "societal" or economy-wide benefits) that accrue to a broad range of market participants and the economy as a whole.

- *Understand Total Benefits Prior to Cost Allocation.* Understanding the overall project benefits prior to making cost allocation decisions will enable participants in the planning process to identify those projects that are most beneficial in the long run from an economy-wide perspective. How the distribution of the identified benefits is estimated to accrue to regions, areas, and market participants will ultimately drive both regional and interregional cost allocation—but cost allocation should be addressed only *after* the overall benefits of transmission projects have been considered for inclusion in regional plans. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in the rejection of even very valuable projects. Aggregating beneficial transmission projects into larger portfolios of projects can simplify the necessary cost allocation analyses, reduce misperceptions that benefits appear to accrue only to a limited subset of market participants, and thus facilitate cost allocation.

- *Consider All Regional Benefits in Interregional Planning.* 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. Focusing only on common benefits results in the consideration of a narrower set of benefits in interregional projects than are considered for region-internal projects. To avoid this "least common denominator" outcome in interregional planning, we recommend that neighboring regions evaluate interregional projects in light of the full set of potential benefits that are considered for regional projects in each region. This approach would help planners and policy makers to better understand the full benefits of interregional projects to their planning region and to make decisions that are more efficient from an interregional perspective and well-aligned with the interest of all affected regions. Without an inclusive recognition of all potential benefits by each of the neighboring regions, coordinated interregional planning in compliance with FERC Order No. 1000 would not be able to identify and ensure the development of many projects that benefit two or more regions.

- *Address Uncertainties.* The industry faces considerable uncertainties on both a near- and long-term basis that should be considered in transmission planning. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure is generally disproportionately concentrated in periods of more challenging, or possibly extreme, market conditions. The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. We recommend a more comprehensive planning approach that includes: (1) evaluating long-term uncertainties through scenario-based analyses; and (2) evaluating near-term uncertainties within scenarios through sensitivity or "probabilistic" analyses.

- *Consider Long-Term Benefits.* Several methods exist for comparing benefits and costs in the transmission planning processes. The methods currently used by planners and regulators differ by the number of years analyzed (*i.e.*, planning horizons), how benefits are estimated over the short-term and long-term, whether levelized or present values are used in the benefit and cost estimations, and the benefit-to-cost threshold that projects must clear. After analyzing the various methods currently employed in different planning regions, we recommend that the estimated benefits be compared with estimated project costs—either on a present value or levelized annual basis—over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets. Paying attention to how benefits and costs accrue over time and across future scenarios will also help planners to optimize the timing of transmission investments from a long-term value perspective.

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

The purpose of this study is three-fold. First, WIRES, also known as the **W**orking Group for **I**nvestment in **R**eliable and **E**conomic Electric **S**ystems, has asked *The Brattle Group* to document the broad range of potential transmission-related benefits and how they can be identified and estimated for specific transmission investments. Second, we document and discuss the experiences of regional transmission organizations (RTOs) and non-RTO regions in analyzing the economic, reliability, public policy, and other benefits that new or upgraded transmission can provide. Third, based on the collective experience documented, we catalogue the range of potential benefits offered by transmission investments and summarize the experience with the estimation of these benefits. Put together, the transmission-related potential benefits, metrics, and estimation practices documented in this report can be applied to evaluate any individual or group of transmission investments.

Traditionally, the majority of transmission projects have been proposed and developed by vertically-integrated utilities whose primary focus is to serve native load and maintain a reliable transmission system within their franchised service areas. For the most part, maintaining a system that meets all applicable reliability standards has been the main driver of transmission planning over the last several decades,[1] as transmission additions are often necessary to address load-serving needs, generation interconnection requests, and new transmission service requests. To ensure that system reliability is maintained, utilities and transmission planning organizations conduct engineering studies and identify the most cost-effective system upgrades to address the identified reliability needs.

In the last decade, the focus of transmission planning has gradually expanded beyond addressing reliability concerns to include "economic" (also referred to as "market efficiency") and public-policy drivers for transmission investments. New Federal Energy Regulatory Commission (FERC) requirements for allocating costs roughly commensurate with benefits have also brought additional attention to the identification and analysis of transmission benefits. As a result, understanding the benefits of transmission projects and comparing these benefits to project costs has become increasingly important. This type of benefit-cost analysis has also attracted the attention of policy makers and transmission customers, who ultimately have to pay for the costs of the new facilities.

In response to the evolving need to consider transmission investment drivers beyond reliability requirements, transmission companies and RTOs have developed new processes for evaluating economic or market-efficiency projects. Similar to reliability-driven planning processes, many of the evaluation methodologies for economic projects were specified in a formulaic fashion.

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1 Reliability violations set a standard for maintaining a secure supply of electricity to all consumers. There are currently in place well-established processes for reliability-driven transmission planning that requires engineering analyses based on well-defined cases to first identify and then address reliability violations, such as the so-called "N-1" criteria violations, as determined by the North American Electric Reliability Council (NERC). These reliability standards provide clear criteria, which led to the development of well-honed formulaic evaluation processes that use established analytical tools (such as power flow models) to identify future reliability violations and how to avoid these violations through transmission upgrades or non-transmission alternatives. (NERC Reliability Standards, 2013)

These formulaic methods often narrowly relied on simplified production cost analyses to measure economic benefits. The unintended consequence of these narrow, formulaic approaches is that few (if any) economic transmission projects could ever meet the specified thresholds and planning criteria because the simplified production cost analyses do not measure all of the potential benefits associated with transmission projects, and, therefore many beneficial projects may not be developed.

The simplified production cost analyses do not easily to help planners assess the value of transmission needed due to public policy drivers. Thus, a few RTOs and other transmission planners have recognized that planning for economic and public-policy driven projects requires a broader perspective that recognizes multiple transmission-related benefits. However, there is no industry standard for the consideration of a broad set of transmission-related benefits in the planning process. Consequently, we intend, through this report, to address this gap and develop approaches that can be used as a standard to identify, document, and evaluate a broader range of transmission-related benefits and communicate a more comprehensive "business case" for transmission projects. In doing so, we identify approaches and best practices that allow for a more complete evaluation and estimation of benefits associated with transmission infrastructure investment.

The remainder of this report is organized as follows. **Section I** provides background, including the purpose and scope of our report. For the benefit of both policy makers and practitioners, **Section II** discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. Compiled from a detailed review of industry practices and our own experience, we then present a "checklist of economic benefits" that can be used to help identify the potential benefits of transmission investments. We recommend policy makers and planners use this checklist to document, evaluate, and communicate a comprehensive "business case" for transmission projects.

To explain further how benefit-cost analyses can be used in the planning process, **Section III** focuses on a proposed improvement to the current planning and cost allocation processes through a four-step framework for identifying and evaluating valuable transmission projects and their potential benefits. The four steps will be followed by a discussion of how the benefits of transmission should be analyzed in light of the considerable near-term and long-term uncertainties. Next, **Section IV** raises and provides solutions to several methodological challenges associated with the identification and evaluation of transmission projects. We discuss: (a) how the costs of transmission investments should be compared with the investments' benefits over the various time horizons; (b) the difference between overall benefits (often referred to "societal" or economy-wide benefits) and electricity-customer impacts; (c) how estimates for the distribution of benefits should be used to inform cost allocation; and (d) how transmission-related benefits should be considered and analyzed in interregional planning;.

Section V then summarizes the extent to which transmission planning efforts in RTOs and non-RTO regions have addressed and quantified various economic, reliability, public policy, and other benefits that transmission investment can provide. And finally, for the benefit of practitioners, **Section VI** provides a detailed technical discussion to document the available approaches, best practices, and metrics that allow for a more comprehensive evaluation and estimation of benefits associated with transmission infrastructure investment. This section of our report is targeted to industry executives, managers, and planning staff charged with evaluating transmission investments, performing the necessary analyses, and developing the business case for potential projects.

Transmission planning faces many other challenges today. However, while we are tempted to comment on all of them, this report focuses on the identification and evaluation of transmission benefits. Some of the **topics we are *not* addressing** include the challenges associated with: (1) the permitting and siting of new transmission facilities; (2) the processes and available options for the allocation and recovery of transmission costs; (3) the differences between cost-of-service-regulated and market-based (or "merchant") transmission investments; (4) the differences between transmission planning and integrated resource planning (IRP) processes of vertically-integrated utilities; (5) the detailed step-by-step and iterative transmission planning process itself, including the comparisons of different transmission options and non-transmission alternatives and how one selects the most valuable projects and configurations; (6) the development of decision-analysis tools or frameworks that may be able to streamline the planning decision based on comprehensive analyses of transmission and non-transmission investment options; (7) the institutional and organizational barriers to creating a credible, unbiased, and comprehensive planning process; (8) the implications of setting different allowed rates of return on transmission investments and regulatory incentives for such investments; and (9) the broader political economy associated with building transmission, cost allocation, permitting, and regulation.

Even though these topics are not directly addressed in this report, we feel that its main topic—identifying, understanding, and evaluating transmission-related benefits—is a critical component of transmission planning and therefore serves as a foundation upon which these other topics can be addressed. It is our overarching recommendation that policy makers and planners consider the full set of potential benefits in all planning efforts going forward. To support this recommendation, we also suggest supplementing existing planning processes with a four-step framework under which the broad set of benefits would first be identified and then be analyzed for public interest determinations.

II. TYPES OF TRANSMISSION-RELATED BENEFITS

This section of our report first discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. We then present a "checklist of economic benefits" that is based on our review of industry practices as presented in Section IV and our own experience. As we discuss in Section III, this checklist can be used to help identify the potential benefits of transmission investments that would be useful for communicating a comprehensive "business case" for transmission projects.

As is at least conceptually understood, transmission investments can support a wide range of benefits. The most common benefits include increased reliability, decreased transmission congestion, renewables integration, reduced losses, reduced resource adequacy requirements, and increased competition in power markets. Some of these benefits spread across wide geographic regions and multiple utility service areas and states, and can significantly affect market participants ranging from generators to retail electricity customers. Over the long-life of the transmission assets, the nature and the magnitude of the benefits can also change significantly. For example, benefits associated with today's transmission grid, such as the ability to operate competitive wholesale electricity markets, could hardly have been imagined or estimated when the facilities were built four or five decades ago, long before the advent of open access to the transmission grid.

Recent transmission planning experiences have also shown that the scope of transmission-related benefits generally extends beyond the main driver of a particular project. While many transmission investments are motivated by a single driver—such as reliability, congestion relief, or renewable generation integration—the benefits of these transmission investments generally extend beyond the individual driver. For example, many reliability-driven projects also will reduce congestion and support the integration of renewable generation. Similarly, a transmission project driven by congestion-relief objectives also will also increase system reliability, help to avoid or delay reliability projects that would otherwise be needed in the future, or reduce system-wide investment needs by allowing access to lower-cost generation resources. This multi-purpose, multi-value aspect of transmission investments requires a more systematic analysis of the wide range of transmission-related benefits and the interaction of transmission investments with other system-wide costs and non-transmission investments.

A. Production Cost Savings as a Traditional Benefit Metric

The most commonly-considered economic benefits of transmission investments are estimated reductions in simulated fuel and other variable operating costs of power generation (generally referred to as production cost savings) and the impact on wholesale electricity market prices (in many cases referred to as locational marginal prices or LMPs) at load-serving locations of the grid. These production cost savings and load LMP benefits are typically estimated with production cost models that—in attempts to streamline the modeling effort—are configured to simulate generation dispatch and transmission congestion based on simplified approximations of power flows, predefined transmission constraints, and normalized system conditions.

In a recent assessment of RTO performance by FERC, the majority of RTOs cited congestion relief as a main benefit from expanding transmission capacity. For example, PJM noted that market simulations of recently-approved high-voltage upgrades indicate that these upgrades will reduce congestion charges by approximately $1.7 billion compared to congestion charges without the upgrades.[2] While changes in total congestion charges are informative, the economic value of such congestion relief is generally reflected in production cost savings (from an economy-wide perspective) and load LMP benefits (from the perspective of customers in restructured retail electricity markets) because a reduction in congestion typically increases the use of more efficient (lower cost) generators over inefficient (higher cost) ones.

[2] FERC Performance Metrics, 2011, Appendix H: PJM, p. 275. Additionally, an 82% reduction in annual congestion costs is forecast from $980 million "as is" 2012 baseline to $173 million "as planned" based on PJM's 2016 RTEP (Cash, 2013).

Since production cost simulations have become a standard tool for many transmission developers and grid operators, production cost savings estimation is the analysis that can be repeated for all proposed transmission projects or groups of projects. While production cost savings are readily estimated (based on simplified assumptions), the results only provide estimates of the short-term dispatch-cost savings of system operations. These savings are only a portion of the overall economic benefits provided by transmission investments and do not capture a wide range of other transmission-related benefits, including many long-term capital and operational cost savings. For example, as a Western Electric Coordinating Council (WECC) planning group recognized:

> The real societal [*i.e.*, overall economic] benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost simulation] analysis.[3]

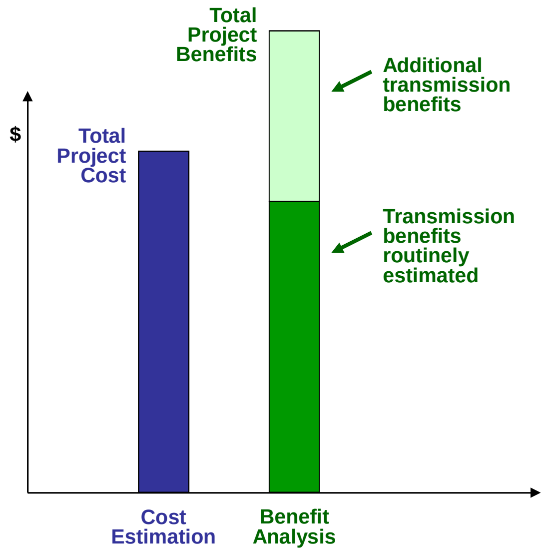
In addition, as we explain in more detail later in Section VI, production cost simulations as traditionally undertaken are based on a number of simplified assumptions that can significantly understate the derived estimates of production cost savings.

B. Examples of a More Fully Articulated Set of Transmission Benefits

Aside from production cost savings, other benefits—particularly those associated with improved reliability, reduced generation capital costs, reduced market power and demand—are often omitted in many transmission benefit-cost analyses. These omitted benefits are sometimes inaccurately viewed as "soft" or "intangible" benefits simply because they are not yet routinely estimated by transmission owners and system operators. Even though some of these additional benefits can be difficult to estimate in certain situations, omitting them effectively assumes these benefits are zero, which may not be the case. Instead, estimating the approximate range of likely benefits will yield a more accurate benefit-cost analysis and provide more insightful comparisons that avoid rejecting beneficial transmission investments. For example, transmission lines can increase competition in wholesale electricity markets as more generators gain access to a wider set of customers. In some cases, transmission upgrades can reduce a region's resource adequacy needs and offer access to lower-cost generating resources. While estimates of resource adequacy or competitive benefits might not be precise at times, rough estimates of the likely magnitude of these benefits can generally be developed. As conceptually illustrated in Figure 1, overlooking or ignoring such difficult-to-quantify or not-commonly-estimated benefits can lead to rejection of otherwise desirable projects.

3 SSG-WI Transmission Report, October 2003.

Figure 1



As we noted in a prior report for WIRES,[4] the post-construction assessment of the Arrowhead-Weston transmission line in Wisconsin, developed by American Transmission Company (ATC) in 2008, provides a good example of the broad range of benefits associated with that project. The primary driver of the Arrowhead-Weston line was to increase reliability in northwestern and central Wisconsin by adding another high voltage transmission line in what the federal government designated at the time as "the second-most constrained transmission system interface in the country."[5] The project addressed this **reliability** issue by adding 600 MW of carrying capacity and improving voltage support, the impact of which was noticeable in both Wisconsin and in southeastern Minnesota. By also **reducing congestion**, ATC estimated that the line allowed Wisconsin utilities to decrease their power purchase costs by $5.1 million annually, saving $94 million in net present value terms over the ensuing 40 years. Similarly, ATC estimated that the project saved $1.2 million in **reduced costs for scheduled maintenance**. The high voltage of the line (345 kV) also **reduced on-peak energy losses** on the system by 35 MW, which **reduced new generation investments** equivalent to a 40 MW power plant. The reduced losses also avoid generating 5.7 million MWh of electricity that would **reduce CO_2 emissions** by 5.3 million tons over the initial 40-year life of the facility. In addition, the transmission line has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to **help Wisconsin meet its RPS requirements**. The construction of the line **supported 2,560 jobs**, generated $9.5 million in **tax revenue**, created $464 million in total **economic stimulus**, and will provide $62 million of **income to local communities** over the next 40 years. The increased reliability of the electric system has provided **economic development benefits** by improving the operations of existing commercial and industrial customers and attracting new customers. Lastly, the project also provided **insurance value against extreme market conditions** as was illustrated in a North American Electric Reliability Corporation (NERC) report which noted that if the Arrowhead-

[4] Pfeifenberger and Hou, 2011, Section IV.

[5] ATC (2009), p. 7.

Weston line had been in service earlier, it would have **averted blackouts** in the region which impacted an area that stretched from Wisconsin and Minnesota to western Ontario and Saskatchewan, affecting hundreds of thousands of customers.

Figure 2 and Figure 3 summarize examples of transmission benefit-cost analyses that identified and estimated a number of the transmission-related benefits discussed above. As shown, the examples show projects that provide benefits significantly in excess of transmission-related rate increases, with the estimated economic benefits exceeding their costs by 60% to 70%. These examples also show that the traditionally estimated production cost savings are only a portion of the total benefits.

A comprehensive analysis of a broad range of transmission-related benefits also may show that some benefits have negative values (*i.e.*, representing costs). For example, transmission investments that help integrate lower-cost but distant generating resources can also increase system-wide transmission losses. Some transmission expansions can lead to increased emissions and associated environmental costs; or in some cases, certain transmission projects may cause larger environmental impacts in terms of their land use. From a consumer perspective, new transmission could decrease the value of existing physical or financial transmission rights (FTRs), thereby offsetting benefits related to congestion relief or the increased availability of transmission rights.[6]

[6] The economic analysis of the Paddock-Rockdale Project is a good example of transmission benefits that could be positive or negative. We have presented in Figure 2 the summary results of one of the seven scenarios examined when ATC evaluated the project. In Figure 2, we show that additional "FTR and Congestion Benefits" added $6 million to the savings of the project. However, the results for the other Scenarios analyzed by ATC showed different patterns. Specifically, the "FTR and Congestion Benefits" was actually negative in three of the seven scenarios. In fact, it had a negative value of $117 million in one of them, which offset $379 million in production cost savings for that scenario. These results also document that benefits can vary greatly across possible different futures, which illustrates the importance of scenario analysis to evaluate the robustness of project economics as we discuss further below.

Figure 2
Total Benefits Quantified for ATC's Paddock-Rockdale Project

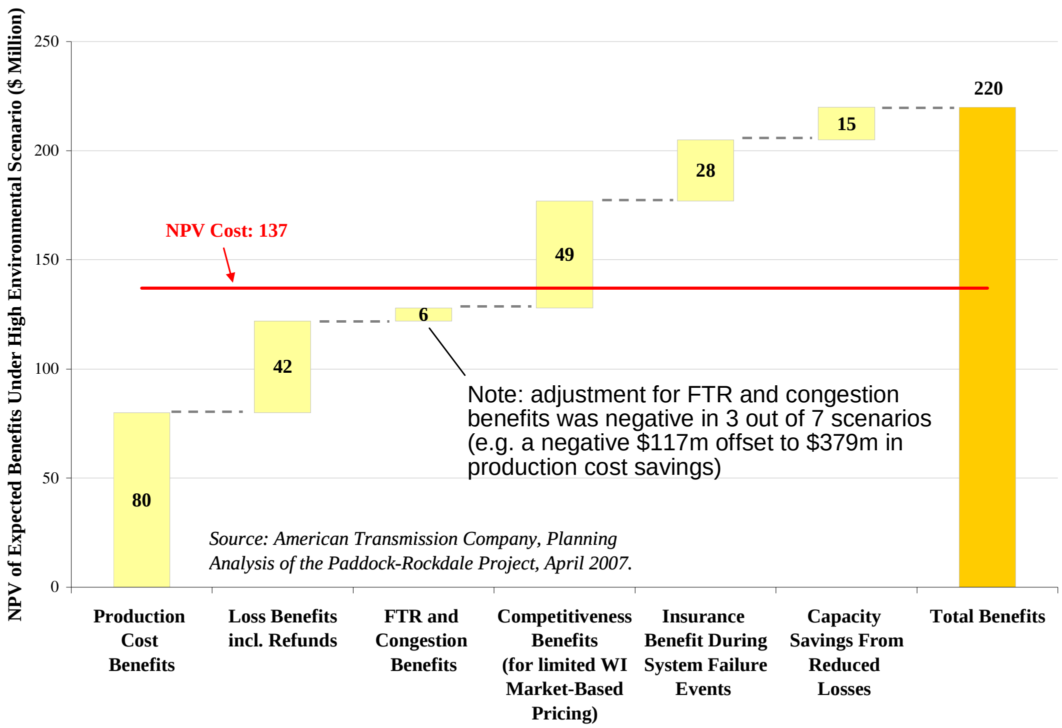
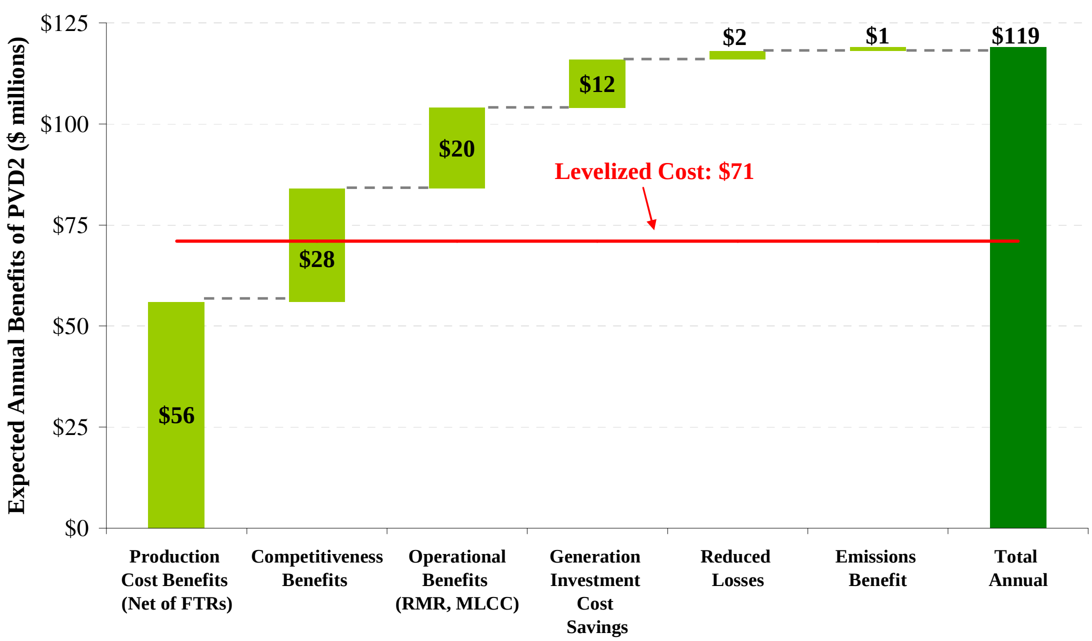


Figure 3
Total Benefits Quantified for Southern California Edison's Palo Verde-Devers 2 Project



Source: California ISO (CAISO), *Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2),* February 24, 2005.

C. A "CHECKLIST" OF POTENTIAL ECONOMIC BENEFITS OF TRANSMISSION INVESTMENTS

Recent developments in transmission planning around the country (summarized more systematically in Section V of this report) for both RTO and non-RTO regions show that the industry and regulators have reached a juncture where a more complete, standardized catalogue of benefits and methodologies for estimating benefits can be articulated. Based on this industry experience and our own experience of working with transmission developers and RTOs, we assembled a comprehensive catalogue of potential economic benefits that transmission investments can provide. This "checklist of economic benefits" is summarized in Table 1 and presented in more detail in Appendix A. It shows the production cost savings traditionally estimated as well as additional categories of benefits that often are not evaluated or even considered. Section VI provides a more technical discussion of the metrics and experience with analytical techniques that can be applied to estimate the value of these benefits.

This more comprehensive catalogue of transmission-related benefits reflects that the magnitude of the economic benefits of transmission investments depends on the market conditions and the physics of electric power flows. It does not depend on how stakeholders can agree voluntarily on which benefits count and which do not. For example, just because a certain subset of transmission-related benefits, such as congestion relief, might not be *considered* in a particular region's current planning processes, it does not mean that transmission investments would not reduce congestion and associated production costs. While regional differences may have significant impacts on the type of benefits that would likely materialize, these regional differences will mostly affect the magnitude of the benefits but not their existence.[7] We consequently recommend that these benefits be considered for all proposed transmission projects to assess if they provide significant value, and if so, be evaluated further to estimate their magnitudes. It is important to recognize, however, that individual transmission projects will not yield all of these benefits and may not found to be cost-effective even if all benefits are considered.

In the next section, Section III, we provide suggestions on how these benefits metrics can be incorporated in transmission planning (or resource planning) processes.

[7] For example, the value of the storm-hardening benefits of a new transmission project may be substantially less in regions with few severe storms.

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
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	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 or 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

III. INCORPORATING ECONOMIC BENEFITS IN THE TRANSMISSION PLANNING PROCESS

Utilizing an expanded list of transmission-related benefits in the planning process raises several methodological challenges, including when and how the benefits can be identified and evaluated. In this section, we address some of these challenges at a high level. We first propose to augment current planning and cost allocation processes through a four-step procedural framework. Then we discuss how the benefits of transmission should be analyzed in light of considerable near-term and long-term uncertainties.

A. A FRAMEWORK TO FACILITATE IDENTIFYING AND CONSIDERING TRANSMISSION PROJECTS AND THEIR BENEFITS

First and foremost, the transmission planning process and the considerations for transmission-related benefits go hand in hand. The choice of what projects to pursue is directly linked to how planners and developers view the need for transmission projects and, thereby, the potential benefits that these projects would provide. Through our experience, we have found that a successful approach to the identification of potentially beneficial projects is to consider all the potential benefits offered by the contemplated transmission investments at the outset, when assessing the need of certain projects. Putting all the benefits on the table upfront helps avoid encumbering the overall planning process by focusing too early on time-consuming market simulations. Also recognizing that cost allocation debates can sometimes get in the way of developing innovative transmission projects that offer benefits to a wide range of market participants and service areas, as discussed further below, we present a simple four-step process that begins with project identification using the checklist of potential economic benefits.

(1) The first step in our recommended framework is to bring together system planners, project developers, and other stakeholders **to identify potential transmission projects that could supplement or replace baseline reliability projects and to develop a comprehensive list of their likely benefits**. Such "brainstorming" sessions would be most effective when facilitated by independent, unbiased planning professionals such as RTO staff. They may also need to involve market participants to help inform assumptions about existing and anticipated system conditions. The participants would propose and document project ideas while simultaneously describing anticipated benefits. The goal of this step is to identify a wide range of possible projects that could address reliability needs, meet public policy objectives, and offer economic benefits without impeding or limiting the scope of options and benefits considered at the outset. This step is also used to gather an inventory (and possibly ranking) of promising transmission projects and their likely costs and benefits with no screening of projects based on how readily benefits could be estimated or how costs might allocated. This screening can be done at a later stage after more analyses have been conducted. Only two questions should be asked at this stage of the process: (a) What transmission projects would likely be beneficial in addition to or instead of those that have been identified to meet reliability standards?; and (b) What are the likely types of benefits that these projects would offer and why are they expected to be significant?

(2) The second step of this framework is to perform an unbiased evaluation of the proposed projects from both a reliability and economic perspective and to **estimate the value of as many of the identified benefits as practical** without regard to how the benefits would be distributed across the region, to neighboring regions, or to different groups of transmission customers, generators, or other market participants. Some of the economic benefits can be measured readily through traditional benefit metrics, such as "Adjusted Production Cost" or "APC" savings. These traditional benefit metrics would be analyzed for every project or portfolio of projects through simulations and pre-specified formulaic calculations that can be undertaken routinely within each planning cycle. Other benefits may not lend themselves to routine analyses through formulaic benefit metrics. The value of those benefits would be estimated when the anticipated magnitude is significant such that it could materially affect the attractiveness of the proposed projects. Benefits that could be significant but are more difficult to estimate should be analyzed by estimating at least their likely range and magnitudes—rather than implicitly assuming that they have zero value because their precise values are difficult to calculate. Benefits that are unique to specific projects could be assessed only if and when they are applicable.

(3) The third step is to **determine whether the proposed transmission investments would be beneficial overall** by comparing the magnitude of estimated economy-wide (often referred to as "societal") benefits with estimates of the total costs of the projects.[8] Once the overall value of benefits has been estimated, a benefit/cost ratio can be calculated and compared to the applicable threshold to determine whether a project or portfolio of projects is worth pursuing. This is also the step where non-transmission alternatives should be considered when comparing benefits and costs of proposed projects. We have found that, while it is intuitive to estimate the economic benefits associated with every proposed transmission project, often several projects could be considered jointly because the combination of the projects can provide higher (or in some cases lower) benefits than the sum of each project's individual benefits. By analogy, a particular section of the interstate highway system would have little value unless it is integrated with the rest of the system. Likewise, a group of transmission facilities that serve as a regional overlay may provide substantially greater regional benefits (*e.g.*, in the form of reliability, congestion relief, emissions reduction, advanced load serving capability, *etc.*) than the sum of the benefits for each individual segment that makes up the regional overlay. Competing or conflicting projects would need to be evaluated independently. Such distinction reinforces the need to describe and understand the potential benefits of each project upfront before delving into the quantitative analyses. If a group of facilities can offer more benefits jointly than independently, developing efficient portfolios of

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8 This approach is consistent with Principle No. 3 ("The appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region being examined") in the whitepaper by the Blue Ribbon Panel (Baldick, *et al.,* 2007). We add, however, that (consistent with Principle 4A of the same whitepaper) the "geographic region being examined" should not necessarily be limited to a single planning region, but be large enough to include all planning regions that are anticipated to see significant benefits from a proposed project (or group of projects).

transmission projects would require iterative analyses of several transmission options and non-transmission alternatives in this step.

(4) The fourth step is to **address cost allocation**. It is important to address cost allocation only after transmission projects have been found to be beneficial overall. Estimates of the distribution of the identified benefits can then be used to inform cost allocation. In this step, through facilitation by an unbiased planning entity, an allocation of costs should be achieved that is commensurate with the benefits received. Again, for this effort, aggregating beneficial transmission projects across a region into a portfolio of projects is advisable before determining cost allocations because a larger portfolio of transmission projects that is distributed throughout the evaluated region will tend to offer benefits that are distributed more evenly as well. We have also found that, since it is generally more contentious and difficult to estimate the distribution of benefits than to estimate the overall magnitude of the benefits, aggregating transmission projects into larger portfolios of projects will often simplify the necessary analyses, reduce any misperception that benefits appear to accrue only to a subset of market participants, and thereby help facilitate cost allocations. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in the premature rejection of even very valuable projects.

Since each system already has an existing planning process in place, we suggest system planners integrate the above framework with existing planning processes to help facilitate efficient development of transmission options and non-transmission alternatives and select the most valuable projects and configurations.

We recognize that the development of reasonably "optimal" transmission expansion plans is a challenging, iterative process. To improve the efficiency and robustness of this planning process, analytical tools that can simultaneously evaluate a wider range of transmission-related benefits under uncertain future market conditions and more integrated decision-analytical frameworks will need to be developed.[9]

B. CONSIDERING UNCERTAINTY

The economic analysis associated with evaluating new transmission investments often is limited to the evaluation of the projects under a single forecast of future market conditions. A common practice in evaluating transmission projects involves using a "Base Case" scenario that represents the planners' best guess of future market conditions or a continuation of the most recent market condition, without accounting for any potentially very large divergences in future outcomes over the long term. While the Base Case scenario provides one "vision" of the world for which the

[9] We address tools and frameworks available to evaluate a broader range of transmission benefits in Section VI of this report. For evolving analytical tools and decision-analytical frameworks—particularly with respect to planning transmission in the context of integrating renewable generation—see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

future value of transmission investments can be estimated, using one "Base Case" scenario could ultimately lead to over or under estimating the projects' value.

In some cases, planners may shy away from making investment decisions fearing that uncertain futures could dramatically change the value of those investments and result in regrets. However, shying away from making investment decisions because of difficulties in predicting the future could lead to a perpetual focus on small incremental 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 address longer-term needs more effectively. To address this challenge, we recommend a more comprehensive planning approach that includes: (1) evaluating long-term uncertainties through scenario-based analyses and decision-analytical frameworks; and (2) evaluating near-term uncertainties through sensitivity analyses or "probabilistic" approaches.[10]

Evaluating long-term uncertainties through various 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 that can substantially affect the need and size of future transmission projects are best analyzed through scenario-based analyses. The results can be used to: (1) identify "least-regrets" projects 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) to create valuable options that can be exercised in the future depending on how the industry actually evolves.

Evaluating short-term uncertainties around weather patterns, fuel-price volatilities that drive changes in generation dispatch and therefore flow patterns on the system, and generation and transmission outages can be done by specifying probabilities and correlations for key variables, importance sampling, and undertaking Monte Carlo simulations for the selected set of cases. The probability-weighted average of transmission benefits across a range of load uncertainties, fuel price fluctuations, and outage uncertainties tends to exceed the value of transmission under normalized or most likely conditions. This is because the value of transmission projects is disproportionately higher during more challenging market conditions. Thus, not analyzing the proposed projects under challenging but realistic market conditions risks underestimating their values. However, 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) with case studies (*e.g.*, simulating past extreme contingencies, outages, weather patterns) can serve as an important step toward more fully capturing the values of projects. It can also help planners better understand how these near-term uncertainties can affect the expected value of projects in any particular future year.

[10] 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.

Several regional planning organizations have started to employ scenario and sensitivity analyses in their planning processes. For example, the Electric Reliability Council of Texas (ERCOT), the Midwest Independent System Operator (MISO), and the Southwest Power Pool (SPP) employ multiple future scenarios to evaluate transmission expansion options. The scenarios take into account (to various degrees) divergent assumptions about renewable energy additions, load levels, and a few other factors.

To address how uncertainties affect the value of transmission projects, the California Energy Commission has 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. The variables considered in the case provided are different levels of load growth, hydro conditions, natural gas price, and generator market power.[11] Similarly, ERCOT performed simulations for normal, higher-than-normal, and lower-than-normal levels of loads and natural gas prices in its evaluation of a Houston Import Project. The ERCOT 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.[12]

The next section, Section IV, discusses key challenges often encountered when evaluating the costs and benefits of transmission investments in the planning process and for allocating costs.

IV. CONSIDERATIONS IN THE EVALUATION OF TRANSMISSION COSTS AND BENEFITS FOR PLANNING AND COST ALLOCATION

In this section of our report, we first discuss how to compare benefits to costs, particularly given the longevity of the investments and that the amount of benefits may change over time. Second, we discuss how transmission-related benefits should be considered in interregional planning. Third, we address the differences between overall benefits (often referred to "societal" or economy-wide benefits) and electricity-customer impacts of transmission investments. And fourth, we discuss how and when estimates for the distribution of benefits should be used to inform cost allocation.

A. COMPARING BENEFITS AND COSTS

To assess the net value and desirability of economically justified transmission investment requires a comparison of benefits and costs. Such a comparison is generally conducted by calculating a benefit-to-cost ratio. FERC Order 1000 requires that the benefit-cost threshold applied to evaluate the desirability of regional transmission projects must not exceed 1.25. In other words, if a threshold for economic projects is set by planners or regulators, FERC prohibits

[11] Toolsen, 2005.

[12] ERCOT, 2011, p. 10.

criteria that would require benefits to exceed costs by more than 25%.[13] While there is a FERC requirement on the threshold, there is less guidance on which benefits should be considered or how the benefits and costs should be calculated. Accordingly, practices vary considerably across regions. For example, ERCOT currently calculates benefit-cost ratios of economically-justified projects based on the revenue requirements for the first year of a transmission project's operations (*e.g.*, 5 or 10 years from today) and the benefit of the project in that same year, not taking into account any potential benefits in subsequent years. The California Independent System Operator's (CAISO's) previous evaluations of its Path 26 upgrade and Palo Verde-Devers Line No.2 (PVD-2) project compared the "levelized" annual benefits of the transmission projects to its levelized costs, both of which are levelized over the entire (*e.g.*, 50-year) economic life of the projects.[14] Most other planning processes—such as those for the New York Independent System Operator (NYISO), PJM Interconnection (PJM), Independent System Operator of New England (ISO-NE), MISO, SPP, and the process currently used by the CAISO—compare the present values of benefits to the present values of costs, with present values calculated over the first 10, 20, 40 or 50 years of an investment's useful life.[15]

To simplify the benefits estimation, planning efforts generally include analyzing the benefits for only a small number of study years, with estimates for the intermediate and outer years derived by interpolating and extrapolating from the study year results. For example, to estimate production cost savings for the next 20 to 40 years, MISO interpolated the estimated savings between three simulated years, 2021, 2026, and 2031. MISO also extrapolated the benefit trend estimated for its 2026 and 2031 simulations for another 30 years.[16] SPP's planning process for its Priority Projects estimated benefits for 40 years by simulating the systems for 2009, 2014, and 2019 and extrapolating the 2014–19 trend for another 10 years beyond 2019 before holding annual benefits constant in inflation-adjusted terms until the fortieth year.[17] Similarly, the CAISO used simulations to estimated benefits for planning years 5 and 10, but estimated benefits for the ensuing 35 to 45 years by applying a 1% real escalation rate to planning-year 10 benefits to capture the combined impacts of inflation and other factors on likely future benefits.[18]

The annual values of transmission costs are generally based on estimates of annual transmission revenue requirements (TRRs) that include the cost of depreciating the investment, a regulated return on net ratebase, taxes, and estimates of annual O&M costs. To correctly represent total costs relative to total benefits, realistic estimates of all anticipated costs should be included.

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[13] This requirement that benefit-to-cost thresholds should not be higher than 1.25:1 was motivated in part by experience with planning criteria that required thresholds as high as 3:1 that essentially eliminated the feasibility of approving economically-justified transmission projects.

[14] CAISO TEAM Report, 2004 and CAISO PVD2 Report, 2005.

[15] The transmission planning organizations use the following time horizons to calculate benefit: NYISO 10 years; PJM 15 years; MISO 20 and 40 years; ISO-NE 10 years; SPP 40 years; and CAISO 40 years for upgrades to existing facilities and 50 years for new facilities.

[16] MISO, 2011, p. 27.

[17] SPP, 2010a, p. 28.

[18] CAISO PVD2 Report, 2005, pp. 21–22 and CAISO Transmission Plan, 2013, p. 315.

We recommend that estimated benefits be compared—either on a present value or a levelized annual basis—to estimated project costs over a time period (such as 40 or 50 years) that at least approaches the useful life of the physical facilities. This approach is particularly important because many benefits tend to increase over time with both load growth and fuel price inflation and because the regulated revenue requirements are "front-loaded" and tend to decrease over time as the facilities are depreciated.[19] Requiring comparison of only the first year or even the first 10 years of estimated benefits with annual transmission revenue requirements for the same number of years is equivalent to raising the benefit-to-cost threshold that projects must overcome. For instance, if benefits grow with inflation over time, setting a benefit-to-cost threshold of *one* when comparing the first year of benefits (which increase with inflation) with the first year of transmission revenue requirements is mathematically equivalent to setting the benefit-to-cost threshold of approximately *two* when comparing the 40 year present value of the same stream of annual benefits and costs.

To calculate the present value of costs and benefits (or, alternatively, the "levelized" annual value of these benefits and costs) requires the selection of a discount rate. We recommend using the weighted-average cost of capital (WACC) or the allowed rate of return of the transmission owner as the discount rate for this purpose. Others have also evaluated projects using a much lower social discount rate. For example, MISO uses in its evaluation of MVPs both a 20- and 40-year NPV with two discount rates: 3% (to reflect a "societal" rate) and 8.2% (to reflect the allowed rates of return of transmission owners).[20]

Observing and analyzing the level of benefits compared to costs (in terms of the revenue requirements of the projects) on an annual basis will also be useful because that information will allow planners to optimize the timing of transmission investments. For example, the option to delay certain proposed projects until their expected annual benefits exceed estimated annual costs can increase the net present value of the investment. Similarly, it may also be possible to accelerate certain projects if earlier in-service dates would allow the project to capture additional benefits, such as avoiding transmission upgrades needed to meet reliability standards or allowing the deferral of generation investments. Such optimization will require the careful and systematic analysis of available options and alternatives, including non-transmission alternatives.

B. OVERALL ECONOMIC BENEFITS DISTINGUISHED FROM BENEFITS TO ELECTRICITY CUSTOMERS

Society as a whole benefits from transmission investments. While it is most relevant to examine the benefits associated with transmission investments from an economy-wide or societal perspective when making public-policy or regulatory decisions, many regulators and utilities

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19 While we recognize that estimating benefits for 40 years is challenging, the approaches used by SPP, MISO, and CAISO should reasonably capture the possible range of future benefits.

20 As transmission projects are often seen as a "public good," some advocate that a social discount rate should be applied to future benefits of transmission lines as it has previously been used for "public projects in sectors such as transport, agriculture, water resources development, and land use." The recommended social discount rates generally are in the 3% to 5% range, although rates have been suggested to be as low as 0.1% for the future costs of global warming. (Budhraja *et al.*, 2008, pp. 14–19.).

tend to focus on how electricity customers (*i.e.*, "ratepayers") might benefit from the proposed transmission facilities.[21] This electricity-customer perspective is most relevant when one evaluates how much those who pay for the transmission projects would benefit from them. For instance, electricity customers are likely to benefit from production cost savings (through reduced electricity bills from cost-of-service regulated utilities), from improved reliability (which increases the value of the received service), from an increase in wholesale power market competition (even if that reduces generator profits), from reduced resource adequacy requirements or a reduction in the capacity cost of new generating resources (which reduces electricity bills), and from the avoidance or deferral of transmission or generation investments that would need to be built in the absence of the proposed transmission investment (which provides an offset to the larger transmission projects' costs).

Increased system reliability, reduced emissions, or regional economic development will benefit society as a whole, which includes electricity customers. But these benefits may not directly reduce electricity customer bills. Because benefits to electricity customers can be either a subset of total economy-wide benefits (*e.g.*, because there are benefits that do not directly accrue to electricity customers) or exceed economy-wide benefits (*e.g.*, because generators may see reduced earnings or other electric customers may see increased rates), the benefit-to-cost balance from an economy-wide perspective may differ from that of electricity customers. For example, a transmission project may offer only limited system-wide production cost savings but offer significant electricity customer benefits by reducing market prices. Alternatively, a significant portion of system-wide production cost savings may be captured by merchant generators through increased earnings, resulting in electricity customer benefits that are less than the identified production cost savings.

The existence and extent of the divergence between consumer and societal perspectives can depend on three factors: market structure, geographic scope of the study, and consideration of economy-wide benefits not reflected in electricity rates.

Market Structure. Generally speaking, the cost of power delivered to electricity customers can decrease if a transmission line allows for the dispatch of lower-cost generation or the purchase of wholesale power at lower prices. However, the extent to which electricity customers will benefit also depends on the structure of retail power markets. Under the traditional cost-of-service regulated model, electricity customers will directly benefit from: (1) reductions in the production costs of cost-of-service regulated generating plants; (2) lower-cost off-system purchases by the regulated utility; and (3) the achievement of higher off-system-sales prices for power from such regulated generating plants to offset the revenue requirement to be recovered from franchised ratepayers. In contrast, if electricity customers are served mostly through wholesale power purchases at market prices, such as in retail-access states, customers will benefit if a transmission project reduces the wholesale price of purchased power, irrespective of actual production cost

[21] Note that the academic literature generally discusses this subject matter by distinguishing between "societal benefits" (or total "welfare gains"), "consumer benefits" (or changes in "consumer surplus"), and "supplier benefits" (or changes in "supplier surplus"). We discuss these concepts in terms of overall economic (or economy-wide) benefits and electricity-customer benefits. See also Baldick, *et al.*, 2007, pp. 17-21.

savings. Reducing the cost of power to electricity customers is not automatically an economy-wide benefit because, when customers pay less for their power, a portion of those savings may be a transfer of economic gains from generators to those customers. This transfer of gains can yield a result in which the economy-wide benefit is less than the electricity-customer benefit. In other words, when customers pay less, generators may earn less, leaving the economy-wide benefit to be less than the direct benefits electricity customers may enjoy.

Geographic Scope of the Study. Transmission investments can affect a wide range of market participants in regions adjacent to where a project is located. When estimating the overall benefits of this type of transmission project, the impacts on consumers and generators in neighboring regions need to be considered as well. In some situations, the overall benefits of a transmission project may exceed the benefits realized in a particular region because additional benefits may accrue to electricity customers and generators in neighboring regions. It is also possible that the benefits to electricity customers in the region where the project is located exceed the overall economy-wide benefit if the transmission project increases electricity customers' costs in the neighboring regions. For example, a new transmission line that allows for local electricity customers to purchase power at lower prices from a neighboring market may cause wholesale prices to increase in that neighboring market, possibly benefitting generators but increasing electricity customers' costs in the neighboring market.[22]

Economy-wide Benefits Not Reflected in Electricity Rates. The benefits of transmission investments may also extend beyond the direct benefits to electricity market participants. This is the case when some of the economy-wide benefits of transmission investments accrue to society more broadly—external to the scope of electricity costs, generator profits, or system reliability. For example, a reduction of greenhouse gas emissions due to a shift in generation resources towards more renewable energy resources resulting from a transmission upgrade can provide a societal benefit. Without a market that places an explicit monetary cost on the emissions, the societal benefit associated with reduced emissions would not materialize in reduced costs to electricity customers. Only if a price was placed on greenhouse gas emissions (as is the case for SO_2 and NO_x emissions) will the benefits associated with emissions reduction accrue to electricity customers through reduced costs. However, even though these emissions are not priced today, it is important to value on a probabilistic basis—including from a risk mitigation perspective—the likelihood that they will be priced in the future. Economy-wide benefits can also include the employment and economic development benefits of expanding the existing transmission infrastructure,[23] including benefits from stimulating the local economy, producing additional tax revenues, supporting industrial growth, or allowing the development of renewable power projects that, in turn, provide many similar economic stimulus benefits. However, the jobs and economic stimulus associated with constructing and maintaining the transmission system would only provide incremental benefits to a region if alternative investment activities

22 For a simplified illustration and discussion of how economy-wide benefits compare to electricity customer and generator benefits in two regions interconnected by a transmission upgrade, see also Hogan, 2011.

23 However, it is important to ensure that the partial macroeconomic impacts associated with changes in spending in the power sector is not directly added to the spending effects already accounted for in the other benefit categories.

could not offer similar benefits.[24] Thus, while it is useful to estimate the potential employment and economic stimulus benefits associated with certain transmission investments, they cannot simply be added to other project benefits for the purpose of benefit-cost analyses.

Overall, we recommend using a societal or economy-wide perspective (with a sufficiently wide geographic scope) when evaluating the benefits and costs of transmission projects. However, due to regulatory requirements or for cost allocation purposes, it may also be necessary to conduct the analysis from an electricity customer perspective. In either case, it is important to deliberately specify how market structure and the geographic scope of the study will affect the investments' benefits and costs. Evaluating impacts from an electricity customer perspective should also consider benefits (such as increased reliability) that are not reflected in electricity rates.

C. Distribution of Benefits to Inform Project Cost Allocation

When evaluating the benefits associated with a new transmission project, one of the initial questions is "Who will be the beneficiaries?" FERC ratemaking has always focused on cost causation and cost responsibility. FERC has articulated the "beneficiary-pays" principle, and FERC Order 1000 specifically requires that cost allocation be "at least roughly commensurate with estimated benefits" and those that receive no benefit must not be allocated costs involuntarily. However, such cost allocation should not be based only on a narrowly defined set of benefits for which the specific value to individual market participants can be determined precisely. This is consistent with findings by Judge Posner, writing for the U.S. Court of Appeals in an unanimous decision upholding challenges to MISO's MVP tariff related to the relevance of a range of benefits and the spread of beneficiaries:

> No one can know how fast wind power will grow. But the best guess is that it will grow fast and confer substantial benefits on the region served by MISO.… There is no reason to think these benefits will be denied to particular subregions of MISO. Other benefits of MVPs, such as increasing the reliability of the grid, also can't be calculated in advance, especially on a subregional basis, yet are real and will benefit utilities and consumers in all of MISO's subregions.[25]

The estimation of how benefits are distributed and the associated identification of beneficiaries often will influence how transmission costs are allocated. While sponsors of transmission projects will generally want to demonstrate high levels of benefits for their projects for both planning and cost allocation purposes, many stakeholders may be overly skeptical about some of these benefits because of their implications on cost allocation. The possibility of being allocated

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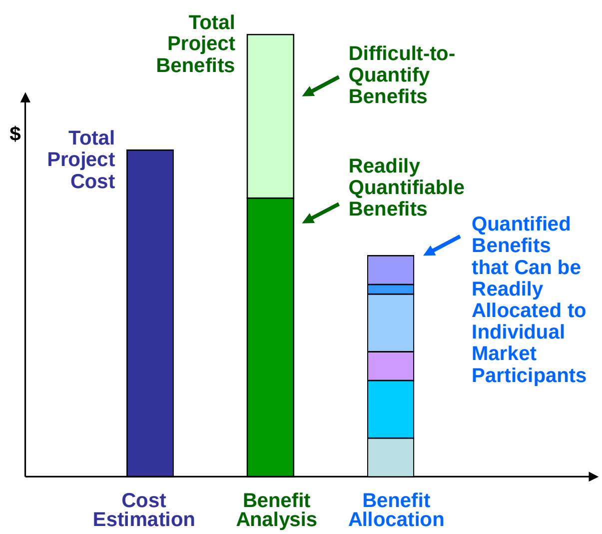
24 For example, if workers are fully employed in an economy, building more transmission may not offer additional employment benefits to the region, and job creation alone does not necessarily or automatically ensure that certain investments provide a productive use of the associated investment capital. Further, the employment-related benefits from constructing transmission facilities would need to be weighed against the economic implications of potential increases in electricity rates.

25 *Illinois Commerce Commission v. FERC*, No. 11-3421 *et al.*, 2013 WL 2451766 (7th Cir. June 7, 2013) , p. 12.

an unwarranted share of the projects' costs can provide certain market participants with strong incentives to question the benefits they are estimated to receive, to insist on evaluating only a limited set of benefits of a proposed project (both within a system footprint or region and between regions), and to limit planning horizons to the foreseeable future instead of over the life of the investment. Thus, narrowly interpreting and implementing the "beneficiaries-pay" framework can create strong incentives to dismiss categories of legitimate benefits on grounds that they are too uncertain or not measurable with sufficient precision, or understate them in an attempt to reduce beneficiaries' share of costs. An analysis that ignores or rejects benefits that are not measured with precision implicitly assumes that the value of such benefits is zero. This will systematically understate the overall value of transmission investments.[26] It will also, in turn, lead to the unintended consequence of rejecting valuable transmission projects that offer a broad set of long-term benefits with total values that exceed project costs.

Rejecting projects based on the misperception that the value is less than the projects' costs is illustrated in Figure 4, showing that the sum of the benefits readily allocated to individual market participants can be significantly below a project's overall, economy-wide benefits.

Figure 4



To avoid such pitfalls, we recommend that benefits be identified, analyzed, and applied in four steps as previously discussed: (1) allow projects to be proposed and benefits identified; (2) estimate the identified benefits from an economy-wide perspective; (3) compare the benefits to the costs and determine if a project provides net benefits overall; and (4) determine cost allocations of beneficial projects roughly based on the benefits received by the identified beneficiaries. We recommend that planning efforts first estimate a project's overall economic

[26] Assuming that the value of a "soft" benefit is zero is often the worst possible estimate. Even if an estimate of a material benefit or cost is imprecise due to the nature or timing of the benefit, using that estimate will often yield a more accurate assessment than using zero or assuming zero. For example, if one does not exactly know what a hotel may be charging for a night when planning a visit to New York City, it would not make sense to assume the hotel will be free.

benefits without considering how those benefits might be distributed. That way, planning efforts are focused on developing the most socially-beneficial transmission projects as opposed to selecting only those projects whose beneficiaries are easiest to identify. Planning and stakeholder processes that focus too early on cost allocation or limit the scope of benefits to traditional benefit metrics or those estimated by pre-existing analytical tools will fail to identify potentially beneficial projects to the detriment of overall market efficiency and economy-wide benefits.

Once portfolios of projects that are beneficial from an overall, economy-wide perspective are identified, several approaches can be used to allocate costs in a manner that is roughly commensurate with the estimated distribution of benefits. While using the ratio of the value of benefits received by the different parties would seem to be preferable—particularly if estimates of the distribution of the monetary value are available for most if not all of the projects' overall benefits—cost allocations based on non-monetary metrics can be more practical as long as it can be shown that these metrics result in cost allocations that are roughly commensurate with the allocation of overall economic benefits. For example, costs could be allocated to beneficiaries based on each entity's relative contribution to the need for a project—as long as such relative contributions to need are roughly proportionate to the benefits received by each entity. Costs could also be allocated based on each entity's projected or allocated usage share of the projects' added transmission capability (*e.g.*, allocated shares of increased flow-gate capacity). Other examples of cost allocations include applying load-ratio shares or shares of power flows that drive reliability-based upgrades, apportioning costs based on the power purchases of various load-serving entities when allocating the costs of renewables-integration driven projects, or using the project's physical location in each entity's footprint (*e.g.*, shares of circuit miles or direct assignment of project segments) if there is agreement that such usage or footprint-based shares are roughly proportionate to the benefits received by each party.[27]

Understanding how benefits from portfolios of projects within and across regions will be distributed across many stakeholders is also useful in determining how the costs of transmission projects should be allocated intra- and interregionally.[28] However, before determining the actual distribution of benefits, it is advisable to aggregate transmission projects across the region because the overall benefits of a portfolio of transmission projects will tend to be more evenly distributed. For example, transmission lines that allow for increased imports of lower-cost generation from a neighboring region can provide benefits to both regions: the importing region through a lower cost of delivered power and the exporting region through increased revenues to the exporting suppliers. The increased export revenue can also be a benefit to electricity customers in the exporting region if these additional revenues are used to offset the cost of regulated generation assets or if wheeling out the revenues paid by exporting merchant generators can be used to offset the exporting region's transmission revenue requirements. The same project may also provide reliability benefits to customers in both regions. While these benefits can be distributed quite unevenly for individual projects, as a larger portfolio of projects,

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[27] For a discussion of these cost allocation options in the context of interregional projects, see Pfeifenberger and Hou, 2012b, pp. 58-61.

[28] For a discussion of interregional cost allocations, see Section IV.D below. See also Pfeifenberger and Hou, 2012.

the benefit distribution is more likely to be evened out. Having evenly distributed benefits will tend to diffuse contentiousness of cost allocation and facilitate broader stakeholder support of proposed transmission plans.

D. CONSIDERING BENEFITS FOR INTERREGIONAL PLANNING

Transmission planning and benefit estimation is particularly challenging for interregional transmission projects. The current lack of clarity on joint planning and how benefits should be considered for interregional projects has created what some have called a "demilitarized zone" or gap of transmission investments near or across market seams. Because there is not a single transmission planning entity that considers all benefits that accrue to multiple regions, beneficial projects often cannot be identified through current planning processes. This gap in interregional planning was recognized by FERC when it issued Order 1000, which explicitly notes 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."[29] In an attempt to avoid such an outcome, the Order requires the development of interregional planning processes that identify the transmission needs across regions and a method to allocate costs associated with the interregional solutions to meet those needs.

Interregional transmission planning is especially challenging given the number of barriers that can prevent the identification of interregional projects.[30] In part because individual interregional projects may appear at first to offer a very different mix of benefits (*e.g.*, reliability, market efficiency, and public policy benefits) to each of the neighboring regions and their transmission owners, a failure by neighboring regions to recognize the full range of benefits provided by such projects is perhaps the most significant barrier to effective interregional planning. This barrier can be labeled the "least common denominator trap" as it is created by the natural tendency of neighboring transmission planning entities to evaluate only the subset of benefits that are considered in both of the neighboring regions' planning processes. In fact, we have observed regions conducting interregional benefit calculations that consider only those benefits metrics that are utilized in *both* regions' benefit estimation methodologies. For example, if each of two neighboring planning entities typically considers six different types of transmission benefits, but only three of them are considered by both entities, the respective regions reviewing an interregional project might agree to use only the three benefits that are common to both regions. This practice will generally reduce the types of benefits considered in interregional planning compared to the types of benefits that each of the planning entities will consider in their respective regional planning efforts.

This "least common denominator" approach will disadvantage interregional projects because relying on a smaller subset of benefits will tend to understate the value of the projects. To avoid such outcomes, we recommend that each of the neighboring regions, at a minimum, evaluate its

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29 FERC Order 1000, P 350.

30 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, 2012b, and Pfeifenberger, Chang, and Hou, 2012.

share of an interregional project's benefits by including all types of benefits considered in its own internal transmission planning efforts. Using this approach, the total benefits of the interregional project will be at least equal to the sum of the benefits that each entity determines for its own footprint, considering the full set of the benefits that would be considered for each entity's own regional projects. In this way, benefits and metrics can comprehensively cover all reliability, operations, public policy, and economic benefits considered in both 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 also make an effort to consider some or all of 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. Moreover, interregional planning processes should recognize that projects might offer unique benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues or benefits from increased reserve sharing capability. Further, interregional projects could at times avoid or delay the cost of other upgrades, such as projects already included in each region's existing plans, or upgrades that might be needed in the future to meet local or regional needs, or to satisfy generation interconnection or transmission service requests. These considerations may affect the net value of some proposed projects and should be examined carefully.

V. CURRENT SCOPE OF REGIONAL TRANSMISSION BENEFIT-COST ANALYSES

Transmission planning has developed over the past decade and continues to evolve with the issuance of FERC Order No. 1000 and the tariff filings that implement it. While most RTOs initially added planning processes that allowed for the evaluation of "economic" or "market efficiency" projects, these processes tended to be focused on transmission projects that could be justified via production cost savings that resulted from the congestion-relief provided by the projects. In most recent years, several RTOs have continued to expand the scope of transmission benefits considered in their planning processes to include, for example, metrics related to public-policy requirements and resource adequacy benefits. At the same time, transmission planning in non-RTO regions has also evolved beyond addressing expected reliability violations. For example, regional planning in most non-RTO regions now considers the benefits of avoiding local reliability projects, realized when larger regional transmission projects provide more cost-effective solutions than the local reliability projects proposed by individual transmission owners.

This section summarizes the range of the economic benefits of transmission investments that are currently considered in the transmission planning efforts of various regions and provides examples of the extent to which federal and state regulatory commissions have recognized these benefits in evaluating project proposals.

A. TRANSMISSION BENEFITS CONSIDERED BY RTOS

Over the past decade, several RTOs have significantly expanded the scope of the transmission benefits considered in their planning efforts to include a range of economic and public-policy benefits. Initial steps were taken by CAISO in 2004 to support the planning of multi-utility, multi-purpose, and renewable integration projects. RTOs in regions with significant renewable generation potential, such as SPP and MISO, have similarly expanded the scope of the transmission benefits considered in their planning processes—particularly in efforts to better coordinate transmission planning for the integration of renewable resources.

1. Focus on Reliability Needs and Production Cost Savings

Currently, while the exact methodologies differ, four RTOs (NYISO, ERCOT, ISO-NE, and PJM[31]) are primarily planning for reliability needs and are using estimated production cost savings to screen for new "economic" or "market efficiency" transmission projects. As an example, along with its standard reliability analyses, NYISO performs an economic evaluation process for transmission projects called the Congestion Assessment and Resource Integration Study (CARIS). In that process, NYISO estimates the state-wide production cost savings by simulating its system with and without the proposed transmission project. The resulting production cost savings estimate is compared to project costs in the NYISO's benefit-cost ratio analysis.[32] Other benefits can also be estimated through the CARIS process—such as emissions costs, load and generator payments, installed capacity costs, and Transmission Congestion Contract value—for the purpose of later developing cost allocations, but these additional benefits are not included in the benefit-cost ratio used to determine whether to proceed with the project.[33]

In PJM, the economic evaluation process for transmission projects through the Regional Transmission Expansion Plan (RTEP) focuses on determining whether reliability projects identified through traditional reliability studies can be enhanced to provide additional "market efficiency" benefits.[34] PJM estimates production cost savings and reductions in the cost of energy to load-serving entities to determine the economic benefits of transmission projects.[35] PJM applies a Benefit-to-Cost Ratio Threshold of 1.25-to-1 to determine whether to proceed with certain projects by comparing the present value of estimated benefits to the present value of the projects' revenue requirements over a 15-year period. At the time of authoring this report, other economic benefits are not considered in this evaluation process.

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31 NYISO, ERCOT, ISO-NE, and PJM.

32 Similar to the traditional approach used by other planning entities, NYISO calculates production cost savings only as the change in simulated variable generation cost, including fuel costs, variable operating and maintenance (O&M) costs, and emissions costs. The limitations of this traditional approach are discussed in Section VI below.

33 NYISO, 2012.

34 The goals of the RTEP market efficiency analysis are to: (1) determine which reliability upgrades, if any, have an economic benefit if accelerated; (2) identify new transmission upgrades that may result in economic benefits; and (3) identify economic benefits associated with modification to the reliability-based enhancements that are already included in RTEP but, when modified, would also relieve one or more economic constraints.

35 PJM 2011 RTEP. PJM's estimates economic benefit as the weighted average of the estimated change in region-wide production cost (70% weight) and the change in load energy payment (30% weight). The change in load energy payment is calculated as the change in total load payments based on estimated locational marginal price minus the change in transmission right credits (PJM 2011 RTEP).

Recognizing the limits of its economic project planning process, PJM has started to collaborate with states within its region to expand its RTEP process to include public-policy-driven transmission projects and to implement a "multi-driver" planning process. The development of this multi-driver process builds on PJM's methodology of expanding reliability projects and determining whether the incremental cost of certain project expansions are justified by the incremental benefits. In the case of public-policy-driven projects, the transmission investments would have to be proposed and paid for by PJM member states[36] as "Supplemental Projects" to RTEP.[37]

ERCOT, starting with transmission needs identified in its reliability analysis, identifies potential "economic" alternatives to the reliability projects based on the sum of estimated production cost savings and the deferred or avoided cost of the displaced reliability projects. To determine whether to proceed with an economic transmission project, ERCOT estimates and compares the production cost savings for a single year (***e.g.***, 5 years out in its Five-Year Plan and 10 years out in its Long-Term System (LTS) Assessment) to the first year's revenue requirements for the project. Similarly recognizing the limitations of its current approach, ERCOT has initiated an effort to increase the scope of its planning processes.[38]

In ISO-NE, stakeholders may submit a request for ISO-NE to perform an economic study to estimate the production costs savings from proposed market-efficiency transmission projects. ISO-NE determines in its evaluation process whether a proposed transmission project will "result in: (i) a net reduction of total production costs for system load, (ii) reduced congestion, or (iii) the integration of new resources and/or loads."[39] The 2012 ISO-NE Regional System Plan (RSP) states that the ISO is currently conducting studies on the economic benefits of transmission projects based on metrics including "production costs, LSE energy expenses, congestion, environmental emissions, average LMPs, fuel consumption and energy production by fuel type, revenues from the energy market, and the capital investment supported by simulated energy revenues."[40]

In both ERCOT and ISO-NE, in addition to analyzing transmission projects driven by market efficiency, the RTOs are analyzing the transmission projects proposed to support the increased use of renewable generation, particularly as those projects help deliver remotely located resources to load centers. With the goal of building over 18,000 MW of wind generation capacity, ERCOT and the Public Utility Commission of Texas developed transmission plans for accessing wind generation from Competitive Renewable Energy Zones (CREZ). While the additional benefits of the CREZ projects are recognized by the Texas regulators, the projects have been developed primarily to meet public-policy goals objectives. ISO-NE conducts a similar review of the transmission needs to meet the RPS goals in New England. It is doing so

36 The guidelines for proposing public-policy projects are provided in the State Agreement Approach outlined in a letter from the Organization of PJM States, Inc. (OPSI) on June 12, 2012 (OPSI, 2012).

37 PJM RPPTF 2012

38 For a summary of this effort, see Pfeifenberger and Chang, 2013.

39 ISO-NE, 2012, p. 44. See also FERC, 2008, 123 FERC ¶ 61,161.

40 ISO-NE, 2013, note 41, p. 32.

through a collaborative process with the New England State Committee on Electricity (NESCOE), which is made up of policy representatives from each of the New England states. If the results of the study are positive, the identified public-policy-driven transmission projects can be sponsored and paid for by the supporting states.[41]

2. Evolving Practices in Considering a Broader Range of Transmission Benefits

The scope of the transmission-related benefits considered by CAISO, SPP, and MISO is significantly broader than that of NYISO, ERCOT, ISO-NE, and PJM. For instance, recognizing that additional transmission would have significantly mitigated the costs incurred during the California power crisis, California modified its transmission review process to consider a broad range of transmission-related benefits. Accordingly, the CAISO created its transmission economic assessment methodology (TEAM) in 2004 to "establish a standard methodology for assessing the economic benefit of major transmission upgrades that can be used by California regulatory and operating agencies and market participants."[42] The TEAM process, at that time, significantly expanded the scope of CAISO transmission planning to include benefits from the increased competition, risk mitigation capability of transmission infrastructure, and the ability to import lower-cost energy and capacity from other regions.[43]

The TEAM approach 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.[44]

The California Public Utilities Commission (CPUC) adopted the broad scope of transmission benefits considered through the TEAM approach. Specifically applying the approach, the CPUC approved the Palo Verde-Devers No. 2 (PVD2) transmission project, recognizing transmission benefits including:

- Production cost savings and reduced energy prices from both a societal (*i.e.*, economy-wide) and customer perspective;
- Mitigation of market power;
- Insurance value for high-impact, low-probability events;

41 ISO-NE, 2012.

42 CAISO TEAM Report, 2004.

43 CAISO PVD2 Report, 2005.

44 CAISO TEAM Report, 2004, p. ES-10.

- Capacity benefits due to reduced generation investment costs;
- Operational benefits (such as reduced reliability-must-run costs and providing the system operator with more options for responding to transmission and generation outages);
- Reduced transmission losses;
- Facilitation of the retirement of aging power plants;
- Encouraging fuel diversity;
- Improved reserve sharing; and
- Increased voltage support.

In the CPUC's decision for the PVD2 project, the regulator drew additional attention to some of the benefits for which specific values were not measured. The CPUC noted: "discussion of these potential additional benefits…is useful in extending our attention beyond the limits of the quantitative analysis. We consider these factors in our consideration of [the project's] economic value, even though their potential benefits have not been measured."[45] The importance of these and other transmission-related benefits of transmission investments have also been discussed in a report sponsored by the California Energy Commission.[46]

The Integrated Transmission Planning (ITP) efforts by SPP have similarly moved toward examining a range of transmission-related benefits in its "Priority Projects" evaluations, such as reduced transmission losses, wind revenue impacts, and reliability benefits. The full list of benefits considered is shown in Table 2 below. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group also agreed that a number of transmission benefits that require further analysis include:

- Enabling future markets;
- Storm hardening;
- Improving operating practices/maintenance schedules;
- Lowering reliability margins;
- Improving dynamic performance and grid stability during extreme events; and
- Societal economic benefits.[47]

To support cost allocation efforts, SPP's Metrics Task Force has further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or the loss of load probabilities, the increased wheeling through and out of revenues (which can offset a portion of transmission costs that need to be recovered from SPP's internal loads), and the value of meeting public-policy goals.[48] SPP's Metrics Task Force also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

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45 CPUC *Opinion*, 2007, p. 50.

46 Budhraja *et al.*, 2008.

47 *Id.*, p. 37.

48 SPP, 2012.

Similarly, MISO estimates the value of a broad set of transmission benefits in the scope of its transmission planning efforts. In its Multi-Value Project (MVP) transmission planning process and associated cost-allocation methodology, MISO estimates a wide range of benefits for portfolios of projects that meet the MVP criteria.[49] In addition, MISO also stressed that the MVP portfolio provides a number of difficult-to-estimate benefits, such as enhanced generation flexibility, increased system robustness, and decreased natural gas price risk.[50] MISO is also in the process of further expanding the scope of its economic valuation process. For example, in the currently-ongoing Manitoba Hydro Wind Synergy Study,[51] MISO has estimated benefits related to production cost savings, load cost savings, ancillary service cost savings, wind generation changes, and thermal plant cycling reduction. In addition, MISO noted (but did not estimate) capacity benefits, potential operating reserve benefits (new reserve resources), and the storage and energy benefits of the most flexible new hydro generation. These benefits are evaluated further through sensitivity and risk assessment.

FERC has also recognized the importance of the broad range of benefits provided by transmission investments. For example, FERC specifically noted in its approval of SPP's Highway-Byway transmission tariff that:

> [R]elying 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.[52]

Several states have also recognized that transmission projects can provide a broad range of benefits. The Wisconsin Public Service Commission approved in June 2008 its first "economic" transmission line, the Paddock-Rockdale project. That project was approved based on both estimated and qualitatively-discussed economic benefits (for seven alternative future scenarios) that included: (1) adjusted production cost savings; (2) energy and capacity cost savings from reduced transmission losses; (3) reduced power purchase costs due to increased competition; (4) reliability and system failure insurance benefits; (5) long-term resource cost advantages; (6) lower reserve margin requirements; and (7) benefits from the increased availability of financial transmission rights (FTRs).[53]

Table 2 below summarizes the transmission-related benefits discussed above and compares the metrics used in the various RTOs planning processes.[54] Additional transmission-related benefits

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[49] MISO, 2011, pp. 25-44.

[50] *Id.*, pp. 53-63.

[51] MISO, 2013.

[52] FERC, 2010, 131 FERC ¶ 61,252.

[53] ATC (2007).

[54] For a discussion of the evolving scope of RTO transmission-planning efforts see also Pfeifenberger Direct Testimony, 2012a; and Pfeifenberger (2012).

may be considered within individual utilities' integrated resource planning (IRP) processes and will depend on state regulatory requirements.

Table 2
Transmission Benefits Considered in RTO Planning Processes

RTO Planning Process	Estimated Benefits	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	• Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits	• Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	• Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction	• Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP's Metrics Task Force	• Reduced energy losses, • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or loss of load probability • Increased wheeling through and out revenues • Value of meeting public policy goals	• Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity
MISO MVP Analysis	• Production cost savings • Reduced operating reserves • Reduced planning reserves • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs	• Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO_2 emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	• Reliability benefits • Production cost savings	• Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	• Reliability benefits • Production cost savings	• Public policy benefits
ERCOT LTS	• Reliability benefits • Production cost savings • Avoided transmission project costs	• Public policy benefits
ISO-NE RSP	• Reliability benefits • Net reduction in total production costs	• Public policy benefits

B. TRANSMISSION BENEFITS CONSIDERED IN NON-RTO REGIONS

In the non-RTO transmission planning processes, the predominant method for analyzing transmission benefits is based on identifying the regional transmission projects that provide a lower-cost solution to those projects identified through the individual utilities' local planning processes. In addition, individual vertically-integrated utilities may consider a range of generation and transmission alternatives when planning for system reliability, economics, and public policy goals under their states' Integrated Resource Planning (IRP) requirements. In the context of IRPs, a wide range of transmission-related benefits also can be analyzed to evaluate the merits of specific projects or groups of projects.

In Florida and the Southeast U.S.—through the Southeastern Regional Transmission Planning Process (SERTP) and the North Carolina Transmission Planning Collaborative (NCTPC)—state-level IRP requirements are the primary process for creating the list of local projects to be considered at the regional level. Under these processes, the only economic benefit considered for regional projects is the avoided cost of local projects. Production cost estimations are not conducted to evaluate the merits of the regional projects.

At the regional level, the Florida regional planning group refers to its bottom-up process as a "roll-up" of the individual utility transmission plans, followed by a top-down analysis of whether more "Cost Effective and/or Efficient Regional Transmission Solutions" (CEERTS) projects can be identified to avoid or defer the costs of the local projects. In SERTP, only those transmission lines rated 300 kV and above that traverse over 100 miles and cross more than two balancing areas are considered regional in nature. SERTP views its process as an "*ex ante* method for determining costs and benefits" that avoids dependencies on highly uncertain energy prices and other forward market assumptions used in production cost and similar market simulations.[55] In North Carolina, the NCTPC has considered adding additional economic benefits to their transmission planning process but, after negative feedback from participants, decided to exclude the use of any estimated production cost benefits.[56]

In the Western Interconnect, the Western Electricity Coordinating Council (WECC) performs a system-wide study of transmission expansion based on input from several transmission planning subgroups. The sub-groups include one RTO (CAISO) and three non-RTO regions (ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect). While WECC notes the difficulty of performing production cost simulations in its region due to uncertain long-term contract and fuel prices and the differences in scheduling rules within its footprint,[57] production costs simulations are used to calculate the energy costs savings of transmission projects in WECC's long-term transmission planning studies. The savings associated with reductions in the capital costs of generation and transmission additions are estimated separately.

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[55] SoCos, 2013, pp. 17–20.

[56] Duke, 2012, pp. 32–33.

[57] WECC, 2011, pp. 19–21.

The non-RTO regions in WECC also use the avoided costs of local transmission projects as a benefit of regional transmission lines. However, WestConnect is developing a process to evaluate additional transmission benefits through the efforts of its Cost Allocation Strike Team. Recommendations have been made that benefits be calculated based on the type of transmission project being considered, and that the evaluation of economic projects includes an assessment of the savings associated with reductions of production costs and reserve sharing requirements.[58] NTTG also evaluates whether new transmission projects will provide benefits associated with reducing energy losses and the costs of providing reserves.[59] ColumbiaGrid is currently relying only on the avoided cost metric.[60]

Table 3 summarizes the economic benefits of regional transmission projects considered in the regional planning processes of non-RTO regions. Even if some of the benefits are not considered explicitly within the transmission planning process, some of them already may be considered within state-regulated integrated resource planning efforts.

Table 3
Transmission Benefits Considered in Non-RTO Regional Planning Processes

Non-RTO Planning Organization	Benefits Considered in Regional Planning
WECC	• Avoided local transmission project costs • Production cost savings • Reduced generation capital costs
ColumbiaGrid	• Avoided local transmission project costs
NTTG	• Avoided local transmission project costs • Reduced energy losses • Reduced reserve costs
WestConnect	• Avoided local transmission project costs • Production cost savings • Reserve sharing benefits
SERTP	• Avoided local transmission project costs
NCTPC	• Avoided local transmission project costs
Florida Sponsors	• Avoided local transmission project costs

58 WestConnect, 2012. Since WestConnect is not an RTO, note that it is important that the *hurdle rate* is calculated to ensure that the transactions modeled are likely to actually occur.

59 NTTG, 2012, p 32.

60 ColumbiaGrid, 2012, Appendix A, Section 10.3.2.2, p. 18.

As explained previously, the limited scope of the transmission benefits that are considered in the regional planning processes of many non-RTO regions does not mean that other benefits do not exist in these regions. For instance, even if locational prices are not used in the market, the potential benefits of projects that reduce congestion and related production costs can still be estimated. Thus, a similar approach to estimating transmission benefits would appropriately apply in the Southeast as it would elsewhere.

As noted, some utilities in non-RTO regions are at times considering in their individual or joint planning efforts a broader range of transmission-related benefits than those formally specified in their FERC-approved regional planning processes. For example, through facilitation by a state commissioner, Entergy Gulf States Louisiana, Cleco Power, and Lafayette Utilities System jointly considered the various economic benefits associated with the approximately $200 million Acadiana Load Pocket (ALP) project. The ALP project consists of a series of new transmission lines and substations to address a variety of reliability and economic considerations in south-central Louisiana. The ALP region had been experiencing several problems, including an increase in the use of transmission loading relief (TLR) procedures to curtail non-firm transmission service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to the accommodation of additional transmission service. A joint planning study documented a range of benefits from the transmission investment that would accrue to the three utilities individually and jointly. The study found that approximately $70 million of the project was justified by the reduced use of TLR procedures (thereby allowing for increased economic import) and improved load serving capability in the region. The rest, approximately $130 million of the project, was found to be justified by allowing for the removal of must-run generation, production cost (*i.e.*, fuel cost) savings, and additional generation dispatch flexibility.[61]

Similarly, the Western Area Power Administration (WAPA)—which owns and operates transmission systems in both western and eastern interconnections—stated in its 2011 Strategic Plan that it will use a business case analysis to evaluate the benefits, costs, and risks of new transmission projects. It stated, for example, that transmission planning aims to: (1) meet or exceed national and regional reliability standards; (2) support renewable energy development and deliver renewable power to markets; (3) reduce vulnerability to supply disruption; (4) increase flexibility to meet customers' needs for electricity; and (5) provide access to surplus generating capacity to protect and maximize the value of WAPA's generating resources.[62]

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[61] Pfeifenberger and Hou (2012b), pp. 35-41.

[62] WAPA, 2011.

VI. CURRENT EXPERIENCE IN THE EVALUATION OF TRANSMISSION BENEFITS

This section of the report presents a technical discussion of the range of the economic benefits of transmission investments identified in Table 1 above and summarizes the available experience on how they are estimated. It also documents current industry practices in the analysis of these benefits, describes in detail how certain benefits not traditionally quantified can be measured, and explains why they are important in assessing the benefit-cost impact of proposed transmission projects.[63] Consistent with Table 1, the transmission benefits discussed in more detail include:

1. Production cost savings;
2. Reliability and resource adequacy benefits;
3. Generation capacity cost savings;
4. Market benefits, such as improved competition and market liquidity;
5. Environmental benefits;
6. Public policy benefits; employment and economic development benefits; and
7. Other project-specific benefits such as 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.

A. PRODUCTION COST SAVINGS

The most commonly used metric for measuring the economic benefits of transmission investments is the reductions in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

1. Definition and Method of Calculating "Adjusted Production Cost" Savings

Within production cost models, changes in system-wide production costs can be estimated readily. These estimated changes, however, do not necessarily capture how costs change within

63 Some of the discussion in this section is taken from the recent SPP Metrics Task report we helped prepare (SPP, 2012).

individual regions or utility service areas. This is because the cost of serving these regions and areas will not only depend on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. The production costs within individual areas thus need to be "adjusted" for such purchases and sales. This is approximated through a widely-used benefit metric referred to as Adjusted Production Costs (APC).

Adjusted production costs for an individual utility are typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility's market-based power purchases and sales.[64] The traditional method for estimating the changes in the APC associated with a proposed transmission project is to compare the adjusted production costs with and without the transmission project. Analysts typically call the market simulations without the transmission project the "Base Case" and the simulations with the transmission project the "Change Case."

These simulations can also provide estimates of how the proposed transmission projects affect the pattern of transmission congestion, the overall production costs necessary to serve load, the prices that utilities (and ultimately their customers) pay for market-based energy purchases, and the revenues that generators receive for market-based energy sales. Thus, through production cost simulations, one can quantify the direction and magnitude of cost and price changes by comparing the results from the Change Case with those from the Base Case.

For example, SPP estimated that its Priorities Projects will result in $1.3 billion of adjusted production cost savings. This amount of APC savings is equal to approximately 62% of the estimated costs of the transmission projects that enable those savings.[65]

2. Limitations of Production Cost Simulations and Estimated APC Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners are increasingly recognizing that traditional production cost simulations are limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by necessary simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. In most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;

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[64] For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs of the utility's load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility's generation locations (Gen LMP).

[65] SPP, 2010b, p. 26.

- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Weather-normalized peak loads and monthly energy (*i.e.*, no extreme weather conditions);
- Perfect foresight of all real-time market conditions;
- Incomplete plant cycling costs;
- Over-simplified modeling of ancillary service-related costs;
- Incomplete simulation of reliability must-run conditions;
- Unrealistically optimal system utilization in "Day-1" markets

In some cases, we also have observed that market simulations did not consider forced generation outages.[66]

We discuss each of the common limitations listed above in Subsections 3 through 11, and provide examples of how the components of production cost savings that are not captured due to these simplifying assumptions can be or have been estimated.[67] Following that, Subsection 12 discusses how adjusted production cost calculations simplify the estimated charges for congestion and marginal transmission losses, which can result in the under- or over-estimation of transmission-related benefits from an electricity-customer's perspective.

3. Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.[68] Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost

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66 For example, forced outages are not currently considered in the simulations performed for the evaluation of economic projects in ERCOT's long-term transmission planning process.

67 See *also ibid.*, Section 4.

68 For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see *ibid.*, Section 4.2. See also Pfeifenberger Direct Testimony, 2008.

savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.[69] Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.[70] For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional $11 to 29 million in annual savings compared to the older technology.[71]

4. Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the value of transmission upgrades and additions because outages, when they occur, typically cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[72]

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.[73] Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.[74] MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to

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69 ATC, 2007, pp. 4 (project cost) and 63 (losses benefit).

70 Pioneer, 2009, at p. 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

71 Pfeifenberger and Newell Direct Testimony, 2011.

72 For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see SPP, 2010b, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

73 PJM FTR Report 2012, p. 32. See also PJM FTR Presentation, 2011.

74 Patton, 2011.

account for unmodeled events such as unplanned transmission outages and loop flows.[75] As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and west-east price differentials.[76] These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than $10 million a year, with PJM's Load locational pricing payments decreasing by more than $40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.[77]

At the time of writing this report, our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (e.g., peak load) conditions. Higher additional transmission–outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (i.e., not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month

75 See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manuals. Posted at: https://www.midwestiso.org/LIBRARY/BUSINESSPRACTICESMANUALS/Pages/BusinessPracticesManuals.aspx.

76 Pfeifenberger and Newell, 2006.

77 Pfeifenberger and Newell Direct Testimony, 2011.

period.[78] The TSM report also showed that, for the five most constrained flowgates on the Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This also indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

5. Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[79]

78 Potomac Economics (2013).

79 ATC, 2007, pp. 4 (project cost) and 50-53 (insurance benefit).

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San Onofre outage.[80] This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.[81]

Further, the analysis of high-impact, low-probability events also documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only $77 million for 2013—there was a 10% probability that the annual benefit would exceed $190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between $360 and $517 million.[82]

6. Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.[83]

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.[84] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions.

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80 CPUC *Opinion*, 2007, pp. 37–41.

81 See Wald, 2013.

82 CAISO PVD2 Report, 2005, p. 24.

83 Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

84 See SPP, 2012, Section 9.6.

While it is difficult to estimate how often such conditions might occur in the future, they do occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the base case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[85]

7. Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.[86] From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.[87] These benefits will generally be more significant if

85 ERCOT, 2011, p. 10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

86 Pfeifenberger and Newell Direct Testimony, 2011.

87 For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial

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transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[88]

8. Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about $200/MW per start (with a range between $160/MW and $260/MW). The costs associated with equipment damage account for more than 80% of this total.[89]

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transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from $5.77 to $8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between $2.26/MWh and $2.84/MWh, while within-day variability accounts for $2.93/MWh to $5.74/MWh of wind energy injected. See EnerNex, 2013 ($/MWh in US$2024).

88 For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

89 See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from $2008 to $2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP's Metrics Task Force recently suggested that production simulations be developed and tested,[90] this is an area where standard analytical methodology still needs to be developed.

9. Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis, finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of $28 to $87 million, or less than one percent of the cost of the transmission projects evaluated.[91] In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may be significantly larger. However, to quantify these benefits often requires specialized simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements. Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

[90] SPP, 2012, Section 9.4.

[91] MISO, 2011, pp. 29-33.

10. Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such "reliability must run" (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately $50 million to $100 million per year.[92] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

11. Estimating Production Costs in "Day-1" Markets

When analyzing transmission benefits in bilateral, non-RTO markets, it is important to recognize that generation unit commitment and dispatch in such "Day-1" markets is not the same as in an LMP-based RTO market. Thus, if simulated as security-constrained LMP-based regional markets, the simulations would understate the benefit of transmission investments in non-RTO markets by over-optimizing the system operations compared to real-world outcomes. To recognize some of the realities of such "Day-1" markets, planners have traditionally imposed "hurdle rates" on transactions between individual balancing areas. This is important to prevent the simulations from over-optimizing system dispatch relative to actual market outcomes. However, relying solely on hurdle rates to approximate realistic market outcomes may not be sufficient. Thus, derates of transmission limits may also be necessary to capture the fact that congestion management through transmission loading relief (TLR) processes in "Day-1" markets typically results in under-utilization of flow-gate limits. For example, an analysis of RTO-market benefits by the Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5-10% increase in the total transfer capabilities on transmission interfaces.[93] Similarly, a study of congestion management in MISO's "Day-1" market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO subregions during TLR events

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92 Pfeifenberger Direct Testimony, 2012a, pp. 48-49.

93 USDOE, 2003, pp. 7-8 and 41-42.

compared to the flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch.[94]

We recommend that "Day-1" market simulations use both hurdle rates and derates to more realistically approximate actual market conditions (in both base and change case simulations). Hurdle rates as traditionally used will appropriately decrease flows between balancing areas, reduce congestion, and thus reduce the economic value of increased transmission between balancing areas. In contrast, derates will tend to simulate more realistic level of congestion within and across balancing areas, which will tend to increase the estimated production cost savings of transmission upgrades. These potential additional production cost savings will not be captured in traditional market simulations that rely solely on hurdle rates to approximate "Day-1" market conditions.

12. Estimating Overall Economic and Electricity-Customer Savings

System-wide production cost savings from the simulations of transmission investments as discussed in this section represent economy-wide benefits. In a regulatory environment where all generation is cost-of-service regulated with no market-based purchases and off-system sales, these system-wide savings will also reflect customer benefits for the entire simulated footprint—which usually includes all neighboring regions. To measure transmission-related benefits to an individual region, individual utilities, or other load-serving entities (LSEs), analysts typically rely on metrics such as Adjusted Production Costs (APC) and Load LMP costs. As noted above, these metrics can approximate electricity-customer benefits but they differ from the magnitude of the economy-wide benefits. The magnitude of these benefits depends on assumptions about market structure and the extent to which LSEs would be exposed to cost-based generation, market-based purchases and sales, and (within RTO markets) marginal loss charges and unhedged congestion charges.

For example, the APC metric measures the change in variable costs of generation within (or contracted to) an LSE's service area, adjusted for market-based purchases and sales. As a measure of customer impacts, the metric approximates customer costs for a vertically-integrated, cost-of-service regulated utility environment, consistent with simplifying assumptions that: (1) all owned or contracted resources supply power at variable production costs; (2) all imports and other non-cost-based purchases are market-based, priced at the area's internal Load LMP (***i.e.***, no fixed-priced contracts and assuming congestion charges for imports and purchases could not be hedged with allocated FTRs); (3) all off-system sales from an LSE's cost-based resources are priced at the area-internal Generation LMP; (4) no congestion costs charges are incurred in transmitting energy from cost-based generation to load within the LSE's service area (***i.e.***, all transactions from cost-based resources are fully hedged with allocated FTRs); and (5) no marginal loss charges are incurred on transactions from cost-based resources.

The load-weighted LMP metric measures the change in market-based power purchase costs that would be paid by customers in an LSE's service area if all load was served at LMPs at the load's

94 McNamara Affidavit, 2004, p. 14.

location. This metric thus approximates customer impacts in a retail access environment, implicitly reflecting an assumption that all load is served at market prices without any cost-of-service-based generation, long-term contracts, FTR allocations that would hedge congestion charges, or the partial refunds of marginal-loss-related charges.

Because some RTO service areas cover both cost-of-service regulated, vertically-integrated utilities as well as LSEs that supply customers through market-based purchases, both APC and Load LMP metrics may be relevant. In fact, PJM has defined a blended metric based on a 70% APC and 30% Load-LMP weighted average. This hybrid metric roughly represents a market structure under which retail rates reflect roughly 70% cost-based generation that is fully hedged against congestion charges and 30% market-based generation (including imports) that is entirely unhedged through FTR allocations.[95]

While these metrics and the simplifying assumptions used to derive them will be sufficient in many cases, a more accurate calculation of customer impacts for individual utilities or LSEs may be necessary because these traditional metrics do not explicitly take into account a number of energy and congestion-related factors that can be important in estimating the impacts of transmission investments from a customer-cost perspective. In particular, they may need to be modified to more accurately account for: (1) the degree of cost-based versus market-based generation; (2) long-term contracts and their pricing (*e.g.*, variable-cost based, fixed, or market-based); (3) the level of FTR coverage for a service area's internal and contracted generation; (4) the level of FTR coverage for imports into the service area; (5) the extent to which the transmission projects make additional FTRs available to LSEs in the service area; and (6) the difference between marginal loss charges, loss refunds, and the simulation's treatment of energy losses.[96]

B. Reliability and Resource Adequacy Benefits of Transmission Projects

This and the following subsections of our report address transmission-related benefits that are not reflected in production cost savings. As noted earlier, production cost savings only measure the reduction in variable production costs, including fuel, variable O&M costs, and emission costs.[97] This means that production cost savings, even if the simulations capture the additional factors discussed above, will not capture the benefits associated with reliability, capital costs, increased competition, certain environmental benefits and other public policy benefits, or economic development benefits. These benefits provide additional value to electricity customers and to the economy as a whole.

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example,

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95 MISO also previously used this hybrid (70%/30%) metric for production cost savings but has changed to a 100% Adjusted Production Cost Savings metric as they have found it better represents their load characteristics (MISO, 2012).

96 For an example of more detailed estimates of customer impacts, see Pfeifenberger Direct Testimony, 2008.

97 Emissions costs are only considered to the extent that the simulations assume a price for emissions such as SO_2, NO_x, and in some cases CO_2.

additional transmission investment made for market efficiency and public policy goals can avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

1. Benefits from Avoided or Deferred Reliability Projects

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the net cost of planned economic or public-policy projects. These benefits can be estimated by comparing the revenue requirements of reliability-based transmission upgrades without the proposed project (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed project would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (***i.e.***, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.[98] Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be $357 million, or 25% of the costs of the proposed new transmission projects.[99] This method has also been used by MISO, who found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.[100]

2. Benefits of Reduced Loss of Load Probability <u>or</u> Reduced Planning Reserve Margin Requirements

Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for

[98] See SPP, 2012, Section 3.3.

[99] Pfeifenberger Direct Testimony, 2012a, pp. 77-78.

[100] MISO, 2011, pp. 42-44.

connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on higher-cost measures to avoid shedding load (a production cost benefit considered in the previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).[101] The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in $/MWh). Estimates of the average VOLL can exceed $5,000 to $10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.[102]

When a transmission investment reduces the loss of load probabilities, system operators may be able to reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.[103]

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation

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[101] SPP, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

[102] ATC, 2009.

[103] This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

capital investment needs ranging from $1.0 billion to $5.1 billion in present value terms, accounting for 10–30% of total MVP project costs.[104] This benefit was similarly recognized by the SPP Metrics Task Force,[105] as well as by the Public Service Commission of Wisconsin, which noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.[106]

C. Generation Capacity Cost Savings

Transmission investments can also reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three benefits.

1. Capacity Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.[107]

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[104] MISO, 2011, pp. 34-36.

[105] SPP, 2012, Section 5.1.

[106] PSC WI, 2008, p. 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

[107] Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP's evaluation of its Priority Projects showed $71 million in capacity savings from reduced losses, or 3% of total project costs.[108]
- ATC found that its Paddock-Rockdale project provided an estimated $15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.[109]
- MISO also found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of $111 to $396 million, offsetting 1–2% of project costs.[110]
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately $50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.[111]

2. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy's service area showed that the transmission projects provide increased import capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy's resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at $320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.[112] A similar analysis also identified approximately $400 million in resource adequacy benefits from deferred generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

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108 SPP, 2010b, p. 26.

109 ATC, 2007, pp. 4 (project cost) and 63 (capacity savings from reduced losses).

110 MISO, 2011, pp. 25 and 27.

111 Pfeifenberger Direct Testimony, 2012a, pp. 58-59.

112 *Id.*, pp. 69.

3. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case (*e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.[113] The capital cost savings were estimated at $12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.[114] The analysis found that sites in Illinois offered significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin. In that instance, the analysis should have implemented different production cost assumptions in the Base and Change Cases to reflect the access to lower production cost generation with the new line compared to the status quo.

Access to a lower-cost generation option can also significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits" in Subsection F below, the Midwest ISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more

[113] CAISO PVD2 Report, 2005, pp. 25-26.

[114] ATC, 2007, pp. 54-55.

transmission investment.[115] This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have also provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

D. Benefits from Increased Competition and Market Liquidity

Transmission projects can provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets.

1. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include mark-ups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market. Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers' market power and reduce overall market concentration. The overall magnitude of benefits from increased competition can range widely, from a small fraction to multiples of the simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12 month period during which the crisis occurred.[116] More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."[117]

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[115] MISO, 2010, p. 32 and Appendix A.

[116] CAISO TEAM Report, 2004, pp. ES-9.

[117] FERC Performance Metrics, 2011, p. 106.

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide $28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.[118] Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.[119] A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[120]

2. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets also imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (***e.g.***, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[121] At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a $0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save $4 million to $40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately $500 million annually on a nation-wide basis.

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118 CAISO PVD2 Report, 2005, pp. 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

119 CAISO TEAM Report, 2004 (using the proposed Path 26 upgrade as case study).

120 Pfeifenberger Direct Testimony, 2008; and ATC, 2007, pp. 44-47 and pp. 4 (project cost) and 63 (competitiveness benefit).

121 Pfeifenberger Oral Testimony, 2006, p. 39.

E. Environmental Benefits

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.,* SO_2, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emission generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emission prices such as SO_2 and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO_2 in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emission generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde- Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO_2 emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of $1 million to 10 million per year.[122] Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO_2 emissions from fossil-fuel generators every year.[123] That estimated emission reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

F. Public-Policy Benefits

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by ***one quarter*** for the same amount of renewable energy produced compared

[122] CAISO PVD2 Report, 2005, pp. 26.

[123] Pfeifenberger Direct Testimony, 2012a, pp. 83.

to the investment costs of wind generation in locations with a 30% capacity factor.[124] Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be $500 to $700 per kW of installed wind capacity.

As noted earlier, the Midwest ISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over $110 billion for either all local or all regional wind resources to $80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over $30 billion.[125] These cost savings could be achieved by increasing the transmission investment per kW of wind generation from $422/kW in the all-local-wind case to $597/kW in the lowest-total-cost case.

A similar analysis was also carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[126] Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.[127]

Additional transmission investment can also help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operations (which includes a variable cost reduction). If less generating capacity from conventional generation is needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only $1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed $25 million.

To summarize, even though making significant transmission investments to gain access to remotely-located renewable resources seems to increase the cost of delivering renewable

[124] For example, see Burns & McDonnell, 2010, pp. 1–2, Figure 2.

[125] MISO, 2010, p. 32 and Appendix A.

[126] MISO, 2011, pp. 25 and 38-41.

[127] ATC, 2009, p. 7.

generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.[128] While this rationale will not apply to every public-policy-driven transmission project, it is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

G. Employment and Economic Stimulus Benefits

Transmission investments will also stimulate the local, regional, and national economy, supporting employment and regional economic activities. However, unlike the other economic benefits described above, the direct and indirect employment and economic stimulus associated with the construction and operations of the transmission system are benefits that do not reduce customer's electricity rates or improve their quality of service. These benefits are a measure of the effects of changes in power sector spending on other sectors in the economy, taking into account the input and output relationships among industries, consumers, and governments. For example, the construction of transmission facilities requires the use of labor and materials. Most of the manufacturing and construction activities will directly benefit the local economy by creating construction jobs. While certain input materials, such as towers and concrete, likely are sourced from within the region or from near-by regions, other materials such as cables and other electrical components may be imported from outside of the project's region or even from outside the U.S.

To measure the employment and overall economic activity supported by transmission investments, studies rely on a class of models known as input-output models.[129] Input-output models are universally used by economists and policy analysts to estimate how specified changes in spending affect every sector of a state's or region's economy.[130] Input-output models are used

[128] In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not be to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

[129] Some of the studies did not utilize full input-output models but relied on the "economic multipliers" taken from these models. Nonetheless, the multipliers are consistent with input-output models and assumptions. Input-output models are based on detailed economic data on how goods and services are produced and consumed. An input-output model rebalances the overall economy after an increase in expenditures on particular types of products (*e.g.*, construction activities and electric transmission equipment) such that the quantity produced equals the quantity consumed for every industry. These models specifically consider how much of the consumed products and services are supplied from each sector of a state or region.

[130] The majority of the studies we surveyed relied on the well-known and widely-used IMPLAN Model of the Minnesota IMPLAN Group (MIG) to estimate the employment and economic stimulus benefits of transmission investments. The IMPLAN (IMpact analysis for PLANning) economic impact modeling system is developed and maintained by MIG, which has continued the original work on the system done at the University of Minnesota in close partnership with the U.S. Forest Service's Land and Management Planning Unit. IMPLAN divides the economy into 440 sectors and allows the user to specify the

Continued on next page

to estimate: (1) the number of jobs supported in the region (in full-time-equivalent years or "FTE-years" of employment);[131] and (2) the economic activities generated in the region (*i.e.*, increased "economic output" as measured in total sales and resale revenues of businesses within the study region). Since these models report economic activity as the sum of the value of all goods and services sold at each level of the supply chain (*i.e.*, sales and resale revenues), the reported economic output refers to the total flow of money that occurs throughout the local economy. The measured impacts are the cumulative (undiscounted) number of jobs (or FTE-years of employment or FTE jobs each year), and the overall economic activity (in constant dollars) associated with investing in transmission projects over the entire construction phase.[132]

It is important to note, however, that the employment and economic stimulus impacts associated with the construction and operation of the transmission system are not additive to the economic benefits accruing in the power sector. In addition, increasing or decreasing costs for electric customers or increasing or decreasing profits to the investors of generators will also have downstream employment and economic stimulus effects.

Our 2011 analysis conducted for WIRES shows that every $1 billion of U.S. transmission investment directly and indirectly supports approximately 13,000 full-time-equivalent (FTE) years of employment and $2.4 billion in total economic activity.[133] Approximately one-third of this employment benefit is associated with the direct construction and manufacturing of transmission facilities. Two-thirds of the total impact is associated with indirect and induced

Continued from previous page

expenditure allocations associated with a given expansion in demand to all relevant parts of the local economy in order to derive the economic impacts—changes in employment, earnings, and economic output. According to the U.S. Department of Agriculture, currently "over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis." In 2009, the U.S. Army Corps of Engineers Civil Works program utilized IMPLAN employment multipliers "to estimate the potential number of jobs preserved or created" by the American Recovery and Reinvestment Act of 2009. In addition, the U.S. Department of Commerce, the Bureau of Economic Analysis, the U.S. Department of Interior, the Bureau of Land Management, and the Federal Reserve System member banks are also among the agencies that utilize IMPLAN for economic impact analysis.

131 Employment impacts are generally reported as full-time-equivalent (FTE) job years, that is, 2,080 hours of full employment. For example, reporting 100 FTE years of employment could mean 200 full-time jobs supported for 6 months, 100 jobs supported for a year, or 10 jobs supported for 10 years.

132 The employment and economic stimulus effects are typically quantified under three types of effects: "direct," "indirect," and "induced" impacts. Direct effects represent the changes in employment and economic activity in the industries which directly benefit from the investment (*i.e.*, construction companies, transmission materials and equipment manufacturing, and design services). Indirect effects measure the changes in the supply chain and inter-industry purchases generated from the transmission construction and manufacturing activities (*e.g.*, suppliers to transmission equipment manufacturers). Induced effects reflect the increased spending on food, clothing, and other services by those who are directly or indirectly employed in the construction of the transmission lines and substations. Employment supporting the three activities represents discrete net gains to the overall economy if the labor force is not being utilized elsewhere in the economy absent the projects. If the employment in a certain region is tight such that creating new jobs only allows people to change from less to more desirable jobs, very few new jobs would be created.

133 Pfeifenberger and Hou, 2011.

employment by suppliers and service providers to the transmission construction and equipment manufacturing sectors. As shown in Table 4, the WIRES report also summarized nine previous studies of the employment and economic stimulus benefits of transmission investments, covering a wide range of regions in the U.S. as well as portions of Canada.[134]

The summary shows that the local, state-level employment impacts range from a low of 2 FTE-years of total employment supported per million dollars of investment to a high of 18 FTE-years per million of investment (shown in Table 4 column [E]), with a majority of studies showing that each million dollars of transmission investment supports between 5 and 8 FTE-years of local employment. The economic output per million dollars of total transmission capital cost ranges from a low of $0.2 million to $2.9 million (shown in Table 4, column [F]).

In addition to employment and economic output, some studies also have estimated the increase in personal income earned by employees, local tax revenues, lease payments to local landowners, and stimulus to individual industries. While not all of the studies estimate these additional employment and economic stimulus benefits (and they cannot simply be added to other project benefits for the purpose of benefit-cost analyses as discussed in Section IV.B of this report), they nevertheless represent actual flows of wealth throughout a defined regional economy.

H. Other Potential Project-Specific Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

1. Storm Hardening

In regions that experience storm-induced transmission outages, certain transmission upgrades can improve the storm resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where VOLL can be significantly large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.[135]

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[134] There are several other studies discussing transmission-investment-related benefits to the regional or national economies, which are not included on our summary due to insufficient detail contained in or the different nature of these studies. For example, see Build Energy America!, 2011; McBride, *et al.*, 2008.

More recent studies not summarized in the following discussion include: Perryman, 2010; Lewis and Pfister, 2010; and Lowe *et al.*, 2011.

[135] Pfeifenberger Direct Testimony, 2012a, pp. 79–80.

Table 4
Employment and Economic Impacts of Transmission Investments per Million Dollars of Total and Local Spending

	Study Sponsor	Project Summary	% Local Spending	Based on Total Transmission Capital Cost: FTE-Years of Employment Per $ Million		Based on Total Transmission Capital Cost: Total Economic Output Per $ Million	Based on Local Spending: FTE-Years of Employment Per $ Million		Based on Local Spending: Total Economic Output Per $ Million
				Direct	Total	($ Million)	Direct	Total	($ Million)
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
[1]	AltaLink	AltaLink's estimated capital spending							
		Alberta	75%	5	7	N/A	7	9	N/A
		Rest of Canada Outside of Alberta	75%	N/A	3	N/A	N/A	3	N/A
[2]	ATC LLC	Two completed projects							
		1. 138 kV Femrite-Sprecher	46%	N/A	5	$0.7	N/A	11	$1.5
		2. 345 kV Arrowhead-Weston	100%	N/A	8	$1.4	N/A	8	$1.4
[3]	CapX2020	Five major transmission projects	100%	7	13	$1.9	7	13	$1.9
[4]	Central Maine Power	Maine Power Reliability	81%	4	6	N/A	5	7	N/A
[5]	Montana Department of Labor & Industry	Six major projects planned or under construction in Montana							
		1. Out-of-state contractors	11%	1	2	$0.2	11	17	$1.7
		2. In-state contractors	33%	2	5	$0.6	7	14	$1.7
		3. In- and out-of-state contractors	17%	2	3	$0.3	9	16	$1.7
[6]	Perryman Group	CREZ transmission	100%	N/A	18	$2.9	N/A	18	$2.9
[7]	South Dakota Wind Energy Association	Eastern South Dakota 345 kV transmission	25%	1	3	$0.3	8	11	$1.3
[8]	SPP	Various Priority Projects							
		1. Group 1 - low in-region	47%	4	7	$0.9	8	14	$1.8
		2. Group 1 - high in-region	74%	5	8	$1.3	6	11	$1.7
		3. Group 2 - low in-region	47%	4	7	$0.8	8	14	$1.8
		4. Group 2 - high in-region	73%	5	8	$1.2	6	11	$1.7
[9]	Wyoming Infrastructure Authority	Combination of 500 kV HVDC, 500 kV HVDC, and 230 kV HVAC	33%	5	5	$0.4	14	15	$1.3

Sources and Notes:

For full source citations, please refer to Table 3 in Pfeifenberger and Hou, 2011.

[1]: "Rest of Canada Outside of Alberta" impacts reflect AltaLink's capital spending on other provinces. The study provided a value-added impact which is not reflected in the table above.

[3]: Direct output assumed to be local spending.

[4]: The study provided a value-added impact which is not reflected in the table above.

[5]: Direct output assumed to be local spending.

[6]: The study provided a value-added impact which is not reflected in the table above.

[9]: NREL "direct" employment data have been adjusted by adding "indirect" impacts to align with other IMPLAN study definitions.

2. Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[136]

3. Synergies with Future Transmission Projects

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that region.[137] Planning a set of "no-regrets" projects that will be needed under a wide range of future market conditions can help capitalize on such "option value." For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a "no regrets" step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states' RPS requirements over the next 10 to 20 years.[138] A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project's standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout.

4. Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way "corridors" on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, "upsizing" a transmission line ahead of actual need (*e.g.*, to a double-circuit

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136 For example, see *ibid.*, p. 80.

137 CAISO TEAM Report, 2004, pp. 9–21. Tehachapi region referred to as Kern County.

138 Pfeifenberger and Newell Direct Testimony, 2011.

or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (***e.g.***, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to "up-size" lines in the future may be valuable even without right of way limits, this option will be particularly valuable if finding additional right of ways would be very difficult or expensive.

5. Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

6. Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.[139]

7. Increased Wheeling Revenues

As mentioned in the context of interregional cost allocation, a transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing a transmission owner's wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately $400 million of potential resource adequacy benefits were realized from deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant

[139] Budhraja ***et al.***, 2008, pp. 43-44.

generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately $130 million of the $400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.[140]

8. Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs by allowing imports from lower-cost portions of the region.[141] While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.[142]

9. Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current ("HVDC") transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;[143] (2) supply voltage and frequency support;[144] (3) improve transient stability[145] and reactive performance;[146] (4) provide AC system

140 For example, see Pfeifenberger Direct Testimony, 2012a, pp. 73-76.

141 As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

142 Pfeifenberger Direct Testimony, 2008, Appendix A; and ATC, 2007, p. 63 (FTR and congestion).

143 Bahrman (2008), p. 5.

144 Wang, *et al.*, 2008, p. 19.

145 IEEE PES, 2005, p. 75.

damping;[147] (5) serve as a "firewall" to limit the spread of system disturbances;[148] (6) "decouple" the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;[149] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of the network.[150] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[151] It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.[152]

VII. RECOMMENDATIONS

Recent developments in transmission planning around the country show that the industry and regulators have reached a point where a more complete catalogue of benefits and the methodologies for estimating benefits is being articulated and understood. Based on this industry experience and our own, we assembled a comprehensive list of economic benefits that transmission investments can provide. We recommend that this list of benefits be used as a "checklist" during initial transmission project conceptualization efforts to help planners identify potentially beneficial projects and their associated benefits. The likely benefits of the proposed projects should then be evaluated through more detailed analyses. Overall, starting with a comprehensive inventory of possible transmission benefits during the initial project conceptualization effort would avoid limiting the scope of benefits considered to those for which analytical tools are readily available or only those that have been evaluated traditionally. Potentially significant benefits that are more difficult to estimate should, at a minimum, be analyzed by calculating their likely range of magnitudes.

We offer the following suggestions to planners and policy makers when evaluating the merits of transmission projects:

- *Consider all Benefits*. Production cost simulations have been a tool for many transmission planners, and while such a shift represents significant progress in evaluating the economic benefits of transmission, the results only provide estimates of the short-term dispatch-cost savings under a singular set of generally simplified system conditions. Traditionally, these simplified simulations yield benefit estimates that reflect just a

Continued from previous page
146 As noted in several sources including: (1) UMD CIER, 2010, p. 51; (2) EWEA, 2009, p. 27; (3) Siemens, n.d.; and (4) Wright *et al.*, 2002, p. 5.

147 IEEE PES, 2005, p. 75.

148 Siemens, n.d.

149 Lazaridis, 2005, p. 34.

150 As noted in several sources including: (1) EWEA, 2009, p. 27; (2) Siemens, n.d.; (3) Lazaridis, 2005, p. 34; and (4) Wright *et al.*, 2002.

151 PJM 2008 RTEP Update, pp. 8-10.

152 Pfeifenberger and Newell Direct Testimony, 2010.

portion of total production cost savings and an even smaller portion of the overall economy-wide benefits provided by transmission investments. While not all proposed transmission projects can (or should) be justified economically, we suggest that planners use the checklist to avoid overlooking benefits simply because the traditional tools do not automatically capture these benefits.

- *Define the Scope of Transmission Benefits and the Perspective Taken.* The process for identifying transmission benefits is often limited to the impacts of new projects on customer rates within a utility's system or a planning region. However, a benefit analysis limited to the direct rate impact on customers, especially customers in a single utility footprint or in the planning region, could miss benefits to a region or a larger portion of the economy. Overly narrow benefits evaluations of economic or public policy-driven projects can also miss increased value from improved reliability and ignore benefits that accrue to other market participants or regions. To avoid under- or overstating the total benefits of transmission investments, we recommend that benefit-cost analyses of transmission projects be derived from a perspective that considers the overall benefits (often referred to as "societal" or economy-wide benefits) that accrue to a broad range of market participants and the economy as a whole.

- *Understand Total Benefits Prior to Cost Allocation.* Understanding overall project benefits prior to making cost allocation decisions will enable participants in the planning process to identify those projects that are most beneficial in the long run from an economy-wide perspective. How the distribution of the identified benefits is estimated to accrue to regions, areas, and market participants will ultimately drive both regional and interregional cost allocation—but cost allocation should be addressed only *after* the overall benefits of transmission projects have been considered for inclusion in regional plans. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in rejection of very valuable projects. We also suggest aggregating beneficial transmission projects into larger portfolios of projects to simplify the necessary cost allocation analyses, reduce misperceptions that benefits appear to accrue only to a limited subset of market participants, and facilitate less contentious cost allocation processes.

- *Consider All Regional Benefits in Interregional Planning.* Interregional transmission planning and cost allocation is especially challenging given the tendency of neighboring regions to evaluate interregional projects only based on the subset of benefits that are common to the planning processes of each of the respective regions involved. Only focusing on common benefits results in considering a narrower set of benefits in interregional projects than those considered for region-internal projects. To avoid this "least common denominator" outcome in interregional planning, we recommend that neighboring regions evaluate interregional projects using the full set of potential benefits that are considered for regional projects in each region. This approach would help planners and policy makers to better understand the full benefits of interregional projects to their planning region and to make decisions that are more efficient from an interregional perspective and well-aligned with the interest of all affected regions.

Without an inclusive recognition of all potential benefits by each of the neighboring regions, coordinated interregional planning in compliance with FERC Order No. 1000 would not be able to identify and ensure the development of many projects that benefit two or more regions.

- *Address Uncertainties.* The industry faces considerable uncertainties on both a near- and long-term basis that should be considered in transmission planning. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure generally is disproportionately concentrated in periods of more challenging, or possibly extreme, market conditions. The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. We recommend a more comprehensive planning approach that includes (1) evaluating long-term uncertainties through scenario-based analyses; and (2) evaluating near-term uncertainties within scenarios through sensitivity or "probabilistic" analyses.

- *Consider Long-Term Benefits.* Several methods exist for comparing benefits and costs in the transmission planning processes. The methods currently used by planners and regulators differ by the number of years analyzed (*i.e.*, planning horizons), how benefits are estimated over the short-term and long-term, whether levelized or present values are used in the benefit and cost estimations, and the benefit-to-cost threshold that projects must clear. After analyzing the various methods currently employed in different planning regions, we recommend that the estimated benefits be compared with estimated project costs—either on a present value or levelized annual basis—over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets. Paying attention to how benefits and costs accrue over time across future scenarios will also help planners to optimize the timing of transmission investments from a long-term value perspective.

LIST OF ACRONYMS

1-in-10	One-Day-In-Ten-Years
AEP	American Electric Power
AESO	Alberta Electric System Operator
ALP	Acadiana Load Pocket
APC	Adjusted Production Costs
APS	Arizona Power Service
ATC	American Transmission Company
BPA	Bonneville Power Administration
CAISO	California ISO
CARIS	Congestion Assessment and Resource Integration Study
CBM	Capacity Benefit Margin
CC	Combined Cycle
CEC	California Energy Commission
CEERTS	Cost Effective and/or Efficient Regional Transmission Solutions
CERTS	Consortium for Electric Reliability Technology Solutions
CIEE	California Institute for Energy and the Environment
CIER	Center for Integrative Environmental Research
CMWG	Congestion Management Working Group
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CT	Combustion Turbine
CVaR	Conditional Value at Risk
DC	Direct Current
DR	Demand Response
DPV2	Devers-Palo Verde No. 2
EFORd	Effective Forced Outage Rate Data
ELCC	Effective Load Carrying Capability
ENS	Energy-Not-Served
EOP	Emergency Operating Procedure

ERCOT	Electric Reliability Council of Texas
ETIP	Energy Technology Innovation Policy
EWEA	European Wind Energy Association
EWITS	Eastern Wind Integration Transmission Study
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FTE	Full-Time Equivalent
FTR	Financial Transmission Rights
GADS	Generation Availability Data System
GDP	Gross Domestic Product
GE-MARS	General Electric – Multi-Area Reliability Simulation
GTRPMTF	Generation and Transmission Reliability Planning Models Task Force
HR	Hour
HVDC	High-Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator (Ontario)
IMPLAN	IMpact Analysis for PLANning
IRM	Integrated Resource Management
IRP	Integrated Resource Planning
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Integrated Transmission Planning
kV	Kilovolt
kW	Kilowatt
kW-yr	Kilowatt year
kWh	Kilowatt hour
LGE&KU	Louisville Gas and Electric Company and Kentucky Utilities Company
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group

LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LSE	Load-Serving Entities
LTS	Long-Term Study
MAPP	Mid-Continent Area Power Pool
MARS	Multi-Area Reliability Simulation
MIG	Minnesota IMPLAN Group
MIS	Mission: Integrated Systems (MIS Energy Management)
MLCC	Multi-Layer Ceramic Chip
MMbtu	Million Metric British Thermal Units
MISO	Midwest ISO
MVP	Multi-Value Project
MW	Megawatt
MWh	Megawatt hour
NCTPC	North Carolina Transmission Planning Collaborative
NEM	National Energy Market
NERC	North American Electric Reliability Corporation
NESCOE	New England State Committee on Electricity
NO_x	Nitrogen Oxide
NPC	Nevada Power Company
NPCC	Northwest Power and Conservation Council
NREL	National Renewable Energy Laboratory
NRRI	Natural Resource Research Institute
NTTG	Northern Tier Transmission Group
NWPP	Northwest Power Pool
NYISO	New York ISO
NYSRC	New York State Reliability Council
O&M	Operations and Maintenance
PIER	Public Interest Energy Research
PJM	PJM Interconnection, Inc.
PLWG	Planning Work Group
PNM	Public Service Company of New Mexico
PNW	Pinnacle West Capital Corporation

PRISM	Parameter-Elevation Regressions on Independent Slopes Model
PRM	Planning Reserve Margin
PtP	Point-to-Point
PV	Photovoltaic
PVD2	Palo Verde-Devers Line 2
RES	Regulatory and Economic Studies
RFC	Reliability First Corporation
RGOS	Regional Generation Outlet Study
RM	Reserve Margin
RMR	Reliability Must Run
RPM	Reliability Pricing MODEL
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RWG	Resource Working Group
SCE&G	South Carolina Electric & Gas Company
SERC	SERC Reliability Corporation
SERTP	Southeastern Regional Transmission Planning Process
SERVM	Strategic Energy Risk Valuation Model
SO_2	Sulfur Dioxide
SOCO	Southern Company
SPP	Southwest Power Pool
TEAC	Transmission Expansion Advisory Committee,
TEAM	Transmission Economic Assessment Methodology
TEPPC	Transmission Expansion Planning Policy Committee
TLR	Transmission Loading Relief
TRG	Technical Review Group
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance
VSC	Voltage Source Converter
WACC	Weighted-Average Cost of Capital

WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WIRES	Working Group for Investment in Reliable and Economic Electric Systems

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APPENDIX A:

CHECKLIST OF ECONOMIC BENEFITS OF TRANSMISSION PROJECTS

Summary Table of Economic Benefits	
Benefit Category	**Transmission Benefit**
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated, including impact of planned and forced generation outages
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 or 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

1. Additional Production Cost Savings

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1.	**Additional Production Cost Savings**			
--	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
a.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
b.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
c.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
d.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
e.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	
f.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study
g.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
h.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)
i.	More realistic representation of system utilization in "Day-1" markets	Transmission offers higher benefits if market design is utilizing the existing grid less efficiently	Use flowgate derates (in addition to the traditional use of hurdle rates between balancing areas) in production cost simulations to more realistically approximate system utilization in "Day-1" markets	MISO "Day-2" Market benefit analysis

2–3. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability Or:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3. Generation Capacity Cost Savings				
a.	Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4–7. Market, Environmental, Public Policy, and Economic Stimulus Benefits

Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	
6.	**Public Policy Benefits**	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost-effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7.	**Employment and Economic Development Benefits**	Increased full-time equivalent (FTE) years of employment, economic activity related to new transmission line, and tax revenues	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

8. Other Project-Specific Benefits

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
8.	**Other Project-Specific Benefits**			
a.	Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
b.	Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
c.	Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
d.	Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
e.	Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
f.	Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
g.	Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

Summary of Peer Review

of

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

The discussion that follows has been prepared by Professor Ross Baldick, Dr. Keith Casey, Dr. Gary Stern and Dr. Richard Tabors at the request of WIRES.[1] We have reviewed The Brattle Group report independently and have had the opportunity of several joint discussions among the review team and with the principal authors of the report.

Overview

We commend WIRES for commissioning the study and The Brattle Group for undertaking the effort. The Brattle Group authors have provided a thorough review and cataloguing of the multiple benefits of transmission investment. The report offers, predominantly from a societal perspective, the methodologies required to account adequately for the multiple benefits of transmission, balanced with those of expansion in generation or demand-side management. The report itself is clear in its statement of what is considered and what is not. However, it is not surprising that this cataloguing of the benefits of one major sub-system of the power system has raised almost as many new avenues and issues for further thought and research as it has answered. As reviewers, we have provided comments on the content of the report but also on what still needs to be considered in the transmission investment decision-making processes.

In our review, we focus on three areas of specific contribution of the *Benefits of Electric Transmission* report.

- Cataloguing of the numerous economic, environmental and societal benefits provided by transmission investments;
- Framing a general methodology for considering the totality of the benefits relative to transmission costs; and

[1] Dr. Ross Baldick, Professor and Leland Barclay Fellow, Department of Electrical and Computer Engineering, The University of Texas; Dr. Keith Casey, VP Market & Infrastructure Development, The California ISO; Dr Gary Stern, Director of Regulatory Policy, Southern California Edison Company; Dr. Richard Tabors, President, Across the Charles and Director Utility of the Future Project, MIT Energy Initiative.

The opinions expressed in this review are those of the authors and do not necessarily reflect the opinions of the institutions or universities of which they are a part.

- Explicitly separating the calculation of the benefits of transmission from the issues associated with allocation of the costs of transmission development.

We also provide a discussion of the need for the development of a more comprehensive and optimal decision-analytic framework for assessing the overall system benefits of alternative transmission investments.

Cataloguing of Societal Benefits of Transmission

The Brattle Group authors have presented what is arguably the most complete catalogue of the benefits of transmission investments that has been assembled to date. More importantly, the cataloguing has been structured such that the discussion in the text flows by logical steps from the most commonly used and most easily estimated benefits to those that are less easily (if at all) estimated but which, the authors argue and we agree, should be considered in benefit evaluations.

The report begins with the traditional methods and inclusions of total production cost savings that capture the reductions of the variable costs of generation alone. Importantly it then extends the discussion to reduction in transmission losses, capital requirements, the costs associated with cycling of units, operating reserves and other ancillary services, and reduction in reliability-must-run generation.

The report retains an overall flow that moves through eight major categories of benefits focusing on those that are conceptually most obvious to those that are least frequently discussed and likely to be the most difficult to estimate using traditional cost and benefit analysis techniques. Moving from production costs savings to reliability and resource adequacy is the first step, followed by generation capacity cost savings, and then market, environmental, public policy, employment and economic stimulus, and project-specific benefits. Estimation of such benefits goes beyond the capabilities of standard production cost software, implying a need for development of methodologies to evaluate these benefits together with enhancement of industry tools.

The authors arrive at a range of conclusions and summary points with regard to the benefit measures identified. Two overall conclusions flow through the benefit discussions in the document.

- Not looking broadly at the benefits of transmission asset development within the structure of the power system will tend to underestimate – and potentially significantly – the value of transmission investments. This underestimation may be more serious for transmission assets than the underestimation of analogous benefits in other sub-systems. That is, the underestimation will tend to systematically bias against transmission solutions.

- Not looking at the breadth of benefits because "they might be difficult to estimate" relative to the benefits of other investment opportunities within the power sector is not a sufficient justification for ignoring what could well be some of the most critical of the advantages of transmission investments.

A General Methodology for Assessment of Transmission Benefits

The authors propose a four stage approach for considering transmission benefits and cost allocation that consists of the following:

1. Identify potential transmission projects and develop a comprehensive list of their likely benefits.
2. Estimate the monetary value of as many of the identified benefits as practical.
3. Determine whether the proposed transmission investments would be beneficial overall.
4. Address cost allocation.

In general, we support the key principles underlying this four stage approach. Specifically;

- Consideration early in the process of a broad range of potential transmission projects over as broad a region as possible before rushing to evaluate an initial preferred solution.
- Identifying a full set of benefits and estimating the monetary value of as many of the identified benefits as practical.
- Identifying beneficial projects by considering of societal benefits relative to costs and potential synergies of considering several projects jointly.
- For the identified portfolio of beneficial projects, using estimates of the distribution of the identified benefits to inform cost allocation decisions.

However, we believe the proposed evaluation approach could be enhanced by considering the following:

Identification of System Needs/Planning Objectives **–** We believe the first stage of a planning process should include explicit consideration of the potential needs/drivers for the new transmission (e.g., identify public policy objectives, reliability needs, baseline congestion projections, etc).

Consideration of Non-Transmission Alternatives - The authors' note that the proposed brainstorming session should recognize non-transmission alternatives. We agree that consideration of non-wire options (generation, demand response, storage, etc.) should be considered and recommend that the process of doing so should be defined explicitly and in a manner that avoids systematic biases in the evaluation of transmission solutions vis a vis other options.

Need for a Systematic Approach for Identifying and Evaluating Transmission Projects – As we discuss in greater detail below, the proposed process for identifying and evaluating the benefits of transmission projects relies heavily on the transmission planner's initial judgment about the value of a potential project or combinations of projects. Ultimately, we believe a more systematic approach is needed to identify optimal transmission projects and synergistic benefits of joining individual projects.

Separation of the Estimated Benefits of Transmission Enhancements from the Allocation of Their Costs

The report correctly focuses on the incentive problems associated with tying cost allocation to the calculated benefits of particular parties or regions. The proposed solution of first calculating the benefits and only subsequently assessing the cost allocation for a portfolio of beneficial projects is a necessary but not sufficient condition to solve this incentive problem. One of the key challenges is that added transmission is very likely to benefit different constituents differently. Relieving congestion may be societally beneficial, but when examined in isolation, load in an area where generation is "trapped" gets lower prices and may gain from the congestion and thus have a negative benefit from the transmission investment, whereas generation in that same area, again examined in isolation, may be harmed by the congestion and would receive a benefit from the transmission investment. Economic benefit to the region may accrue, but the utility's ratepayers might still see a net increase in rates depending on the allocation of costs. While the overall society benefits, there may be pockets of a utility's ratepayers that do not benefit. In addition, as the Brattle authors note, and possibly far easier to say than to implement, to ensure a fair assessment of the benefits of transmission additions and their distribution, it would be desirable to have the entity responsible for estimation of benefits be an independent "honest broker" without any vested interest in the outcome.

The authors suggest in their cost allocation stage of the evaluation process that "aggregating beneficial transmission projects across a region into a portfolio of projects is advisable before determining cost allocations because the benefits associated with a more geographically-diverse, larger portfolio of transmission projects will tend to be more evenly distributed." We do not believe this will necessarily be the case and suspect that stakeholders within most planning regions will want to understand how they benefit from individual major elements/segments of a proposed set of transmission projects.

We do agree that disaggregating the benefits of a combined set of transmission projects that are highly interdependent and synergistic is problematic in that the benefits of any individual element depends on whether the other elements are assumed developed as well. In such cases, we believe the combined set of transmission projects should be viewed as one holistic project and the costs allocated to each impacted planning region should be allocated based on the estimated benefits it receives from the total project. In cases where individual transmission projects have very few interdependencies, cost allocation should be based on assessing the regional benefits of each project separately so that the costs allocated to each planning region are proportional to the benefits received.

Other Considerations and Methodological Questions

As we discussed briefly above, the *Benefits of Electric Transmission* raises a number of questions that go well beyond the acknowledged scope and objective of the current report. The reviewers believe these questions should be raised in the context of providing for a greater level of completeness to the larger topic of assessment of transmission investments, acknowledging that there are no quick and easy answers. Raising these questions in no manner diminishes the usefulness or quality of the current effort but rather points to both the complexity of the issues surrounding decisions for transmission investment as well as the fact that only limited effort has been applied to date to developing the analytic technologies and overall methodological approach to transmission investment planning.

The electric power system is a complex, interconnected whole. While the interconnection may be argued to be the transmission system, the whole incorporates generation (both central and distributed), storage (again central and potentially distributed), distribution in all of its complexity, and the interaction with end users at all levels and at all levels of complexity in use and control.

It is difficult, if not impossible, to fully evaluate the benefits of transmission without reaching into the competing benefits of investments in other sub-systems of the power system. Technology is not standing still in terms of the transmission system or in terms of the other sub-systems of the power system. Two examples of changes whose impacts upon asset growth in transmission have yet to be quantified are:

- The impact of significant investment in distributed generation and potentially storage within the distribution system. These changes are being brought about by public policy decisions combined with a dramatic expansion in communications and controls allowing for the development of distributed energy systems that interact with the larger utility system.

- The impact of sensing and control of the transmission system that allows for dynamic reconfiguration of the topology of the transmission system. Often referred to as "line switching," the benefits have been known by system operators for decades. It is only with increased monitoring, advances in analytic techniques, and computation speed that these concepts can be brought into the operational time frame.

Technological changes are adding points of pressure to the power system in general and specifically to the transmission sub-system as the interchange network that allows the system to remain balanced.

If there is a single missing element in the puzzle of evaluation of the benefits of transmission it is the lack of a systematic methodology for benefit evaluation. The Brattle Group authors and we have suggested an overall approach to the process. What follows is our – albeit brief – discussion of what is needed to take the next step in development of a systematic and reproducible methodology for transmission benefit (and cost) evaluation.

We acknowledge that there is no comprehensive methodology for evaluating transmission (or more generally systems level) investments in the power sector. During the 1980s and 1990s relatively little new transmission was built in the United States. The decision to construct new transmission revolved around individual projects that were needed to meet applicable reliability criteria or could be evaluated using relatively simple with/without economic analysis in conjunction with the standard tools of production cost modeling and power flow. This has changed in the last decade with objectives of increased renewable energy penetration and the need to replace aging transmission system assets. The implication is that there will be large investments in transmission construction that must face an uncertain future of alternative scenarios for carbon legislation, fuel cost, and demand growth. The CREZ transmission project in ERCOT, for example, will cost around $7 billion. Such expansions consist of large numbers of individual elements that interact synergistically. However, traditional tools such as power flow and production cost modeling have not yet been augmented with decision support tools or frameworks that could more effectively address the far more complex decision analysis that implicitly needs to be done for projects like CREZ.

The development of a formal decision support framework could significantly benefit current planning processes by systematically integrating (if not automating) many of the calculations needed to consider the detailed alternatives and winnowing out the best (or better) alternatives and eliminating the less good alternatives, freeing transmission planners to focus more effectively on bigger picture issues. A decision support methodology would begin with geographical information system input and use known land use information to roughly plan various alternative routes for new transmission assets. It would include information on current electrical system constraints and, as such, would be a tool that would provide a first cut at physical and electrical parameters for various alternative routes that would be invaluable in winnowing out the particular lines and assets that collectively satisfy the planning constraints at least cost. Such an analytic structure would be dynamic in that it would consider multiple future scenarios over an extended planning horizon.

The result of such a structure would, as pointed out by The Brattle Group study, include information about the quality of the solution and uncertainties in outcomes in contrast to current planning processes that do not systematically consider alternative future scenarios and provide very little assurance that construction plans are at least cost.

While we realize no such comprehensive structure exists in transmission planning to date, we believe that analytical tools based upon developments in advanced computing and optimization such as have been seen in other segments of the industry (e.g., operations/market dispatch) could help inform the design of improved analytical and decision frameworks for transmission planning. While such formal advanced analytical methods will not lend themselves to capturing all of the potential benefits of a transmission project (e.g., wider economy benefits), they should be designed to be able to capture the most important of the potential benefits. This will lead to better decision making relative to what too often occurs today.

Summary and Conclusions

In our view, the *Benefits of Electric Transmission* report provides a very useful, thorough cataloguing of both the easy and the difficult-to-measure benefits of transmission investments. As pointed out in our review, there is work still to be done in developing methodologies to systematically evaluate transmission investments within the totality of the power system. We believe that the advances in other segments of the industry can and will help inform the design of improved analytical and decision frameworks for transmission planning.

Even with such advances in evaluation techniques and consideration of a broader range of benefits, the process of evaluating transmission investment is and will remain contentious. There will be parties to the process who will legitimately have interests not aligned with the broad social benefit. The reality of today's combined State and Federal regulatory environment assures there will be specific instances where ratepayer interests can and will continue to trump the overall social welfare benefits in specific instances and that the role of the FERC will continue to be a point of contention, particularly when FERC allows transmission return on investments that are above currently-authorized returns by the individual states.

These are the realities of transmission investment. That said, however, understanding the benefits of transmission investment in all of their complexity and uncertainties represents a first and most critical step.

Reviewer Biographies

Ross Baldick is Professor and Leland Barclay Fellow in the Department of Electrical and Computer Engineering at The University of Texas at Austin. He received his B.Sc. and B.E. (medal (pr. acc.)) degrees from the University of Sydney, Australia and his M.S. and Ph.D. from the University of California, Berkeley. From 1991-1992 he was a post-doctoral fellow at the Lawrence Berkeley Laboratory. In 1992 and 1993 he was an assistant professor at Worcester Polytechnic Institute.

Dr. Baldick received a National Science Foundation Research Initiation Award in 1993; a National Science Foundation Young Investigator Award in 1994; and Engineering Foundation Faculty Award, University of Texas at Austin, in1997, and has been the Principal Investigator on approximately 20 funded research projects. He has published over fifty refereed journal articles, made presentations on over seventy-five different topics, and has research interests in a number of areas in electric power. He received the Best Presentation in Energy Sponsored Sessions Award, INFORMS Conference, Atlanta, Georgia, October 2003 (with Stathis Tompaidis and Sergey Kolos) and the IEEE Power Engineering Society, Power System Analysis, Computing, and Economics Technical Committee Prize Paper Award, in 2006 (with Richard P. O'Neill, Udi Helman, Michael H. Rothkopf, and William Stewart, Jr.)

Keith Casey, Ph.D. is Vice President, Market and Infrastructure Development at the California Independent System Operator Corporation (ISO). The division is responsible for developing efficient markets and effective infrastructure planning. Part of the organization’s start-up team in 1997, Dr. Casey served as Director, ISO Department of Market Monitoring from 2005 to 2009 and played a key role in designing a new market and monitoring program that guards against manipulation and fosters healthy competition.

Since 2009, Dr. Casey has served as Vice President, Market & Infrastructure Development. He is responsible for developing market design and infrastructure policies and overseeing the transmission planning and generation interconnection process to ensure all of these critical functions evolve to effectively address the changing needs of the industry and facilitate California’s transition to a greener and smarter electric grid. Dr. Casey also serves on the Western Electricity Coordinating Council Board of Directors. Dr. Casey received his bachelor's degree in economics from the University of California San Diego. He has a master's degree in economics from the University of Maine and earned his doctorate in agricultural and resource economics with a specialization in environmental economics from the University of California Davis.

Gary Stern is the Director of Regulatory Policy for Southern California Edison Company (SCE). Reporting to the Senior Vice President of Regulatory Policy & Affairs, he manages a division responsible for the development of policy in matters relating to the California Public Utilities Commission, California Energy Commission, California Independent System Operator, and the Federal Energy Regulatory Commission. His organization is also responsible for case management associated with proceedings with all of these entities. Previously, Gary directed SCE's resource planning, market design and analysis, and strategic project groups. Gary Stern holds a Ph.D. in Economics from the University of California at San Diego. He has an M.A. in Economics, and a B.A. in mathematics also from UC San Diego.

Richard D. Tabors, Ph.D. is an economist and scientist with 35 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. He is currently President and Principal of *Across the Charles* an energy, water and wastewater consulting group in Cambridge, Senior Consultant at Greylock McKinnon of Cambridge and an Affiliate of the MIT Energy Initiative. Prior to forming *Across the Charles* Dr. Tabors was Vice President of Charles River Associates.

From 1976 until 2006 Dr. Tabors held a variety of position at Massachusetts Institute of Technology culminating in the title of Senior Research Engineer and Senior Lecturer. These positions involved research development and supervision as well as academic teaching and included being Assistant Director of the power systems engineering laboratory (LEES) and associated director of the Technology and Policy master's program. Prior to MIT Dr. Tabors was Assistant Professor of City and Regional Planning and a member of the teaching faculty of the College of Arts & Sciences at Harvard University. At present he is a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland.

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Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	23
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	August 1, 2018		

Question:

Topic:	Benefit-Cost Analysis of the Environmental Impact Statement Route Segments
Reference(s):	Environmental Impact Statement Scoping Decision dated July 17, 2018

The Minnesota Department of Commerce released an Environmental Impact Statement (EIS) Scoping Decision on July 17, 2018. Please provide the following information:

1. Do the additional routes, route segments, and alignment alternatives (EIS routes) to be included in the EIS due to the July 17, 2018 EIS Scoping Decision change the high or low end of the cost estimate for the Project?
    a. If the range of cost estimates does change as a result of the EIS routes, please provide the same level of benefit-cost analysis as was done for the Project and its alternatives.
2. For any future additional route segments proposed by the Applicants, please provide benefit-cost analysis if the additional route segments change the high or low end of the cost estimate for the Project.

Response:

1. Yes, certain routes, route segments, and alignment alternatives that will be included in the EIS change both the high and low end of the cost estimate for the Project.
    a. Please see **Attachment 1**.

2. The Applicants agree to provide benefit-cost analysis to the extent they propose additional route segments that change the high or low end of the cost estimate for the Project.

Preparer: Grant Stevenson, Xcel Energy
Title: Senior Project Manager
Department: Transmission Project Management North
Telephone: 612-330-6330
Date: August 13, 2018

DOC IR 23: Huntley - Wilmarth Low and High Estimates as Revised by Scoping Segments (2016$)

This analysis calculates new lowest and highest cost bookends for each route estimate assuming the original route would be modified to the greatest extent possible by applicable scoping segments. Totals are rounded to the nearest $100,000 and segments to the nearest $10,000.

Summary

Lowest Cost	Highest Cost
$104.8 million Purple Route, single circuit H-frame 2.18 Benefit/Cost (MTEP17)	$160.7 million Purple-E-Red Route, double and single circuit monopole 1.42 Benefit/Cost (MTEP17)

High and Low by Route

	Purple		Green		Red		Blue		Purple-E-Red	
	Low	High	Low	High	Low	High	Low	High	Low	High
Project Cost (millions, 2016$)	$ 104.8	$ 147.3	$ 108.2	$ 124.8	$ 134.4	$ 143.8	$ 123.7	$ 142.5	$ 157.0	$ 160.7
Benefit-Cost Ratio, MTEP17	2.18	1.55	2.11	1.83	1.70	1.59	1.85	1.6	1.46	1.42

Details by Route

	Purple		Segment
	Low (SCH)	High (SCM + DC)	Design
Application	105,800,000	137,900,000	
F	(70,000)		SCM
H		4,040,000	SCM + DC
J	(930,000)		SCH
N		2,680,000	SCM
AA3		2,640,000	TC
	104,800,000	147,300,000	
MTEP17 B/C	2.18	1.55	

Segment F is SCM for its entire length due to concerns about fitting H frames near buildings in Judson

Segment Design Notes:
SCH: single circuit H-frame
SCM: single circuit monopole
DC: double circuit
TC: triple circuit

	Green		Segment
	Low (SCH)	High (SCM)	Design
Application	109,000,000	121,300,000	
A		2,130,000	SCM + DC
B	(790,000)		SCH
O		1,320,000	SCM
	108,200,000	124,800,000	
MTEP17 B/C	2.11	1.83	

	Red		Segment
	Low (SCH + DC)	High (SCM + DC)	Design
Application	135,200,000	138,000,000	
A		2,130,000	SCM + DC
B	(790,000)		SCH
Q		3,200,000	DC
Y		440,000	DC
	134,400,000	143,800,000	
MTEP17 B/C	1.70	1.59	

	Blue		Segment
	Low (SCH + DC)	High (SCM + DC)	Design
Application	123,700,000	135,800,000	
G		1,960,000	SCM
P		1,550,000	SCM
Q		3,200,000	DC
	123,700,000	142,500,000	
MTEP17 B/C	1.85	1.60	

	Purple-E-Red		Segment
	Low (SCM + DC)	High (SCM + DC)	Design
Red DC Application	138,000,000	138,000,000	
E	19,040,000	19,040,000	SCM + DC
Y		440,000	DC
Q		3,200,000	DC
	157,000,000	160,700,000	
MTEP17 B/C	1.46	1.42	

Purple-E-Red was proposed by the local government task force to connect Purple double circuit to Red double circuit to reduce impacts to agriculture. In that spirit, Purple-E-Red is estimated only as single circuit and double circuit monopoles. Therefore, the base Purple-E-Red estimate is the Red double circuit estimate from the application modified by scoping segment E, which results in $157 million low cost (2016$.) Note that Segment E in this analysis does not match Segment E in the route application per EERA scoping estimate endpoint maps.

ATTACHMENT FF

TRANSMISSION EXPANSION PLANNING PROTOCOL

I. Transmission Expansion Plan - Purpose and Scope, Definition and Role of OMS Committee: This Attachment FF describes the process to be used by the Transmission Provider to develop the MISO Transmission Expansion Plan ("MTEP"), subject to review and approval by the Transmission Provider Board. The provisions of this Attachment FF are consistent with the applicable provisions of Appendix B of the ISO Agreement and this Tariff. For purposes of this Attachment FF, all references to Transmission Owner(s) will include ITC(s). The costs incurred by the Transmission Provider in the performance of data collection, analyses and review, and in the development of the MTEP report, costs incurred under Section I.C of this Attachment FF, and costs incurred under Section I.D of this Attachment FF shall be recovered from all Transmission Customers under Schedule 10 of the Tariff.

A. Enrollment Process: The MTEP is developed to facilitate the timely and orderly expansion of and/or modification to the Transmission System to maintain reliability, promote efficiency in bulk power markets and facilitate compliance with applicable Federal and state laws, regulatory mandates and regulatory obligations. Any transmission provider that wishes to enroll in the Transmission Provider planning process for purposes of Order No. 1000 compliance must become a Transmission Owner, by signing the ISO Agreement, and by, within a reasonable period of time: (1) turning over functional control of its transmission facilities to the Transmission Provider; and (2) taking service under this Tariff for all its load that is physically located within the geographic area comprising the Transmission System. All Transmission Owners enrolled in the Transmission Provider's transmission planning region are listed in either

VIII.I OBLIGATION TO NEGOTIATE INTERCONNECTION AGREEMENTS

The Selected Developer(s) and any Transmission Owner(s) whose facilities will interconnect to the Competitive Transmission Facilities that the Selected Developer is obligated to construct shall each take commercially reasonable efforts to finalize and execute any required Transmission-to-Transmission Interconnection Agreements at least one hundred and twenty (120) calendar days before the scheduled in service date of the Competitive Transmission Project.

IX. VARIANCE ANALYSIS

After the Transmission Provider Board approves an Eligible Project for inclusion in Appendix A of the MTEP, certain circumstances or events may significantly affect the cost, schedule, and or the ability of Selected Developers and Transmission Owners to complete and place into service the facilities comprising an Eligible Project for which they are responsible as specified in the MTEP. Under these circumstances or events, the Transmission Provider may need to perform a Variance Analysis in order to further understand the reasons for such circumstances or events and to evaluate any potential impacts that they may have on the successful completion of the Project or on the Transmission System.

IX.A. Applicability and Scope of Variance Analysis

The provisions set forth in this Section IX of Attachment FF are only applicable to Eligible Projects (and the facilities that comprise these projects) approved by the Transmission Provider Board for inclusion in Appendix A of the MTEP after December 1, 2015. These provisions become applicable upon: (i) the date the Transmission Provider Board approves the respective Eligible Project for facilities that are not Competitive Transmission Facilities; or (ii) the date the Selected Developer Agreement has been executed or filed unexecuted with the Commission for Competitive Transmission Facilities. Facilities comprising Eligible Projects shall remain subject to the provisions of Attachment FF Section IX until such facilities have been placed into service and placed under the Transmission Provider's functional control.

IX.B. Variance Analysis Governance

The Competitive Transmission Executive Committee shall have the exclusive and final authority to oversee and implement Variance Analysis, including the decision to implement any of the appropriate Variance Analysis Outcomes pursuant to Section IX.E of this Attachment FF. Such exclusive and final authority shall: (1) be subject to the Dispute Resolution provisions of Section IX.G of this Attachment FF and to Attachment HH; and (2) shall not prejudice any rights or obligations the Transmission Provider, Selected Developer(s), and incumbent Transmission Owner(s) have to make filings before the Commission.

IX.C. Grounds for Variance Analysis

The following circumstances or events shall trigger the Transmission Provider's Variance Analysis for facilities included in an Eligible Project.

IX.C.1. Cost Increase

If the Transmission Provider determines that the estimated cost to complete an entity's portion of an approved Eligible Project (e.g. the competitively bid facilities of the Competitive Transmission Project or the facilities assigned to an incumbent Transmission Owner included in an Eligible Project(s) either has exceeded or is projected to exceed the Baseline Cost Estimate as set forth in Section IX.C.1.1 by twenty-five percent (25%) or more, the Transmission Provider shall initiate a Variance Analysis.

The Transmission Provider will not consider any portion of cost increases under this section to the extent that the Selected Developer has agreed to internalize such costs through an accepted binding cost cap and/or cost-containment mechanism(s). However in the event that the accepted binding cost caps and/or binding cost-containment mechanism(s) are applied and the remaining estimated cost increase still has exceeded or is projected to exceed the threshold, the Transmission Provider shall initiate a Variance Analysis.

IX.C.1.1. Baseline Cost Estimate

The Baseline Cost Estimate for an entity's portion of an Eligible Project shall be set as follows: (i) for Competitive Transmission Facilities the Baseline Cost Estimate shall be the project cost estimate provided in the Selected Proposal as agreed to in the Selected Developer Agreement;

and (ii) for the facilities assigned to an incumbent Transmission Owner included in the Eligible Project not eligible for the Competitive Transmission Process, as described in Attachment FF Section VIII.A of the Tariff, the Baseline Cost Estimate shall be the project cost estimate provided by the respective Transmission Owner through their status update provided upon achieving Milestone #2A pursuant to the Business Practices Manuals. The Baseline Cost Estimate for Competitive Transmission Facilities shall be adjusted appropriately based upon any approved change orders.

IX.C.2. Schedule Delays

If the Transmission Provider determines that the in-service date of facilities included in an approved Eligible Project has been or is projected to be delayed beyond the in-service date as established in MTEP Appendix A, the Transmission Provider shall meet with the Selected Developer(s), incumbent Transmission Owner(s), if applicable, interconnecting Transmission Owner(s), and any entities responsible for facilities to which the delayed facilities interconnect to discuss whether such delay creates a significant risk of one or more NERC reliability standards violations as well as any other material issues, including service obligations, economic or public policy needs that may be jeopardized as a result of the delay. If any such issues are identified, the Transmission Provider shall, in consultation with these entities, develop a plan, as necessary, to address potential NERC reliability standards violations as well as any other issues that may be of material concern arising from the delay of the transmission facilities.

If the potential NERC reliability standards violations, or other issues of material concern, cannot be adequately addressed by the entity responsible for constructing the delayed facilities, the Transmission Provider will take appropriate action; including but not limited to, determining that Reassignment is necessary to complete the transmission solution as set forth in Section IX.E.3 of this Attachment FF.

IX.C.3. Default under the Selected Developer Agreement

If the Transmission Provider determines that a Selected Developer is in Default under a Selected Developer Agreement for an Eligible Project pursuant to the terms thereof.

IX.C.4 Inability to Complete Facilities

If the Transmission Provider makes a determination that a Selected Developer or an incumbent Transmission Owner will be unable to complete facilities for which it has been designated to construct; where such determination may be based on, but is not limited to the following:

a. A Selected Developer's or an incumbent Transmission Owner's inability to secure necessary approvals, permits, certificates, financing, resources, needed expertise and/or third party support identified in the Selected Proposal, property rights, rights of way, or is otherwise unable or unlikely to construct the facilities;

b. A Selected Developer's or an incumbent Transmission Owner's notification to the Transmission Provider that it is unable or unwilling to proceed with construction of its facilities for which it has been designated to construct;

c. A Selected Developer or an incumbent Transmission Owner's abandonment of the facilities it has been designated to construct;

d. A determination by the Transmission Provider that a Selected Developer is no longer a Qualified Transmission Developer; and

e. A determination by the Transmission Provider that reassignment is necessary pursuant to Section IX.E.3 of this Attachment FF.

In selecting the appropriate Variance Analysis Outcome to apply where the Transmission Provider has determined that a Selected Developer or an incumbent Transmission Owner will be unable to complete the facilities for which it has been designated to construct, the Transmission Provider will consider, but is not limited to considering the following, in addition to the general factors set forth in Section IX.D.2.1:

(i) The reasons that the Selected Developer or the Transmission Owner was unable or was unlikely to construct the facilities;

(ii) Whether the facilities are still needed;

(iii) Whether a Mitigation Plan, as further described in Section IX.E.2 of this Attachment FF, is available that could remedy the ground(s) for Variance Analysis, including consideration of the extent to which it will cost; and

(iv) Whether reassignment, as further described in Section IX.E.3 of this Attachment FF, is available, including the impacts of reassigning the facilities to another entity.

IX.C.5 Undisclosed Assignments

If the Transmission Provider determines that the Selected Developer has assigned the Competitive Transmission Facilities, Competitive Transmission Project, or Selected Developer Agreement to an entity not disclosed in its Proposal as required by Section VIII.D.5.13 or on terms materially different than those disclosed in the Proposal, except for assignments to a Project Finance Entity pursuant to Article 14.4 of the Selected Developer Agreement.

IX.D. Variance Analysis Procedure

Variance Analysis shall commence when the Transmission Provider makes an initial determination that one or more of the grounds for Variance Analysis as described in Section IX.C of this Attachment FF exists. The Transmission Provider will adhere to the following steps, as further detailed in the applicable Business Practices Manuals, in performing a Variance Analysis:

IX.D.1. Initial Inquiry and Confirmation of Grounds for Variance Analysis

Upon making an initial determination that one or more of the grounds for Variance Analysis as described in Section IX.C of this Attachment FF exists, the Transmission Provider shall notify the applicable Selected Developer or Transmission Owner in writing that Variance Analysis has commenced, including the ground(s) for commencing Variance Analysis, and a brief description of the Transmission Provider's concerns. The applicable Selected Developer or incumbent Transmission Owner shall be provided an opportunity to be heard by the Transmission Provider and present to the Transmission Provider its position on whether the identified ground(s) for Variance Analysis exist and what outcome it believes is appropriate along with supporting facts and documentation. If the Transmission Provider determines that the ground(s) for Variance Analysis do not exist after considering the Selected Developer or Transmission Owner's response and any other relevant information, the Transmission Provider shall terminate the Variance Analysis. If the Transmission Provider continues to believe that reasonable grounds for Variance Analysis exist after considering the Selected Developer or Transmission Owner's response and any other relevant information, the Transmission Provider shall continue to commence Variance Analysis and so notify the Selected Developer or Transmissions Owner.

IX.D.2. Determination of Variance Analysis Outcome

If the Transmission Provider continues to believe that reasonable ground(s) for Variance Analysis exists pursuant to the process described in Section IX.D.1 of this Attachment FF, the Transmission Provider shall further investigate the circumstances or events and the relevant facts surrounding the facilities identified in Section IX.D.1 above. Upon completing its investigation, the Transmission Provider shall make a determination of which Variance Analysis Outcome to apply, as described in Section IX.E of this Attachment FF. In determining which Variance Analysis Outcome to apply, the Transmission Provider shall consider the general factors set forth in Section IX.D.2.1 and the appropriate factors of Sections IX.E of this Attachment FF.

IX.D.2.1. **General Factors in Variance Analysis Outcome Determination**

Before deciding to impose any Variance Analysis Outcome authorized by the Tariff in Sections IX.E of this Attachment FF, the Transmission provider shall consider the following factors:

A. The causes of, or reasons for, the circumstances or events triggering Variance Analysis, including the degree of fault of the applicable Selected Developer or incumbent Transmission Owner;

B. The potential impacts to the Transmission System and the MTEP, including potential reliability, economic, or public policy impacts;

C. The degree of completion of the Eligible Projects or facilities;

D. A comparison of the estimated costs of each outcome;

E. A comparison of the degree to which each outcome will likely result in the successful completion of or increase the ability to complete the facilities and/or Eligible Projects; and

F. A comparison of the degree to which each outcome will alleviate the ground(s) for Variance Analysis.

IX.D.3. Implementation of Variance Analysis Outcome

Upon completing the procedures detailed in Section IX.D.2 of this Attachment FF, the Transmission Provider shall perform the following as further detailed in the Business Practices Manuals:

A. Inform the applicable Selected Developer(s) or incumbent Transmission Owner and any other affected parties of the Variance Analysis Outcome in writing;

B. Post a description of the Variance Analysis Outcome and the reason(s) it was selected on the Transmission Provider's website, redacting any confidential information and or Critical Energy Infrastructure Information (CEII) as necessary. The Transmission Provider shall be authorized to publically disclose confidential information, limited in scope to the specific information needed to explain the reason(s) Variance Analysis was triggered and why the Transmission Provider selected the Variance Analysis Outcome for implementation;

C. Implement the Variance Analysis Outcome in coordination with the applicable Selected Developer(s), incumbent Transmission Owner(s), and any other affected parties;

D. If implementation of the Variance Analysis Outcome results in a mitigation plan to be placed into effect that alters the schedule, cost, design, or scope of a Competitive Transmission Facility, the Transmission Provider and Selected Developer shall amend the Selected Developer Agreement to include the requirements of the mitigation plan or the Transmission Provider shall file such plan with the Commission unexecuted; and

E. If implementation of the Variance Analysis Outcome results in Reassignment or Cancellation of Competitive Transmission Facilities, the Transmission Provider shall file a Notice of Termination with the Commission to terminate the Selected Developer Agreement pursuant to the provisions of the Selected Developer Agreement. In the event that the Transmission Provider files a Notice of Termination pursuant to Section IX.E of this Attachment FF or otherwise discusses confidential information in the course of administrative or judicial proceedings, the Transmission Provider may request that the information be treated as confidential and non-public pursuant to 18 C.F.R. §1b.20 and 388.112.

IX.E. Variance Analysis Outcomes

In determining which Variance Analysis outcome to apply, the Transmission Provider shall apply the procedures specified in Section IX.D of this Attachment FF.

IX.E.1. No Action

The Transmission Provider may determine to take no action when Variance Analysis is triggered. In determining whether to take no action in Variance Analysis, the Transmission Provider will consider, but is not limited to, the following:

A. The causes of, or reasons for, the circumstances or events triggering Variance Analysis, including the degree of fault of the applicable Selected Developer or incumbent Transmission Owner;

B. The potential impacts to the Transmission System and the MTEP, including any potential reliability, economic, or public policy impacts;

C. The degree of completion of the Eligible Projects or facilities; and

D. The cost and impacts of implementing another Variance Analysis Outcome pursuant to Sections IX.E.2 through IX.E.4 of this Attachment FF as compared to taking no action.

IX.E.2. Mitigation Plan(s)

The Transmission Provider may allow a Selected Developer or incumbent Transmission Owner to alleviate the ground(s) for the Variance Analysis through a mitigation plan. If the Transmission Provider determines that a delay in the applicable facilities and/or Eligible Project's in-service date may cause the Transmission Provider or one or more Transmission Owners, Selected Developers, or non-Members to violate any Applicable Reliability Standards, the Transmission Provider shall identify the potential violation(s) and direct the impacted entities to develop a mitigation plan in coordination with the Transmission Provider. The Transmission Provider, the impacted Transmission Owners(s) and/or Selected Developers, as applicable, shall take any and all reasonable actions necessary to meet the requirements of the mitigation plan and Applicable Reliability Standards.

Mitigation plans may also be utilized to address ground(s) for Variance Analysis arising under Sections IX.C.1 through IX.C.5 that do not involve a delay of the in-service date that potentially causes violations of Applicable Reliability Standards, should the Transmission Provider determine it is appropriate. In determining whether to require a mitigation plan, the Transmission Provider will consider the factors set forth in Sections IX.D.2.1 and IX.E.1 of this Attachment FF as well as, but not limited to:

A. The extent to which the ground(s) for Variance Analysis can be remedied through a mitigation plan, if successfully implemented, including the extent to which cost can be restored to baseline and the required in-service date realized;

B. The willingness of the Selected Developer(s) or incumbent Transmission Owner(s) to implement the mitigation plan, including their willingness to bear the costs thereof;

C. The resources and ability of the Selected Developer(s) or incumbent Transmission Owner(s) to successfully implement the mitigation plan; and

D. Whether the Transmission Owner(s) that would receive the reassigned facilities would be better able to alleviate the ground(s) for Variance Analysis than the Selected Developer.

The mitigation measures may include, without limitation, any one or combination of the following components: (i) an updated implementation plan; (ii) an operating procedure; or (iii) alternative facilities and or projects to mitigate reliability violations. If a mitigation plan is used, the Transmission Provider and Selected Developer shall work together to amend the Selected Developer Agreement to reflect the mitigation plan. In the event that the Selected Developer or incumbent Transmission Owner refuses to execute the Transmission Provider's proposed mitigation plan or offer a substitute plan reasonably acceptable to the Transmission Provider, the Transmission Provider may elect either to file its proposed mitigation plan with the Commission unexecuted, select an alternate

Variance Analysis Outcome or, in if the Selected Developer is a signatory to the ISO Agreement, proceed thereunder.

IX.E.3. Reassignment

The Transmission Provider may determine to reassign Competitive Transmission Facilities in accordance with Section IX.E.3.1 of this Attachment FF. Reassignment shall also be proper if a Selected Developer fails to maintain its Qualified Transmission Developer status after the expiration of any applicable cure period. If a Selected Developer is the incumbent Transmission Owner whose service area is the service area for which the facilities triggering Variance Analysis are located, the Transmission Provider shall seek recourse through the ISO Agreement or FERC, as appropriate. In all other cases, the Transmission Provider will consider the factors set forth in Sections IX.D.2.1, IX.E.1, and IX.E.2 of this Attachment FF as well as the following, in determining whether Reassignment is applied including but not limited to:

A. Whether a mitigation plan would be sufficient to alleviate the ground(s) for Variance Analysis;

B. The actions that the incumbent Transmission Owner(s), to whom the facilities would be reassigned to if the Transmission Provider selects the Reassignment Variance Analysis Outcome, would reasonably be required to take to successfully complete the facilities;

C. The incremental costs of the Reassignment Variance Analysis Outcome; and

D. The extent of any potential delay that the Reassignment Variance Analysis Outcome may cause and any potential impacts on reliability.

If the Transmission Provider selects the Reassignment Variance Analysis Outcome, the Selected Developer(s) shall be obligated to work cooperatively and in good faith with the Transmission Provider, the incumbent Transmission Owner(s), and the affected Transmission Owner(s) and/or non-MISO transmission owners, to implement the transition.

IX.E.3.1. Procedure for Reassignment

Reassigned facilities and or projects will be offered to the applicable Transmission Owner(s), as defined below:

A. Ownership and the responsibility to construct facilities which are connected to a single Transmission Owner's system belong to that Transmission Owner;

B. Ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Transmission Owner, unless such Transmission Owners otherwise agree; and

C. Ownership and the responsibility to construct facilities which are connected between a Transmission Owner(s)' system and a system or systems that are not part of the Transmission Provider belong to such

Transmission Owner(s) unless the Transmission Owner(s) and the non-Transmission Provider party or parties otherwise agree.

If the applicable Transmission Owner(s) decline to construct the reassigned facilities and or Eligible Project, the Transmission Provider will reassign, as applicable, the facilities and/or Eligible Projects through the Competitive Transmission Developer Selection Process, as described in Section VIII of Attachment FF of the Tariff.

IX.E.4. Cancellation of Facilities and or Projects

The Transmission Provider may determine to cancel Eligible Projects and/or facilities comprising such projects. In determining whether to cancel Eligible Projects or facilities, the Transmission Provider will consider the factors set forth in Sections IX.D.2.1, IX.E.1, IX.E.2, and X.E.3 of this Attachment FF.

IX.F. Variance Analysis Confidentiality

The Transmission Provider shall not disclose to the public that a Variance Analysis has commenced until such time as it has confirmed its initial determination that a ground for Variance Analysis exists pursuant with Section IX.D.1 of this Attachment FF. Notwithstanding the preceding sentence, the Transmission Provider shall be allowed to disclose that it is commencing a Variance Analysis to third parties, including interconnecting Transmission Owners, Selected Developers, or non-Members from whom the Transmission Provider requires information to determine whether the ground(s) for Variance Analysis exist. However, no confidential information will be disclosed when the Transmission Provider solicits information from third parties unless and to the extent such disclosure is needed to obtain information necessary to determine any potential NERC reliability standards violations, service obligation issues, and economic or public policy needs that may be jeopardized.

In the event that the Transmission Provider determines pursuant to Section IX.D.1 of this Attachment FF that ground(s) for Variance Analysis do not exist, the Transmission provider shall treat any information collected pursuant to Section IX.D.1 as Project Confidential Information. In the event that the Transmission Provider determines pursuant to IX.D.1 of this Attachment FF that ground(s) for Variance Analysis do exist, the Transmission provider shall be authorized to share Project Confidential Information with such third parties as the Transmission Provider determines are reasonably necessary in order to enable the Transmission Provider to obtain needed input and information to identify any potential system reliability impacts of Variance Analysis Outcomes, including impacts from any potential NERC reliability standards violations, service obligation issues, and economic or public policy needs that may be jeopardized. The Transmission Provider shall consult with the Selected Developer and or the incumbent Transmission Owner prior to sharing any such confidential information for the purposes of discussing reasonable confidentiality safeguards.

IX.G. Variance Analysis Dispute Resolution

All disputes by the affected Selected Developer or Transmission Owner shall be addressed in accordance with the provisions of Attachment HH, except that disputes involving the termination of a Selected Developer Agreement shall be addressed in accordance with the Dispute Resolution provisions of the Selected Developer Agreement.

IX.H Project Financial Security

The Transmission Provider may utilize Project Financial Security to cover the costs of Variance Analysis resulting from Default under the Selected Developer Agreement. In such event, the Transmission Provider may draw upon such funds after confirming that a Default exists pursuant to Section IX.D.1 of this Attachment FF. The Transmission Provider shall utilize such funds to offset any costs reasonably incurred by the Transmission Provider in performing a Variance Analysis, transitioning the Competitive Transmission Project to a new Selected Developer and/or incumbent Transmission Owner(s), and otherwise distribute such funds as determined by the Commission to cover Variance Analysis and transition costs. Costs for which Project Financial Security funds may be used include reasonable consultant fees, attorneys' fees, costs of litigation and or regulatory proceedings, and staffing costs directly attributable to taking actions under the Variance Analysis provisions of the Tariff. The Transmission Provider shall track its use of Project Financial Security and provide an informational filing to the Commission within six (6) months after the Transmission Provider concludes implementation of the selected outcome.

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	10
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018	**SUPPLEMENT**	

Question:

Topic: Congestion Relief of the 161 kV Huntley-Wilmarth Alternative
Reference(s): Application, Sec. 5.1.1.2, p. 104

Support and explain the conclusion that the 161 kV Huntley-Wilmarth alternative relieves only 84% of the identified congestion and that it appears to be trending downward.

Response

The 84% is the year 2031 weighted reduction in branch congestion of the target constraint (the Huntley-Blue Earth – South Bend – Wilmarth line) measured in dollars after the transmission line alternative (Huntley – Wilmarth 161 kV alternative) is added to the MTEP17 PROMOD simulations. The observation that the Huntley – Wilmarth 161 kV alternative has a downward trending congestion relief is based on the study years 2021, 2026, and 2031 and the alternative providing congestion relief of 100%, 88% and 84%, respectively for those three years. Neither MISO nor the Applicants developed PROMOD models to perform an analysis beyond the year 2031. The congestion relief results for the Huntley – Wilmarth 161 kV alternative for three MTEP17 individual futures are shown in Table 1 below.

Table 1: Huntley – Wilmarth 161 kV Target Constraint Congestion Relief[1]

	EF (31%)	PR (43%)	AAT (26%)	Weighted
2021	99%	100%	100%	100%
2026	100%	92%	69%	88%
2031	88%	86%	78%	84%

[1] Congestion relief is shown for three MTEP17 Futures: Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT).

Supplement:

Applicants submit this supplemental response to correct the weighted congestion reduction percentage in the original response and stated on page 107 of the Certificate of Need Application. In calculating the weighted percentages for the 161 kV alternative, the MISO weighting formula for each Future was incorrectly applied to each Futures' congestion reduction percentage instead of the congestion reduction dollars meaning there were inconsistent denominators for the weighted percentages. This error was discovered while preparing Direct Testimony. Applicants recalculated the weighted percentages to correct this error. The updated weighted congestion reduction decreases from the values originally provided. Applicants updated the original response below with the updated values are underlined and the prior incorrect values are shown in strikethrough format:

The ~~84~~80% is the year 2031 weighted reduction in branch congestion of the target constraint (the Huntley-Blue Earth – South Bend – Wilmarth line) measured in dollars after the transmission line alternative (Huntley – Wilmarth 161 kV alternative) is added to the MTEP17 PROMOD simulations. The observation that the Huntley – Wilmarth 161 kV alternative has a downward trending congestion relief is based on the study years 2021, 2026, and 2031 and the alternative providing congestion relief of 100%, ~~88~~75% and ~~84~~80%, respectively for those three years. Neither MISO nor the Applicants developed PROMOD models to perform an analysis beyond the year 2031. The congestion relief results for the Huntley – Wilmarth 161 kV alternative for three MTEP17 individual futures are shown in Table 1 below.

Table 1: Huntley – Wilmarth 161 kV Target Constraint Congestion Relief[1]

	EF (31%)	PR (43%)	AAT (26%)	Weighted
2021	99%	100%	100%	100%
2026	100%	92%	69%	~~88~~75%
2031	88%	86%	78%	~~84~~80%

Preparer: Benjamin Abing
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Department: Regional Planning
Telephone: (248) 946-3341
Date: May 11, 2018 **Supplemented:** August 31, 2018

Comparison of Huntley – Wilmarth 345 kV line and Huntley – Wilmarth 161 kV line Curtailment Relief under MTEP18

Table 1
Limited Fleet Change Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2022	Huntley – Wilmarth 345 kV line	479,596	467,253	12,343	2.6%
2022	Huntley – Wilmarth 161 kV line	485,551	470,837	14,714	3.0%
2027	Huntley – Wilmarth 345 kV line	453,047	431,996	21,051	4.6%
2027	Huntley – Wilmarth 161 kV line	457,883	442,032	15,851	3.5%
2032	Huntley – Wilmarth 345 kV line	355,319	325,436	29,882	8.4%
2032	Huntley – Wilmarth 161 kV line	357,639	334,245	23,394	6.5%

Table 2
Continued Fleet Change Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2022	Huntley – Wilmarth 345 kV line	453,211	439,824	13,387	3.0%
2022	Huntley – Wilmarth 161 kV line	456,554	450,279	6,276	1.4%
2027	Huntley – Wilmarth 345 kV line	620,819	546,275	74,544	12.0%
2027	Huntley – Wilmarth 161 kV line	625,773	581,319	44,454	7.1%
2032	Huntley – Wilmarth 345 kV line	1,486,970	1,255,300	231,670	15.6%
2032	Huntley – Wilmarth 161 kV line	1,492,722	1,358,376	134,346	9.0%

Table 3
Accelerated Fleet Change Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2022	Huntley – Wilmarth 345 kV line	959,194	841,523	117,671	12.3%
2022	Huntley – Wilmarth 161 kV line	967,667	890,438	77,229	8.0%
2027	Huntley – Wilmarth 345 kV line	9,664,207	8,468,401	1,195,806	12.4%
2027	Huntley – Wilmarth 161 kV line	9,692,133	9,041,129	651,004	6.7%
2032	Huntley – Wilmarth 345 kV line	36,018,968	33,274,577	2,744,391	7.6%
2032	Huntley – Wilmarth 161 kV line	36,069,674	34,291,867	1,777,807	4.9%

Table 4
Distributed & Emerging Technologies Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2022	Huntley – Wilmarth 345 kV line	316,435	295,094	21,341	6.7%
2022	Huntley – Wilmarth 161 kV line	318,515	299,551	18,964	6.0%
2027	Huntley – Wilmarth 345 kV line	722,397	589,281	133,116	18.4%
2027	Huntley – Wilmarth 161 kV line	723,229	635,751	87,479	12.1%
2032	Huntley – Wilmarth 345 kV line	2,466,922	2,062,667	404,255	16.4%
2032	Huntley – Wilmarth 161 kV line	2,467,008	2,290,496	176,512	7.2%