BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

REPLY TESTIMONY OF BRITTANY ANDRUS

January 19, 2022

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Brittany Andrus. I am currently self-employed as a consultant in the energy industry.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of NewSun Energy LLC (NewSun).

Q. Are you the same Brittany Andrus that previously testified in this proceeding on behalf of NewSun?

A. Yes.

Q. Please summarize your testimony.

A. My testimony responds to the reply testimony submitted by the Joint Utilities, the Oregon Public Utility Commission (Commission) Staff (Staff), and the Interconnection Customer Coalition on December 11, 2020.

In this reply testimony, I take the two issues presented in this phase I of the docket in reverse order: first I address the reply testimonies' positions on the issue of whether qualifying facilities (QFs) should be required to take Network Resource Interconnection Service (NRIS) or also allowed to take Energy Resource Interconnection Service (ERIS); second, I address the reply testimonies' positions on the issue of whether users and beneficiaries should be required to pay for Network Upgrades (NUs) to interconnect a QF to the host utility; finally, I respond to testimony on Oregon's climate policies.

II. ENERGY RESOURCE INTERCONNECTION SERVICE

Q. In their direct testimony, Joint Utilities identified several reasons why they believe NRIS is the only appropriate interconnection service for QFs. Was there anything in their reply testimony on these points that you would like to respond to?

A. Yes.

Q. What are the reasons Joint Utilities identified in their direct testimony?

A. The Joint Utilities gave three reasons. First, Joint Utilities assert that NRIS is appropriate given the Federal Energy Regulatory Commission's (FERC) articulation of the requirements for the delivery of a QF's output under the Public Utility Regulatory Policies Act (PURPA).[1] They noted that they believe FERC requires QFs to be delivered on firm transmission,[2] and that "[s]ecuring NRIS thus operates as a prerequisite to allowing a generator to qualify for firm network transmission service."[3]

Second, Joint Utilities assert that allowing ERIS would violate the customer indifference standard.[4]

Third, Joint Utilities assert that there are certain practical differences between FERC-jurisdictional interconnection customers and QFs that bear on this question.[5] Specifically, the Joint Utilities elaborated that there are two "practical differences" relevant to the question. First, they note that FERC-jurisdictional generators do not necessarily operate like QFs in that they "may need firm delivery or they may not; they may be used for load service, or they may not; [and] they may be economically curtailable, or they may not," but that "[t]his operational and financial flexibility does not exist for QF power, because of the nature of the obligations QFs place on utilities."[6] Second, they note that FERC-jurisdictional generators are "often *both* the interconnection

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1 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/27 (as revised Oct. 19, 2020).
2 *Id*. at 29.
3 *Id*. at 17.
4 *Id*. at 27.
5 *Id*. at 27.
6 *Id*. at 33.

customer *and* the transmission customer," but that this "unity of identity does not necessarily exist for directly interconnected QFs."[7]

Q. Ok. So, was there anything notable in reply testimony on their first reason that you would like to respond to?

A. Yes. In reply testimony, Joint Utilities contradict themselves in agreeing with NewSun and the Interconnection Customer Coalition that the "[Open Access Transmission Tariff (OATT)] does not require a customer requesting firm transmission service to secure NRIS as a prerequisite."[8]

Q. Right, so does this mean that a generator, including a QF, could interconnect under ERIS and still get firm transmission service?

A. Yes, leaving aside the issue of whether a QF is required by FERC or otherwise to be delivered over firm transmission service, an issue I believe is better suited to briefing.

Q. Are you aware of any specific instances where a generator has interconnected with ERIS and received firm transmission in the transmission service request process?

A. Yes. Portland General Electric Company's (PGE) Port Westward 2 generating facility is interconnected with ERIS and is designated as a network resource.[9] Further, Idaho Power Company (Idaho Power) provides firm transmission service to five generators interconnected with ERIS including: Big Sky Dairy Digester (2 MW), Rock Creek Dairy Digester (2 MW), Lucky Peak (101 MW), Jackpot Solar (120 MW), and Elkhorn Wind (101 MW).[10] PacifiCorp did not provide any specific examples in response to data

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7 *Id*. at 33 (emphasis in original).
8 Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/27.
9 NewSun/401, Andrus/6 (PGE response to NewSun DR 20).
10 NewSun/402, Andrus/9 (Idaho Power response to NewSun DR 19).

requests, however, as noted above, the Joint Utilities' reply testimony confirms that NRIS is not a prerequisite to obtaining firm transmission.

Q. Thanks, moving onto to the Joint Utilities second reason to require NRIS for QFs, was there anything notable in reply testimony that you would like to respond to?

A. Yes. In reply testimony, the Joint Utilities further claim that "allowing a QF to interconnect using ERIS simply shifts the identification of deliverability driven Network Upgrades to the [Transmission Service Request (TSR)] study process and the burden of paying for those Network Upgrades to retail customers."[11] I have a few responses to this. First, as noted above, there are instances in which a generator can take ERIS in the interconnection process and still receive firm transmission in the TSR process without incurring additional upgrade costs.

Second, a QF could propose to deliver only in a narrow time window[12] during which they could avoid transmission constraints and the need for upgrades at all.

Third, the Joint Utilities' statement assumes the status quo, but the Commission is reviewing whether to make policy changes in this docket. As Staff noted in its Response Testimony, the Community Solar Program (CSP) has adopted a process "allowing generators to interconnect as ERIS and address[] Network Upgrades if they arise in the TSR process."[13] A non-CSP QF might also prefer to address Network Upgrades in the TSR process rather than in the interconnection process. And the Commission has the opportunity in this docket to consider the entire range of possibilities for how it might

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[11] Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/27.
[12] NewSun/403, Andrus/28 (PacifiCorp response to NewSun DR 27).
[13] Staff/100, Moore/34.

implement the policies it adopts.

Fourth, as pertains to the risk of cost-shifting, this assumes that there are only costs and no benefits. FERC has stated that transmission rates are ultimately a function of both the amount of power moved through the transmission system and the rate base, such that the customer pays the higher of an incremental or an embedded average cost rate.[14] FERC observed that:

> Our experience indicates that the incremental rate associated with network upgrades required to interconnect a new generator (dividing the costs of any necessary network upgrades by the projected transmission usage by the new generator) will generally be less than the embedded average cost rate (including the costs of the new facilities in the numerator and the additional usage of the system in the denominator). *In other words, in most instances, the additional usage of the transmission system by a new Interconnection Customer will generally cause the average embedded cost transmission rate to decline for all remaining customers.* Accordingly, we would expect that the Transmission Provider would want to roll-in the costs of any Network Upgrades necessary to interconnect the new generator to enable its existing transmission customers to benefit from this overall lower average embedded cost rate. This, in turn, is dependent upon an appropriate mechanism for returning any money contributed by the Interconnection Customer related to the initial financing of the necessary upgrades.[15]

As applied here, this would mean that even if network upgrade costs are shifted from the interconnection to the TSR process, in most instances, the additional usage will cause the average embedded cost to decline and thus retail customers will be better off. The additional usage of the system enabled by a particular network upgrade is one potential

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14 Order No. 2003-A, *Standardization of Generator Interconnection Agreements and Procedures*, 106 FERC ¶ 61,220 at PP. 580-581, *order on reh'g,* Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd Nat'l Ass'n of Reg. Util. Comm'rs v. FERC,* 475 F.3d 1277 (D.C. Cir. 2007) ("*NARUC v. FERC*").

15 *Id.* at P. 581.

benefit to the system, but there may be many other benefits as described more fully below.

Finally, while the legal issue of whether the customer indifference standard is violated should be addressed in briefing, this discussion demonstrates as a factual matter that in most cases, network upgrades associated with new generation will provide benefits for all transmission customers regardless of whether the cost of the upgrades is included in the transmission utility's rate base.

Q. Ok. So finally, on the Joint Utilities third reason to require NRIS for QFs, was there anything notable in reply testimony that you would like to respond to?

A. Yes. The first practical difference the Joint Utilities note between FERC-jurisdictional generators and QFs in terms of requiring firm delivery or not from an operational and PURPA perspective is essentially the same argument they made in their first reason. As I just noted, that practical difference does not hold up because even if firm delivery is required (an issue for briefing), it can still be achieved with an ERIS interconnection as the Joint Utilities admitted in reply testimony and is demonstrated by the above examples.

The second practical reason Joint Utilities provide is that FERC-jurisdictional generators are often both the interconnection customer and the transmission customer but that this unity of identity does not necessarily exist for QFs. However, this distinction also does not hold up.

Q. Can you provide specific examples?

A. Yes. There are other FERC-jurisdictional generators where the "unity of identity" the Joint Utilities describe also does not exist.

For example, on PacifiCorp's system, the following on-system generators in Oregon sell to PacifiCorp under non-PURPA agreements but have been submitted by PacifiCorp's Merchant Function to the Transmission Function under the transmission service request process: Black Cap Solar (2 MW), Combine Hills I, LLC (41 MW), Millican Solar Energy, LLC (60 MW), Old Mill Solar (5 MW), and Prineville Solar Energy, LLC (40 MW).[16]

Further, "Idaho Power holds network transmission capacity on behalf of all PURPA [QFs] and Non-PURPA facilities under contract to deliver their generation to Idaho Power," and it is "Idaho Power's Supply business unit that submits the transmission service request for facilities under contract to deliver their generation to the Company."[17] The non-PURPA generators Idaho Power lists include Elkhorn Wind (100.65 MW), Neal Hot Springs Unit #1 (22 MW), Raft River Unit #1 (13 MW), and Jackpot Holdings, LLC (120 MW).[18]

Finally, PGE did not provide a complete answer to NewSun's data request in which NewSun asked PGE to provide the entity that submitted the transmission service request for each of its power purchase agreements (PPAs). PGE further represents that the only on-system non-PURPA power purchase agreements it has are for projects that pre-date the queue concept and so PGE cannot provide queue numbers for those projects.[19]

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[16] NewSun/403, Andrus/1-5 (PacifiCorp response to NewSun DR 6); NewSun/404, Andrus/1-12 (PacifiCorp TSR Queue as of Jan 1, 2022). Note that you need to cross reference the TSR Queue Numbers provided by PacifiCorp in response to NewSun DR 6 with the TSR queue in order to locate which entity submitted the TSR.

[17] NewSun/402, Andrus/4-5 (Idaho Power response to NewSun DR 5).

[18] *Id*.

[19] NewSun/401, Andrus/2 (PGE response to NewSun DR 6).

Q. Thank you. So, in light of your findings, do you think the practical differences between QFs and non-QFs noted by the Joint Utilities justify requiring differential treatment between the two?

A. No because the practical differences they cite do not appear to hold up in every circumstance. First, even if firm transmission is required for QFs, there are non-QFs that have been able to interconnect as ERIS and obtain firm transmission. Second, as with QFs, there are also non-QFs where the "unity of identity" as both the interconnection customer and transmission customer also does not exist, but instead the utility's merchant function is the transmission customer.

Q. Is there anything else on the ERIS question that you would like to respond to?

A. No.

III. NETWORK UPGRADES

Q. On the question of who should pay for Network Upgrades, was there anything in reply testimony you would like to respond to?

A. Yes. I would like to respond to the claims that there is no evidence to support the idea that all system users may benefit from Network Upgrades or other investments in the transmission system. Specifically, Joint Utilities fault NewSun for "provid[ing] no factual support" for this assumption.[20] Additionally, Staff notes that NewSun did not provide any evidence to support the assumptions that all Network Upgrades provide system-wide benefits.[21]

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[20] Joint Utilities/300, Wilding-Macfarlane-Williams/2.
[21] Staff/200, Moore/9.

Q. How would you like to respond?

A. First, I would like to clarify that my initial testimony stated that "QFs should be reimbursed for all system upgrades other than those that demonstrably benefit only a single facility."[22] Second, while Joint Utilities fault NewSun for not providing any evidence to support the idea that other system users benefit from Network Upgrades, they too provide no evidence indicating support for the opposite assumption that Network Upgrades funded by QFs provide no benefits to the system. Indeed, PGE clarified that it "does not take the position that a Network Upgrade constructed for a QF interconnection could never result in a system-wide benefit."[23] Third, Joint Utilities and Staff both state that this issue should be addressed in Phase II of this docket.[24] Fourth, the Commission has now stated that while the question in Phase I requires some evidence to elucidate, it is essentially designated as a general policy question.[25]

So, with that context in mind, I can provide a high-level review of some evidence surrounding transmission level upgrades and the system benefits they provide. Mark Bossevian (NewSun/500) provides further testimony detailing some specific examples of how various upgrades provide benefits to the system. First, I reviewed testimony in rate cases in which the Joint Utilities' contradict their testimony in this case by detailing various types of distribution and transmission system projects and how those upgrades

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22 NewSun/200, Andrus/18.
23 NewSun/401, Andrus/5 (PGE response to NewSun DR 15).
24 Joint Utilities/300, Wilding-Macfarlane-Williams/3, 5, 6, 20, 21, 22, 26, 29, 30, 32; Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/2, 6, 15, 23, 24; Staff/200, Moore/6.
25 Order No. 21-343.

broadly benefit the entire system. Second, I provide other studies by experts in the industry describing various types of system benefits from transmission level upgrades.

Q. Thank you. Can you provide an example of evidence on system benefits in rate cases?

A. Sure. In reply testimony in this case, the Joint Utilities "disagree. . .that Network Upgrades presumptively provide system-wide benefits."[26] Yet, in PacifiCorp's rate case, Docket No. UE 374, Witness Richard A. Vail broadly claims that "[c]ustomers across the Company's six-state service territory all receive the benefit of the interconnected transmission system through access to generation resources and transfer capability across the integrated transmission system to reduce the cost of energy service by optimizing the resource mix across the entire system" and that "investments required to maintain reliable operation of all segments of the PacifiCorp transmission system benefit all customers of the transmission system, regardless of the state in which a specific customer resides."[27]

Q. Interesting, so what types of investments in the transmission system is Mr. Vail referring to?

A. In making those above statements, Witness Vail was specifically referring to out-of-state investments in new transmission lines and new substations.[28] Further on in his testimony and in an exhibit attached thereto, he provides some detail regarding "the nature and

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26 Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/2.

27 UE 374, PAC/4200, Vail/23-24, 32.

28 UE 374, PAC/4200, Vail/33-36 (The specific projects witness Vail was referring to include: 1) the Goshen-Sugarmill-Rigby 161 kV line; 2) the SW Wyoming Silver Creek Project which included multiple 138 kV and 230 kV lines; 3) the Lassen Substation; and 4) the Utah State Prison at Salt Lake City Project which would provide a 138 kV tie to an eventual new substation.)

benefit" of a variety of other transmission investments.[29] The general types of transmission investments include: transmission lines or upgrades to transmission lines, substations or upgrades to substation equipment, meters, relay equipment, communications equipment, conductors, protection and control upgrades, breakers, poles, reclosers, supervisory control and indication equipment (SCADA) and more.[30]

Q. Does PacifiCorp describe what types of benefits might result from such transmission system improvements?

A. Yes. Witness Vail notes that benefits associated with various transmission and distribution level investments include "increased load serving capability, enhanced reliability, conformance with [North American Electric Reliability Corporation (NERC)] Reliability Standards, improved transfer capability within the existing system, relief of existing congestion, and interconnection and integration of new. . . resources into PacifiCorp's transmission system."[31] Specifically, as relates to reliability upgrades, Witness Vail notes that:

> [T]he reliable performance of the transmission system in all areas—not just an area local to a single customer or group of customers—is critical to maintaining the ability to economically use the full transfer capability of the greater transmission system. Although electrically remote, a transmission line outage in Wyoming or Utah that results in a reduction in availability of a low cost energy resource, increased cost for transmission to move a resource across another transmission path, or increased cost for transmission to customers in Oregon. This occurs specifically because Oregon customers have been receiving the benefits of the transmission system in those states.[32]

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29 UE 374, PAC/4200, Vail/38; *See also* NewSun/403, Andrus/10-27 (PacifiCorp response to NewSun DR 10).

30 NewSun/403, Andrus/15-27 (PacifiCorp response to NewSun DR 10).

31 UE 374, PAC/1000, Vail/12.

32 UE 374, PAC/4200, Vail/31-32.

Further, Witness Vail describes specific system benefits of various upgrades as follows:

> to "add or enhance existing operational function,"
> to "resolve a potential overloading issue,"
> "to decrease risk of transmission equipment failure during the wildfire season,"
> to "improve the clearing times for protective relaying schemes,"
> to avoid "load shedding,"
> "to reliably serve customer,"
> to comply with "NERC Reliability Standards,"
> "to maintain compliance with system performance requirements,"
> "to ensure properly functioning equipment,"
> by "providing efficient and reliable electrical power,"
> "reduce the need for future…replacements,"
> to "improve the durability of the line,"
> to "improve[]…resistance to wildfires and severe weather,"
> "to meet firm transmission obligations,"
> among others.[33]

Q. Thank you. And what about other studies by experts in the industry?

A. Since the last round of testimony was filed in this case, several other studies have been published, which discuss the broad range of benefits that upgrades can provide to the system. Notably, FERC opened a new proceeding to review transmission planning, cost allocation, and generator interconnection (Transmission ANOPR).[34] The various studies I referenced were submitted in that docket.

Q. Great. Can you provide some examples?

A. Yes. Of note are a few studies attached to the comments of the Americans for a Clean Energy Grid (ACEG). One such study by the Brattle Group, includes a comprehensive

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33 NewSun/403, Andrus/15-27 (PacifiCorp response to NewSun DR 10).

34 Advance Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (hereafter Transmission ANOPR), FERC Docket No. RM21-17-000.

summary and quantification of transmission benefits.[35] Tables 5 and 6 from that study are reproduced below and detail several examples of benefits from transmission system upgrades:

TABLE 5. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

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[35] NewSun/405 (Transmission ANOPR, Initial Comments of Americans for a Clean Energy Grid, FERC Docket No. RM21-17 Appendix A (Oct. 12, 2021)).

[36] NewSun/405, Andrus/39.

TABLE 6. TRANSMISSION BENEFITS BEYOND ELECTRICITY SYSTEM IMPACTS

Benefit Category	Transmission Benefit
9. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
10. Increased Health Benefits	Lower fossil-fuel burn can result in better air quality

[37]

In another study, ACEG notes that:

> Large new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others. MISO, for example, has estimated that its 17 Multi-Value Projects (MVPs) approved in 2011 will generate between \$7.3 to \$39 billion in net benefits over the next 20 to 40 years, producing cost-to-benefit ratios ranging from 1.8 to 3.1. Additionally, SPP's portfolio of transmission projects constructed between 2012 and 2014 is estimated to generate upwards of \$12 billion in net benefits over the next 40 years, with a cost-to-benefit ratio of 3.5. Charging only interconnecting generators for the construction of transmission additions that generate benefits similar to those found in MISO and SPP is a classic example of the "free rider" problem. This type of market failure found in various other economic sectors involving networks, such as water and sewage systems and highways, signals why it is more efficient to broadly allocate the cost of "public goods." If required to pay for upgrades that mostly benefit others, interconnecting generators tend to balk and drop out of the interconnection queue.[38]

Q. Thank you. What does this evidence about types of transmission system investments and the benefits they provide to the system lead you to conclude as relates to this case?

A. Well, it is my understanding that these transmission level investments are the same types of network upgrades that a QF may be required to fund in the interconnection process, and in light of the vast array of benefits such upgrades provide to the system, it appears

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37 NewSun/405, Andrus/40.
38 NewSun/406, Andrus/16 (Transmission ANOPR, Initial Comments of Americans for a Clean Energy Grid, FERC Docket No. RM21-17 Appendix B (Oct. 12, 2021)).

categorically impossible for there to be no benefits to the system flowing from projects funded by QFs.

Q. Is there anything else in the reply testimony that you would like to respond to?

A. Yes. Joint Utilities note that state utility jurisdiction only attaches to QF interconnections where the QF is selling 100 percent of its output to the directly interconnected utility.[39] However, the issue is more nuanced than that.

Q. Can you please explain?

Yes. First, I will point out that the Joint Utilities' statement necessarily implies that state jurisdiction does not attach to QF interconnections when the QF is "off-system," i.e., selling its output to a utility to which it is not interconnected, or if it is selling anything less than 100 percent of its output to its directly interconnected utility. Second, Idaho Power and PacifiCorp both clarified that they will use the FERC-jurisdictional interconnection rules to process an interconnection request for a facility that is certified as a QF but that does not invoke PURPA's must-purchase obligation to sell 100 percent of its power to a directly interconnected utility.[40] Third, projects can switch between being a QF or not, in order to gain more favorable treatment.

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[39] Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/32.

[40] NewSun/403, Andrus/6 (PacifiCorp clarifying email in response to NewSun DR 6); NewSun/402, Andrus/7 (Idaho Power clarifying email in response to NewSun DR 5) (Note that Idaho Power initially noted in DR 5 that Neal Hot Springs interconnected under the Oregon Generator Interconnection Rules, but later clarified that this was in error).

Q. Can you provide any examples?

A. Yes. Neal Hot Springs is an interesting example. As noted above, that project sells to Idaho Power under a non-PURPA agreement. Yet, it has several QF self-certifications on file in FERC docket QF12-389.[41] Without opining on whether those are still legally in effect, I see no notice withdrawing any self-certifications. In addition, in docket IPC-E-09-34 before the Idaho Public Utilities Commission (IPUC), I noted that the IPUC approved the Neal Hot Springs agreement specifically stating that it was not a PURPA contract and offering the following comparison:

> Beginning in 2012, the flat energy price is $96/MWh. The price escalates annually, resulting in a 25-year levelized contract price of approximately $117.56/MWh. This compares to a levelized price for a 20-year PURPA contract of $95.56/MWh. . .The Application states that with the addition of a relatively minor system upgrade, sufficient firm transmission capacity is available for the full output of the project to be delivered to Idaho Power's load centers.[42]

Another example is the Pryor Mountain wind project. According to Witness Vail, the project was initially proposed as a QF under PURPA and would have been responsible for 100 percent of the interconnection costs with no reimbursement from PacifiCorp.[43] PacifiCorp later purchased the project making it no longer a QF under PURPA and instead subject to PacifiCorp's OATT process.[44] Not only that, but when PacifiCorp decided to invest in the project its QF avoided cost pricing in Wyoming was $26.00 per

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41 FERC Docket No. QF12-389.

42 *In re Application of Idaho Power for Approval of an Agreement to Purchase Capacity and Energy from USG Oregon, LLC and Authorize Recovery in the Company's Power Cost Adjustment*, IPUC Docket No. IPC-E-09-34, Order No. 31087 (May 20, 2010).

43 UE 374, PAC/4200, Vail/18.

44 *Id*. at 19.

MWh, but PacifiCorp sought rate recovery for more than $26.00 per MWh from its investment in Pryor Mountain.[45]

Q. Thank you. So, what do you conclude based on these examples?

A. I conclude that it makes no sense from a practical and policy perspective to single out on-system QFs that invoke PURPA's must-purchase obligation to sell 100 percent of their output to their interconnected utility for differential treatment. Rather, all generators should have the option to interconnect via either ERIS or NRIS and get reimbursements for network upgrades. At a minimum, generators subject to the state's jurisdiction should be no worse off than FERC-jurisdictional interconnection customers.

IV. OREGON'S CLIMATE POLICY

Q. In your initial testimony, you commented that the process for funding and delivering system upgrades would need to undergo significant change in order to advance Oregon's climate goals. Is there anything in reply testimony related to this, that you would like to respond to?

A. Yes. Staff agrees that expanding the capacity of the transmission system is likely required to meet the state's greenhouse gas reduction goals but is concerned about the cost of doing so.[46]

Q. How do you respond?

A. First, I would note that since the last round of testimony, the Oregon Legislature passed HB 2021, which accelerates the State's greenhouse gas emissions reduction targets by

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[45] *In re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations*, Utah Pub. Serv. Comm'n Docket No. 20-035-04, Post-Hearing Brief of the Utah Association of Energy Users at 3-4 available at https://pscdocs.utah.gov/electric/20docs/2003504/316613PstHrngBrfUAE11-30-2020.pdf.

[46] Staff/200, Moore/10.

ensuring that investor-owned utilities and electricity service suppliers reduce greenhouse gas emissions associated with electricity sold in Oregon: 80% emissions reductions by 2030, 90% by 2035, and 100% by 2040.

Second, Joint Utilities have individually published Integrated Resource Plans (IRPs) and Requests for Proposals (RFPs) estimating their renewable resource needs, in the thousands of MW within the remainder of this decade (summarized below in Table 1).

Third, Oregon has vast renewable resource potential, and the need for upgraded transmission system has been clearly identified in multiple studies.[47]

<u>Table 1: Summary of Renewable Acquisitions During the 2020s.</u>

PGE	"…the **approximately 1,500 – 2,000 MW of clean and renewable resources we estimate we will need between now and 2030** to meet our target. We also estimate we will need **approximately 800 MW of non-emitting capacity resources by 2030** to help ensure continued reliable service is available for all. To make necessary progress to meet the 2030 GHG reduction target and the clean energy expectations of our customers, we are seeking through our RFP approximately 400 – 500 MW of clean and renewable resources, approximately 375 MW of non-emitting capacity resources and an additional 100 MW of clean and renewable resources to meet customer demand in support of PGE's Green Tariff…"[48]
PacifiCorp	"The 2022AS RFP contains the following components: • Seeks **up to 1,345 MW of new wind and solar resources co-located with 600 MW of new battery energy storage** system capacity. Eligible bids will be accepted throughout PacifiCorp service territory including bids from off-system resources.

47 See, e.g., Oregon Renewable Energy Siting Assessment (ORESA) available at https://www.oregon.gov/energy/energy-oregon/Pages/ORESA.aspx.

48 Docket No. UM 2166, PGE cover letter to 2021 RFP, October 15, 2021. https://edocs.puc.state.or.us/efdocs/HAC/um2166hac155830.pdf.

	• Projects must achieve a **commercial operation date of no later than December 31, 2026**”[49]
Idaho Power	“[t]he 20-year plan includes the addition of 3,790 megawatts (MW) of new non-carbon emitting resources consisting of wind, solar, and storage technologies,”[50] including **700 MW of wind and 1,105 MW of solar by 2030**, as shown below in an excerpt from the recently filed 2021 IRP.

Table 1.1 Preferred Portfolio additions and coal exits (MW)

	Base B2H (MW)						
Year	Gas	Wind	Solar	Storage	Trans.	DR	Coal Exits
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	300	0
2023	0	0	120	115	0	20	-357
2024	357	700	0	5	0	0	0
2025	0	0	300	105	0	20	-308
2026	0	0	215	0	500	0	0
2027	0	0	250	5	0	0	0
2028	0	0	120	55	0	0	-175
2029	0	0	100	255	0	0	0
2030	0	0	0	55	0	0	0

Q. And what do you conclude based on your review or Oregon’s Climate Goals as relates to this docket?

A. Interconnected renewables in Oregon will certainly play a significant role in meeting utility obligations under HB 2021. Significant upgrades to the transmission system in Oregon are inevitable and necessary given these realities, and the existing interconnection processes and policies cannot support this buildout. This problem is demonstrated by the low success rates of renewable projects seeking interconnection, and significant numbers

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49 Docket No. UM 2193, PacifiCorp Application for Approval of 2022 All-Source Request for Proposals https://edocs.puc.state.or.us/efdocs/HAH/um2193hah155625.pdf.

50 Docket No. LC 78, Idaho Power Company 2021 Integrated Resource Plan, filed December 20, 2021. https://edocs.puc.state.or.us/efdocs/HAA/lc78haa103337.pdf

of projects dropping out of interconnection queues largely due to inefficient and ineffective processes. For example, many QF projects previously in the interconnection queues have now withdrawn or been removed, in large part due to the policies at issue in this docket. My comments in my initial testimony indicating that significant change will be needed to efficiently develop the resources needed to support Oregon's climate goals are even more pronounced now following the changes observed this last year.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/401

PORTLAND GENERAL ELECTRIC RESPONSES TO DATA REQUESTS

January 19, 2022

June 16, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Third Supplemental Response to NewSun Data Request No. 006
Dated January 6, 2020

Request:

Please list all power purchase agreements under which PGE purchases power including:

a. Project name,
b. Nameplate capacity,
c. Term of power purchases,
d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,
e. Whether the facility is certified as a qualifying facility under PURPA,
f. Under what interconnection rules/process the facility was interconnected,
g. Whether the facility interconnected as ERIS or NRIS,
h. The cost of network upgrades funded under the interconnection agreement,
i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,
j. The type of transmission service,
k. The entity that submitted the transmission service request,
l. The cost of network upgrades funded under the transmission service request.

Third Supplemental Response:

On May 11, 2021, Marie Barlow sent an email to counsel for the Joint Utilities requesting additional information. One of the requests, directed to PGE, was that PGE "provide [NewSun] with [QF] interconnection studies or make them publicly available like they are for PacifiCorp and Idaho Power."

As discussed in previous data requests, interconnection studies for small QFs are publicly available on OASIS (https://www.oasis.oati.com/pge/), with the following pathway: Generation Interconnection → Oregon Small Generator Interconnection→ Study Reports. In the update to Attachment A to NIPPC DR 1, PGE provides the queue number for small QFs where applicable. Accordingly, it is PGE's understanding that NewSun should be able to match the publicly available interconnection studies for small QF generators with their respective projects using the queue numbers in Attachment A to NIPPC DR 1.

Counsel for NewSun further claims in the email that PGE's "interconnection studies are not even publicly available on OASIS." It is PGE's understanding that counsel for NewSun is referring to the folder for large QF interconnection studies, with the following pathway: Generation Interconnection → Interconnection Studies and Cases → Interconnection Studies and Cases Website. To comply with FERC Order No. 845 and requirements to protect customers' sensitive business information, interconnection studies for large projects are kept on a SharePoint website where access to the public is available by submitting a request form to PGE.

Because of this security measure to protect customers' confidential information, PGE provided the relevant large QF interconnection studies identifying Network Upgrades as attachments in the Company's response to NIPPC DR 3. In its initial response to NewSun DR 6, PGE directed NewSun to PGE's Response to NIPPC DR 3, where PGE attached the then available interconnection studies and restudies for two large QFs identifying Network Upgrades. Project # 17-068 is Madras Solar and Project #19-081 is Jefferson Solar.

Please see Attachments 003A, 003B, and 003C for the studies, which identify all Network Upgrades.

A restudy for one of the two large QFs was recently completed on May 3, 2021. For the new restudy, please see Attachment 003D.

June 2, 2021

<u>Second Supplemental Response:</u>

On May 11, 2021, Marie Barlow sent an email to counsel for the Joint Utilities requesting additional information. One of the requests, directed to PGE, was that PGE supplement its response to DR 6 by providing information that NewSun could use to link generation facilities that have a PPA to their interconnection and transmission arrangements. In a follow up call, Ms. Barlow clarified that NewSun requests that PGE update its attachments provided in responses to NIPPC DR 1 and NIPPC DR 33 by providing queue numbers.

In the attached update to Attachment A to DR 1, PGE provides the queue number where applicable. With respect to the projects listed on Attachment A to DR 33, all of these projects except Covanta and Yamhill are off system and therefore do not have PGE queue numbers. Both the Covanta and Yamhill project predate the queue concept.

Also, in response to a question posed by Ms. Barlow in the May 11, 2021 email, if a generator wishes to negotiate a non-QF PPA, PGE does not check to determine whether or not that generator might be certified with FERC as a QF.

March 5, 2021

<u>Supplemental Response:</u>

After conferral with NewSun, PGE understands that the intent of these data requests was to allow NewSun to trace specific generators through the interconnection and transmission-service-request processes to evaluate the Joint Utilities' testimony that Network Upgrades can be shifted from the interconnection process to the transmission-service-request process when a generator interconnects with ERIS instead of NRIS. PGE notes that the potential for upgrade-shifting that NewSun seeks to confirm is a straightforward application of the OATT and related FERC orders. In addition, as noted in PGE's initial responses, the additional information NewSun requests is voluminous and would be extremely burdensome to compile, if it were even available. However, PGE provides this supplemental response in an effort to respond directly to the narrower question that PGE now understands NewSun is asking. PGE understands that NewSun is not interested in reviewing every transmission and interconnection study, and PGE believes that this supplemental response more efficiently and directly responds to NewSun's question than providing information about numerous interconnection and transmission service requests.

As PGE has explained in testimony and in response to other data requests, all of PGE's on-system QFs interconnected with NRIS. Of the on-system, non-QF resources that PGE owns or purchases power from, only one generator originally interconnected with ERIS.[1] As PGE previously indicated in response to NewSun Data Request No. 20, "PGE's Port Westward 2 generating facility interconnected with ERIS. No network upgrades were required to designate Port Westward 2 as a network resource because sufficient transmission capacity existed on PGE's system to deliver the output to PGE's network load." Port Westward 2 is located near PGE's Port Westward 1 and Beaver facilities. When developing and interconnecting Port Westward 2, PGE's Merchant Function knew that it already possessed sufficient transmission capacity to deliver Port Westward 2's output to PGE's load and therefore decided to interconnect the facility using ERIS.

To the extent NewSun is interested in identifying the magnitude of Network Upgrades that could be shifted if a generator interconnected with ERIS, Attachment 001A to PGE's response to Staff Data Request No. 1 shows the deliverability-driven Network Upgrades PGE has identified in system impact studies for two large generators, one of which is a QF with more than $10 million in deliverability-driven Network Upgrades.

Note this response applies to NewSun Data Request Nos. 6, 8, 19 and 20.

January 21, 2021

<u>Response:</u>

PGE objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

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[1] Many of PGE's on-system resource interconnected well before FERC issued Order 2003, which adopted the NRIS and ERIS concepts, and took effect on January 20, 2004. See Order 2003-A at ¶ 40.

Notwithstanding and without waiving these objections: Please see PGE's Responses to NIPPC Data Request Nos. 1, 2, 3, 4, 7, 8, 31, and 33; PGE's Response to Staff Data Request Nos. 5, 8, and 12; docket RE 143; and PGE's small and large generator interconnection queues, which are publicly available on OASIS. PGE does not track and compile information regarding the interconnection arrangements of the resources from which it purchases under non-QF PPAs or the off-system QFs from which it purchases. All QFs directly interconnected to PGE interconnected with NRIS. Similarly, PGE does not compile information regarding the off-system transmission arrangements of resources from which it purchases. PGE has not constructed any Network Upgrades on PGE's transmission system associated with requests for transmission service from PGE.

January 20, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NewSun Data Request No. 015
Dated January 6, 2020

Request:

Please provide all evidentiary support for the premise that upgrades to the transmission network caused by qualifying facility interconnections provide no system benefits.

Response:

PGE objects that this request is lacking in foundation, and that the request for "all evidentiary support" is overly broad and vague and ambiguous. PGE also objects to the extent this request suggests that the referenced "premise" is PGE's position. Notwithstanding and without waiving these objections: In this context, system-wide benefits result from Network Upgrades that are prudent when the need for the upgrade and its costs are considered. PGE does not take the position that a Network Upgrade constructed for a QF interconnection could never result in a system-wide benefit.

January 20, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NewSun Data Request No. 020
Dated January 6, 2020

Request:

Identify all instances in which PGE provides firm transmission service, including either Network Interconnection Transmission Service or Point-to-Point Transmission service, to generators interconnected using ERIS.

Response:

PGE objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. PGE also objects that this request asks PGE to develop information that would be unduly burdensome and does not have a high degree of relevance to the case.

Notwithstanding and without waiving these objections:

Please see PGE's Response to NewSun Data Request No. 19. PGE typically does not have insight into the interconnection arrangements for resources that are not interconnected directly to PGE. Please see PGE's Responses to NewSun Data Requests Nos. 29 and 30 for information about interconnection arrangements for the PGE-owned, off-system Carty and Wheatridge resources. All of the QFs that are designated network resources and interconnected directly to PGE obtained NRIS. PGE's Port Westward 2 generating facility interconnected with ERIS. No network upgrades were required to designate Port Westward 2 as a network resource because sufficient transmission capacity existed on PGE's system to deliver the output to PGE's network load.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/402

IDAHO POWER RESPONSES TO DATA REQUESTS

January 19, 2022

<u>NEWSUN DATA REQUEST NO. 5</u>:

Please list all power purchase agreements under which Idaho Power purchases power including:

- a. **Project name,**
- b. **Nameplate capacity,**
- c. **Term of power purchases,**
- d. **Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,**
- e. **Whether the facility is certified as a qualifying facility under PURPA,**
- f. **Under what interconnection rules/process the facility was interconnected,**
- g. **Whether the facility interconnected as ERIS or NRIS,**
- h. **The cost of network upgrades funded under the interconnection agreement,**
- i. **Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,**
- j. **The type of transmission service,**
- k. **The entity that submitted the transmission service request,**
- l. **The cost of network upgrades funded under the transmission service request.**

<u>IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 5</u>:

Idaho Power objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

Subject to and without waiving the foregoing objection, Idaho Power responds as follows: Idaho Power's responses to subparts a. – f. are in the table below:

a.	b.	c.	d.	e.	f.
Project Name	**Nameplate Capacity**	**Contract Term**	**Contract Type**	**PURPA QF**	**Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")**
American Falls Solar II, LLC	20.00	20	PURPA	Yes	Schedule 72
American Falls Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Arena Drop	0.45	20	PURPA	Yes	Schedule 72
Baker City Hydro	0.24	15	PURPA	Yes	Off-System
Baker Solar Center	15.00	20	PURPA	Yes	OCGIR
Bannock County Landfill	3.20	20	PURPA	Yes	Schedule 72
Barber Dam	3.70	35	PURPA	Yes	Schedule 72
Bennett Creek Wind Farm	21.00	20	PURPA	Yes	Schedule 72
Benson Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Birch Creek	0.07	20	PURPA	Yes	Schedule 72
Black Canyon #3	0.13	20	PURPA	Yes	Schedule 72
Black Canyon Bliss Hydro	0.03	20	PURPA	Yes	Schedule 72
Blind Canyon	1.63	20	PURPA	Yes	Schedule 72
Box Canyon	0.30	20	PURPA	Yes	Schedule 72

a.	b.	c.	d.	e.	f.
Project Name	**Nameplate Capacity**	**Contract Term**	**Contract Type**	**PURPA QF**	**Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")**
Briggs Creek	0.60	20	PURPA	Yes	Schedule 72
Brush Solar	2.75	20	PURPA	Yes	OCGIR
Burley Butte Wind Park	21.30	20	PURPA	Yes	Schedule 72
Bypass	9.96	35	PURPA	Yes	Schedule 72
Camp Reed Wind Park	22.50	20	PURPA	Yes	Schedule 72
Canyon Springs	0.11	20	PURPA	Yes	Schedule 72
Cassia Wind Farm LLC	10.50	20	PURPA	Yes	Schedule 72
Cedar Draw	1.55	20	PURPA	Yes	Schedule 72
Clear Springs Trout	0.56	20	PURPA	Yes	Schedule 72
Cold Springs Windfarm	23.00	20	PURPA	Yes	Schedule 72
Crystal Springs	2.44	35	PURPA	Yes	Schedule 72
Curry Cattle Company	0.25	15	PURPA	Yes	Schedule 72
Desert Meadow Windfarm	23.00	20	PURPA	Yes	Schedule 72
Dietrich Drop	4.50	35	PURPA	Yes	Schedule 72
Durbin Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Eightmile Hydro Project	0.36	20	PURPA	Yes	Schedule 72
Elk Creek	2.00	35	PURPA	Yes	Schedule 72
Fall River	9.10	35	PURPA	Yes	Schedule 72
Fargo Drop Hydroelectric	1.27	20	PURPA	Yes	Schedule 72
Faulkner Ranch	0.87	35	PURPA	Yes	Schedule 72
Fighting Creek Landfill Gas	3.06	15	PURPA	Yes	Off-System
Fisheries Dev.	0.26	50	PURPA	Yes	Schedule 72
Fossil Gulch Wind	10.50	20	PURPA	Yes	Schedule 72
Geo-Bon #2	0.93	35	PURPA	Yes	Schedule 72
Golden Valley Wind Park	12.00	20	PURPA	Yes	Schedule 72
Grand View PV Solar Two	80.00	20	PURPA	Yes	Schedule 72
Grove Solar Center, LLC	6.00	20	PURPA	Yes	OCGIR
Hailey CSPP	0.04	5	PURPA	Yes	Schedule 72
Hammett Hill Windfarm	23.00	20	PURPA	Yes	Schedule 72
Hazelton A	8.10	15	PURPA	Yes	Schedule 72
Hazelton B	7.60	35	PURPA	Yes	Schedule 72
Head of U Canal Project	1.28	20	PURPA	Yes	Schedule 72
Hidden Hollow Landfill Gas	3.20	20	PURPA	Yes	Schedule 72
High Mesa Wind Project	40.00	20	PURPA	Yes	Schedule 72
Horseshoe Bend Hydro	9.50	35	PURPA	Yes	Schedule 72
Horseshoe Bend Wind	9.00	20	PURPA	Yes	Off-System
Hot Springs Wind Farm	21.00	20	PURPA	Yes	Schedule 72
Hyline Solar Center, LLC	9.00	20	PURPA	Yes	OCGIR
ID Solar 1	40.00	20	PURPA	Yes	Schedule 72
Jett Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Jim Knight	0.34	35	PURPA	Yes	Schedule 72
Koyle Small Hydro	1.25	20	PURPA	Yes	Schedule 72
Lateral #10	2.06	20	PURPA	Yes	Schedule 72

a.	b.	c.	d.	e.	f.
Project Name	**Nameplate Capacity**	**Contract Term**	**Contract Type**	**PURPA QF**	**Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")**
LeMoyne Hydro	0.08	10	PURPA	Yes	Schedule 72
Lime Wind Energy	3.00	20	PURPA	Yes	OCGIR
Little Wood River Ranch II	1.25	20	PURPA	Yes	Schedule 72
Little Wood Rvr Res	2.85	20	PURPA	Yes	Schedule 72
Littlewood / Arkoosh	0.87	35	PURPA	Yes	Schedule 72
Low Line Canal	8.20	20	PURPA	Yes	Schedule 72
Low Line Midway Hydro	2.50	20	PURPA	Yes	Schedule 72
Lowline #2	2.79	35	PURPA	Yes	Schedule 72
Magic Reservoir	9.07	35	PURPA	Yes	Schedule 72
Mainline Windfarm	23.00	20	PURPA	Yes	Schedule 72
Malad River	1.17	20	PURPA	Yes	Schedule 72
Marco Ranches	1.20	20	PURPA	Yes	Schedule 72
Mile 28	1.50	35	PURPA	Yes	Schedule 72
Milner Dam Wind	19.92	20	PURPA	Yes	Schedule 72
Mitchell Butte	2.09	45	PURPA	Yes	OCGIR
Mora Drop Hydro	1.85	20	PURPA	Yes	Schedule 72
Morgan Solar	3.00	20	PURPA	Yes	OCGIR
Mt. Home Solar 1, LLC	20.00	20	PURPA	Yes	Schedule 72
Mud Creek S and S	0.52	20	PURPA	Yes	Schedule 72
Mud Creek/White	0.21	35	PURPA	Yes	Schedule 72
Murphy Flat Power, LLC	20.00	20	PURPA	Yes	Schedule 72
North Gooding Main Hydro	1.30	20	PURPA	Yes	Schedule 72
Ontario Solar Center	3.00	20	PURPA	Yes	OCGIR
Open Range Solar Center	10.00	20	PURPA	Yes	OCGIR
Orchard Ranch Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Oregon Trail Wind Park	13.50	20	PURPA	Yes	Schedule 72
Owyhee Dam Cspp	5.00	40	PURPA	Yes	OCGIR
Payne's Ferry Wind Park	21.00	20	PURPA	Yes	Schedule 72
Pico Energy, LLC	2.13	10	PURPA	Yes	Schedule 72
Pigeon Cove	1.75	20	PURPA	Yes	Schedule 72
Pilgrim Stage Station Wind	10.50	20	PURPA	Yes	Schedule 72
Pocatello Waste	0.46	35	PURPA	Yes	Schedule 72
Pristine Springs #1	0.13	20	PURPA	Yes	Schedule 72
Pristine Springs #3	0.20	20	PURPA	Yes	Schedule 72
Prospector Windfarm	10.00	20	PURPA	Yes	OCGIR
Railroad Solar Center, LLC	4.50	20	PURPA	Yes	OCGIR
Reynolds Irrigation	0.26	35	PURPA	Yes	Schedule 72
Rock Creek #1	2.17	20	PURPA	Yes	Schedule 72
Rock Creek #2	1.90	35	PURPA	Yes	Schedule 72
Rockland Wind Farm	80.00	25	PURPA	Yes	Schedule 72
Ryegrass Windfarm	23.00	20	PURPA	Yes	Schedule 72
Sagebrush	0.43	35	PURPA	Yes	Schedule 72
Sahko Hydro	0.50	10	PURPA	Yes	Schedule 72

a.	b.	c.	d.	e.	f.
Project Name	**Nameplate Capacity**	**Contract Term**	**Contract Type**	**PURPA QF**	**Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")**
Salmon Falls Wind	22.00	20	PURPA	Yes	Schedule 72
Sawtooth Wind Project	22.00	20	PURPA	Yes	Schedule 72
Schaffner	0.53	35	PURPA	Yes	Schedule 72
Shingle Creek	0.22	5	PURPA	Yes	Schedule 72
Shoshone #2	0.58	35	PURPA	Yes	Schedule 72
Shoshone CSPP	0.36	20	PURPA	Yes	Schedule 72
Simcoe Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Simplot - Pocatello	15.90	3	PURPA	Yes	Schedule 72
SISW LFGE	5.00	20	PURPA	Yes	Schedule 72
Snake River Pottery	0.09	8	PURPA	Yes	Schedule 72
Snedigar	0.50	20	PURPA	Yes	Schedule 72
Tamarack CSPP	6.25	20	PURPA	Yes	Schedule 72
Tasco - Nampa	2.00	5	PURPA	Yes	Schedule 72
Tasco - Twin Falls	3.00	1	PURPA	Yes	Schedule 72
Thousand Springs Wind Park	12.00	20	PURPA	Yes	Schedule 72
Thunderegg Solar Center, LLC	10.00	20	PURPA	Yes	OCGIR
Tiber Dam	7.50	20	PURPA	Yes	Off-System
Trout-Co	0.24	35	PURPA	Yes	Schedule 72
Tuana Gulch Wind Park	10.50	20	PURPA	Yes	Schedule 72
Tuana Springs Expansion	35.70	20	PURPA	Yes	Schedule 72
Tunnel #1	7.00	42	PURPA	Yes	OCGIR
Two Ponds Windfarm	23.00	20	PURPA	Yes	Schedule 72
Vale Air Solar Center, LLC	10.00	20	PURPA	Yes	OCGIR
Vale I Solar	3.00	20	PURPA	Yes	OCGIR
White Water Ranch	0.16	20	PURPA	Yes	Schedule 72
Willow Spring Windfarm	10.00	20	PURPA	Yes	OCGIR
Wilson Lake Hydro	8.40	35	PURPA	Yes	Schedule 72
Yahoo Creek Wind Park	21.00	20	PURPA	Yes	Schedule 72
Coleman Hydro	0.80	20	PURPA	Yes	Schedule 72
Durkee Solar	3.00	20	PURPA	Yes	OCGIR
MC6 Hydro	2.10	20	PURPA	Yes	Schedule 72
Elkhorn Wind	100.65	25	RFP	N/A	OCGIR
Neal Hot Springs Unit #1	22	25	RFP	N/A	OCGIR
Raft River Unit #1	13	25	RFP	N/A	Off-System
Jackpot Holdings, LLC	120	20	Bi-Lateral	N/A	Schedule 72

g. All PURPA Qualifying Facilities and Non-PURPA facilities interconnected to Idaho Power's system and under contract to deliver their generation to the Company are designated as Network Resources.

h. See the Excel spreadsheet attached to the Company's Response to NIPPC DR No. 7 and Confidential Excel spreadsheet attached to the Company's Response to Staff's IR No. 12.

i. See Idaho Power's response to subpart h.

j. Idaho Power holds network transmission capacity on behalf of all PURPA Qualifying Facilities and Non-PURPA facilities under contract to deliver their generation to Idaho Power pursuant to the completion of any transmission system upgrades, at the generation facility's expense, required to serve network load with generation from the contracted facility.

k. Idaho Power's Power Supply business unit submits the transmission service request for facilities under contract to deliver their generation to the Company.

l. See Idaho Power's response to subpart h.

<u>NEWSUN DATA REQUEST NO. 5</u>:

Please list all power purchase agreements under which Idaho Power purchases power including:

- **a. Project name,**
- **b. Nameplate capacity,**
- **c. Term of power purchases,**
- **d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,**
- **e. Whether the facility is certified as a qualifying facility under PURPA,**
- **f. Under what interconnection rules/process the facility was interconnected,**
- **g. Whether the facility interconnected as ERIS or NRIS,**
- **h. The cost of network upgrades funded under the interconnection agreement,**
- **i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,**
- **j. The type of transmission service,**
- **k. The entity that submitted the transmission service request,**
- **l. The cost of network upgrades funded under the transmission service request.**

<u>IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO NEWSUN DATA REQUEST NO. 5</u>:

l. Idaho Power's prior response to parts h and l cross-referenced the Company's attachment in response to Staff IR No. 12, which provided network upgrade actual costs. For the purpose of clarification:

- The provided costs for PURPA projects in Idaho Power's process constitute both the interconnection-related network upgrades and the transmission service-related network upgrades.
- For the PPAs and the exchange agreement listed in the Company's response to Staff IR No. 12 (Elkhorn, Neal Hot Springs and Arrowrock), there were no transmission service-related network upgrades for the service Idaho Power currently provides.
- For the Jackpot Holdings agreement included in the original response to this DR, the estimated transmission service network upgrade costs total $10,483,000.

Subject: RE: UM 2032 DR Clarifications
Date: Monday, May 17, 2021 at 4:01:48 PM Pacific Daylight Time
From: Adam Lowney
To: Marie Barlow
CC: Annis, Mark, Donovan Walker (DWalker@Idahopower.com)

Hi Marie,

Idaho Power objected to DR 7 on the ground that it was overly broad and unduly burdensome. Despite that objection, Idaho Power provided extensive data for Oregon interconnections. Idaho Power believes that its response is reasonable and adequate, and does not believe that a request for information for generators beyond Oregon is reasonable, appropriate, or justified in this instance. If NewSun disagrees, however, Idaho Power would be interested in understanding why the information provided is inadequate.

Regarding your second question, the interconnection rules that apply to a particular generator are dictated by whether the interconnection is subject to state or FERC jurisdiction. The Joint Utilities' testimony (page 7 of Joint Utilities/100) explains when a QF interconnection is subject to FERC's jurisdiction. The Neal Hot Springs project was interconnected pursuant to Idaho Power's OATT because it is not selling its output to Idaho Power pursuant to a QF PPA. The reference in DR 5 to the Oregon rules is therefore an error.

Please feel free to give me a call if you'd like to discuss further.

Adam

Adam Lowney
McDowell Rackner Gibson PC
419 SW 11th Ave, Suite 400 Portland, OR 97205
Direct: 503-595-3926 | Mobile: 503-956-0081
Website: www.mrg-law.com | Email: adam@mrg-law.com
Pronouns: he/him/his

From: Marie Barlow <mbarlow@newsunenergy.net>
Sent: Tuesday, May 11, 2021 4:08 PM
To: Jordan Schoonover <jordan@mrg-law.com>; Lisa Rackner <lisa@mrg-law.com>; donald.light@pgn.com; Adam Lowney <adam@mrg-law.com>; Walker, Donovan <DWalker@Idahopower.com>; Lisa Hardie <lisa.hardie@mrg-law.com>; karen.kruse@pacificorp.com; carla.scarsella@pacificorp.com
Subject: [External] UM 2032 DR Clarifications

Good Afternoon All,

I had a few clarifying questions regarding your supplemental responses to our data requests and was hoping you would be able to answer these in order to limit the issues for the motion to compel. These are all relating to the three questions NewSun asked of each utility regarding PPAs (PGE DR 6, PAC DR 6, IPC DR 5), interconnections (PGE DR 7, PAC DR 8, IPC DR 7) and transmission arrangements (PGE DR 19, PAC DR 24, IPC DR 18) in order to understand the relationship between all three.

First, the requests were meant to cover more than just Oregon-sited projects. In response to PAC DR 6 and Idaho Power DR 7, it appears that only Oregon-sited projects were listed. Can each of you expand those responses to the entire system?

Second, NewSun was seeking to understand which interconnection rules each utility applies or will apply to a facility that is certified as or eligible to be a QF but sells under a contract that is something other than a QF PPA, such as an RFP or bi-lateral agreement. Your responses appear inconsistent with QF certifications filed at FERC and/or the OPUC, so we wanted to seek clarifications. For example, the Neal Hot Springs geothermal project listed in Idaho Power's data responses appears to be certified as a QF at FERC, but is listed as not a QF in the data responses. Also in response to DR 5, Idaho Power notes that Neal is interconnected under the Oregon Commission Interconnection Rules, but in response to DR 8 Idaho Power notes they were FERC jurisdictional. Can you please clarify? I also noted that PGE's Portland Hydro and PAC's Black Cap Solar projects both have a QF certification on file with the OPUC, but your responses indicated that they were no QFs. Can you clarify your responses on those projects? I have not reviewed each and every project and whether it has a QF certification on file with FERC and/or the OPUC but it would be helpful if you could double check your responses in light of the inconsistencies noted and provide a simple answer to the question of what interconnection rules applies or will apply to a facility that is certified as or eligible to be a QF but sells under a contract that is something other than a QF PPA, such as an RFP or bi-lateral agreement.

Finally, PGE's responses were inadequate to provide us with enough information to link named facilities that have a PPA with PGE to their interconnection and transmission arrangements. Idaho Power and PacifiCorp were able to provide at least some info. PGE often simply refers us to its OASIS site, yet its interconnection studies are not even publicly available on OASIS. Can PGE please provide a response more like Idaho Power's (response to IPC DR 18) and PacifiCorp's (response to PAC DR 6) and provide us with the interconnection studies or make them publicly available like they are for PacifiCorp and Idaho Power? These requests are relevant and germane to the policy decisions in this docket.

Thank you. I'm available if there are any questions. I would appreciate a brief response in the next few days letting me know if you are able to provide this information along with an estimate of when you think you can provide it.

Marie P. Barlow | In-House Counsel, Policy & Regulatory Affairs | she/her
NewSun Energy | Office: (503) 420-7734 | Cell: (509) 389-4847

<u>NEWSUN DATA REQUEST NO. 19</u>:

Identify all instances in which Idaho Power provides firm transmission service, including either Network Interconnection Transmission Service or Point-to-Point Transmission service, to generators interconnected using ERIS.

<u>IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 19</u>:

Idaho Power objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Idaho Power also objects that this request asks Idaho Power to develop information that would be unduly burdensome and does not have a high degree of relevance to the case.

Subject to and without waiving the foregoing objection the Company responds as follows: Idaho Power provides firm transmission service for the following generators interconnected in the Generator Interconnection queue as ERIS:

1. Big Sky Dairy Digester – 2 MW LTF TSR scheduled by VTOL, POR/POD = MDSK-M345
2. Rock Creek Dairy Digester – 2 MW STF TSR scheduled by TNSK, POR/POD = MDSK-GSHN
3. Lucky Peak – 101 MW LTF TSR scheduled by MSCG, POR/POD = LYPK-LaGrande
4. Jackpot Solar – 120 MW Pending Network Firm, POR/POD = M345-IPCO, TSR will be designated as a Network Resource
5. Elkhorn Wind – 101 MW Network, POR/POD = NPSS-IPCO, TSR designated as Network Resource

With respect to Elkhorn, the amount of available Network Integration Transmission Service varies based on seasonal forecasts. In order to avoid paying for the network upgrades necessary to deliver its entire output to Idaho Power under Network Integration Transmission Service, Elkhorn chose to accept contractual provisions that would limit its ability to sell power to Idaho Power during the times that there is no Network Integration Transmission Service available. Of Elkhorn's 101 MW, 35 are interconnected under ERIS and 66 MW are interconnected under NRIS

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/403

PACIFICORP RESPONSES TO DATA REQUESTS

January 19, 2022

UM 2032 / PacifiCorp
January 21, 2021
NewSun Information Request 1.6

NewSun Information Request 1.6

Please list all power purchase agreements under which PacifiCorp purchases power including:

(a) Project name,

(b) Nameplate capacity,

(c) Term of power purchases,

(d) Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,

(e) Whether the facility is certified as a qualifying facility under PURPA,

(f) Under what interconnection rules/process the facility was interconnected,

(g) Whether the facility interconnected as ERIS or NRIS,

(h) The cost of network upgrades funded under the interconnection agreement,

(i) Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,

(j) The type of transmission service,

(k) The entity that submitted the transmission service request, and

(l) The cost of network upgrades funded under the transmission service request.

Response to NewSun Information Request 1.6

PacifiCorp objects to this data request to the extent it is overly broad, unduly burdensome, and seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding and without waiving this objection, PacifiCorp responds as follows:

Please refer to Attachment NewSun 1.6 and to the Company's responses to the following NewSun Information Requests: NewSun Information Request 1.8 and supportive documentation, NewSun Information Request 1.10, NewSun Information Request 1 .24, and NewSun Information Request 1.26.

UM 2032 / PacifiCorp
March 5, 2021
NewSun Information Request 1.6 – 1st Supplemental

NewSun Information Request 1.6

Please list all power purchase agreements under which PacifiCorp purchases power including:

(a) Project name,

(b) Nameplate capacity,

(c) Term of power purchases,

(d) Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,

(e) Whether the facility is certified as a qualifying facility under PURPA,

(f) Under what interconnection rules/process the facility was interconnected,

(g) Whether the facility interconnected as ERIS or NRIS,

(h) The cost of network upgrades funded under the interconnection agreement,

(i) Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,

(j) The type of transmission service,

(k) The entity that submitted the transmission service request, and

(l) The cost of network upgrades funded under the transmission service request.

1st Supplemental Response to NewSun Information Request 1.6

In further support of the Company's response to NewSun Information Request 1.6 dated January 21, 2021, the Company responds further as follows:

During discovery conferences with NewSun, PacifiCorp learned that many of NewSun's requests and their multiple subparts, including this request, were also intended to elicit information that would allow NewSun to trace specific generators through the interconnection and transmission service request (TSR) processes. As PacifiCorp explained, PacifiCorp does not compile information or keep records in this manner in the normal course of business. The additional information is voluminous and would be extremely burdensome to compile for all power purchase agreements (PPA), in the event it is even available. Even making the bare linkages from the interconnection queue to the TSR queue for all PPAs would require time-consuming investigation by PacifiCorp personnel and must be done one generator at a time. Thus, to the extent NewSun is asking PacifiCorp to "link up" generators associated with all PPAs from the interconnection process through the TSR process, the data request is overly broad and unduly burdensome. To the extent NewSun further asks PacifiCorp to perform various types of analyses on each generator to generate data for NewSun about such linkages, the data request is likewise overly broad and unduly burdensome.

Nevertheless, and without waiving its objections to this request, PacifiCorp responds as follows:

Please refer to Attachment NewSun 1.6 1st Supplemental. Note: this attachment supplements the attachment provided with PacifiCorp's original response to NewSun Information Request 1.6 (Attachment NewSun 1.6) by "linking up" the interconnection queue numbers and TSR queue numbers for all PPAs in Oregon under which PacifiCorp purchases power, to the extent that information exists.

The interconnection queue number allows NewSun to access the generator's interconnection studies on the Open Access Same-Time Information System (OASIS), including detailed information about the generator, the generator's interconnection service request (including interconnection service type), and upgrades and upgrade costs identified by those studies. The associated TSR queue number allows NewSun to access the same generator's transmission service request on OASIS, including the requesting party, the type of transmission service requested, any upgrades needed to effectuate the transmission service, and the upgrade costs.

Attachment NewSun 1.6 1st Supplemental

(a)		(b)	(c)	(d)	(e)	Supplemental Information		
Name	State	MW	Term (Years)[1]	Agreement Source	Qualifying Facility (QF)	Interconnection Queue Number[2]	TSR Queue Number	AREF
Adams Solar Center, LLC	OR	10.00	20	PURPA	QF	556	2074	82489720
BC Solar, LLC	OR	8.00	20	PURPA	QF	585	1893	80039313
Bear Creek Solar Center, LLC	OR	10.00	20	PURPA	QF	580	1891	80035471
Big Top LLC	OR	1.65	20	PURPA	QF	145	1637	77877455
Biomass One, L.P.	OR	32.50	15	PURPA	QF	151	1638	77877558
Black Cap Solar	OR	2.00	16	RFP	Non-QF	392	1506	796780
Bly Solar Center, LLC	OR	8.50	20	PURPA	QF	566	1897	80103182
Butter Creek Power LLC	OR	4.95	20	PURPA	QF	145-B	1687	77979419
C Drop Hydro, LLC	OR	1.10	15	PURPA	QF	299	1640	77879485
Captain Jack Solar	OR	2.70	20	PURPA	QF	971	2845	92200965
Central Oregon Irrigation District (COID) (Juniper Ridge)	OR	5.00	20	PURPA	QF	248	1642	77879661
Central Oregon Irrigation District (COID) (Siphon)	OR	6.00	35	PURPA	QF	Legacy	2553	88223254
Chiloquin Solar, LLC	OR	9.90	20	PURPA	QF	612	2018	81774198
Chopin Wind, LLC	OR	10.00	20	PURPA	QF	547	1866	79672901
City of Albany, Department of Public Works	OR	0.50	15	PURPA	QF	Legacy	1647	77888579
City of Astoria	OR	0.03	15	PURPA	QF	352	1949	80781778
City of Portland, Portland Water Bureau	OR	0.03	15	PURPA	QF	296	1643	77880688
Combine Hills I, LLC	OR	41.00	20	RFP	Non-QF	17	1699	78002619
Deschutes Valley Water District (Opal Springs)	OR	5.93	15	PURPA	QF	1012	2453	86943452
Dorena Hydro, LLC	OR	6.10	20	PURPA	QF	364	1708	78040128
Douglas County Forest Products	OR	6.25	10	PURPA	QF	53	2838	91806183
Eagle Point Irrigation District (Nichols Gap)	OR	0.72	35	PURPA	QF	Legacy	1464	780644
EBD Hydro, LLC (45 Mile Hydro)	OR	2.99	15	PURPA	QF	372	1649	77888834
Elbe Solar Center, LLC	OR	10.00	20	PURPA	QF	556	2075	82489752
Farm Power Misty Meadow, LLC	OR	0.75	15	PURPA	QF	Off System	1695	77979576
Farmers Irrigation District	OR	4.80	15	PURPA	QF	643	1651	77888858
Finley Bioenergy, LLC	OR	4.80	15	PURPA	QF	Off System	1661	77888964
Four Corners Windfarm LLC	OR	10.00	20	PURPA	QF	104	1652	77888996
Four Mile Canyon Windfarm LLC	OR	10.00	20	PURPA	QF	106	1653	77889056
Galesville Dam (Douglas County)	OR	1.80	35	PURPA	QF	Legacy	1659	77913519
Klamath Falls Solar 1, LLC	OR	0.83	20	PURPA	QF	581	1965	80959436
Klamath Falls Solar 2, LLC	OR	2.90	20	PURPA	QF	624	1984	81235960
Lacomb Irrigation Limited Partnership	OR	0.96	35	PURPA	QF	Legacy	1724	78194569
Loyd Fery	OR	0.07	3	PURPA	QF	169	2829	91643352
Middle Fork Irrigation District	OR	3.70	15	PURPA	QF	Off System	1665	77913704
Millican Solar Energy, LLC	OR	60.00	20	RFP	Non-QF	850	2892	92863803
Monroe Hydro, LLC	OR	0.30	15	PURPA	QF	413	1707	78040097
Mountain Energy, Inc	OR	0.05	15	PURPA	QF	355	1681	77972311
Norwest Energy 2 LLC (Neff)	OR	9.90	15	PURPA	QF	571	1995	81269090
Norwest Energy 4 LLC (Bonanza)	OR	4.80	15	PURPA	QF	577	2002	81460501

Attachment NewSun 1.6 1st Supplemental

(a)		(b)	(c)	(d)	(e)	Supplemental Information		
Name	State	MW	Term (Years)[1]	Agreement Source	Qualifying Facility (QF)	Interconnection Queue Number[2]	TSR Queue Number	AREF
Norwest Energy 7 LLC (Eagle Point)	OR	9.90	15	PURPA	QF	578	1982	81269111
Norwest Energy 9 LLC (Pendleton)	OR	6.00	15	PURPA	QF	588	1998	81369319
Old Mill Solar	OR	5.00	25	RFP	Non-QF	573	1974	81074553
OR Solar 2, LLC	OR	10.00	20	PURPA	QF	660	1986	81288775
OR Solar 3, LLC	OR	10.00	20	PURPA	QF	661	1987	81288790
OR Solar 5, LLC	OR	8.00	20	PURPA	QF	670	1992	81316143
OR Solar 6, LLC	OR	10.00	20	PURPA	QF	672	1991	81316106
OR Solar 8, LLC	OR	10.00	20	PURPA	QF	671	1989	81315991
Orchard Wind Farm 1, LLC	OR	10.00	20	PURPA	QF	650	2144	83693097
Orchard Wind Farm 2, LLC	OR	10.00	20	PURPA	QF	651	2145	83693107
Orchard Wind Farm 3, LLC	OR	10.00	20	PURPA	QF	652	2146	83693112
Orchard Wind Farm 4, LLC	OR	10.00	20	PURPA	QF	653	2147	83693115
Oregon Environmental Industries, LLC	OR	3.20	15	PURPA	QF	Legacy	1670	77921043
Oregon Institute of Technology (OIT)	OR	0.28	20	PURPA	QF	251	1671	77921092
Oregon Solar Land Holdings (OSLH, LLC)	OR	9.90	15	PURPA	QF	572	1997	81369264
Oregon State University	OR	6.50	10	PURPA	QF	174	2830	91643443
Oregon Trail Windfarm LLC	OR	9.90	20	PURPA	QF	102	1673	77921139
Pacific Canyon Windfarm LLC	OR	8.25	15	PURPA	QF	145-A	1674	77921166
Prineville Solar Energy, LLC	OR	40.00	20	RFP	Non-QF	621/731	2891	92863796
RES Ag - Oak Lea, LLC	OR	0.17	15	PURPA	QF	303	1667	77913784
Roseburg Forest Products Company - Dillard	OR	20.00	10	PURPA	QF	5	2603	88868661
Roseburg Landfill Gas Energy, LLC	OR	1.60	20	PURPA	QF	366	1677	77971685
Sand Ranch Windfarm LLC	OR	9.90	20	PURPA	QF	105	1678	77971814
Skysol, LLC	OR	55.00	20	PURPA	QF	721	2804	91223004
Sprague Hydro (North Fork Sprague)	OR	0.75	35	PURPA	QF	Legacy	1665	77913704
Stahlbush Island Farms, Inc	OR	1.60	4	PURPA	QF	176	2626	89079189
Swalley Irrigation District	OR	0.75	20	PURPA	QF	141	1683	77972520
Three Sisters Irrigation District (Watson Hydro) (700 kW)	OR	0.70	15	PURPA	QF	Off System	1788	79026180
Three Sisters Irrigation District (Watson Hydro) (200 kW)	OR	0.20	20	PURPA	QF	Off System	2456	86939977
Threemile Canyon Wind I LLC	OR	9.90	20	PURPA	QF	71	1932	80179624
TMF Biofuels	OR	4.80	10	PURPA	QF	360	1691	77973101
Tumbleweed Solar, LLC	OR	9.90	20	PURPA	QF	613	2017	81774191
Wagon Trail LLC	OR	3.30	20	PURPA	QF	147	1693	77973304
Ward Butte Windfarm LLC	OR	6.60	20	PURPA	QF	103	1684	77973341
Woodline Solar LLC	OR	8.00	20	PURPA	QF	609	1983	81235956

Notes:

1. Term is for current transaction as a number of the QFs are PPA renewals.
2. Legacy means prior to interconnection serial queue numbering system established by FERC

Subject: RE: [External] UM 2032 DR Clarifications
Date: Wednesday, May 26, 2021 at 4:10:27 PM Pacific Daylight Time
From: Lisa Hardie
To: Marie Barlow
CC: Kruse, Karen (PacifiCorp), Scarsella, Carla

Marie,

You have asked what rules apply to a facility that is certified as or eligible to be a QF but sells under a contract that is something other than a QF PPA, such as an RFP or bi-lateral agreement. QFs that invoke PURPA's must-purchase obligation to sell 100 percent of their power to a directly interconnected utility under a state-jurisdictional QF PPA are subject to state interconnection rules. Otherwise, QFs are subject to FERC-jurisdictional interconnection rules (and market competition).

You also stated that NewSun is interested in the treatment of facilities (presumably, referring to interconnection-driven Network Upgrades) across states. Please see PacifiCorp's response to OPUC DR 7, where PacifiCorp describes the treatment of Network Upgrades in other states in more detail.

Many thanks,
Lisa

Lisa D. Hardie
McDowell Rackner Gibson PC
419 SW 11th Ave, Suite 400 Portland, OR 97205
Direct: 503-290-3629 | Mobile: 541-921-5424
Website: www.mrg-law.com | Email: lisa.hardie@mrg-law.com
Pronouns: she/her/hers

From: Marie Barlow <mbarlow@newsunenergy.net>
Sent: Monday, May 24, 2021 9:15 AM
To: Lisa Hardie <lisa.hardie@mrg-law.com>
Cc: Kruse, Karen (PacifiCorp) <Karen.Kruse@pacificorp.com>; Scarsella, Carla <Carla.Scarsella@pacificorp.com>
Subject: Re: [External] UM 2032 DR Clarifications

Lisa,

Thanks for the reply on question 6. Are you able to provide a response on my second question regarding facilities certified as QFs but not selling under a QF-PPA?

As I explained earlier, these questions were aimed at understanding the relationship between and treatment of all the various types of PPAs, interconnections, and transmission arrangements. The treatment of facilities may differ across states since states have jurisdiction over certain types of interconnections at issue in this case. If another state treats QFs differently than how they are currently treated in Oregon, then it is relevant to the policy decision the Oregon Commission is being asked to make in this case. Similarly, if an upgrade in one state provides benefits to the system as a whole or other users and beneficiaries, a similar upgrade in Oregon could also provide such benefits. Further, PacifiCorp's witnesses state, in testimony, that Oregon's implementation is consistent with its experience in other states. I cannot verify this factually without reviewing the data across all states.

Marie P. Barlow | In-House Counsel, Policy & Regulatory Affairs | she/her
NewSun Energy | Office: (503) 420-7734 | Cell: (509) 389-4847

From: Lisa Hardie <lisa.hardie@mrg-law.com>
Date: Friday, May 14, 2021 at 4:01 PM
To: Marie Barlow <mbarlow@newsunenergy.net>
Cc: Kruse, Karen (PacifiCorp) <Karen.Kruse@pacificorp.com>, Scarsella, Carla <Carla.Scarsella@pacificorp.com>
Subject: RE: UM 2032 DR Clarifications

Marie,

With respect to New Sun Information Request 1.6, PacifiCorp understood from conversations with NewSun that the request was intended to elicit information that would allow NewSun to trace specific generators through the interconnection and TSR processes so that NewSun could better understand the connections between the two. (Several other requests propounded by NewSun ostensibly had this same purpose.)

PacifiCorp objected to the request on the ground that it was overly broad and unduly burdensome. PacifiCorp explained why the request was extremely overbroad and burdensome, and identified the challenges associated with responding to the request in both its discussions with NewSun and in PacifiCorp's responses to Information Request 1.6 – see PacifiCorp's Supplemental Response to NewSun Information Request 1.6.

Nevertheless, PacifiCorp was interested in providing NewSun with information illustrating the connections NewSun was trying to understand. PacifiCorp investigated the issue, and provided NewSun with the "linkages" for interconnection queue numbers and TSR queue numbers for all PPAs in Oregon under which PacifiCorp purchases power, to the extent that information exists. The information provided is precisely the type of information NewSun stated it was looking for, and the response provides examples of the relationships NewSun stated it was trying to understand.

PacifiCorp believes that its response is reasonable and adequate, and does not believe that a request for information for generators beyond Oregon is reasonable, appropriate, or justified in this instance. If NewSun disagrees, however, PacifiCorp would be interested in hearing NewSun's reasoning.

Many thanks,

Lisa

Lisa D. Hardie
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Direct: 503-290-3629 | Mobile: 541-921-5424
Website: www.mrg-law.com | Email: lisa.hardie@mrg-law.com
Pronouns: she/her/hers

From: Marie Barlow <mbarlow@newsunenergy.net>
Sent: Tuesday, May 11, 2021 4:08 PM
To: Jordan Schoonover <jordan@mrg-law.com>; Lisa Rackner <lisa@mrg-law.com>; donald.light@pgn.com; Adam Lowney <adam@mrg-law.com>; Walker, Donovan <DWalker@Idahopower.com>; Lisa Hardie <lisa.hardie@mrg-law.com>; karen.kruse@pacificorp.com; carla.scarsella@pacificorp.com
Subject: [External] UM 2032 DR Clarifications

Good Afternoon All,

I had a few clarifying questions regarding your supplemental responses to our data requests and was hoping you would be able to answer these in order to limit the issues for the motion to compel. These are all relating to the three questions NewSun asked of each utility regarding PPAs (PGE DR 6, PAC DR 6, IPC DR 5), interconnections (PGE DR 7, PAC DR 8, IPC DR 7) and transmission arrangements (PGE DR 19, PAC DR 24, IPC DR 18) in order to understand the relationship between all three.

First, the requests were meant to cover more than just Oregon-sited projects. In response to PAC DR 6 and Idaho Power DR 7, it appears that only Oregon-sited projects were listed. Can each of you expand those responses to the entire system?

Second, NewSun was seeking to understand which interconnection rules each utility applies or will apply to a facility that is certified as or eligible to be a QF but sells under a contract that is something other than a QF PPA, such as an RFP or bi-lateral agreement. Your responses appear inconsistent with QF certifications filed at FERC and/or the OPUC, so we wanted to seek clarifications. For example, the Neal Hot Springs geothermal project listed in Idaho Power's data responses appears to be certified as a QF at FERC, but is listed as not a QF in the data responses. Also in response to DR 5, Idaho Power notes that Neal is interconnected under the Oregon Commission Interconnection Rules, but in response to DR 8 Idaho Power notes they were FERC jurisdictional. Can you please clarify? I also noted that PGE's Portland Hydro and PAC's Black Cap Solar projects both have a QF certification on file with the OPUC, but your responses indicated that they were no QFs. Can you clarify your responses on those projects? I have not reviewed each and every project and whether it has a QF certification on file with FERC and/or the OPUC but it would be helpful if you could double check your responses in light of the inconsistencies noted and provide a simple answer to the question of what interconnection rules applies or will apply to a facility that is certified as or eligible to be a QF but sells under a contract that is something other than a QF PPA, such as an RFP or bi-lateral agreement.

Finally, PGE's responses were inadequate to provide us with enough information to link named facilities that have a PPA with PGE to their interconnection and transmission arrangements. Idaho Power and PacifiCorp were able to provide at least some info. PGE often simply refers us to its OASIS site, yet its interconnection studies are not even publicly available on OASIS. Can PGE please provide a response more like Idaho Power's (response to IPC DR 18) and PacifiCorp's (response to PAC DR 6) and provide us with the interconnection studies or make them publicly available like they are for PacifiCorp and Idaho Power? These requests are relevant and germane to the policy decisions in this docket.

Thank you. I'm available if there are any questions. I would appreciate a brief response in the next few days letting me know if you are able to provide this information along with an estimate of when you think you can provide it.

Marie P. Barlow | In-House Counsel, Policy & Regulatory Affairs | she/her
NewSun Energy | Office: (503) 420-7734 | Cell: (509) 389-4847

UM 2032 / PacifiCorp
January 21, 2021
NewSun Information Request 1.10

NewSun Information Request 1.10

For each network upgrade constructed since January 1, 2014, please provide:

(a) The cost of the network upgrade,

(b) Where PacifiCorp first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),

(c) How the network upgrade was funded (e.g., utility funded, queue number funded, other),

(d) Whether the network upgrade was included in rate base or whether PacifiCorp intends to include it in rate base,

(e) If the network upgrade was included in rate base, the rate of return earned on the network upgrade,

(f) The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others), and

(g) The net increase or decrease in transmission customer rates that resulted from the network upgrade,

Response to NewSun Information Request 1.10

PacifiCorp objects to this data request on the grounds that certain information requested is overly broad and unduly burdensome, including subparts (b), (f) and (g). Moreover, subpart (f) is vague and ambiguous and subpart (b), to the extent it goes beyond generator interconnection-driven network upgrades, is not reasonably calculated to lead to the discovery of admissible evidence in this case. It is not clear what "incremental transmission operations resulting from the network upgrade" refers to. Subject to and without waiving these objections, PacifiCorp responds as follows:

PacifiCorp understands the term "Network Upgrades" to refer to generator interconnection-driven Network Upgrades as defined by PacifiCorp's Open Access Transmission Tariff (OATT), a definition Public Utility Commission of Oregon (OPUC) staff and the Joint Utilities have used throughout the course of this docket. With that understanding, information regarding Network Upgrades identified in interconnection studies is publicly available on PacifiCorp's Open Access Same-Time Information System (OASIS), and also in PacifiCorp's responses to OPUC data requests propounded in this docket, including OPUC Information Request 13. In addition:

UM 2032 / PacifiCorp
January 21, 2021
NewSun Information Request 1.10

(a) Please refer to PacifiCorp's responses to OPUC Information Request 13.

(b) PacifiCorp's responses to OPUC Information Request 13.

(c) PacifiCorp's responses to OPUC Information Request 13.

(d) PacifiCorp's responses to OPUC Information Request Nos. 13 and 14. Network upgrades constructed and placed in-service from January 1, 2014, through December 31, 2020, as identified in the response to this data request, are included in Oregon rate base, but not included in Oregon customer rates until January 1, 2021.

(e) The approved rate of return in Oregon on rate base is 7.137 percent, effective January 1, 2021.

UM 2032 / PacifiCorp
March 5, 2021
NewSun Information Request 1.10 – 1st Supplemental

NewSun Information Request 1.10

For each network upgrade constructed since January 1, 2014, please provide:

(a) The cost of the network upgrade,

(b) Where PacifiCorp first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),

(c) How the network upgrade was funded (e.g., utility funded, queue number funded, other),

(d) Whether the network upgrade was included in rate base or whether PacifiCorp intends to include it in rate base,

(e) If the network upgrade was included in rate base, the rate of return earned on the network upgrade,

(f) The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others), and

(g) The net increase or decrease in transmission customer rates that resulted from the network upgrade,

1st Supplemental Response to NewSun Information Request 1.10

In further support of the Company's response to NewSun Information Request 1.10 dated January 21, 2021, the Company responds further as follows:

After conferral with NewSun, PacifiCorp understands that a number of NewSun Data Requests, including 1.10, 1.19, 1.20, 1.21, and 1.22 were seeking information on upgrades to the transmission system more broadly, not just Network Upgrades associated with interconnection service, as that term has been defined by the Federal Energy Regulatory Commission (FERC) and used by the Public Utility Commission of Oregon (OPUC) and parties to this proceeding.

Specifically, PacifiCorp understands that NewSun seeks information regarding various types of major transmission system upgrades PacifiCorp has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects that NewSun is interested in, NewSun mentioned constructing a new transmission line,

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reconductoring a transmission line, constructing a new substation, and adding breakers, disconnects, or communications equipment.

Because NewSun's data requests used the term "network upgrades," a term that is defined in the Open Access Transmission Tariff (OATT), and a term that all parties have used in testimony consistently with the OATT's definition, PacifiCorp maintains that its original data request responses were complete and adequate. Based on PacifiCorp's new understanding that NewSun's requests were intended to encompass upgrades to the transmission system more broadly, PacifiCorp reiterates its objections that the requests are overly broad and unduly burdensome. Moreover, the data requests relate to issues outside the scope of Phase 1 of this proceeding, and that may be addressed in Phase 2. Notwithstanding and without waiving these objections or its original objections, PacifiCorp responds as follows:

Please refer to the testimony of Richard A. Vail in docket UE 374, PacifiCorp's most recent general rate case. Mr. Vail's testimony details major transmission investments made by PacifiCorp from 2013 through 2020, and the rationale for PacifiCorp's request that these investments be included in Oregon rates. See, e.g., docket UE 374; PacifiCorp/1000, PacifiCorp/2800, and PacifiCorp/4200, and associated exhibits. In addition, please refer to Confidential Attachment NewSun 1.10, detailing recent, smaller additions to PacifiCorp's transmission system and the high-level rationale for their construction and inclusion in customer rates.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

REDACTED
Docket No. UE 374
Exhibit PAC/4202
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Description of Pro Forma Transmission Plant Additions Over $500,000
(Total-Company)

August 2020

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Vantage Pomona Heights 230kV Line	May-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/35) and Surrebuttal (PAC/4200) Testimony.
PP Trans New Connect	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new interconnections in California, Oregon, and Washington. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Goshen-Sugarmill-Rigby 161kV Transm Line	Nov-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/38) and Surrebuttal (PAC/4200) Testimony.
TMP Generation Interconnection Projects East	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Idaho, Utah. and Wyoming with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Transmission Blankets	Various	[redacted]	OPUC 226-1	These 2019 projects provide functional upgrades and asset replacements to transmission substations and lines in Utah, Wyoming, and Idaho. These projects will add or enhance an existing operational function and replace assets that have failed or deteriorated and are deemed a risk to public safety and/or reliability.
Goshen #3 345/161 kV 700 MVA Trfrmr Inst	Nov-20	[redacted]	OPUC 226-1	This project involves the installation of a third 345/161 kV transformer at the Goshen substation located in southeast Idaho. This project is needed in order to resolve a potential overloading issue at the existing Goshen 345/161 kV transformers. Load in the Goshen area has continued to increase and as the load continues to grow, the risk of overloading the two existing Goshen 345/161 kV transformers increases. The 2016 Goshen area studies indicated that by 2021, loss of either one of the Goshen 345/161 kV transformers can overload the remaining Goshen 345/161 kV transformer above its emergency rating. Cost estimate included in rate case is for the installation of the third transformer being placed in-service in 2020. A replacement spare transformer is being ordered but will be received outside the dates of this rate case.
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 226-1	These blanket projects will fund projects to decrease risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Jordanelle - Midway Construct 138 kV Line - Trans	2021	[redacted]	OPUC 226-1	This project has experienced major delays in obtaining a conditional use permit and is now projected to be placed in service sometime mid-2021. There will be $0.00 placed in service prior to 2021. This project will construct 9 miles of 138 kV transmission line with 795 ACSR conductor between Midway and Jordanelle substations. It will also construct a 138 kV three breaker ring bus at Midway substation, fiber optic communications between Silver Creek and Midway substations, and protection and control upgrades at all affected substations. Multiple outage scenarios on the 138 kV and 46 kV lines in the Summit and Wasatch County areas, and the outage of the Midway 75 MVA 138-46 kV transformer causes low voltage or voltage collapse conditions on the 138 kV and 46 kV systems in the area, which may result in load shedding. A 138 kV tie between Midway and Jordanelle substations mitigates this issue. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Oregon New Large Load Network Upgrades	Dec-20		OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new large load interconnections in Oregon. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. The specific projects that make up this category are Network Upgrade needed to serve a 60 MW Load Addition project. The customer intends to add an additional 220 MW of load between 2020 and 2022 that the proposed improvements will also be able to service.
Q0542 Pryor Mountain	Dec-20		OPUC 226-1	Addressed in Vail Surrebuttal (PAC/4200) Testimony. This project is to interconnect 240 megawatts of new wind generation to PacifiCorp's Frannie - Yellowtail 230 kilovolt transmission line approximately 14.2 miles north of the Frannie substation located in Carbon County, Montana.
PP Trans	Various		OPUC 226-1; OPUC 745-2 2nd Supp CONF	These blanket projects will fund functional upgrades and asset replacements to transmission substations and lines in Oregon, Washington, and Idaho. These projects replace assets that have deteriorated, or add efficiency improvements and/or enhance productivity functions of an asset. An example of this activity is as follows: A breaker is in excellent working condition, however, the required fault interrupting capability is not high enough. You replace the breaker with one that meets the requirements and because you are enhancing the required functions of the breaker the “Modernize and Upgrade” activity would be used.
TMP Trans Main Grid East	Various		OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2020 but are under $10m are rolled into this category. See tab 2 for projects included in this cost category.

REDACTED

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation Plan - CA T	Various	[redacted]	OPUC 226-1	This blanket project provides the means of allocating capital funds to mitigate operational risk within geographic regions that present the greatest risk of catastrophic wildfires. These investments are implemented consistent with the Company's 2020 Wildfire Mitigation Plan, including of 38 line miles of covered conductor, installation and commissioning of 31 system automation programs, replacement of 3 line miles of small diameter Cu conductor with aluminum stranded conductor, replacement of 189 in-service wooden poles with fiberglass for enhanced structural resilience, as well as evaluation of various pilot project results and continued implementation of enhanced inspection and correction programs.
TMP Gateway Projects	Various		OPUC 226-1	This 2019 blanket project provides the means of allocating capital funds for condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. The settlement included the relocation of the line from customer's property to the adjacent Forest Service property.
TMP Transmission Major Projects - PP	Various		OPUC 226-1	This 2020 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that arepart of the sub-transmission system. See tab 2 for the projects with in-service dates planned in 2020 included in this cost category.
TMP Trans Main Grid West	Various		OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All projects that fit the above description with estimated in-service in 2020, but are under $10M, are rolled into this category. See tab 2 for projects included in this cost category.
TMP Trans Customer Generated East	Various		OPUC 226-1	This category of projects represents system upgrades required in Utah, Wyoming, or Idaho to reliably serve transmission network customer requested loads as specified by the network customers in their OATT required load and resource submittals. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Replace Substation Switchgear, Breakers, Reclosers - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace - Storm & Casualty - UT Trans	Various		OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Utah due to a storm or external event (like a car hit pole).
TMP Trans Customer Generated East	Various		OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2019 used to determine costs.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Oregon - Rplc-OH Trans-Pole	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Oregon that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Generation Interconnections West	Various		OPUC 220-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system in Oregon, Washington and California. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects used to determine costs.
U2 2-2 GSU Replacement	Oct-19		OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. The replacement of the existing (40+) year old 2-2 GSUT with a new transformer will result in a reduced risk of an unscheduled outage at Huntington Plant. The project reduces the risk of failure of the existing 2-2 GSUT if it were replaced with a new one. The transformer is over 41 years old and the rate of failure in a transformer increases with age.
BIA - Fort Hall Grace - Goshen	Jun-20		OPUC 220-1	This project will renew the tribal authority permit for a portion of the Grace-Goshen transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - UT	Various		OPUC 220-1	This 2020 blanket project will replace transmission poles in Utah that have deteriorated and are deemed a risk to public safety and/or system reliability.
U0 Spare GSU Transformer	Dec-20		OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. Having a new universal spare will benefit PacifiCorp by reducing installation time (due to not having to manufacture bussing to tie into) in case of a GSUT failure. If the current spare GSUT is installed in an emergency, it will eventually need to be replaced, thus creating lost generation, restricted loads and unnecessary costs to perform the equipment change twice.
TMP Transmission Major Projects - PP	Various		OPUC 220-1	This 2019 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that are part of the sub-transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects behind cost estimate.
Replace Overhead Transmission Lines - Other - UT	Various		OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Utah that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Gateway Projects	Various		OPUC 220-1	This 2020 blanket project provides the means of allocating capital funds for the final condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. This The case involves a property owner who has contested valuation based on potential future mining and quarry activities and perceived profit potential from the area occupied by the project, and is still proceeding through the court. The Company anticipates resolution during the calendar year 2021.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 220-1	These 2019 projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.
Oregon - Transmission Improvements	Various	[redacted]	OPUC 220-1	The linescope reliability projects are being performed to enhance system visibility on the transmission system in strategic locations, enabling rapid response to faulted lines, ultimately enabling accurate fault location and quicker sectionalizing and restoration of customers.
Reroute JB Goshen 345kV line for Slide: IPC Shared	2021	[redacted]	OPUC 220-1	This project will not be placed in service until 2021 or later. There will be $0.00 placed in service prior to 2021. This project will relocate 2.5 miles of the Jim Bridger - Goshen 345kV transmission line out of a land slide area. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Pavant - Improve Transformer Protection	Dec-20	[redacted]	OPUC 220-1	This project will allow for maintenance to be performed on either transformer without requiring an outage to the entire Pavant 46 kV system. This will increase reliability for customers served from the Pavant substation.
Replace Transmission Conductor / Armor Rod - ID	Various	[redacted]	OPUC 220-1	These projects are needed to maintain reliability of existing facilities by replacing deteriorated transmission line conductor and/or reinforcing existing conductor with armor rod. Damage has occurred mainly from Aeolian vibration so vibration dampeners are also installed.
Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase	Dec-20	[redacted]	OPUC 220-1	A spare transformer analysis identified a spare transformer deficiency (or gap) in the Delta-Wye portion of the installed 230-69 kV transformer fleet. A new 230-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the six (6) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Idaho Power - Borah - Midpoint #1 replace wood w/ steel	Various	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) This project will fund the PacifiCorp portion of the replacement of wood structures with steel structures on the Idaho Power operated Borah to Midpoint #1 line. This will reduce the need for future priority 2 replacements as well as improve the durability of the line by improving its resistance to fires and severe weather conditions.
Replace Substation Transformers - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation transformers in Utah when equipment has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Calif - Rplc- Trans Strm&Cas	Various	[redacted]	OPUC 220-1	This blanket project provides the means of allocating capital funds to replace damaged equipment due to a storm or external event (like a car hit pole).
Replace Substation Bushings, Glass & Other - ID	Various	[redacted]	OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Idaho that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Oregon - Rplc-OH Trans-Othr	Various	[redacted]	OPUC 220-1	This blanket project provides the means of allocating capital funds to replace transmission line items other than poles that have deteriorated. Deteriorated Transmission cross arms, insulators, water passage culverts, easement access gates, are all examples of "other" items that fall into this category and are reported during annual field inspections.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
302 Spare GSU Replacement	Oct-19	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining reliability and ensure Hunter Plant can continue to provide efficient electrical power at full unit rating. The purchase of a new spare GSU will result in a lower risk of an extended load restriction in the event of a failure of one of the in-service transformers. If a spare GSU transformer is onsite, the estimated time frame to remove a failed transformer from service and install the spare is 10–14 days. The best case scenario to purchase a GSU replacement is 18 months. The project reduces the risk of an extended half load restriction due to a GSU failure of an in-service transformer.
BIA Camp Williams 4 Corners: BIA ROW Renewal - Ute Mtn Tribal	Apr-20		OPUC 220-1	This project will renew the tribal authority permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
State Prison at Salt Lake City - 8 MW Load	Sep-20		OPUC 220-1	This project will provide the customer a 138 kV connection in order to serve their requested load. This will also provide property for a future Rocky Mountain Power owned distribution substation to serve other projected load growth in the area.
Sams Valley 500-230kV New Substation	Nov-20		OPUC 220-1	The Sams Valley 500-230kV project is being placed in service in separate sequences. This is for upgrades at Grants Pass substation to reinforce the 230kV transmission system and resolve NERC reliability standard issues.
BLM Camp Williams 4 Corners: ROW Renewal PL#99001	Feb-20		OPUC 220-1	This project will renew the BLM permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
Replace Substation Bushings, Glass & Other - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Utah that has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
TMP Trans Main Grid East	Various		OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects included in this cost estimate.
Replace - Storm & Casualty - ID Trans	Various		OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Idaho due to a storm or external event (like a car hit pole). The pro forma amount is based on historical performance for this cost category.
Purchase One (1) 230-69kV 150 MVA 3 Phase Wye-Delta XFMR	Dec-20		OPUC 220-1	This is a second phase to Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase project discussed above.
Replace Overhead Transmission Poles - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission poles in Idaho that have deteriorated and are deemed a risk to public safety and/or system reliability.
Replace Overhead Transmission Lines - Other - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Idaho that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Upgrade Trans CB and Relays UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will fund functional upgrades to transmission substations in Utah. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Purchase One (1) 115-69 kV Wye-Delta 100 MVA 3 Phase XFMR Dedicated for Columbia	Dec-20		OPUC 220-1	A spare transformer analysis identified an aging spare transformer concern in the Delta-Wye portion of the installed 115-69 kV transformer fleet. A new 115-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the two (2) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Naples 138-12.5 kV New Substation TPL	Aug-2020			Transmission portion of new substation construction to address compliance with NERC Reliability Standards related to unacceptable voltage deviation and low voltage issues.
Parowan Valley Reg Replacement	Dec-20			This project was mis-classified as a transmission level project. This is a distribution level project in the state of Utah and should be removed from this filing. This project will replace the existing regulators at Parowan Valley substation that are projected to overload due to area load growth. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Oregon Trans- Rplc Sub-Swgr,Brk,Rec	various			This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
BLM - Antelope Bannock Pass Anaconda -	May-20			This project will renew the BLM permit for a portion of the Antelope-Amps-Peterson Flat 230 kV transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - WY	Various			This 2020 blanket project will replace transmission poles in Wyoming that have deteriorated and are deemed a risk to public safety and/or system reliability.
Oregon Trans - Repl Sub - Mtrs &	various			This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Oregon - Rplc- Trans Strm&Cas	various			This 2020 blanket project will replace damaged transmission equipment in Oregon due to a storm or external event (like a car hit pole).
Asset Removal - UT	Various			This 2020 blanket project will remove transmission utility assets in Utah that have been abandoned for some length of time.
Wildfire Mitigation Plan - OR T	various			This 2020 blanket project provides the means of allocating capital funds to mitigate operational risk in Oregon that present the greatest risk of catastrophic wildfires.
Upgrade Trans CB and Relays WY	Various			This 2020 blanket project will fund functional upgrades to transmission substations in Wyoming. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Replace Substation Switchgear, Breakers, Reclosers - WY	Various			This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Wyoming when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Block 216 Tower Service Request	Oct-2020	[redacted]		This project was mis-classified as a transmission level project. This is a distribution level project in the state of Oregon and should be 100 percent assigned to Oregon from this filing. This project provides distribution service to a mixed use new customer load addition. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Replace Substation Meters and Relays - UT	Various			This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Lassen Sub-New 69x115 kV sub to replace Mt Shasta Sub(Net 12.5 MVA) T	Jun-2020			Addressed in Vail Surrebuttal (PAC/4200) Testimony.
Targeted reliability Improvement, Trans - UT	Various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in Utah in order to improve customer reliability within a targeted area.
Replace Overhead Transmission Lines - Other - WY	Various			This 2020 blanket project will replace transmission line assets other than poles in Wyoming that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
Upgrade Trans CB and Relays ID	Various			This 2020 blanket project will fund functional upgrades to transmission substations in Idaho An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
TMP Generation Interconnections West	Various			This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Oregon, Washington, and California with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Replace - Storm & Casualty - WY Trans	Various			This 2020 blanket project will replace damaged transmission equipment in Wyoming due to a storm or external event (like a car hit pole).
Wash - Rplc-OH Trans-Pole	various			This 2020 blanket project provides the means of allocating capital funds to replace transmission poles in Washington that have deteriorated.
SF6 - Replace Naughton CB 235	5/1/2020			This project will replace the 1971 vintage, 230 kV circuit breaker at Naughton substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
SF6 - Replace Antelope CB 201 - shared IPC	10/1/2020			This project will replace the 1969 vintage, 230 kV circuit breaker at Antelope substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
Calif - Transmission Improvements	various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in California in order to improve customer reliability within a targeted area.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Replace Substation Meters and Relays - ID	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace Substation Switchgear, Breakers, Reclosers - ID	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
System Reinforcement - Local Transmission Projects	Various	[redacted]		This 2020 blanket project will fund transmission level system reinforcement projects in Utah in order to maintain acceptable reliability for the growing load. These projects typically consist of capacity increase projects such as replacing substation class transformers with larger ones.
Replace Substation Bushings, Glass & Other - WY	Various	[redacted]		This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Wyoming that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Projects Less Than $500 Thousand	Various	[redacted]		Of the 110 line items that make up the list of projects under $500k, 98 are program level funding which is based on historical experience. The Company forecasts a level of capital associated with unexpected events and smaller maintenance that requires capital replacement. The remaining line items are individual small projects or close-out costs on projects that enter service prior to the test period covered in this rate case.
Transmission Five Year Average Removals		[redacted]		
		[redacted]		

REDACTED

Projects By Budget Category

Category	Project Name	Planned Cost ($million)	Project Description
TMP Gen Interconnection East		**$ 21.4**	
	Q589 Sigurd Solar, LLC	[redacted]	This project interconnects 80 MW of new generation to PacifiCorp’s Sigurd 230 kV substation located in Sevier County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes adding a new breaker, dead-end, switches, and other protection and control equipment at Sigurd substation. As well as updating communications at Salt Lake Control Center.
	Q0631 Milford Solar 1, LLC - Interconnection	[redacted]	This project interconnects 99 MW of new generation to PacifiCorp's Hickory 345 kV substation located in Beaver County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes expanding Hickory substation and adding a new 345 kV position and related communication/relay equipment.
	Q737 Cove Mountain Solar 2, LLC	[redacted]	This project interconnects 122 MW of new generation to PacifiCorp's Enterprise Valley substation 138 kV bus located in Washington County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes new relaying and communications equipment at the Enterprise Valley substation. Communications and relaying to be installed at the Richfield service center and Holt, West Cedar, Clover, and Sigurd substations to support a Remedial Action Scheme (RAS).
	Q754 Steel Solar	[redacted]	The project interconnects 80 MW of new generation to PacifiCorp's 138 kV line east of Washakie substation located in Box Elder County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes installation of a new three breaker ring bus substation for the Point of Interconnection (POI), including all appurtenant metering and communication equipment and the loop in/out of the Wheelon-Nucor 138 kV transmission line at the new POI substation.
	Q764 Graphite Solar	[redacted]	The project interconnect 80 MW of new generation to PacifiCorp's Mathington 138 kV substation located in Carbon County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: new RAS panel at Carbon substation; a new bay and RAS master at Mathington substation; and a new reactor and RAS panel at Spanish Fork substation.
	Q0781 Elektron Solar	[redacted]	This project interconnects 80 MW of new generation to PacifiCorp's Craner Flat 138 kV substation located in Tooele County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes: a new circuit breaker at Craner Flat substation to tap to Homestead Knoll – Horseshoe transmission line; and modification of communications equipment and settings at Homestead and Horseshoe substations.
	Program level funding	[redacted]	
TMP Transmission Major Projects - PP		**$ 7.7**	

REDACTED

Projects By Budget Category

	Corvallis 115kV Loop - Reconductor 1 mile Fry - Circle Blvd	[redacted]	This project will reconductor a 1.1 mile section of the Fry – Circle Boulevard 115 kV line and replace the getaway conductor at Circle Boulevard substation. This project is needed to increase capacity on the Fry to Circle end of the 115 kV Corvallis loop and eliminates the need to shed up to 13 MW of load for an outage of the Hazelwood – Circle Tap 115 kV line during heavy summer loading.
	Dry Gulch Substation - Replace 115/69kV Transformer	[redacted]	This project replaces the existing 115/69 kV, 20 megavolt ampere (MVA) transformer, T-2210, with new 115/69 kV, 50 MVA transformer with on-load tap changer (LTC) at Dry Gulch substation located in Eastern Washington near Clarkston. Installation of a new 115/69 kV transformer at Dry Gulch with the ability to automatically control voltage on the 69 kV system will allow the 69 kV line to operate in a normal open configuration, with a sectionalizing point in the middle of the line. This will resolve a North American Electric Reliability Corporation (NERC) transmission planning (TPL) deficiency for a bus fault at the substation that results in low voltages. It will mitigate overloads for outages of heavily loaded parallel main grid lines. Also, by sectionalizing the line, customer outage exposure will be reduced.
	Yreka Sub 115/69 kV Tx addition - Install	[redacted]	This project will install a new 115/69 kV, 30/40/50 MVA LTC transformer at Yreka substation, relocate existing circuit breaker 3G85 to 69 kV breaker bay, and reroute Line 47 within Yreka substation so that 69 kV wire bus does not pass above new transformer bay. Transmission voltage in the Scott Valley is projected to fall below the 0.90 per unit guideline limit at summer peak during normal system operation, beyond the range of distribution substation regulators to maintain customer voltage within American National Standards Institute (ANSI) limits. The addition of an LTC transformer at Yreka will improve control of the 69 kV system voltage and will allow the use of load drop compensation feature to further improve the Scott Valley transmission voltage profile over the long term.
TMP Trans Main Grid East		**$ 12.2**	
	Siphon Tap - Pingree Junction 138 kV Reconductor	[redacted]	This project reconductored the 8.9-mile-long Siphon Tap to Pingree 138 kV line section of Idaho Power Company's (IPC) Don to Pingree to Blackfoot line, located in eastern Idaho. A construction agreement was signed with IPC outlining that all of the work for this project will be performed by IPC. IPC will own the completed project and all associated equipment. PacifiCorp will fund 100 percent of the actual project costs as agreed in the construction agreement. Results of the NERC TPL-001-4 Assessment, identified that the loss of the Goshen 345 kV source can cause the Don – Pingree 138 kV line to load up to 220 MVA. Thus, in order to eliminate the overload, preemptive load shedding of up to 150 MW would have been required in the Goshen area. By reconductoring the Don – Pingree line the rating will increase to at least 191.2 MVA continuous and emergency, and will reduce the preemptive load shedding requirement up to 65 MW.
	Spanish Fork 345/138 Transformer Upgrade TPL	[redacted]	This project upgrades the existing Spanish Fork substation transformer #3, installs backup bus differential relays, and replaces jumpers on the Spanish Fork – Tanner 138 kV line.. The project, based on the NERC TPL-001-4 and the Utah Valley 10-year study, will resolve thermal overload issues, eliminate voltage issues, and eliminate risk of load shedding or generation curtailment identified as NERC TPL-001-4 Category P1, P2, P3 and P6 issues impacting the system.
	TPL Backup Bus Differential Relays	[redacted]	Program level funding to mitigate NERC TPL-001-4 Category P5-5 contingency events for a failure of the relay to clear a bus fault. The backup bus differential relays monitors for bus faults and initiate tripping of circuit breakers thereby providing backup protection for the failure of the primary bus differential relays to operate. The failure of a bus differential relay during system peak load conditions could result in NERC TPL-001-4 performance violations resulting from thermal overloads or low voltage issues in the surrounding network.

REDACTED

Projects By Budget Category

	TPL Overdutied Circuit Breaker Replacements	[redacted]	Program level funding to replace overdutied circuit breakers with higher interrupt capability breakers. The failure of overdutied breakers during system peak load conditions could result in NERC TPL-001-4 deficiencies resulting from thermal overloads or low voltage issues in the surrounding area.
TMP Trans Main Grid West		**$ 7.1**	
	Hazelwood Sub- Expand Yard & Install Ring Bus	[redacted]	Treasureton 138 kV Sub Cap Bank Backup Protection ($0.1 million) - This project installs backup relays for two 49.5-MVAr capacitor banks providing backup protection for the failure of the primary relays at Treasureton 138 kV substation located in Preston, Idaho. The projects, based on the TPL-001-4 Category P5-4 analysis, which is a delayed fault clearing due to the failure of a non-redundant relay, will mitigate the issues impacting the system. Operating procedures cannot be implemented to mitigate the risk of P5-4 contingency events from occurring.
	Lone Pine Circuit Breaker Replacement		This project replaces four 115 kV circuit breakers with non-oil-filled units rated for 40,000 Amp RMS fault current capability to withstand and interrupt fault current at Lone Pine substation in Medford, Oregon. This project will resolve NERC Standard TPL-001-4 requirements that short circuit current interrupting ratings of circuit breakers be adequate to interrupt the available short circuit current. The momentary and interrupting capabilities of the existing 115 kV circuit breakers are not adequate to withstand the available fault current since the energization of Whetstone 230-115 kV substation.
	Meridian RAS Expansion		This project expands the existing Meridian RAS to cover three additional N-1-1 contingencies on the southern Oregon 500 kV system and trip additional load. The proposed RAS expansion will ensure compliance with the NERC PRC-014 Reliability Standard, Western Electricity Coordinating Council (WECC) PRC-(012-014)-WECC-CRT-2 Regional Criterion and NERC TPL-001-4 Reliability Standard. In addition, expanding the RAS will avoid relying on the Southern Oregon under Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500 kV system.
TMP Trans Customer Generated East- 2020		**$ 6.9**	
	Q2469 PacifiCorp ESM	[redacted]	This project is due to a PacifiCorp's energy supply management (ESM) request on PacifiCorp's Open Access, Same-time Information System (OASIS) for Designated Network Resource (DNR) status. The Construction Agreement was executed between PacifiCorp, on behalf of its merchant function (ESM), and PacifiCorp, on behalf of its transmission function on December 20, 2018. The project is associated with Generation Interconnection queue request Q0631. The network upgrade work includes: development and installation of new relay settings for the Spanish Fork – Timp transmission line at Spanish Fork substation, installation of new fiber and the decommissioning of the Spanish Fork – Lake Mountain microwave link; installation of a new 138 kV circuit breaker (and associated switches) at Timp substation; reconductoring of approximately 5.23 miles of the Spanish Fork- Timp transmission line; and installation of fiber in the shield wire position from Timp to Spanish Fork substation. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.

REDACTED

Projects By Budget Category

	Q155 UAMPS	[redacted]	This project is in response to a transmission service request from UAMPS pursuant to its Transmission Service and Operating Agreement for a new point of delivery. The scope consists of constructing a new 138 kV substation with four circuit breakers, switches, etc., looping the Jordanelle – Midway 138 kV line in and out of the substation and two 138 kV delivery connections to UAMPS customer. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.
TMP Trans Customer Generated East- 2019		**$ 4.3**	
	Bull River to Carter Substation 138 kV Conv - Trans	[redacted]	This project was required for increased load service for a UAMPS network customer. The project is to re-build 2.3 miles of the Lehi Bull River tap to Saratoga tap 46 kV line to 138 kV line.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Generation Interconnections West		[redacted]	
	Q729 Airport Solar, LLC - Airport Solar	[redacted]	This project interconnects a total of 47.25 MW of new generation to PacifiCorp's Chiloquin-Alturas 115 kV line at 42.178563°N, 120.357580°W located in Lake County, Oregon. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes: construction of a new 115 kV three-breaker ring bus substation.
TMP Transmission Major Projects - PP		**$ 2.6**	
	NE Portland Trans Upgrade	[redacted]	This project addressed electrical network deficiencies required to improve reliability within Northeast Portland. This project is a systemic solution to the operational and contingency related network issues in the Portland transmission and substation system. The dollars in 2019 were for the last phase of the project which was the installation of a second transformer at Albina substation.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Trans Main Grid East		[redacted]	
	90th South Bus Tie Breaker	[redacted]	The project, based on the 2017 TPL Assessment, identified that a fault on the 90th South 138 kV bus tie breaker results in a loss of the entire 90th South 138 kV substation. Once the project is completed, loss of the entire 90th South 138 kV substation will be prevented. Thermal overloads on the following 138 kV line segments will be resolved: Lone Peak – Lone Peak Tap, Travers Mtn. – South Mtn. South Tap, and South Mtn. South Tap – South Mountain. Low voltages on the 106th South, 108th South, Quarry, Dimple Dell and Dumas substations will not occur, and overloading of the Camp Williams transformer as seen in the 2022 TPL case will be prevented.

REDACTED

UM 2032 / PacifiCorp
January 20, 2021
NewSun Information Request 1.27

NewSun Information Request 1.27

Indicate whether PacifiCorp believes it is obligated to purchase power from a QF in the following circumstances:

(a) If it is interconnected via a FERC jurisdictional interconnection? If such interconnection is ER? If NR?

(b) Is that answer different if the QF was off-system or on-system?

(c) If the QF only proposes to sell one hour per year to the QF?

(d) If the QF proposes to sell all of its output except 1 day per year?

(e) If the QF proposes solely to sell PacifiCorp power seasonally?

(f) If the QF sells some of its other output to another utility?

Response to NewSun Information Request 1.27

PacifiCorp is required to purchase power from a qualifying facility (QF) in circumstances stated in subparts (a) through (f) of this data request.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/404

PACIFICORP TSR QUEUE AS OF JANUARY 7, 2022

January 19, 2022

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
273	316762	PAC Merchant	12/12/05	12/16/05	East	NT	Confirmed 7/22/06	PACE	PACE	15.000	01/01/07	06/30/25	SIS	
276	316773	PAC Merchant	12/12/05	12/16/05	West	NT	Confirmed 7/27/06	PACW	PACW	14.000	12/15/05	12/14/25	SIS	
293	323874	PAC Merchant	01/27/06	01/31/06	East	NT	Confirmed 7/27/06	PACE	PACE	6.000	04/01/07	03/31/26		
303	335872	PAC Merchant	03/29/06	03/31/06	West	NT	Confirmed 6/30/06	BPAT.PACW	PACW	78.000	05/01/06	04/30/26		
307	337682	PAC Merchant	04/05/06	04/12/06	East	NT	Superseded 10/17/06	PACE	PACE	68.000	04/06/06	04/05/26		
320	340738	PAC Merchant	04/18/06	05/03/06	East	NT	Confirmed 6/15/06	PACE	PACE	141.000	04/19/06	04/18/26		
333	341848	PAC Merchant	04/24/06	04/28/06	East	NT	Confirmed 6/27/06	PACE	PACE	7.000	04/25/06	04/24/26		
336	341855	PAC Merchant	04/24/06	04/28/06	East	NT	Confirmed 06/20/06	PACE	PACE	3.360	04/25/06	04/24/26		
337	341857	PAC Merchant	04/24/06	04/28/06	East	NT	Confirmed 06/20/06	PACE	PACE	1.000	04/25/06	04/24/26		
338	341868	PAC Merchant	04/24/06	04/28/06	West	NT	Confirmed 06/16/06	PACE	PACW	1.000	04/25/06	04/24/26		
389	344395	PAC Merchant	05/03/06		West	NT	Confirmed 7/19/06	PACW	PACW	10.000	03/29/06	03/28/26		
396	350493	PAC Merchant	05/08/06	05/12/06	East	NT	Confirmed 9/29/06	HTSP	GSHN	5.000	10/01/06	09/30/26		
411	346043	PAC Merchant	05/11/06	05/11/06	East	NT	Confirmed 7/14/06	PACE	PACE	16.000	07/01/06	06/30/26		
442	349036	PAC Merchant	05/22/06	05/24/06	East	NT	Confirmed 9/18/06	PACE	PACE	5.000	11/01/06	10/31/26		
446	355015	PAC Merchant	06/20/06	06/22/06	East	NT	Confirmed 10/23/06	PACE	PACE	5.000	02/01/07	01/31/26	SIS	
450	355582	PAC Merchant	06/23/06	06/28/06	East	NT	Confirmed 7/14/06	PACEW	WYONORTH	2.000	11/01/06	10/31/26		
459	361057	PAC Merchant	07/20/06	07/21/06	West	NT	Confirmed 10/31/06	PACW	BPAT.PACW	3.000	07/21/06	07/21/26		
460	361316	PAC Merchant	07/21/06	07/25/06	West	NT	Confirmed 12/27/06	PGER	PACW	120.000	08/01/06	08/01/26		
467	365983	PAC Merchant	08/14/06	08/15/06	East	NT	Confirmed 12/4/06	PACE	PACE	30.000	04/09/08	04/09/26	SIS	
473	370068	PAC Merchant	09/07/06	09/08/06	East	NT	Confirmed 10/9/06	PACE	PACE	11.000	04/01/07	03/31/26		
474	370071	PAC Merchant	09/07/06	09/08/06	East	NT	Confirmed 10/10/06	PACE	PACE	5/8	12/01/06	11/30/26		
476	370084	PAC Merchant	09/07/06	09/08/06	East	NT	Confirmed 10/10/06	PACE	PACE	1/2	03/01/07	02/28/26		
477	371619	PAC Merchant	09/15/06	09/18/06	East	NT	Confirmed 1/11/07	PACEW	PACE	21/39/45/52/65	02/15/09	02/14/26		
478	371641	PAC Merchant	09/15/06	09/18/06	East	NT	Confirmed 10/9/06	PACE	PACE	3.000	04/01/07	03/31/26		
515	381092	PAC Merchant	11/08/06	11/09/06	West	NT	Confirmed 12/18/06	PACW	PACW	70.000	12/01/06	11/30/26		
516	381093	PAC Merchant	11/08/06	11/09/06	East	NT	Confirmed 12/18/06	PACE	PACE	85.600	12/01/06	11/30/26		
518	381097	PAC Merchant	11/08/06	11/09/06	West	NT	Confirmed 12/18/06	BPAT.PACW	PACW	70.000	12/01/06	11/30/26		
523	384156	PAC Merchant	11/28/06	11/29/06	East	NT	Confirmed 12/8/06	PACE	PACE	13.000	01/01/08	12/31/25		
551	395055	PAC Merchant	01/30/07	01/31/07	East	NT	Confirmed 3/2/07	PACEW	PACEW	3.000	03/01/07	02/28/27		
557	395523	PAC Merchant	02/02/07	02/06/07	East	NT	Confirmed 4/25/07	JBSN	JBSN	44.000	03/01/07	03/01/27		
558	395528/502544	PAC Merchant	02/02/07	02/07/07	East	PTP	3/9/07; supereseded	PACE	BORA	100.000	03/01/07	02/28/22		
565	396235	PAC Merchant	02/06/07	02/07/07	East	NT	Confirmed 3/27/07	PACE	PACE	5.000	11/01/07	11/01/27		
568	397734	PAC Merchant	02/15/07	02/16/07	East	NT	Confirmed 3/27/07	PACE	PACE	11.000	01/01/08	12/31/26		
569	398656	PAC Merchant	02/19/07	02/20/07	East	NT	Confirmed 3/27/07	PACE	PACE	4/13/14/17/18/20	06/01/07	06/01/27		
589	400067	PAC Merchant	02/26/07	02/27/07	East	NT	Confirmed 9/4/12	PACE	PACE	2/3/10/15/20	09/01/08	08/31/27		
609	407454	PAC Merchant	04/05/07	04/09/07	East	NT	Confirmed 5/18/07	PACEW	PACEW	6.000	05/01/08	04/30/27		
626	409421	PAC Merchant	04/13/07	04/17/07	East	NT	Confirmed 5/18/07	PACE	PACE	85/93/100/110/1	06/01/07	05/31/27		
632	412516	PAC Merchant	05/02/07	05/03/07	East	NT	Confirmed 5/18/07	PACEW	PACEW	4/6/7	12/01/07	11/30/27		
658	414225	PAC Merchant	05/11/07	05/14/07	West	NT	Confirmed 6/12/07	PACW	PACW	2.000	12/01/08	11/30/27		
716	425332	PAC Merchant	07/09/07	07/10/07	West	NT	Confirmed 8/6/07	BPAT.PACW	PACW	100.000	08/01/07	08/01/26		
717	425384	PAC Merchant	07/09/07	07/11/07	East	NT	Confirmed 12/11/07	PACE	PACE	19.000	11/01/08	11/01/27		
734	428059	PAC Merchant	07/26/07	07/27/07	East	NT	Confirmed 12/11/07	PACE	PACE	11/22/33	10/01/08	01/01/27	SIS	
752	432805	PAC Merchant	08/20/07	08/20/07	East	NT	Confirmed 1/16/08	PACEW	PACEW	99.000	03/01/08	03/01/27	SIS	
762	434090	PAC Merchant	08/27/07	08/28/07	East	NT	Confirmed 1/16/08	PACEW	PACEW	35.000	01/01/09	01/01/27	SIS	
769	435013	PAC Merchant	08/30/07	08/31/07	West	NT	Confirmed 12/11/07	PACW	BPAT.PACW	8.000	10/01/07	10/01/27		
770	435014	PAC Merchant	08/30/07	08/31/07	West	NT	Confirmed 12/11/07	BPAT.PACW	PACW	8.000	10/01/07	10/01/27		
773	444730	PAC Merchant	10/09/07	10/10/07	East	NT	Confirmed 2/25/08	PACE	PACE	1/2/4	09/01/08	08/31/27	SIS	
784	449030/447988	PAC Merchant	10/26/07	10/29/07	East	NT	rseded 3/27/08 by 44	Deer Creek	PACE	5.000	12/01/07	12/01/27		
805	460548	PAC Merchant	12/26/07	12/28/07	East	NT	Confirmed 5/15/08	PACE	PACE	50.000	01/01/10	01/01/27	SIS	
806	460658	PAC Merchant	12/27/07	12/28/07	East	NT	Confirmed 5/15/08	PACE	PACE	2/3/5	06/01/09	06/01/27	SIS	
813	462538	PAC Merchant	01/08/08	01/10/08	East	NT	Confirmed 5/15/08	PACE	PACE	11/12	05/01/09	05/01/28		
829	464208	PAC Merchant	01/18/08	01/22/08	East	NT	Granted/Confirmed 8	PACEW	PACEW	99.000	03/01/08	03/01/28	SIS	
830	464209	PAC Merchant	01/18/08	01/22/08	East	NT	Granted/Confirmed 8	PACEW	PACEW	39.000	03/01/08	03/01/28	SIS	
836	464970	PAC Merchant	01/23/08	01/24/08	East	NT	Confirmed 2/28/08	PACE	PACE	3.000	08/01/08	08/01/28		
847	469092	PAC Merchant	02/11/08	02/12/08	West	NT	Confirmed 5/15/08	PACW		75.000	10/01/08	10/01/28		
848	469093	PAC Merchant	02/11/08	02/12/08	West	NT	Confirmed 4/29/08	PACW	BPAT.PACW	21.000	04/01/08	04/01/28		
852	470047	PAC Merchant	02/15/08	02/19/08	East	NT	Confirmed 9/17/08	PACE	PACE	8.000	07/01/08	07/01/28	SIS	
863	471741	PAC Merchant	02/25/08	02/27/08	East	NT	Confirmed 12/4/09	PACEW	PACEW	99.000	01/01/09	01/01/28	SIS	
926	484178	PAC Merchant	04/21/08	04/24/08	East	NT	Confirmed 7/30/08	PACEW	PACEW	3.000	11/01/08	11/01/28		
941	489598	PAC Merchant	05/12/08	05/15/08	East	NT	Confirmed 7/30/08	PACEW	PACEW	13-26	03/01/10	03/01/28		
944	492333	PAC Merchant	05/21/08	05/22/08	East	NT	Confirmed 7/30/08	PACE	PACE	3.000	01/01/10	01/01/28		
945	492334	PAC Merchant	05/21/08	05/22/08	East	NT	Confirmed 7/30/08	PACE	PACE	3.000	01/01/10	01/01/28		
950	496691	PAC Merchant	06/10/08	06/11/08	West	NT	Confirmed 6/18/08	REDB	PACW	2.000	07/01/08	07/01/28		
984	498314	PAC Merchant	06/19/08	06/25/08	East	PTP	Confirmed 7/30/08	PACE	GLENCANYON2	225, 250	08/01/08	01/01/22		
992	499761	PAC Merchant	06/26/08	06/27/08	West	NT	Confirmed 9/17/08	MIDC	MIDC	1.000	08/01/08	08/01/28		
1011	505512	PAC Merchant	07/25/08	07/30/08	East	NT	Confirmed 9/8/08	PACEW	PACEW	26-41	01/01/12	01/01/28		
1031	507939	PAC Merchant	08/06/08	08/07/08	East	NT	Confirmed 12/19/08	PACE	PACE	16-25	12/01/10	01/01/28	SIS	
1035	508143	PAC Merchant	08/07/08	08/08/08	West	NT	Confirmed 11/18/08	PACW	BPAT.PACW	1.000	10/01/08	10/01/28		
1041	509734	PAC Merchant	08/15/08	08/18/08	East	NT	Confirmed 12/16/08	PACE	PACE	5.000	07/01/10	07/01/28		
1042	509746	PAC Merchant	08/15/08	08/18/08	East	NT	Confirmed 12/16/08	PACE	PACE	3.000	07/01/10	07/01/28		
1043	509749	PAC Merchant	08/15/08	08/18/08	East	NT	Confirmed 12/16/08	PACE	PACE	3.000	07/01/10	07/01/28		
1044	509830	PAC Merchant	08/15/08	08/19/08	West	NT	Confirmed 11/18/08	BPAT.PACW	PACW	520.000	09/15/08	09/15/28		
1045	510630	PAC Merchant	08/19/08	08/21/08	West	NT	Confirmed 11/18/08	BPAT.PACW	PACW	94.000	09/01/08	09/01/28		
1052	513817	PAC Merchant	09/04/08	09/08/08	East	NT	Confirmed 1/27/09	PACE	PACE	2,5,10	06/01/09	06/01/28	SIS	
1078	524662	PAC Merchant	10/28/08	10/30/08	West	NT	Confirmed 11/26/08	PACW	BPAT.PACW	1.000	01/01/09	01/01/28		
1083	525240	PAC Merchant	10/31/08	11/04/08	East	NT	Confirmed 11/26/08	PACE	MDGT	61-120	01/01/09	01/01/28		
1084	526123	PAC Merchant	11/04/08	11/05/08	East	NT	Confirmed 4/14/09	PACE	PACE	18.000	10/01/11	10/01/28	SIS	
1085	526124	PAC Merchant	11/04/08	11/05/08	East	NT	Confirmed 4/14/09	PACE	PACE	9.000	10/01/11	10/01/28	SIS	
1104	539811	PAC Merchant	01/20/09	01/21/09	East	NT	Confirmed 2/3/09	PACE	PACE	15-85	03/01/09	03/01/29		
1109	541087	PAC Merchant	01/28/09	01/29/09	East	NT	Confirmed 6/26/09	PACE	PACE	2-100	02/01/09	02/01/24	SIS	
1114	547782	PAC Merchant	03/13/09	03/18/09	West	NT	Confirmed 5/4/09	BPAT.PACW	PACW	70.000	06/01/09	06/01/29		
1115	547784	PAC Merchant	03/13/09	03/18/09	West	NT	Confirmed 5/4/09	BPAT.PACW	PACW	420.000	06/01/09	06/01/29		
1127	552990	PAC Merchant	04/21/09	04/24/09	East	NT	Confirmed 8/10/09	PACE	PACE	2-4	05/01/10	01/01/29	SIS	
1135	557157	PAC Merchant	05/15/09	05/20/09	West	NT	Confirmed 8/24/09	PACW	BPAT.PACW	1.000	05/19/09	01/01/29		
1137	558491	PAC Merchant	05/21/09	05/26/09	East	NT	Confirmed 6/23/09	PACEW	PACEW	3.000	09/01/09	01/01/29		
1141	560666	PAC Merchant	06/05/09	06/08/09	East	NT	Confirmed 12/16/10	PACEW	PACEW	111.000	09/30/10	09/30/29	SIS	
1142	560701	PAC Merchant	06/05/09	06/11/09	East	NT	Confirmed 12/4/09	PACEW	PACEW	28.500	11/01/09	11/01/29		
1152	569207/88350807	EWEB	01/09/19	07/31/09	West	PTP	Confirmed 1/23/19	WALLULA	MCNARY	25.000	02/01/19	01/01/27		
1153	570221	PAC Merchant	08/06/09	08/11/09	East	NT	Confirmed 9/10/09	PACEW	PACEW	30.000	03/01/11	03/01/29		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
1154	571257	PAC Merchant	08/10/09	08/12/09	East	NT	Confirmed 10/1/09	PACE	PACE	3.000	11/01/10	11/01/25		
1160	575869	PAC Merchant	09/04/09	09/09/09	East	NT	Confirmed 1/11/10	PACE	PACE	2,4,10	03/01/10	01/01/29	SIS	
1164	578260	PAC Merchant	09/17/09	09/18/09	West	NT	Confirmed 12/7/09	PACW	PACW	30-60	05/01/10	01/01/29	SIS	
1165	578305	PAC Merchant	09/17/09	09/18/09	West	NT	Confirmed 12/7/09	PACW	PACW	20-40	10/01/10	01/01/29		
1166	578402	PAC Merchant	09/18/09	09/22/09	East	NT	Confirmed 10/22/09	PACEW	PACEW	4.000	06/01/11	06/01/29		
1170	583614	PAC Merchant	10/13/09	10/14/09	East	NT	Confirmed 8/22/13	PACE	PACE	1 -- 21	09/01/10	01/01/29	SIS	
1177	591168/79640578	BPA	11/20/09	11/24/09	West	NT	Received/Granted	BPAT.PACW	PACW	1.000	05/01/14	10/01/28	SIS	FS
1212	617905	PAC Merchant	04/30/10	05/04/10	West	NT	Confirmed 6/14/10	PACW	PACW	255.000	07/01/10	07/01/30		
1215	620282	PAC Merchant	05/17/10	05/20/10	East	NT	Confirmed 8/22/13	PACE	PACE	14-17	06/30/11	01/01/30	SIS	
1216	621679	PAC Merchant	05/25/10	05/27/10	East	NT	Confirmed 8/22/13	PACE	PACE	8-15	07/01/10	07/01/30	SIS	
1217	621681	PAC Merchant	05/25/10	05/27/10	East	NT	Confirmed 9/4/12	PACE	PACE	3.000	07/01/10	07/01/30		
1220	624709	PAC Merchant	06/09/10	06/11/10	West	NT	Confirmed 8/22/13	PACW	PACW	30-40	12/31/11	12/31/30	SIS	
1223	625986	PAC Merchant	06/16/10	06/17/10	East	NT	Confirmed 8/22/13	WYOEAST	WYOEAST	2.000	01/01/11	01/01/30		
1224	626003	PAC Merchant	06/16/10	06/17/10	East	NT	Confirmed 8/22/13	PACE	PACE	2.000	10/01/10	10/01/30		
1230	626791	PAC Merchant	06/21/10	06/23/10	East	NT	Confirmed 8/22/13	PACE	PACE	15-30	02/24/11	01/01/30		
1251	645781	PAC Merchant	09/24/10	09/29/10	East	NT	Confirmed 8/22/13	PACE	PACE	2-4	10/01/11	10/01/29		
1252	645790	PAC Merchant	09/24/10	09/29/10	East	NT	Confirmed 8/22/13	PACE	PACE	1-8	12/01/10	04/01/29		
1258	648377	PAC Merchant	10/06/10	10/12/10	East	NT	Confirmed 8/22/13	PACE	PACE	13.000	05/01/13	05/01/30		
1266	656987	PAC Merchant	11/12/10	11/16/10	West	NT	Confirmed 1/5/11	MIDC	MIDC	6.000	12/01/10	12/01/30		
1294	680400	PAC Merchant	02/15/11	02/17/11	West	NT	Confirmed 4/5/11	PACW	PACW	39.000	03/01/11	03/01/30	SIS	
1296	683060	PAC Merchant	02/23/11	02/25/11	West	NT	Confirmed 11/4/16	PACW	PACW	40.000	03/31/14	03/31/30	SIS	
1299	684287	PAC Merchant	02/28/11	03/02/11	East	NT	Confirmed 8/15/11	PACE	PACE	22-27	03/01/12	03/01/31	SIS	
1305	686836	PAC Merchant	03/10/11	03/18/11	East	NT	Confirmed 8/22/13	PACE	PACE	3-6	04/01/11	04/01/31	SIS	
1308	690215	PAC Merchant	03/23/11	03/28/11	East	NT	Confirmed 6/9/11	WYOCENTR	WYOCENTRAL	1-8	07/31/11	07/31/31		
1323	708764	PAC Merchant	05/31/11	06/01/11	West	NT	Confirmed 9/21/11	PACW	BPAT.PACW	4.000	07/01/11	07/01/30		
1332	712775	PAC Merchant	06/17/11	06/21/11	East	NT	Confirmed 9/21/11	WYOCENTR	WYOCENTRAL	1-4	10/01/11	01/01/31		
1338	715151	PAC Merchant	06/28/11	06/30/11	East	NT	Confirmed 9/21/11	PACE	PACE	2-4	10/01/11	01/01/31		
1339	716938	PAC Merchant	07/05/11	07/06/11	East	NT	Confirmed 9/21/11	PACE	PACE	10-17	10/01/11	01/01/31		
1341	717310	PAC Merchant	07/06/11	07/14/11	East	NT	Confirmed 9/21/11	PACE	PACE	5.000	01/01/12	01/01/31		
1343	723544	BPA	7/26/11	7/26/11	West	NT	Study/Granted	BPAT.PACW	PACW	2.000	06/01/12	06/01/28	SIS	FS
1348	727004	PAC Merchant	08/09/11	08/12/11	East	NT	Confirmed 9/21/11	PACE	PACE	2-3	09/01/11	09/01/31		
1357	737417	PAC Merchant	09/20/11	09/21/11	East	NT	Confirmed 11/9/11	WYOCENTR	WYOCENTRAL	12.000	10/01/14	10/01/31		
1360	740690	PAC Merchant	10/04/11	10/10/11	West	NT	Confirmed 8/22/13	PACW	PACW	40.000	06/01/12	01/01/31	SIS	
1371	n/a	UAMPS	n/a	10/21/11	East	NT	Change form 710	FOURCORN	PACE	50.000	01/11/12		SIS	
1376	752491	PAC Merchant	11/22/11	11/29/11	East	NT	Confirmed 8/22/13	PACE	PACE	5.000	01/01/13	01/01/31	SIS	
1384	755740	PAC Merchant	12/06/11	12/08/11	East	NT	Confirmed 4/20/12	PACE	PACE	22.500	12/31/11	12/31/31		
1385	755742	PAC Merchant	12/06/11	12/08/11	East	NT	Confirmed 4/20/12	PACE	PACE	22.500	12/31/11	12/31/31		
1390	757088	PAC Merchant	12/14/11	12/20/11	East	NT	Confirmed 2/3/12	NUT	Sunbeam	1.000	12/15/11	12/31/31		
1392	758471	PAC Merchant	12/22/11	12/29/11	East	NT	Confirmed 12/20/16	PACE	PACE	7.000	06/01/12	06/01/31		
1405	769663	PAC Merchant	02/23/12	02/27/12	East	NT	Confirmed 8/22/13	PACE	PACE	89.000	05/01/12	09/15/32		
1407	770827	PAC Merchant	03/01/12	03/07/12	East	NT	Confirmed 8/22/13	WYONORTH	WYONORTH	4.000	05/01/12	01/01/32	SIS	
1412	775561	PAC Merchant	03/26/12	03/27/12	East	NT	Confirmed 12/20/16	GSHN	GSHN	3.000	10/01/13	12/31/31		
1433	780038	PAC Merchant	04/18/12	04/23/12	East	NT	Confirmed 6/11/12	PACE	PACE	36.000	07/01/12	07/01/32		
1455	780564	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/11/12	PACE	PACE	979.000	07/01/12	07/01/32		
1456	780568	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/29/12	WYOEAST	WYOEAST	811.000	07/01/12	07/01/32		
1458	780574	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/29/12	WYOEAST	WYOEAST	280.000	07/01/12	07/01/32		
1460	780582	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/11/12	PACE	PACE	129.000	07/01/12	07/01/32		
1461	780584	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/11/12	PACE	PACE	613.000	07/01/12	07/01/32		
1462	780595/90083949	PAC Merchant	04/20/12	04/25/12	East	NT	Confirmed 6/11/12	GSHN	GSHN	7.000	07/01/12	07/01/32		
1463	780638	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	62.000	07/01/12	07/01/32		
1464	780644	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	4.000	07/01/12	07/01/32		
1465	780649	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	4.000	07/01/12	07/01/32		
1466	780652	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	7.000	07/01/12	07/01/32		
1467	780655	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	9.000	07/01/12	07/01/32		
1468	780659	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	2.000	07/01/12	07/01/32		
1469	780661	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	13.000	07/01/12	07/01/32		
1471	780651	PAC Merchant	04/20/12	04/25/12	West	NT	Confirmed 6/11/12	PACW	PACW	151.000	07/01/12	07/01/32		
1473	781030	PAC Merchant	04/23/12	04/27/12	West	NT	Confirmed 6/11/12	PACW	PACW	45.000	07/01/12	07/01/32		
1474	781039	PAC Merchant	04/23/12	04/27/12	West	NT	Confirmed 6/11/12	PACW	PACW	2.000	07/01/12	07/01/32		
1475	781045	PAC Merchant	04/23/12	04/27/12	West	NT	Confirmed 6/11/12	PACW	PACW	173.000	07/01/12	07/01/32		
1476	781053	PAC Merchant	04/23/12	04/27/12	East	NT	Confirmed 6/11/12	PACE	PACE	25.000	07/01/12	07/01/32		
1478	781072	PAC Merchant	04/23/12	05/02/12	West	NT	Confirmed 6/29/12	Talbot	WALLAWALLA	211.000	07/01/12	07/01/32		
1495	784431	BPA	05/10/12	05/14/12	West	NT	Confirmed 7/31/12	BPAT.PACW	PACW	7.000	08/01/12	08/01/28		
1501	789618	PAC Merchant	06/07/12	06/11/12	East	NT	Confirmed 8/6/12	PACE	PACE	719.000	07/01/12	07/01/32		
1506	796780	PAC Merchant	07/13/12	07/17/12	West	NT	Confirmed 9/27/12	PACW	PACW	2.000	10/01/12	10/01/32		
1521	804043	PAC Merchant	08/14/12	08/15/12	East	NT	Confirmed 5/12/16	WYOCENTR	WYOCENTRAL	0.100	10/15/12	08/23/22		
1532	806494	PAC Merchant	08/28/12	08/30/12	East	NT	Confirmed 8/22/13	PACE	PACE	2.000	01/01/15	01/01/32	SIS	
1533	806544	PAC Merchant	08/28/12	08/30/12	East	NT	Confirmed 8/22/13	PACE	PACE	4.000	11/01/12	01/01/32	SIS	
1534	806561	PAC Merchant	08/28/12	08/30/12	East	NT	Confirmed 8/22/13	PACE	PACE	6.000	03/01/13	03/01/32	SIS	
1535	806585	PAC Merchant	08/28/12	08/30/12	East	NT	Confirmed 8/22/13	PACE	PACE	8.000	12/01/12	01/01/32		
1549	810053/90084018	PAC Merchant	09/17/12	10/10/12	East	NT	Confirmed 11/15/12	GSHN	GSHN	0.290	09/01/29	09/01/29		
1550	810067	UAMPS	09/17/12	09/13/12	East	NT	Confirmed 1/25/13	REDBL	PACE	3.200	10/31/12	10/31/24		
1557	810176	PAC Merchant	09/18/12	10/10/12	East	NT	Confirmed 11/15/12	PACE	PACE	0.500	09/20/12	03/01/32		
1558	810181/90084030	PAC Merchant	09/18/12	10/10/12	East	NT	Confirmed 11/15/12	GSHN	GSHN	4.000	09/19/12	05/01/22		
1561	810236	PAC Merchant	09/18/12	10/10/12	East	NT	Confirmed 11/15/12	PACE	PACE	2.457	09/19/12	01/10/25		
1570	811956	PAC Merchant	09/28/12	10/11/12	East	NT	Confirmed 11/15/12	PACE	PACE	61.000	09/29/12	07/02/32		
1571	811983	PAC Merchant	09/28/12	10/11/12	East	NT	Confirmed 11/15/12	PACE	PACE	80.000	09/29/12	09/30/32		
1573	812020	PAC Merchant	09/28/12	10/15/12	East	NT	Confirmed 11/15/12	PACE	PACE	1.000	09/29/12	02/01/22		
1576	1234	PAC Merchant	10/28/12	10/28/12	East	NT	Confirmed 1/23/13	PACE	PACE	0.520	04/01/13	04/01/23		
1579	77669471/ 7773612	BPA	12/12/12	12/11/12	West	NT	Confirmed 1/3/12	BPAT.PACW	PACW	40.000	01/01/13	09/30/28		
1599	77699698/9008406	PAC Merchant	12/20/12	12/27/12	East	NT	Confirmed 3/23/15	GSHN	GSHN	1.000	11/01/13	12/01/33		
1600	77766563/9008404	PAC Merchant	01/11/13	01/17/13	East	NT	Confirmed 04/05/13	GSHN	GSHN	40.000	03/01/13	12/31/32		
1601	77766732/90084057	PAC Merchant	01/11/13	01/17/13	East	NT	Confirmed 04/05/13	GSHN	GSHN	80.000	03/01/13	07/01/32		
1625	92683121/95094242	PAC Merchant	02/18/13	03/07/13	East	NT	ed 4/16/13 RECALLE	GSHN	GSHN	0.650	05/01/13	01/01/23		
1626	77888485/9008402	PAC Merchant	02/18/13	03/07/13	East	NT	Confirmed 4/16/13	GSHN	GSHN	3.000	05/01/13	04/01/22		
1628	77875813	PAC Merchant	02/14/13	03/07/13	East	NT	Confirmed 4/17/13	PACE	PACE	19.000	05/01/13	07/31/28		
1629	77875926	PAC Merchant	02/14/13	03/07/13	East	NT	Confirmed 4/17/13	PACE	PACE	53.000	05/01/13	09/01/23		
1630	77875947	PAC Merchant	02/14/13	03/07/13	East	NT	Confirmed 4/17/13	PACE	PACE	1.000	05/01/13	12/01/23		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
1637	77877455	PAC Merchant	02/14/13	03/07/13	West	NT	Confirmed 4/16/13	PACW	PACW	1.650	02/14/13	01/30/29		
1638	77877558	PAC Merchant	02/14/13	03/07/13	West	NT	Confirmed 4/16/13	PACW	PACW	30.000	05/01/13	01/01/27		
1639	77879241	PAC Merchant	02/15/13	03/07/13	West	NT	Confirmed 4/16/13	PACW	PACW	1.000	05/01/13	01/01/41		
1640	77879485	PAC Merchant	02/15/13	03/07/13	West	NT	Confirmed 4/16/13	PACW	PACW	2.000	05/01/13	03/15/32		
1642	77879661/91590723	PAC Merchant	02/15/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	5.000	05/01/13	08/02/30		
1643	77880688	PAC Merchant	02/15/13	03/04/13	West	NT	Confirmed 4/17/13	PACW	PACW	1.000	05/01/13	03/01/27		
1645	77880997	PAC Merchant	02/15/13	03/07/13	East	NT	Confirmed 4/17/13	PACE	PACE	4.000	05/01/13	04/01/22		
1647	77888579	PAC Merchant	02/18/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	1.000	05/01/13	10/10/23		
1649	77888834	PAC Merchant	02/18/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	3.000	05/01/13	04/15/28		
1651	77888858	PAC Merchant	02/18/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	5.000	05/01/13	01/01/26		
1652	77888996	PAC Merchant	02/18/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	10.000	05/01/13	07/01/29		
1653	77889056	PAC Merchant	02/18/13	03/07/13	West	NT	Confirmed 4/17/13	PACW	PACW	10.000	05/01/13	07/01/29		
1658	77888573	PAC Merchant	02/18/13	03/07/13	East	NT	Confirmed 4/17/13	PACE	PACE	2.000	05/01/13	03/29/28		
1659	77913519	PAC Merchant	02/25/13	03/13/13	West	NT	Confirmed 4/17/13	PACW	PACW	2.000	05/01/13	01/01/22		
1661	77888964	PAC Merchant	02/18/13	03/14/13	West	NT	Confirmed 4/17/13	BPAT.PACW	PACW	5.000	05/01/13	11/16/22		
1665	77913704	PAC Merchant	02/25/13	03/14/13	West	NT	Confirmed 4/17/13	Troutdale	PACW	5.000	05/01/13	01/01/22		
1666	77913774	PAC Merchant	02/25/13	03/14/13	West	NT	Confirmed 4/17/13	PACW	PACW	2.000	05/01/13	01/01/22		
1667	77913784	PAC Merchant	02/25/13	03/04/13	West	NT	Confirmed 4/17/13	PACW	PACW	1.000	05/01/13	12/01/26		
1670	77921043	PAC Merchant	02/27/13	03/14/13	West	NT	Confirmed 4/17/13	PACW	PACW	4.000	05/01/13	08/01/22		
1671	77921092	PAC Merchant	02/27/13	03/14/13	West	NT	Confirmed 4/17/13	PACW	PACW	1.000	05/01/13	03/18/30		
1673	77921139	PAC Merchant	02/27/13	03/14/13	West	NT	Confirmed 4/17/13	PACW	PACW	10.000	05/01/13	01/16/29		
1674	77921166	PAC Merchant	02/27/13	03/14/13	West	NT	Confirmed 4/17/13	PACW	PACW	9.000	05/01/13	01/23/29		
1677	77971685	PAC Merchant	03/13/13	03/20/13	West	NT	Confirmed 5/29/13	PACW	PACW	2.000	06/01/13	05/01/32		
1678	77971814	PAC Merchant	03/13/13	03/19/13	West	NT	Confirmed 5/29/13	PACW	PACW	10.000	06/01/13	01/16/29		
1681	77972311	PAC Merchant	03/13/13	03/19/13	West	NT	Confirmed 5/29/13	PACW	PACW	1.000	06/01/13	01/01/23		
1683	77972520	PAC Merchant	03/13/13	03/20/13	West	NT	Confirmed 5/29/13	PACW	PACW	1.000	06/01/13	01/04/30		
1684	77973341	PAC Merchant	03/13/13	03/19/13	West	NT	Confirmed 5/29/13	PACW	PACW	7.000	06/01/13	01/16/29		
1687	77979419	PAC Merchant	03/15/13	03/21/13	West	NT	Confirmed 5/2/13	PACW	PACW	5.000	06/01/13	01/30/29		
1688	77979970	PAC Merchant	03/15/13	03/21/13	East	NT	Confirmed 5/2/13	MDGT	PACE	100.000	06/01/13	10/01/24		
1691	77973101	PAC Merchant	03/13/13	03/25/13	West	NT	Confirmed 5/2/13	BPAT.PACW	PACW	5.000	06/30/13	05/01/23		
1692	77973137	PAC Merchant	03/13/13	03/25/13	West	NT	Confirmed 5/2/13	Dalreed	Dalreed	5.000	06/30/13	05/01/23		
1693	77973304	PAC Merchant	03/13/13	03/19/13	West	NT	Confirmed 5/2/13	PACW	PACW	4.000	06/01/13	01/30/29		
1695	77979576	PAC Merchant	03/15/13	03/26/13	West	NT	Confirmed 5/2/13	BPAT.PACW	PACW	1.000	06/01/13	10/01/27		
1698	77979847	PAC Merchant	03/15/13	03/28/13	East	NT	Confirmed 5/2/13	WYOEAST	WYOEAST	99.000	06/01/13	01/01/30		
1699	78002619	PAC Merchant	03/21/13	03/26/13	West	NT	Confirmed 5/2/13	PACW	PACW	41.000	06/01/13	12/22/23		
1700	78002264	PAC Merchant	03/21/13	03/26/13	West	NT	Confirmed 5/2/13	PACW	PACW	175.000	06/01/13	03/01/22		
1704	78032207/90084130	PAC Merchant	03/27/13	04/03/13	East	NT	Confirmed 5/29/13	GSHN	GSHN	65.000	06/01/13	12/30/25		
1707	78040097	PAC Merchant	03/29/13	04/08/13	West	NT	Confirmed 5/12/16	PACW	PACW	0.296	05/31/14	09/01/28		
1708	78040128	PAC Merchant	03/29/13	04/08/13	West	NT	Confirmed 3/11/15	PACW	PACW	7.000	06/01/13	12/01/32		
1714	78057044	PAC Merchant	04/05/13	04/11/13	West	NT	Confirmed 5/30/13	PACW	PACW	171.000	07/01/13	01/01/51		
1724	78194569	PAC Merchant	05/07/13	05/10/13	West	NT	Confirmed 6/28/13	PACW	PACW	2.000	08/01/13	01/01/23		
1725	78170238	BPA	04/30/13	05/17/13	East	NT	Confirmed 4/23/14	GSHN	GSHN	176.000	07/01/16	06/30/28		
1726	78170253	BPA	04/30/13	05/17/13	East	NT	Confirmed 4/23/14	GSHN	GSHN	176.000	07/01/16	06/30/28		
1740	78333987	PAC Merchant	06/10/13	06/14/13	East	NT	Confirmed 7/12/13	MDGT	PACE	29.000	09/01/13	09/01/32		
1741	78345681	PAC Merchant	06/13/13	06/17/13	East	NT	Confirmed 7/18/13	PACE	PACE	1,220.000	09/01/13	09/01/32		
1742	78345997	PAC Merchant	06/13/13	06/18/13	East	NT	Confirmed 7/18/13	WYOEAST	WYOEAST	102.000	09/01/13	09/01/31		
1743	78346025	PAC Merchant	06/13/13	06/18/13	East	NT	Confirmed 7/18/13	WYOEAST	WYOEAST	21.000	09/01/13	09/01/31		
1744	78347392	PAC Merchant	06/13/13	06/18/13	East	NT	d by 195423, 367199	FOURCORN	PACE	67.000	09/01/13	09/01/32		
1746	78350356	PAC Merchant	06/14/13	06/18/13	East	NT	Confirmed 9/12/16	PINTO	PACE	60.000	05/01/15	05/01/35		
1764	78705565	PAC Merchant	09/12/13	09/17/13	West	NT	Confirmed 10/24/13	HURR	WALLAWALLA	400.000	11/01/13	11/01/30		
1765	78705594	PAC Merchant	09/12/13	09/17/13	West	NT	Confirmed 10/24/13	WALLAWAL	MCNARY	400.000	11/01/13	11/01/30		
1777	78836789	PAC Merchant	10/17/13	10/17/13	West	NT	Confirmed 11/15/13	PACW	CARDWELL	162.000	01/01/14	01/01/30		
1780	78849614	PAC Merchant	10/18/13	10/22/13	East	NT	Confirmed 12/20/16	WYOCENTR	WYOCENTRAL	21.000	01/01/14	01/01/22	SIS	
1781	78865513	PAC Merchant	10/23/13	10/25/13	East	NT	Confirmed 12/20/16	WYOEAST	WYOEAST	20.000	01/01/14	01/01/23	SIS	
1787	78984295	PAC Merchant	11/22/13	11/26/13	East	NT	Confirmed 12/20/16	WYOEAST	WYOEAST	7.500	07/30/14	07/30/22	SIS	
1788	79026180	PAC Merchant	12/03/13	12/05/13	West	NT	Confirmed 4/9/14	BPAT.PACW	PACW	0.700	04/01/14	04/01/29		
1794	79099043	PAC Merchant	12/20/13	12/23/13	East	NT	Confirmed 12/20/16	PACE	PACE	1.000	03/31/14	01/01/30		
1798	79191300	PAC Merchant	01/14/14	01/16/14	West	NT	Confirmed 3/31/14	BPAT.PACW	PACW	94.000	05/01/14	01/01/30		
1799	N/A	UAMPS	N/A	01/14/14	East	NT	N/A	PACE	PACE	N/A	N/A	N/A	SIS	FS
1802	N/A	UAMPS	N/A	02/06/14	East	NT	N/A	PACE	PACE	N/A	N/A	N/A		
1803	N/A	UAMPS	N/A	02/10/14	East	NT	N/A	PACE	PACE	N/A	N/A	N/A		
1812	79341660	PAC Merchant	02/20/14	02/24/14	East	NT	Confirmed 12/20/16	NUT	NUT	13.000	12/01/14	12/01/34	SIS	
1814	79390277/90342762	PAC Merchant	03/04/14	03/10/14	East	NT	Confirmed 4/10/14	GSHN	GSHN	27.000	05/01/14	09/01/23		
1821	79428784	PAC Merchant	03/12/14	03/17/14	West	NT	Confirmed 4/22/14	BPAT.PACW	PACW	338.000	06/01/14	06/01/34		
1823	79428926	PAC Merchant	03/12/14	03/17/14	West	NT	Confirmed 4/22/14	BPAT.PACW	PACW	400.000	06/01/14	06/01/34		
1829	79495468	PAC Merchant	03/27/14	03/28/14	East	NT	Confirmed 4/23/14	WYOCENTR	JBSN	400.000	04/01/14	04/01/30		
1831	79486154	PAC Merchant	03/25/14	03/31/14	East	NT	Confirmed 11/4/16	WYOEAST	WYOEAST	80.000	06/30/16	07/01/36	SIS	
1832	79490399	PAC Merchant	03/26/14	03/31/14	East	NT	Confirmed 5/29/14	PACE	PACE	712.000	05/01/14	05/01/29		
1840	79620960	PAC Merchant	04/23/14	04/24/14	East	NT	Confirmed 5/29/14	NUT	Trona	400.000	05/01/14	05/01/34		
1841	79620964	PAC Merchant	04/23/14	04/24/14	East	NT	Confirmed 5/29/14	Trona	WYOCENTRAL	400.000	05/01/14	05/01/34		
1843	79625464	PAC Merchant	04/24/14	04/30/14	West	NT	Confirmed 8/9/17	PACW	PACW	2.000	09/01/14	01/01/34		
1845	79648694	PAC Merchant	04/29/14	05/01/14	East	NT	Confirmed 11/2/15	REDBL	PACE	3.000	07/31/15	08/01/35	SIS	
1846	79648850	PAC Merchant	04/29/14	05/01/14	East	NT	Confirmed 12/23/15	PACE	PACE	3.000	07/31/15	08/01/35	SIS	
1847	79648886	PAC Merchant	04/29/14	05/01/14	East	NT	Confirmed 12/23/15	PACE	PACE	3.000	07/31/15	08/01/35	SIS	
1848	79648900	PAC Merchant	04/29/14	05/01/14	East	NT	Confirmed 3/30/16	PACE	PACE	3.000	07/31/15	08/01/35	SIS	
1851	79656579	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/2/15	PACE	PACE	2.100	05/30/15	05/30/35	SIS	
1852	79656649	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/2/15	PACE	PACE	2.100	05/30/15	05/30/35	SIS	
1853	79656693	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/2/15	PACE	PACE	3.000	01/15/15	01/15/35	SIS	FS
1855	79656769	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/3/15	PACE	PACE	3.000	07/31/15	07/31/35	SIS	FS
1856	79656794	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/2/15	PACE	PACE	3.000	07/31/15	07/31/35	SIS	FS
1857	79656841	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 11/2/15	PACE	PACE	3.000	07/31/15	07/31/35	SIS	FS
1858	79656858	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 12/15/15	PACE	PACE	3.000	10/15/15	11/15/35	SIS	
1859	79656968	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 12/9/16	PACE	PACE	3.000	05/30/16	05/30/36	SIS	
1860	79656996	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 12/20/16	PACE	PACE	3.000	06/30/16	06/30/36	SIS	
1861	79657047	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 12/20/16	PACE	PACE	3.000	07/29/16	07/29/36	SIS	
1862	79657068	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 12/15/15	PACE	PACE	3.000	10/15/15	10/15/35	SIS	FS
1863	79657086	PAC Merchant	05/01/14	05/01/14	East	NT	Confirmed 1/5/16	PAVANT	PAVANT	50.000	12/31/15	12/31/35	SIS	
1866	79672901	PAC Merchant	05/05/14	05/07/14	West	NT	Confirmed 1/30/2017	PACW	PACW	10.000	05/30/16	05/30/36	SIS	
1879	79857385	PAC Merchant	06/18/14	06/24/14	East	NT	Confirmed 8/16/16	REDBL	PACE	80.000	10/31/16	10/31/36	SIS	FS

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
1880	79857389	PAC Merchant	06/18/14	06/24/14	East	NT	Confirmed 8/16/16	REDBL	PACE	80.000	10/31/16	10/31/36	SIS	FS
1881	79857395	PAC Merchant	06/18/14	06/24/14	East	NT	Confirmed 8/16/16	REDBL	PACE	80.000	10/31/16	10/31/36	SIS	FS
1882	79857400	PAC Merchant	06/18/14	06/24/14	East	NT	Confirmed 8/16/16	REDBL	PACE	80.000	10/31/16	10/31/36	SIS	FS
1891	80035471	PAC Merchant	07/29/14	08/01/14	West	NT	Confirmed 9/10/2018	PACW	PACW	10.000	10/31/16	10/31/36		
1893	80039313	PAC Merchant	07/30/14	08/01/14	West	NT	Confirmed 1/9/17	PACW	PACW	8.000	12/01/16	12/01/36	SIS	
1897	80103182	PAC Merchant	08/15/14	08/20/14	West	NT	Confirmed 11/30/201	PACW	PACW	9.000	10/31/16	10/31/36		
1904	80262387	PAC Merchant	09/23/14	09/25/14	East	NT	Confirmed 9/30/14	WYODAK	WYONORTH	280.000	10/01/14	10/01/25		
1905	80262401	PAC Merchant	09/23/14	09/25/14	East	NT	Confirmed 9/30/14	WYONORTH	WYODAK	25.000	10/01/14	10/01/25		
1906	80263832	PAC Merchant	09/23/14	09/25/14	East	NT	Confirmed 9/30/14	WYONORTH	WYONORTH	3.000	10/01/14	10/01/25		
1907	80263844	PAC Merchant	09/23/14	09/25/14	East	NT	Confirmed 9/30/14	WYONORTH	WYONORTH	3.000	10/01/14	10/01/25		
1908	80266136	PAC Merchant	09/24/14	09/25/14	East	NT	Confirmed 9/30/14	WYONORTH	WYODAK	18.000	10/01/14	10/01/25		
1909	80267664	PAC Merchant	09/24/14	09/26/14	East	NT	Confirmed 9/30/14	WYONORTH	WYOEAST	163.000	10/01/14	10/01/25		
1916	80364853	PAC Merchant	10/20/14	10/22/14	East	NT	Confirmed 12/4/14	WYOEAST	WYOCENTRAL	880.000	11/15/14	11/15/33		
1920	80429991	PAC Merchant	11/05/14	11/07/14	East	NT	Confirmed 12/8/14	NUT	NUT	12.000	01/01/15	01/01/32		
1923	80457935	PAC Merchant	11/11/14	11/14/14	West	NT	Confirmed 12/16/14	BPAT.PACW	PACW	13.000	11/15/14	11/15/34		
1924	80457957	PAC Merchant	11/11/14	11/14/14	West	NT	Confirmed 12/16/14	BPAT.PACW	PACW	42.000	11/15/14	11/15/34		
1925	80457988	PAC Merchant	11/11/14	11/14/14	West	NT	Confirmed 12/16/14	PACW	BPAT.PACW	42.000	11/15/14	11/15/34		
1932	80179624	PAC Merchant	12/01/14	12/03/14	West	NT	Confirmed 9/5/18	PACW	PACW	10.000	01/01/15	06/18/29		
1943	80656786	PAC Merchant	12/31/14	12/31/14	East	NT	Confirmed 2/13/15	PACE	PACE	16.000	01/01/15	01/01/25		
1946	80715165	PAC Merchant	01/16/15	01/16/15	West	NT	Confirmed 2/16/15	WOODLAND	PACW	8.000	04/01/15	04/01/25		
1947	80715378	PAC Merchant	01/16/15	01/16/15	West	NT	Confirmed 1/22/15	PACW	WOODLANDTA	338.000	02/01/15	02/01/25		
1948	80751816	Tri-State	01/26/15	01/26/15	East	NT	Confirmed 5/24/16	FOURCORN	PINTO	2.000	10/31/15	10/31/25	SIS	
1949	80781778	PAC Merchant	02/03/15	02/10/15	West	NT	Confirmed 5/8/15	PACW	PACW	1.000	02/10/15	12/19/29		
1951	80790269	PAC Merchant	02/05/15	02/10/15	East	NT	Confirmed 5/20/16	NUT	NUT	1.000	03/01/15	03/01/25		
1954	80913347	PAC Merchant	03/05/15	03/10/15	West	NT	Confirmed 4/30/15	BPAT.PACW	PONDEROSA50	140.000	05/01/15	05/01/35		
1955	80913373	PAC Merchant	03/05/15	03/10/15	West	NT	Confirmed 4/30/15	PONDEROSA	SUMMERLAKE	140.000	05/01/15	05/01/35		
1956	80913393	PAC Merchant	03/05/15	03/10/15	West	NT	Confirmed 4/29/15	SUMMERLA	PONDEROSA50	340.000	05/01/15	05/01/35		
1957	80913401	PAC Merchant	03/05/15	03/10/15	West	NT	Confirmed 4/29/15	PILOTBUTE2	PILOTBUTEPAC	220.000	05/01/15	05/01/35		
1958	80913443	PAC Merchant	03/05/15	03/10/15	West	NT	Confirmed 4/29/15	PONDEROSA	PONDEROSAPA	165.000	05/01/15	05/01/35		
1965	80959436	PAC Merchant	03/17/15	03/18/15	West	NT	Confirmed 2/22/17	PACW	PACW	0.825	09/30/15	10/01/35		
1967	80994031	PAC Merchant	03/25/15	03/30/15	East	NT	Confirmed 1/9/17	PAVANT	PAVANT	50.000	12/01/16	12/01/36	SIS	FS
1968	81000040	PAC Merchant	03/26/15	03/30/15	East	NT	Confirmed 4/30/15	WYOEAST	WYOEAST	2.000	04/01/15	04/01/30		
1969	81022295	PAC Merchant	03/31/15	04/09/15	East	NT	Confirmed 3/30/2017	MDWP	PACE	9.000	04/01/17	04/01/22		
1970	81045924	PAC Merchant	04/06/15	04/09/15	East	NT	Confirmed 8/30/16	PACE	NUT	80.000	09/01/16	09/01/36	SIS	
1971	81045929	PAC Merchant	04/06/15	04/09/15	East	NT	Confirmed 9/16/16	PACE	NUT	80.000	08/01/16	08/01/36	SIS	
1972	81045934	PAC Merchant	04/06/15	04/09/15	East	NT	Confirmed 11/9/2016	PACE	NUT	51.000	08/01/16	08/01/36	SIS	FS
1974	81074553	PAC Merchant	04/14/15	04/16/15	West	NT	Confirmed 3/11/16	PACW	PACW	5.000	12/15/15	12/15/40	SIS	
1975	81161645	PAC Merchant	05/08/15	05/12/15	East	NT	Confirmed 12/20/16	NUT	NUT	152.000	08/01/15	08/01/30		
1976	81207078	Black Hills Power	05/20/15	05/20/15	East	NT	Confirmed 12/24/15	JBSN	WYONORTH	58.000	01/01/18	01/01/24	SIS	
1977	81205027	Tri-State	05/20/15	05/27/15	East	NT	Confirmed 8/14/2019	DJ	WYOEAST	5.000	06/05/17	06/05/27	SIS	
1982	81269111	PAC Merchant	06/05/15	06/10/15	West	NT	Confirmed 1/4/18	PACW	PACW	10.000	11/18/16	11/18/31	SIS	
1983	81235956	PAC Merchant	05/28/15	06/16/15	West	NT	Confirmed 1/3/2018	PACW	PACW	8.000	11/30/17	11/30/37	SIS	
1984	81235960	PAC Merchant	05/28/15	06/16/15	West	NT	Confirmed 12/15/17	PACW	PACW	3.000	11/30/17	11/30/37	SIS	
1986	81288775	PAC Merchant	06/10/15	06/20/15	West	NT	90084111 on NITS mo	PACW	PACW	10.000	11/01/16	11/01/36	SIS	
1987	81288790	PAC Merchant	06/10/15	06/20/15	West	NT	Confirmed 1/3/18	PACW	PACW	10.000	11/01/16	11/01/36	SIS	
1989	81315991	PAC Merchant	06/17/15	06/20/15	West	NT	Confirmed 3/16/2018	PACW	PACW	10.000	11/01/16	11/01/36	SIS	
1991	81316106	PAC Merchant	06/17/15	06/20/15	West	NT	Confirmed 1/8/18	PACW	PACW	10.000	11/01/16	11/01/36	SIS	
1992	81316143	PAC Merchant	06/17/15	06/20/15	West	NT	Confirmed 1/12/18	PACW	PACW	8.000	11/01/16	11/01/36	SIS	
1995	81269090	PAC Merchant	06/05/15	06/30/15	West	NT	Confirmed 1/23/2017	PACW	PACW	9.900	11/18/16	11/18/31		
1997	81369264	PAC Merchant	06/30/15	07/03/15	West	NT	Confirmed 2/22/2017	PACW	PACW	10.000	11/18/16	11/18/31		
1998	81369320	PAC Merchant	06/30/15	07/03/15	West	NT	Confirmed 10/3/18	PACW	PACW	6.000	11/18/16	11/18/31		
2002	81460501	PAC Merchant	07/23/15	07/24/15	West	NT	Confirmed 12/31/201	PACW	PACW	4.800	11/18/16	11/18/31	SIS	FS
2005	81518983	PAC Merchant	08/07/15	08/13/15	East	NT	Confirmed 10/12/15	NUT	NUT	0.481	09/30/15	10/01/30		
2006	81550387	PAC Merchant	08/14/15	08/17/15	East	NT	Confirmed 12/9/2016	PACE	PACE	80.000	12/01/16	12/01/36	SIS	
2007	81629597	PAC Merchant	09/03/15	09/10/15	East	NT	Confirmed 10/14/15	NUT	NUT	0.850	01/01/16	01/01/26		
2008	81629610	PAC Merchant	09/03/15	09/10/15	East	NT	Confirmed 10/14/15	NUT	NUT	0.261	01/01/16	01/01/26		
2011	81661717	Basin Electric	09/11/15	09/22/15	East	NT	Confirmed 12/30/15	DJ	WYONORTH	12.000	01/01/16	01/01/26		
2017	81774191	PAC Merchant	10/13/15	10/14/15	West	NT	Confirmed 1/3/18	PACW	PACW	10.000	12/16/16	12/16/36		
2018	81774198	PAC Merchant	10/13/15	10/14/15	West	NT	Confirmed 2/12/18	PACW	PACW	10.000	12/16/16	12/16/36	SIS	
2019	81778517	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	JBSN	POP	1,067.000	11/01/15	11/01/35		
2020	81778565	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	POP	KPRT	533.000	11/01/15	11/01/35		
2021	81778730	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	POP	BORA	1,233.000	11/01/15	11/01/35		
2022	81778755	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	KPRT	GSHN	346.000	11/01/15	11/01/35		
2023	81778778	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	KPRT	BORA	1,090.000	11/01/15	11/01/35		
2024	81778865	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	GSHN	KPRT	156.000	11/01/15	11/01/35		
2025	81778882	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	NUT	POP	400.000	11/01/15	11/01/35		
2026	81778925	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	JBSN	WYOCENTRAL	400.000	11/01/15	11/01/35		
2027	81779029	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	BRDY	NUT	90.000	11/01/15	11/01/35		
2028	81779120	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	GSHN	NUT	142.000	11/01/15	11/01/35		
2029	81779169	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	GSHN	JBSN	200.000	11/01/15	11/01/35		
2030	81779501	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	JBSN	KPRT	533.000	11/01/15	11/01/35		
2031	81779615	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	BORA	NUT	122.000	11/01/15	11/01/35		
2032	81779640	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	KPRT	POP	200.000	11/01/15	11/01/35		
2033	81779667	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	BORA	SMLK	1,090.000	11/01/15	11/01/35		
2034	81779678	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	PACW	SMLK	340.000	11/01/15	11/01/35		
2035	81779697	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	PONDEROSA	SMLK	140.000	11/01/15	11/01/35		
2036	81779943	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	SMLK	PACW	1187-1000	11/01/15	11/01/35		
2037	81779951	PAC Merchant	10/14/15	10/15/15	East	NT	Confirmed 10/16/15	SMLK	PONDEROSA50	340.000	11/01/15	11/01/35		
2038	81826253	PAC Merchant	10/30/15	10/30/15	East	NT	Confirmed 11/2/14	KPRT	GSHN	300.000	11/01/15	11/01/35		
2039	81827402	PAC Merchant	10/30/15	10/30/15	West	NT	Confirmed 11/2/14	WALLAWAL	HURR	1.000	11/01/15	11/01/35		
2040	81942463	PAC Merchant	12/01/15	12/02/15	West	NT	Confirmed 12/23/15	PACW	BPAT.PACW	5.000	01/01/16	01/01/30		
2042	81967014	PAC Merchant	12/08/15	12/09/15	East	NT	Confirmed 12/23/15	WYOEAST	WYOEAST	201.000	01/01/16	10/01/30		
2045	81993310	PAC Merchant	12/15/15	12/16/15	East	NT	Confirmed 1/29/16	NUT	POP	75-150	01/01/18	01/01/30		
2051	82054853	PAC Merchant	12/30/15	01/05/16	East	NT	Confirmed 2/5/16	PACE	PACE	0.575	02/01/16	01/01/36		
2057	82205457	PAC Merchant	02/01/16	02/03/16	East	NT	Confirmed 12/27/201	PAVANT	PAVANT	20.000	12/31/16	12/31/36	SIS	
2060	82324247	PAC Merchant	02/25/16	03/02/16	East	NT	Confirmed 12/31/201	TRONA	TRONA	80.000	11/01/18	11/01/38	SIS	
2063	82366739	PAC Merchant	03/04/16	03/07/16	West	NT	Confirmed 3/29/16	BPAT.PACW	PACW	40.000	04/01/16	04/01/34		
2064	82366794	PAC Merchant	03/04/16	03/07/16	West	NT	Confirmed 3/28/16	BPAT.PACW	PACW	510.000	04/01/16	04/01/34		
2066	82411259	BPA	03/11/16	03/14/16	West	NT	confirmed 7/3/2017	BPAT.PACW	PONDEROSAPA	1.000	10/01/16	10/01/28		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2073	82485007	BPA	03/24/16	03/24/16	East	PTP	Confirmed 4/22/16	BPAT.NWM	GSHN	56.000	07/01/16	07/01/28		
2074	82489720	PAC Merchant	03/25/16	03/28/16	West	NT	Confirmed 7/30/18	PACW	PACW	10.000	04/01/17	04/01/32		
2075	82489752	PAC Merchant	03/25/16	03/28/16	West	NT	Confirmed 6/28/18	PACW	PACW	10.000	04/01/17	04/01/32		
2080	82480414	BPA	03/23/16	03/28/16	East	PTP	Confirmed 12/2/2016	GSHN	GSHN	9.000	10/01/16	10/01/21		
2081	82517852	Powerex	03/30/16	03/30/16	West	PTP	Confirmed 5/19/16	MALIN500	RDM230	100.000	04/01/17	04/01/22		
2082	82517862	Powerex	03/30/16	03/30/16	West	PTP	Confirmed 5/19/16	MALIN500	RDM230	100.000	04/01/17	04/01/22		
2083	82517865	Powerex	03/30/16	03/30/16	West	PTP	Confirmed 5/19/16	MALIN500	RDM230	100.000	04/01/17	04/01/22		
2084	82516008	PAC Merchant	03/30/16	03/31/16	East	NT	Confirmed 5/11/16	BPAT.NWM	ANTE	52.000	07/01/16	07/01/26		
2085	82516048	PAC Merchant	03/30/16	03/31/16	East	NT	Confirmed 5/11/16	ANTE	GSHN	52.000	07/01/16	07/01/26		
2086	82516067	PAC Merchant	03/30/16	03/31/16	East	NT	Confirmed 5/11/16	ANTE	BRDY	52.000	07/01/16	07/01/26		
2087	82510882	PAC Merchant	03/29/16	04/01/16	West	NT	Confirmed 5/2/16	PACW	PACW.PGE	338.000	05/01/16	05/01/36		
2088	82516434	PAC Merchant	03/30/16	04/01/16	West	NT	Confirmed 4/21/16	BPAT.PACW	PACW	56.000	07/01/16	07/01/26		
2095	82755736	UMPA	05/13/16	n/a	East	PTP	Confirmed 6/24/14	PACE	PACE	200.000	07/01/18	07/01/23		
2099	82976725	PAC Merchant	06/23/16	06/23/16	East	NT	Confirmed 6/29/16	NUT	GSHN	148.000	07/01/16	01/01/26		
2102	83020531	PAC Merchant	07/01/16	07/05/16	East	NT	Confirmed 6/12/19	NUT	NUT	3.000	08/01/16	08/01/26	SIS	
2110	83193586	PAC Merchant	08/01/16	08/03/16	East	NT	confirmed 8/15/2016	NUT	NUT	3/5/6/7/8/9	09/30/16	09/30/25		
2129	83501479	BPA	09/27/16	10/06/16	West	NT	Confirmed 1/19/2017	BPAT.PACW	PILOTBUTEPA	1.000	11/30/16	09/30/28		
2130	83578194	BPA	10/12/16	10/06/16	West	NT	Confirmed 11/9/2016	BPAT.PACW	PONDEROSAP	3.000	09/30/16	09/30/28		
2144	83693097	PAC Merchant	11/03/16	11/09/16	West	NT	Received	WALLULA	MCNARY	10.000	09/30/19	09/30/39	SIS	
2145	83693107	PAC Merchant	11/03/16	11/09/16	West	NT	Received	WALLULA	MCNARY	10.000	09/30/19	09/30/39	SIS	
2146	83693112	PAC Merchant	11/03/16	11/09/16	West	NT	Received	WALLULA	MCNARY	10.000	09/30/19	09/30/39	SIS	
2147	83693115	PAC Merchant	11/03/16	11/09/16	West	NT	Received	WALLULA	MCNARY	10.000	09/30/19	09/30/39	SIS	
2148	83693154	PAC Merchant	11/03/16	11/09/16	West	NT	Received	BPAT.PACW	PACW	24.000	09/30/19	09/30/39		
2149	83693161	PAC Merchant	11/03/16	11/09/16	West	NT	Received	BPAT.PACW	PACW	16.000	09/30/19	09/30/39		
2151	83697887	PAC Merchant	11/04/16	11/15/16	East	NT	Confirmed 3/6/17	NUT	NUT	260.000	12/01/16	12/31/25	SIS	
2152	83786266	PAC Merchant	11/21/16	11/23/16	East	NT	Confirmed 1/9/16	WYOEAST	WYOEAST	0.230	01/01/17	01/01/22		
2153	83798966	PAC Merchant	11/23/16	11/29/16	West	NT	Confirmed 7/10/18	PACW	ROUNDBUTTE	2.000	03/31/17	03/31/37		
2154	83799011	PAC Merchant	11/23/16	11/29/16	West	NT	Confirmed 6/28/18	PACW	ROUNDBUTTE	10.000	03/31/17	03/31/37		
2155	83799064	PAC Merchant	11/23/16	11/29/16	West	NT	Confirmed 7/10/18	BPAT.PACW	RDMND115P	2.000	03/31/17	03/31/37		
2156	83799067	PAC Merchant	11/23/16	11/29/16	West	NT	Confirmed 6/28/18	BPAT.PACW	RDMND115P	10.000	03/31/17	03/31/37		
2157	83830882	NextEra	11/29/16	11/29/16	West	PTP	uperseded/Confirme	WALLULA	MIDC	`99/80	12/01/17	12/01/22		
2159	83835621	BPA	11/30/16	11/30/16	West	NT	Confirmed 1/3/2017	BPAT.PACW	PACW	14.000	12/01/16	09/30/28		
2160	83808013	BPA	11/25/16	12/06/16	West	NT	Confirmed 7/3/2017	BPAT.PACW	PACW	1.000	03/01/17	09/30/28		
2163	83910771	PAC Merchant	12/13/16	12/20/16	East	NT	Confirmed 1/19/2017	NUT	NUT	18.000	12/14/16	12/14/29		
2164	83910798	PAC Merchant	12/13/16	12/20/16	East	NT	Confirmed 1/19/2017	WYOEAST	WYOEAST	17.000	12/14/16	12/14/30		
2165	83910809	PAC Merchant	12/13/16	12/20/16	East	NT	Confirmed 1/23/2017	NUT	NUT	11.800	12/14/16	12/14/31		
2166	83910852	PAC Merchant	12/13/16	12/20/16	East	NT	Confirmed 1/19/2017	NUT	NUT	`8.5/10	12/14/16	12/14/36		
2167	83927698	PAC Merchant	12/16/16	12/20/16	East	NT	Confirmed 1/19/2017	NUT	NUT	3.200	12/17/16	12/17/31		
2168	83927782	PAC Merchant	12/16/16	12/20/16	East	NT	Confirmed 2/13/17	PACE	PACE	`2.3/3.1	12/16/16	01/17/24		
2173	83910859	PAC Merchant	12/13/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	`7/9/11	12/14/16	12/14/36		
2174	83920277	PAC Merchant	12/15/16	12/29/16	East	NT	Confirmed 2/9/17	WYOEAST	WYOEAST	3.400	12/16/16	12/16/36		
2175	83941227	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	2.660	12/20/16	12/20/31		
2176	83941304	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	2.500	12/20/16	12/10/29		
2177	83941312	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	2.500	12/20/16	04/16/29		
2178	83941324	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	2.500	12/20/16	12/20/31		
2179	83941373	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	GSHN	GSHN	2.123	12/20/16	02/25/25		
2180	83941597	PAC Merchant	12/19/16	12/29/16	East	NT	Confirmed 2/9/17	NUT	NUT	6.000	12/20/16	12/20/31		
2181	83915654	PAC Merchant	12/14/16	01/05/17	East	NT	Confirmed 2/9/17	WYOEAST	WYOEAST	5.000	12/15/16	12/15/36		
2182	83915665	PAC Merchant	12/14/16	01/05/17	East	NT	Confirmed 2/9/17	NUT	NUT	5.000	12/18/16	12/18/29		
2183	83920245	PAC Merchant	12/15/16	01/05/17	East	NT	Confirmed 2/9/17	WYOCENTR	WYOCENTRAL	4.100	12/16/16	12/16/36		
2184	83920264	PAC Merchant	12/15/16	01/05/17	East	NT	Confirmed 2/9/17	WYOEAST	WYOEAST	4.000	12/16/16	12/16/36		
2185	83920268	PAC Merchant	12/15/16	01/05/17	East	NT	Confirmed 2/9/17	WYOEAST	WYOEAST	4.000	12/16/16	12/16/36		
2186	83920294	PAC Merchant	12/15/16	01/05/17	East	NT	Confirmed 2/9/17	NUT	NUT	4.000	12/16/16	01/20/31		
2187	83927810	PAC Merchant	12/16/16	01/05/17	East	NT	Confirmed 2/9/17	WYOEAST	WYOEAST	3.000	12/16/16	12/16/31		
2188	83928460	PAC Merchant	12/16/16	01/05/17	East	NT	Confirmed 2/9/17	NUT	NUT	3.000	12/17/16	07/16/30		
2189	83941340	PAC Merchant	12/19/16	01/05/17	East	NT	Confirmed 2/9/17	NUT	NUT	3.000	12/20/16	12/20/31		
2190	83941424	PAC Merchant	12/19/16	01/05/17	East	NT	Confirmed 2/9/17	NUT	NUT	2.100	12/20/16	12/20/31		
2192	84059293	Tri-State	01/09/17	01/06/17	East	NT	Received	FOURCORN	PINTO	0.006	03/01/17	03/01/27		
2194	84065221	PAC Merchant	01/10/17	01/11/17	East	NT	Confirmed 2/9/17	NUT	NUT	2.400	10/29/17	10/29/32		
2195	84071299	PAC Merchant	01/11/17	01/12/17	West	NT	Confirmed 3/9/17	PACW	PACW	1.000	01/12/17	01/12/27		
2196	84071303	PAC Merchant	01/11/17	01/12/17	West	NT	Confirmed 3/9/17	PACW	PACW	1.000	01/12/17	01/12/27		
2197	84071307	PAC Merchant	01/11/17	01/12/17	West	NT	Confirmed 3/9/18	PACW	PACW	1.000	01/12/17	01/12/27		
2206	84074242	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	1.8-2.287	01/13/17	01/13/27		
2207	84074249	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	2.8-6	01/13/17	01/13/27		
2208	84074254	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	1.532	01/13/17	01/13/27		
2209	84075952	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	1.137	01/13/17	01/13/27		
2210	84076079	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 3/7/2017	PACW	PACW	2.083	01/13/17	01/13/27		
2211	84076122	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	1.995	01/13/17	01/13/27		
2212	84076439	PAC Merchant	01/12/17	01/17/17	West	NT	Confirmed 2/15/2017	PACW	PACW	1.598	01/13/17	01/13/27		
2213	84075880	PAC Merchant	01/12/17	01/18/17	West	NT	Confirmed 2/16/2017	PACW	PACW	1.600	01/13/17	01/13/27		
2214	84075889	PAC Merchant	01/12/17	01/18/17	West	NT	Confirmed 2/16/2017	PACW	PACW	2.340	01/13/17	01/13/27		
2215	84075905	PAC Merchant	01/12/17	01/18/17	West	NT	Confirmed 2/16/2017	PACW	PACW	1.001	01/13/17	01/13/27		
2216	84075918	PAC Merchant	01/12/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.373	01/13/17	01/13/27		
2217	84101894	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.500	01/18/17	01/18/27		
2218	84101905	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	5.148	01/18/17	01/18/27		
2219	84103289	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.5-1.8	12/01/17	12/01/27		
2220	84103516	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	0.698-1.397	04/30/17	04/30/27		
2221	84103533	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 2/17/2017	PACW	PACW	2.817	01/18/17	01/18/27		
2222	84103629	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.940	01/18/17	01/18/27		
2223	84103686	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.100	01/18/17	01/18/27		
2224	84103699	PAC Merchant	01/17/17	01/18/17	West	NT	Confirmed 2/16/2017	PACW	PACW	2.575	01/18/17	01/18/27		
2225	84107416	PAC Merchant	01/18/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.340	01/19/17	01/19/27		
2226	84107452	PAC Merchant	01/18/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.000	01/19/17	01/19/27		
2227	84107575	PAC Merchant	01/18/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.483	10/31/17	10/31/27		
2228	84107688	PAC Merchant	01/18/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	2.635	01/19/17	01/19/27		
2229	84107772	PAC Merchant	01/18/17	01/18/17	West	NT	Confirmed 3/7/2017	PACW	PACW	1.609	01/19/17	01/19/27		
2230	84115251	PAC Merchant	01/19/17	01/23/17	East	NT	Confirmed 3/9/17	PACE	PACE	2.05-3.5	03/30/17	03/30/32		
2231	83941382	PAC Merchant	12/19/16	01/24/17	East	NT	Confirmed 3/9/17	PACE	PACE	2.100	12/20/16	01/21/30		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

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Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2232	83941436	PAC Merchant	12/19/16	01/24/17	East	NT	Confirmed 3/9/17	NUT	NUT	2.000	12/20/16	08/06/29		
2233	83941545	PAC Merchant	12/19/16	01/24/17	East	NT	Confirmed 3/9/17	NUT	NUT	1.708	12/20/16	03/02/31		
2235	84146682	PAC Merchant	01/24/17	01/25/17	East	NT	Confirmed 3/9/17	NUT	NUT	1.100	10/29/17	10/29/32		
2239	84191413	PAC Merchant	02/01/17	02/06/17	West	NT	Confirmed 3/9/17	PACW	PACW	1.229	02/28/17	02/28/27		
2240	84195006	PAC Merchant	02/02/17	02/06/17	East	NT	Confirmed 3/9/17	NUT	NUT	1.750	02/03/17	02/03/27		
2241	84196207	PAC Merchant	02/02/17	02/06/17	West	NT	Confirmed 3/9/17	PACW	PACW	`0.75/2	02/03/17	02/03/27		
2242	84070751	PAC Merchant	01/11/17	02/08/17	East	NT	Confirmed 3/9/17	NUT	NUT	2.500	02/05/17	02/05/27		
2248	84221133	PAC Merchant	02/07/17	02/10/17	East	NT	Confirmed 3/23/17	NUT	NUT	3.200	10/31/20	10/31/35		
2249	84225950	PAC Merchant	02/08/17	02/10/17	East	NT	Confirmed 3/23/17	GSHN	GSHN	1.400	02/20/17	02/20/27		
2250	84226210	PAC Merchant	02/08/17	02/10/17	East	NT	Confirmed 3/23/17	GSHN	GSHN	1.400	03/31/17	03/31/27		
2251	84226425	PAC Merchant	02/08/17	02/10/17	East	NT	Confirmed 3/23/17	GSHN	GSHN	3.600	05/14/17	05/14/27		
2252	84226622	PAC Merchant	02/08/17	02/10/17	West	NT	confirmed 3/23/17	PACW	PACW	4.190	02/09/17	02/09/27		
2253	84230273	PAC Merchant	02/09/17	02/10/17	West	NT	confirmed 3/31/2017	PACW	PACW	1.236	02/10/17	02/10/27		
2254	84255225	PAC Merchant	02/13/17	02/17/17	East	NT	Confirmed 3/22/17	NUT	NUT	7.600	02/14/17	07/03/29		
2255	84265188	PAC Merchant	02/15/17	02/17/17	East	NT	Confirmed 3/22/17	NUT	NUT	10.000	02/16/17	02/16/27		
2256	84265286	PAC Merchant	02/16/17	02/17/17	East	NT	Confirmed 3/23/17	NUT	NUT	5.000	02/16/17	02/16/27		
2257	84272125	PAC Merchant	02/16/17	02/17/17	East	NT	Confimed 3/22/17	NUT	NUT	15.000	02/17/17	02/17/27		
2258	84272266	PAC Merchant	02/16/17	02/17/17	East	NT	Confimed 3/22/17	PACE	PACE	22.000	02/17/17	02/17/27		
2259	84272328	PAC Merchant	02/16/17	02/17/17	East	NT	Confirmed 3/14/17	NUT	NUT	4.000	02/17/17	02/17/27		
2260	84272349	PAC Merchant	02/16/17	02/17/17	East	NT	Confirmed 3/14/17	PINTO	PINTO	4.000	02/17/17	02/17/27		
2261	84276727	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	NUT	NUT	1.500	02/18/17	02/18/27		
2262	84277004	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	NUT	NUT	22.000	02/18/17	02/18/27		
2263	84277021	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	TRONA	TRONA	60.000	02/18/17	02/18/27		
2264	84277046	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	WYONORTH	WYONORTH	86.000	02/18/17	02/18/27		
2265	84277108	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	TRONA	TRONA	60.000	02/18/17	02/18/27		
2266	84279557	PAC Merchant	02/17/17	02/20/17	East	NT	Confirmed 3/14/17	WYOCENTR	WYOCENTRAL	4.000	02/18/17	02/18/27		
2267	84292113	PAC Merchant	02/20/17	02/21/17	East	NT	Confirmed 3/24/17	PACE	PACE	7.500	02/21/17	02/21/27		
2268	84292143	PAC Merchant	02/20/17	02/21/17	East	NT	Confimed 3/22/17	PACE	PACE	15.000	02/21/17	02/21/27		
2269	84297364	PAC Merchant	02/21/17	02/23/17	East	NT	Confirmed 3/20/17	NUT	NUT	2.500	02/22/17	02/22/27		
2270	84303974	PAC Merchant	02/22/17	02/24/17	East	NT	Confirmed 3/20/17	TRONA	TRONA	10.000	02/23/17	02/23/27		
2272	84310584	PAC Merchant	02/23/17	02/24/17	East	NT	Confirmed 3/20/17	NUT	NUT	32.000	02/24/17	02/24/27		
2273	84310724	PAC Merchant	02/23/17	02/24/17	East	NT	Confirmed 3/20/17	NUT	NUT	18.000	02/24/17	02/24/27		
2275	84311749	PAC Merchant	02/23/17	02/24/17	East	NT	Confirmed 3/23/17	NUT	NUT	2.500	02/24/17	02/24/27		
2276	84316046	PAC Merchant	02/24/17	02/27/17	East	NT	Confirmed 3/20/17	NUT	NUT	7.500	02/25/17	02/25/27		
2278	84316702	PAC Merchant	02/24/17	02/27/17	East	NT	Confimed 3/20/17	NUT	NUT	88.500	02/25/17	02/25/27		
2279	84333973	PAC Merchant	02/27/17	02/28/17	East	NT	Confimed 3/30/17	NUT	NUT	2.549	07/29/17	07/29/32		
2280	84333999	PAC Merchant	02/27/17	02/28/17	East	NT	Confirmed 3/20/17	NUT	NUT	1.500	02/28/17	02/28/27		
2281	84334026	PAC Merchant	02/27/17	02/28/17	East	NT	Confirmed 3/20/17	NUT	NUT	2.000	02/28/17	02/28/27		
2282	84279545/84266661	Tri-State	02/17/17	03/08/17	East	NT	Confired 2/17/17	DJ	WYOEAST	16.000	03/01/17	01/01/00		
2283	84279545/84279550	Tri-State	02/17/17	03/08/17	East	NT	Confired 2/17/17	DJ	WYOEAST	17.000	03/01/17	01/01/00		
2288	84374934	PAC Merchant	03/06/17	03/10/17	West	NT	Confirmed 5/10/17	PACW	PACW	7.100	01/01/18	01/01/38		
2290	84428088	PAC Merchant	03/15/17	03/17/17	East	NT	Confirmed 4/14/17	NUT	NUT	1.751	03/31/17	03/31/32		
2291	84510727	PAC Merchant	03/28/17	03/28/17	East	NT	Confirmed 4/14/17	NUT	NUT	1.247	04/05/17	04/05/32		
2292	84517872	BPA	03/29/17	03/29/17	West	NT	led - replaced by 868	BPAT.PACW	NEWPOINT	1.000	05/31/17	09/30/28	SIS	FS
2293	84517876	BPA	03/29/17	03/29/17	West	NT	Confirmed 8/7/18	BPAT.PAC	PACW	1.000	05/31/17	09/30/28	SIS	FS
2294	84509615	PAC Merchant	03/28/17	03/30/17	West	NT	Confirmed 10/10/19	PACW	PACW	7.146	03/28/17	03/28/32		
2307	84480517	SMUD	03/23/17	03/23/17	West	PTP	Confirmed 5/8/17	MALIN230	MALIN500	30 (19)	06/30/17	06/30/22		
2311	84734589	PAC Merchant	05/02/17	05/03/17	East	NT	Confirmed 5/25/2017	NUT	NUT	42.000	05/31/17	05/31/37		
2319	84736848	PAC Merchant	05/02/17	05/04/17	East	NT	Confirmed 5/26/2017	PACE	PACE	2.174	05/31/17	05/31/37		
2321	84748473	PAC Merchant	05/04/17	05/05/17	East	NT	Confirmed 6/5/17	NUT	NUT	1.300	05/04/17	05/04/37		
2322	84749957	PAC Merchant	05/04/17	05/05/17	West	NT	Confirmed 8/2/17	PACW	PACW	2.46-3.6	12/01/17	01/01/37		
2326	84743353	Evergreen BioPower	05/03/17	05/10/17	West	PTP	Confirmed 12/12/17	PACW	BPAT.PACW	10.000	01/01/18	01/01/33	SIS	
2327	84705949	PAC Merchant	04/27/17	05/11/17	East	NT	Confirmed 6/5/2017	NUT	NUT	25.879	05/07/17	05/07/37		
2328	84773346	PAC Merchant	05/08/17	05/11/17	East	NT	Confirmed 6/6/17	NUT	NUT	1.216	05/08/17	05/08/37		
2332	84790577	PAC Merchant	05/11/17	05/18/17	East	NT	Confirmed 6/6/17	NUT	NUT	1.00 to 3.300	05/31/17	05/31/32		
2333	84838191	PAC Merchant	05/18/17	05/23/17	West	NT	Confirmed 6/15/17	BPAT.PACW	Troutdale	5.000	05/18/17	10/09/26		
2335	84859457	PAC Merchant	05/22/17	05/25/17	East	NT	Confirmed 6/22/17	NUT	NUT	3.030	12/01/17	12/01/37		
2336	84945462	PAC Merchant	06/05/17	06/06/17	East	NT	Confirmed 6/23/17	GSHN	GSHN	5.600	07/31/17	09/28/37		
2337	84943122	PAC Merchant	06/05/17	06/07/17	East	NT	Confirmed 7/10/17	NUT	NUT	35 -57	06/05/17	01/01/27		
2343	84785844/85803261	BPA	05/10/17	06/09/17	West	NT	eplaced by 85803261	BPAT.PACW	NEWPOINT (P/	1.000	01/01/19	09/30/28		
2344	84928225	PAC Merchant	06/02/17	06/09/17	East	NT	Confirmed 7/13/17	JBSN	JBSN	120.000	06/02/17	06/02/37		
2351	85094408	PAC Merchant	06/29/17	06/30/17	East	NT	Confirmed 7/28/17	MDWP	PAVANT	5.000	06/30/17	08/31/21		
2354	85101025	PAC Merchant	06/30/17	07/03/17	West	NT	Confirmed 7/27/2017	PACW	PACW	257 - 346	06/30/17	01/01/26		
2355	85101031	PAC Merchant	06/30/17	07/03/17	West	NT	Confirmed 11/14/17	PACW	PACW	262.000	06/30/17	01/01/26		
2356	85116977	PAC Merchant	07/03/17	07/05/17	East	NT	Confirmed 7/27/17	NUT	NUT	24.000	07/04/17	07/04/27		
2357	84219565	UAMPS	02/07/17	06/26/17	East	NT	Received	PACE	GSHN	3.000	03/01/17	01/01/40		
2358	85140263	PAC Merchant	07/07/17	07/10/17	East	NT	Confirmed 7/27/17	NUT	NUT	12.000	03/01/18	03/01/33		
2359	85169336	PAC Merchant	07/12/17	07/13/17	West	NT	Confirmed 9/9/2019	PACW	PACW	1.431	08/31/19	01/01/27		
2361	85243283	FCP	07/24/17	06/19/17	West	PTP	Confirmed 12/9/2019	PACW	BPAT.PACW	5.000	01/01/20	01/01/35		
2366	85267931	PAC Merchant	07/28/17	07/31/17	East	NT	Confirmed 8/23/17	NUT	NUT	1.500	01/15/18	01/15/33		
2369	85414213	PAC Merchant	08/23/17	08/25/17	East	NT	Confirmed 1/11/18	NUT	NUT	2.300	08/31/17	01/01/33		
2372	85569887	PAC Merchant	09/19/17	09/21/17	East	NT	Confirmed 12/26/17	GSHN	GSHN	12.000	09/19/17	09/19/27		
2373	85575527	PAC Merchant	09/20/17	09/21/17	East	NT	Confirmed 1/18/18	NUT	NUT	5.177-5.677	09/21/17	09/21/32		
2374	85675649	PAC Merchant	10/10/17	10/11/17	East	NT	Confirmed 11/2/17	NUT	NUT	3.000	12/31/17	12/31/27		
2375	85675703	PAC Merchant	10/10/17	10/11/17	East	NT	Confirmed 11/2/17	NUT	NUT	2.1-3	10/10/17	01/01/28		
2376	85724813	PAC Merchant	10/19/17	10/20/17	East	NT	Confirmed 7/27/18	NUT	NUT	2.300	01/01/18	01/01/33		
2377	85769879	PAC Merchant	10/27/17	10/27/17	East	NT	Confirmed 6/22/18	NUT	NUT	9.000	03/30/18	03/31/33		
2378	85769887	PAC Merchant	10/27/17	10/27/17	East	NT	Confirmed 1/11/18	NUT	NUT	1.500	11/30/17	12/01/32		
2379	85829037	PAC Merchant	11/07/17	11/08/17	East	NT	Confirmed 2/13/18	PACE	PACE	2.300	01/05/18	01/05/33		
2380	85944535	PAC Merchant	11/28/17	11/29/17	West	NT	Confirmed 1/2/18	PACW	PACW	1.300	11/29/17	01/01/27		
2381	85955773	PAC Merchant	11/30/17	12/04/17	East	NT	Confirmed 1/2/2018	PACE	PACE	0.400	01/01/18	01/01/38		
2385	85957401	PPMI	11/30/17	12/08/17	West	NT	2/29/17 (replaced by	PONDEROS/	676-H	56.000	01/01/18	01/01/37		
2386	85983746	PAC Merchant	12/05/17	12/08/17	West	NT	Confirmed 11/14/18	PACW	PACW	3.229	06/30/18	06/30/33		
2388	86016454	PAC Merchant	12/11/17	12/12/17	East	NT	Confirmed 5/1/18	NUT	NUT	4.000	01/01/18	01/01/33		
2390	86023192	PAC Merchant	12/12/17	12/13/17	East	NT	Confirmed 1/16/18	NUT	NUT	1.400	01/15/18	01/15/33		
2392	86035784	City of Roseville	12/14/17	12/14/17	West	PTP	Confirmed 2/2/2018	MALIN500	RDM230	50.000	03/01/18	03/01/23		
2393	86039236	PAC Merchant	12/15/17	12/18/17	East	NT	Confirmed 1/11/17	NUT	NUT	30.000	12/16/17	12/31/27		
2394	86039244	PAC Merchant	12/15/17	12/18/17	East	NT	Confirmed 12/16/17	NUT	NUT	6.000	12/16/17	12/16/27		
2395	86055338	PAC Merchant	12/18/17	12/22/17	West	NT	Confirmed 1/16/18	PACW	PACW	3.800	12/20/17	12/20/27		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2396	86059389	PAC Merchant	12/19/17	12/22/17	West	NT	Confirmed 9/10/2019	PACW	PACW	1.446	06/11/18	06/11/28		
2397	86059156	Powerex	12/19/17	12/26/17	West	PTP	Confirmed 2/1/18	MALIN500	RDM230	150.000	01/01/19	01/01/24		
2398	86059158	Powerex	12/19/17	12/26/17	West	PTP	Confirmed 2/1/18	MALIN500	RDM230	50.000	01/01/19	01/01/24		
2401	86100666	PAC Merchant	12/27/17	12/29/17	East	PTP	Confirmed 6/21/18	BORA	PACE	250.000	01/01/19	01/01/24		
2402	86100885	PAC Merchant	12/27/17	12/29/17	East	PTP	Confirmed 6/18/18	FOURCORN	PACE	100.000	01/01/19	01/01/24		
2404	86100909	PAC Merchant	12/27/17	12/29/17	West	PTP	Confirmed 6/18/18	JOHNDAY	PACW	231.000	01/01/19	01/01/24		
2405	86108529	PAC Merchant	12/28/17	12/29/17	West	PTP	Confirmed 10/3/18	PACW	JOHNDAY	432.000	01/01/19	01/01/24		
2406	86113318	PAC Merchant	12/29/17	12/29/17	East	PTP	Confirmed 10/3/18	BRDY	PACE	250.000	01/01/19	01/01/24		
2407	86195239	PAC Merchant	01/12/18	01/23/18	East	NT	Confirmed 2/16/2018	JBSN	JBSN	`1415/2000	01/15/18	01/15/32		
2408	86263143	PAC Merchant	01/24/18	01/30/18	East	PTP	Confirmed 5/23/18	PACE	FOURCORNE34	530.000	01/01/19	01/01/24		
2409	86296315	UAMPS	01/30/18	01/30/18	East	NT	STUDY	PACE		20.000	06/30/20		SIS	
2410	86308040	PAC Merchant	02/01/18	02/02/18	West	NT	Confirmed 8/7/2018	PACW	PACW	5.000	05/31/18	01/01/28		
2411	86263238	PAC Merchant	01/24/18	02/06/18	East	NT	Confirmed 3/16/2020	PACE	PACE	0.650	03/01/19	03/30/49		
2412	86263270	PAC Merchant	01/24/18	02/06/18	East	NT	Confirmed 3/16/2020	PACE	PACE	1.000	03/01/19	03/30/49		
2414	86374196	PAC Merchant	02/12/18	02/13/18	East	NT	Confirmed 4/17/18	NUT	NUT	2.986	02/13/18	07/31/33		
2415	86378465	PAC Merchant	02/13/18	02/14/18	East	NT	Confirmed 4/17/18	NUT	NUT	2.400	02/14/18	11/17/32		
2417	86386896	PAC Merchant	02/14/18	02/22/18	East	NT	Confirmed 4/13/18	NUT	NUT	32.000	02/15/18	02/15/48		
2418	86429393	PAC Merchant	02/21/18	02/22/18	East	NT	Confirmed 12/3/18	NUT	NUT	1.100	01/03/18	03/01/33		
2419	86509703	PAC Merchant	03/06/18	03/07/18	East	NT	Confirmed 9/26/18	NUT	NUT	11.600	03/07/18	03/07/35		
2420	86509769	PAC Merchant	03/06/18	03/07/18	East	NT	Confirmed 3/27/18	NUT	NUT	21.000	03/07/18	03/07/35		
2421	86548675	PAC Merchant	03/13/18	03/14/18	East	NT	Confirmed 4/2/18	NUT	NUT	6.075	03/13/18	03/13/28		
2423	86542658	NTUA	03/26/18	03/13/18	East	NT	led by 87325848 on 7	FOURCORN	PACE	2.730	03/01/18	12/31/57		
2424	86479148	PAC Merchant	03/01/18	03/27/18	East	NT	Confirmed 10/31/2019	GON.PAV	PACE	20.900	08/31/19	08/31/44	SIS	
2425	86649018	PAC Merchant	03/30/18	04/02/18	East	NT	Confirmed 1/6/2020	NUT	NUT	2.100	07/31/18	07/31/33		
2426	86649103	PAC Merchant	03/30/18	04/02/18	East	NT	Confirmed 5/8/18	NUT	NUT	5.800	03/30/18	03/30/33		
2429	86706630	PAC Merchant	04/09/18	04/10/18	East	NT	Confirmed 5/14/18	NUT	NUT	1.500	04/09/18	04/09/33		
2430	86726363	PAC Merchant	04/12/18	04/16/18	West	NT	Confirmed 8/29/18	PACW	PACW	3.000	08/14/18	08/15/38		
2431	86726393	PAC Merchant	04/12/18	04/16/18	West	NT	Confirmed 10/29/18	PACW	PACW	2.000	04/30/18	04/30/33		
2432	86749390	PAC Merchant	04/16/18	04/17/18	West	NT	Confirmed 5/3/18	PACW	PACW	3.000	04/16/18	03/15/23		
2433	86749604	PAC Merchant	04/16/18	04/17/18	West	NT	Confirmed 6/29/18	PACW	PACW	2.000	05/15/18	05/15/33		
2434	86762578	PAC Merchant	04/18/18	04/23/18	East	NT	Confirmed 5/30/18	NUT	NUT	1.019	04/18/18	04/18/33		
2436	86768717	PAC Merchant	04/19/18	04/25/18	West	NT	Confirmed 1/10/19	PACW	PACW	60.000	12/21/18	12/21/33		
2437	86797806	PAC Merchant	04/24/18	04/25/18	West	NT	Confirmed 8/7/2018	PACW	PACW	1.095	06/29/18	06/29/28		
2445	86810353	SD	04/26/18	04/26/18	East	PTP	Confirmed 6/14/18	YTP	WYODAK	4.000	08/31/19	08/31/24		
2446	86816723	PAC Merchant	04/27/18	05/03/18	West	NT	Confirmedi 9/26/18	PACW	PACW	2.537	05/31/18	05/31/33		
2447	86854737	PAC Merchant	05/03/18	05/07/18	East	NT	Confirmed 7/27/18	NUT	NUT	4.200	05/04/18	05/04/28		
2448	86877115	PAC Merchant	05/07/18	05/08/18	East	NT	Confirmed 5/29/2018	NUT	NUT	8.000	05/14/18	05/14/33		
2449	86889647	BPA	05/09/18	05/09/18	East	NT	Received	GSHN	PACE	27.000	06/01/18	07/01/28		
2450	86904241	PAC Merchant	05/11/18	05/14/18	West	NT	Confirmed 8/29/2018	PACW	PACW	1.557	08/30/18	08/30/33		
2452	86937300	PAC Merchant	05/17/18	05/18/18	West	NT	Confirmed 11/6/18	PACW	PACW	1.376	09/14/18	09/14/28		
2453	86943452/90084106	PAC Merchant	05/18/18	05/21/18	West	NT	Received	PACW	PACW	5.930	01/01/21	01/01/35		
2454	86961812	PAC Merchant	05/21/18	05/22/18	East	NT	Confirmed 9/27/18	NUT	NUT	10.000	05/20/18	05/20/23		
2455	86968145	Tri-State	05/22/18	05/17/18	East	NT	Confirmed 2/14/2020	DJ	WYOEAST	41.000	07/01/18	06/30/28	SIS	
2456	86939977	PAC Merchant	05/17/18	05/22/18	West	NT	Confirmed 1/6/20	BPAT.PACW	PACW	0.200	09/14/18	09/14/33		
2457	86854437	PPMI	05/03/18	05/10/18	West	PTP	Confirmed 7/30/18	TRONA	REDB	30.000	04/30/19	04/30/24		
2458	86854448	PPMI	05/03/18	05/10/18	West	PTP	Confirmed 7/30/18	TRONA	MPAC	30.000	04/30/19	04/30/24		
2463	87016884	Idaho Power	05/30/18	05/30/18	East	PTP	Confirmed 7/30/2018	REDB	BORA	50.000	05/31/19	05/31/24		
2464	87058318	PAC Merchant	06/06/18	06/08/18	East	NT	Confirmed 1/6/2020	NUT	NUT	2.000	08/23/18	08/23/28		
2465	87058342	PAC Merchant	06/06/18	06/08/18	East	NT	Confirmed 1/6/2020	NUT	NUT	2.000	08/23/18	08/23/28		
2468	87101984	PAC Merchant	06/13/18	06/13/18	West	NT	Received	PACW	PACW	55.000	12/31/20	12/31/40		
2469	93645083	PAC Merchant	06/13/18	06/13/18	East	NT	Confirmed 10/20/21	PACE	PACE	99.000	11/30/20	11/30/45	SIS	FS
2471	87102351	PAC Merchant	06/13/18	06/13/18	East	NT	STUDY	PACE	PACE	80.000	12/31/20	12/31/45	SIS	FS
2472	92900471	PAC Merchant	06/13/18	06/13/18	East	NT	Confirmed 12/10/20	PACE	PACE	100.000	12/31/20	12/31/45	SIS	FS
2477	87183271	CLSK	06/27/18	06/27/18	West	PTP	Confirmed 9/13/18	BPAT.PACW	TROUTDALE	13.000	09/30/18	09/30/23		
2477	87183289	CLSK	06/27/18	06/27/18	West	PTP	Confirmed 9/13/18	TROUTDALE	PACW	13.000	09/30/18	09/30/23		
2479	87183371	CLSK	06/27/18	06/27/18	West	PTP	Confirmed 9/13/18	BPAT.PACW	TROUTDALE	2.000	09/30/18	09/30/23		
2479	87183379	CLSK	06/27/18	06/27/18	West	PTP	Confirmed 9/13/18	TROUTDALE	PACW	2.000	09/30/18	09/30/23		
2481	87215265	PAC Merchant	07/02/18	07/03/18	East	NT	Confirmed 9/3/19	NUT	NUT	1.090	08/31/18	08/31/33		
2482	87263421	PAC Merchant	07/10/18	07/11/18	East	NT	Confirmed 9/10/18	WYOCENTR	WYOCENTRAL	13.000	07/10/18	01/01/22		
2483	87269242	PAC Merchant	07/11/18	07/12/18	West	NT	Confirmed 8/29/18	PACW	PACW	1.227	08/31/18	08/31/33		
2484	87270442	PAC Merchant	07/11/18	07/12/18	West	NT	Confirmed 10/30/2018	PACW	PACW	0.824	07/31/19	07/31/29		
2489	87325304	PAC Merchant	07/20/18	07/23/18	East	NT	Confirmed 8/2/2018	PINTO	PINTOLOAD	51.000	07/31/18	12/05/26		
2491	87355175	PAC Merchant	07/25/18	07/26/18	East	NT	Confirmed 3/20/19	WYOEAST	WYOEAST	9.100	08/31/18	08/31/33		
2493	87370672	PAC Merchant	07/27/18	07/30/18	West	NT	Confirmed 1/3/19	PACW	PACW	3.800	12/01/18	12/01/28		
2494	87433286	PAC Merchant	08/06/18	08/07/18	East	NT	Received	NUT	NUT	2.000	11/30/18	11/30/33		
2495	87479111	PAC Merchant	08/13/18	08/15/18	East	NT	Confirmed 5/3/19	NUT	NUT	1.250	12/01/18	12/01/33		
2496	87488644	PAC Merchant	08/15/18	08/16/18	East	NT	Confirmed 10/30/2018	NUT	NUT	3.200	08/31/18	08/31/33		
2498	87518647	PAC Merchant	08/20/18	08/27/18	East	NT	STUDY	WYOEAST	WYOEAST	250.000	06/14/20	01/01/51	SIS	
2499	87518661/92248513	PAC Merchant	08/20/18	08/27/18	East	NT	Confirmed 8/9/21	WYOEAST	WYOEAST	250.000	06/14/20	01/01/51	SIS	
2500	87518667	PAC Merchant	08/20/18	08/27/18	East	NT	STUDY	WYOEAST	WYOEAST	250.000	06/14/20	01/01/51	SIS	
2501	87578209	PAC Merchant	08/30/18	08/31/18	East	NT	Confirmed 9/27/18	NUT	NUT	2.000	08/29/18	12/01/33		
2502	87582641	PAC Merchant	08/31/18	09/04/18	East	NT	Confirmed 11/14/18	NUT	NUT	4.000	12/01/18	12/01/33		
2503	87614386	PAC Merchant	09/06/18	09/06/18	East	NT	Confirmed 1/14/19	NUT	NUT	2.000	01/01/19	01/01/34		
2506	87648096/90961361	PAC Merchant	09/12/18	09/13/18	West	NT	Confirmed 10/28/21	PACW	PACW	2.066	08/31/20	08/31/35		
2507	87659292	PAC Merchant	09/14/18	09/18/18	East	NT	Confirmed 11/2/21	NUT	NUT	39.000	06/30/19	06/30/34		
2509	87718654	PAC Merchant	09/25/18	09/27/18	East	NT	Confirmed 12/3/18	NUT	NUT	3.000	11/15/18	11/15/33		
2512	87785656	PAC Merchant	10/08/18	10/11/18	East	NT	Confirmed 11/15/18	WYOEAST	WYOEAST	4.000	10/08/18	10/08/38		
2513	87801884	PAC Merchant	10/11/18	10/12/18	East	NT	Confirmed 1/10/19	NUT	NUT	1.6-1.925	10/11/18	10/11/33		
2518	87874044	PAC Merchant	10/24/18	10/26/18	West	NT	Confirmed 12/6/2019	PACW	PACW	220.000	07/14/19	07/14/39	SIS	
2520	87874081	PAC Merchant	10/24/18	10/29/18	East	NT	Confirmed 2/26/19	NUT	NUT	1.800	01/01/19	01/01/39		
2521	87874109	PAC Merchant	10/24/18	10/29/18	West	NT	Confirmed 1/31/19	PACW	PACW	1.500	01/01/19	01/01/39		
2524	87803174	Salt River Project	10/11/18	10/31/18	East	PTP	Confirmed 11/6/2018	PACE	REDB	25.000	10/31/20	10/31/25		
2526	87922747	PAC Merchant	11/01/18	11/05/18	East	NT	Confirmed 12/14/17	NUT	NUT	4.000	11/30/18	12/01/33		
2529	87961652	PAC Merchant	11/07/18	11/08/18	East	NT	Confirmed 1/14/19	TRONA	TRONA	30.000	01/01/19	01/01/39		
2531	88016689	PAC Merchant	11/16/18	11/19/18	West	NT	Confirmed 1/3/19	PACW	PACW	66.000	11/17/18	07/13/28		
2532	88050302	PAC Merchant	11/21/18	11/21/18	West	NT	Confirmed 1/3/20	PACW	PACW	1.844	11/20/19	11/20/29		
2534	88079902	PAC Merchant	11/26/18	11/28/18	East	NT	Confirmed 12/3/19	NUT	NUT	4.400	06/30/19	06/30/34		
2535	88080646	PAC Merchant	11/26/18	11/28/18	East	NT	Confirmed 1/3/19	PACE	PACE	1.200	11/27/18	11/27/28		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2537	88095011	PAC Merchant	11/28/18	11/29/18	West	NT	Confirmed 4/2/19	PACW	PACW	1.683	12/01/18	12/01/33		
2538	88124942	PAC Merchant	12/03/18	12/04/18	West	NT	Confirmed 2/6/19	PACW	PACW	2.500	12/29/18	12/29/43		
2539	88125084	PAC Merchant	12/03/18	12/04/18	West	NT	Received	BPAT.PACW	PONDEROSA5(	200.000	07/14/19	07/14/39		
2540	88130462	PAC Merchant	12/04/18	12/05/18	East	NT	Confirmed 1/3/19	PACE	PACE	8.300	12/05/18	12/05/43		
2547	88145253	PAC Merchant	12/06/18	12/10/18	West	NT	Confirmed 1/14/19	PACW	PACW	10.000	01/01/19	01/01/29		
2548	88152626	PAC Merchant	12/07/18	12/10/18	East	NT	Confirmed 8/14/19	NUT	NUT	32.000	06/30/19	01/01/28		
2549	88175235	PAC Merchant	12/11/18	12/14/18	West	NT	Received	PACW	PACW	4.200	01/01/19	01/01/34		
2552	88212558	PAC Merchant	12/17/18	12/20/18	East	NT	Confirmed 3/4/19	NUT	NUT	1.298	01/07/19	01/07/34		
2556	88145646	PAC Merchant	12/06/18	12/21/18	East	NT	Confirmed 3/4/19	NUT	NUT	9.000	02/01/19	02/01/29		
2558	88218362	PAC Merchant	12/18/18	12/26/18	East	NT	Received	NUT	NUT	26.000	12/01/19	12/01/29		
2559	88265403	PAC Merchant	12/26/18	12/26/18	West	NT	Confirmed 5/10/19	PACW	PACW	10.800	03/31/19	03/31/29		
2564	88294469	PAC Merchant	12/31/18	01/02/19	East	NT	Confirmed 2/1/19	NUT	NUT	28.000	01/01/19	01/01/29		
2565	88294503	PAC Merchant	12/31/18	01/02/19	East	NT	Confirmed 2/6/19	NUT	NUT	16.000	01/01/19	01/01/24		
2566	88294518	PAC Merchant	12/31/18	01/02/19	East	NT	Received	NUT	NUT	22.160	12/01/22	12/01/37		
2569	88339043	PAC Merchant	01/07/19	01/09/19	East	NT	Confirmed 12/5/19	GSHN	GSHN	6.480	06/30/19	06/30/34		
2571	88342474/88342474	PAC Merchant	01/08/19	01/09/19	East	NT	Confirmed 11/2/21	WYOEAST	WYOEAST	49.000	05/31/19	05/31/39		
2572	38345117/90961361	PAC Merchant	01/08/19	01/09/19	West	NT	Confirmed 10/28/21	PACW	PACW	4.670	05/31/20	05/31/35		
2574	88351357	PAC Merchant	01/09/19	01/10/19	West	NT	STUDY	PONDEROS/	PONDEROSA23	200.000	12/01/23	12/01/33	SIS	FS
2575	88354543	PAC Merchant	01/10/19	01/14/19	East	NT	Confirmed 9/8/2019	NUT	NUT	1.100	06/09/19	06/09/34		
2576	88354601	PAC Merchant	01/10/19	01/14/19	West	NT	Confirmed 3/11/19	PACW	PACW	1.600	02/15/19	02/15/34		
2577	88356261	PAC Merchant	01/10/19	01/14/19	East	NT	Confirmed 9/19/2019	NUT	NUT	1.243	05/09/19	05/09/34		
2579	88356970	PAC Merchant	01/10/19	01/15/19	West	NT	Confirmed 2/14/19	PACW	PACW	1.901	01/16/19	01/16/34		
2580	88383797	PAC Merchant	01/15/19	01/16/19	West	NT	Confirmed 10/14/201	PACW	PACW	2.450	05/09/19	05/09/39		
2581	88426858	PAC Merchant	01/22/19	01/23/19	East	NT	Confirmed 2/24/19	PACE	PACE	1.974	01/23/19	01/23/34		
2582	88434302	PAC Merchant	01/23/19	01/23/19	West	NT	Received	PACW	PACW	1.500	03/29/19	04/29/39		
2583	88431516	PAC Merchant	01/23/19	01/24/19	East	NT	Confirmed 3/4/19	NUT	NUT	1.600	03/01/19	03/01/34		
2584	88434293	PAC Merchant	01/23/19	01/24/19	East	NT	Received	NUT	NUT	1.200	04/11/19	04/11/34		
2588	88521137	PAC Merchant	02/06/19	02/08/19	East	NT	STUDY	WYOEAST	WYOEAST	120.000	11/30/20	11/30/40	SIS	
2589	88571201	PAC Merchant	02/14/19	02/15/19	East	NT	Confirmed 10/14/201	NUT	NUT	3.000	04/14/19	04/14/34		
2590	88574351/90961368	PAC Merchant	02/14/19	02/15/19	East	NT	Confirmed 10/28/21	NUT	NUT	2.720	10/29/19	10/29/34		
2594	88755100	Lucky Star Wind	03/14/19	03/11/19	East	PTP	Confirmed 4/22/21	WYOEAST	MDWP	500.000	01/01/24	01/01/29	SIS	
2595	88755604	PAC Merchant	03/14/19	03/15/19	East	NT	Confirmed 3/22/19	NUT	NUT	10.000	03/14/19	03/14/34		
2596	88788424	PAC Merchant	03/20/19	03/21/19	East	NT	Received	NUT	NUT	1.062	08/29/19	08/29/34		
2597	88797268	PAC Merchant	03/21/19	03/22/19	East	NT	Confirmed 7/15/19	NUT	NUT	1.200	05/18/19	05/18/34		
2598	88797514	PAC Merchant	03/21/19	03/22/19	East	NT	Confirmed 6/3/19	NUT	NUT	1.400	04/30/19	04/30/34		
2599	88801227	PAC Merchant	03/22/19	03/25/19	West	NT	STUDY	PACW	TROUTDALE	338.000	01/01/25	01/01/55	SIS	FS
2601	88820917	PAC Merchant	03/25/19	03/28/19	East	NT	Confirmed 1/3/2020	NUT	NUT	2.100	04/30/19	04/30/34		
2602	88839776	UMPA	03/28/19	03/28/19	East	NT	Confirmed 10/11/21	PACE		80.000	10/01/21	07/01/47	SIS	
2603	88868661	PAC Merchant	04/02/19	04/02/19	West	NT	Confirmed 1/6/20	PACW	PACW	20.000	03/06/20	01/01/29		
2604	88902032	PAC Merchant	04/08/19	04/10/19	West	NT	Confirmed 4/30/19	PACW	PACW	0.309	04/08/19	12/21/27		
2605	88902089	PAC Merchant	04/08/19	04/10/19	West	NT	Confirmed 1/6/20	PACW	PACW	0.421	04/08/19	12/21/28		
2607	88915332	PAC Merchant	04/10/19	04/11/19	East	NT	Confirmed 10/16/19	NUT	NUT	5.000	10/17/19	10/17/34		
2608	88901812	PAC Merchant	04/08/19	04/15/19	West	NT	Confirmed 5/16/19	PACW	PACW	0.411	04/08/19	12/21/27		
2609	88901841	PAC Merchant	04/08/19	04/15/19	West	NT	Confirmed 5/16/19	PACW	PACW	0.254	04/08/19	02/04/29		
2610	88901897	PAC Merchant	04/08/19	04/15/19	West	NT	Confirmed 5/16/19	PACW	PACW	0.425	04/08/19	10/17/26		
2611	88123335	UAMPS	12/03/18	04/16/19	East	NT	Received	PACE		600.000	12/31/25	12/31/99	SIS	FS
2614	88945946	PAC Merchant	04/15/19	04/16/19	East	NT	Confirmed 5/16/19	WYOCENTR	WYOCENTRAL	29.800	04/16/19	04/16/34		
2615	88945987	PAC Merchant	04/15/19	04/16/19	East	NT	Received	WYOCENTR	WYOCENTRAL	42.300	09/01/19	09/01/34		
2616	88946114	PAC Merchant	04/15/19	04/16/19	East	NT	Confirmed 5/16/19	NUT	NUT	1.500	04/16/19	04/16/34		
2617	88946123	PAC Merchant	04/15/19	04/16/19	East	NT	Confirmed 10/14/19	NUT	NUT	4.500	10/01/19	10/01/34		
2619	88946135	PAC Merchant	04/15/19	04/18/19	East	NT	Confirmed 5/17/19	NUT	NUT	1.668	04/16/19	04/16/34		
2620	88953225	PAC Merchant	04/16/19	04/19/19	East	NT	Confirmed 1/6/2020	WYOCENTR	WYOCENTRAL	2.200	05/16/19	05/16/34		
2621	88971783	PAC Merchant	04/19/19	04/22/19	West	NT	Received	PACW	PACW	3.300	09/16/20	09/16/35		
2623	89032403	PAC Merchant	04/29/19	04/30/19	East	NT	Received	WYOEAST	WYOEAST	3.500	06/21/19	06/21/34		
2624	89051360	PAC Merchant	05/02/19	05/03/19	East	NT	Confirmed 5/31/2019	NUT	NUT	35.000	05/03/19	05/03/34		
2627	89084268	PAC Merchant	05/08/19	05/09/19	East	NT	Confirmed 6/7/19	TRONA	TRONA	15.000	05/09/19	05/09/34		
2629	88910013	PAC Merchant	04/09/19	05/16/19	West	NT	STUDY	PACW	PACW	400.000	01/01/20	01/01/50	SIS	FS
2630	89133039/94369279	PAC Merchant	05/16/19	05/17/19	East	NT	Confirmed 11/2/21	NUT	NUT	2.700	06/30/19	06/30/34		
2631	89139646	PAC Merchant	05/17/19	05/20/19	East	NT	Confirmed 6/18/19	NUT	NUT	1.800	05/18/19	05/18/34		
2632	89169599	PAC Merchant	05/22/19	05/23/19	West	NT	Confirmed 6/17/19	PACW	PACW	0.164	05/22/19	08/20/29		
2633	89169808	PAC Merchant	05/22/19	05/24/19	West	NT	Confirmed 6/17/19	PACW	PACW	0.084	05/23/19	04/01/31		
2634	89169866	PAC Merchant	05/22/19	05/24/19	West	NT	Confirmed 6/17/19	PACW	PACW	0.084	05/23/19	10/07/29		
2635	89175725	PAC Merchant	05/23/19	05/24/19	East	NT	Confirmed 6/21/19	NUT	NUT	4.000	05/24/19	05/24/34		
2636	89132671	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2637	89132762	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2638	89132877	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2639	89132879	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2640	89132886	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2641	89132891	EDP Renewables (HZ	05/16/19	05/21/19	West	PTP	Confirmed 7/31/19	PACW	PACW.PGE	10.000	06/01/20	06/01/25		
2642	89169749	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 1/2/20	PACW	PACW	0.307	05/23/19	06/05/27		
2643	89169788	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 6/27/19	PACW	PACW	1.000	05/23/19	05/14/29		
2644	89169881	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 6/27/19	PACW	PACW	1.000	05/23/19	12/28/31		
2645	89169897	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 6/27/19	PACW	PACW	1.000	05/23/19	12/28/31		
2646	89169916	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 6/27/19	PACW	PACW	1.000	05/23/19	12/28/31		
2647	89169935	PAC Merchant	05/22/19	05/29/19	West	NT	Confirmed 6/27/19	PACW	PACW	1.000	05/23/19	12/28/31		
2648	89212919	PAC Merchant	05/29/19	05/31/19	East	NT	Confirmed 6/27/19	WYOEAST	WYOEAST	7.500	05/30/19	05/30/34		
2649	89212969	PAC Merchant	05/29/19	05/31/19	East	NT	Received	WYOEAST	WYOEAST	23.300	03/15/20	03/15/35		
2650	89220577	PAC Merchant	05/30/19	05/31/19	West	NT	Received	PACW	PACW	2.055	10/14/22	10/14/37		
2651	89170002	BPA	05/22/19	06/03/19	West	NT	STUDY	PACW	SMLK	56.000	10/01/20	10/01/28		
2652	89170012/88657077	BPA	05/22/19	06/03/19	West	NT	ed by 88657077 on NI	PACW	SMLK	18.000	10/01/20	10/01/28		
2653	89244550	PAC Merchant	06/03/19	06/04/19	East	NT	Confirmed 8/21/19	TRONA	TRONA	5.000	06/04/19	06/05/29		
2654	89270885	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	NUT	NUT	2.000	06/08/19	06/08/34		
2655	89270974	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/24/19	NUT	NUT	1.663	06/08/19	06/08/34		
2656	89271107	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	NUT	NUT	1.500	06/08/19	06/08/34		
2657	89271246	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	NUT	NUT	1.800	06/08/19	06/08/34		
2658	89271294	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	NUT	NUT	2.000	06/08/19	06/08/34		
2659	89271360	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	WYOCENTR	WYOCENTRAL	5.000	06/08/19	06/08/34		
2660	89272662	PAC Merchant	06/07/19	06/11/19	East	NT	Confirmed 7/8/19	WYOEAST	WYOEAST	1.680	06/08/19	06/08/34		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2661	89287873	PAC Merchant	06/10/19	06/11/19	East	NT	Confirmed 7/8/19	GSHN	GSHN	1.535	06/11/19	06/11/34		
2662	89287946	PAC Merchant	06/10/19	06/11/19	East	NT	Confirmed 7/8/19	GSHN	GSHN	1.150	06/11/19	06/11/34		
2663	89288019	PAC Merchant	06/10/19	06/11/19	East	NT	Confirmed 7/8/19	PACE	PACE	14.000	06/10/19	01/01/30		
2664	89291861	PAC Merchant	06/11/19	06/13/19	East	NT	Confirmed 7/8/19	WYOEAST	WYOEAST	1.500	06/12/19	06/12/34		
2665	89291877	PAC Merchant	06/11/19	06/13/19	East	NT	Confirmed 7/8/19	WYOEAST	WYOEAST	2.000	06/12/19	06/12/34		
2666	89291913	PAC Merchant	06/11/19	06/13/19	East	NT	Confirmed 7/8/19	NUT	NUT	1.375	06/12/19	06/12/34		
2668	89295057	PAC Merchant	06/11/19	06/14/19	East	NT	Confirmed 7/24/19	NUT	NUT	1.000	06/12/19	06/12/34		
2669	89295063	PAC Merchant	06/11/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	2.000	06/12/19	06/12/34		
2670	89295069	PAC Merchant	06/11/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	1.250	06/12/19	06/12/34		
2671	89295078	PAC Merchant	06/11/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	2.000	06/12/19	06/12/34		
2672	89299963	PAC Merchant	06/12/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	1.600	06/28/19	06/28/34		
2673	89299991	PAC Merchant	06/12/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	13.000	06/13/19	06/13/34		
2674	89301655	PAC Merchant	06/12/19	06/14/19	East	NT	Confirmed 7/9/19	NUT	NUT	5.300	06/13/19	06/13/34		
2675	89330350	PAC Merchant	06/17/19	06/18/19	East	NT	Confirmed 10/15/19	WYOEAST	WYOEAST	2.950	10/01/19	10/01/34		
2679	89339913/9436927‌9	PAC Merchant	06/19/19	06/21/19	East	NT	Confirmed 11/2/21	NUT	NUT	1.200	10/10/19	10/10/34		
2680	89341830	PAC Merchant	06/19/19	06/21/19	East	NT	Confirmed 7/24/19	NUT	NUT	1.263	06/20/19	06/20/34		
2681	89342641	PAC Merchant	06/19/19	06/21/19	East	NT	Confirmed 7/23/19	NUT	NUT	1.500	06/20/19	06/20/34		
2682	89346380	PAC Merchant	06/20/19	06/24/19	West	NT	Confirmed 7/23/19	PACW	PACW	1.010	07/09/19	07/09/34		
2683	89354846	PAC Merchant	06/21/19	06/24/19	East	NT	Confirmed 7/23/19	PACE	PACE	1.550	06/22/19	06/22/34		
2684	89356614	PAC Merchant	06/21/19	06/24/19	East	NT	Received	NUT	NUT	1.400	03/01/20	03/01/35		
2685	89250649	PAC Merchant	06/04/19	06/25/19	East	NT	Confirmed 1/7/20	NUT	NUT	3.000	08/01/19	08/01/34		
2686	89300104	PAC Merchant	06/12/19	06/25/19	West	NT	Received	PACW	PACW	1.494	10/01/19	10/01/34		
2687	89371855	PAC Merchant	06/24/19	06/25/19	East	NT	d by 92254087 on NIT	WYONORTH	WYONORTH	240.000	09/01/20	09/01/50	SIS	
2688	89372164	PAC Merchant	06/24/19	06/25/19	East	NT	Confirmed 7/31/19	PACE	PACE	16.000	06/25/19	06/01/27		
2689	89372174	PAC Merchant	06/24/19	06/25/19	East	NT	Confirmed 7/31/19	WYOCENTR	WYOCENTRAL	5.000	06/25/19	01/01/27		
2691	89378899	PAC Merchant	06/25/19	06/26/19	East	NT	Confirmed 7/26/19	NUT	NUT	6.580	06/26/19	06/26/34		
2692	89384684	PAC Merchant	06/26/19	6/27/119	East	NT	Received	NUT	NUT	1.624	08/14/19	08/14/34		
2693	89383455	PAC Merchant	06/26/19	06/27/19	East	NT	Confirmed 7/26/19	NUT	NUT	7.900	06/27/19	06/27/34		
2694	89391377	PAC Merchant	06/27/19	06/28/19	East	NT	Confirmed 7/26/19	NUT	NUT	1.100	06/28/19	06/28/34		
2695	89439570	PAC Merchant	07/05/19	07/08/19	East	NT	Confirmed 8/6/19	WYOEAST	WYOEAST	18.000	07/08/19	10/01/39		
2696	89439573	PAC Merchant	07/05/19	07/08/19	East	NT	Confirmed 8/6/19	WYOEAST	WYOEAST	20.000	07/08/19	10/01/39		
2697	89439576	PAC Merchant	07/05/19	07/08/19	East	NT	Confirmed 8/6/19	WYOEAST	WYOEAST	20.000	07/08/19	10/01/39		
2698	89465532	PAC Merchant	07/09/19	07/10/19	East	NT	Confirmed 8/6/19	PACE	PACE	2.060	07/10/19	07/10/30		
2699	89465551	PAC Merchant	07/09/19	07/10/19	East	NT	Confirmed 8/6/19	NUT	NUT	2.000	07/10/19	07/10/29		
2700	89465561	PAC Merchant	07/09/19	07/10/19	East	NT	Confirmed 8/6/19	NUT	NUT	1.101	07/10/19	07/10/29		
2701	89476839	PAC Merchant	07/11/19	07/15/19	East	NT	Confirmed 8/12/19	NUT	NUT	1.156	07/12/19	07/12/34		
2704	89502388	PAC Merchant	07/15/19	07/17/19	East	NT	Confirmed 8/13/19	WYONORTH	WYONORTH	2.910	07/16/19	07/16/34		
2705	89502414	PAC Merchant	07/15/19	07/17/19	East	NT	Confirmed 8/13/19	WYONORTH	WYONORTH	1.050	07/16/19	07/16/34		
2706	89503014	PAC Merchant	07/15/19	07/17/19	East	NT	Confirmed 10/16/19	WYONORTH	WYONORTH	1.500	09/15/19	09/15/34		
2707	89503082	PAC Merchant	07/15/19	07/17/19	East	NT	Confirmed 8/13/19	NUT	NUT	1.500	07/16/19	07/16/34		
2708	89518449	PAC Merchant	07/17/19	07/18/19	East	NT	Confirmed 8/13/19	PACE	PACE	3.000	07/18/19	07/18/34		
2709	89518467	PAC Merchant	07/17/19	07/18/19	East	NT	Confirmed 8/13/19	PACE	PACE	4.000	07/18/19	07/18/34		
2710	89518473	PAC Merchant	07/17/19	07/18/19	East	NT	Confirmed 8/14/19	PACE	PACE	5.000	07/18/19	07/18/34		
2711	89525666	PAC Merchant	07/18/19	07/23/19	East	NT	Confirmed 8/26/19	WYOEAST	WYOEAST	2.000	07/19/19	07/19/34		
2712	89547876	PAC Merchant	07/22/19	07/24/19	East	NT	Confirmed 8/29/19	WYOEAST	WYOEAST	37.800	07/25/19	07/25/34		
2713	89565206	PAC Merchant	07/25/19	07/26/19	East	NT	Confirmed 8/26/19	WYOEAST	WYOEAST	1.200	07/26/19	07/26/34		
2714	89565222	PAC Merchant	07/25/19	07/29/19	East	NT	Confirmed 8/26/19	WYOEAST	WYOEAST	1.500	07/26/19	07/26/34		
2715	89565232	PAC Merchant	07/25/19	07/29/19	East	NT	Confirmed 8/27/19	WYOEAST	WYOEAST	2.000	07/26/19	07/26/34		
2716	89591218/90961363	PAC Merchant	07/29/19	07/30/19	West	NT	Confirmed 10/28/21	PACW	PACW	7.000	12/26/19	12/26/34		
2718	89664299	PAC Merchant	08/09/19	08/12/19	East	NT	Confirmed 9/11/19	NUT	NUT	3.000	08/12/19	08/10/34		
2719	89664311	PAC Merchant	08/09/19	08/12/19	West	NT	Received	PACW	PACW	2.400	01/01/20	01/01/35		
2720	89681117	PAC Merchant	08/12/19	08/12/19	East	NT	Confirmed 1/3/20	NUT	NUT	1.100	09/30/19	09/30/34		
2721	89681657	PAC Merchant	08/12/19	08/15/19	East	NT	Received	NUT	NUT	1.150	10/28/19	10/28/34		
2723	89736161	PAC Merchant	08/21/19	08/22/19	East	NT	Confirmed 10/14/19	NUT	NUT	1.505	08/22/19	08/22/34		
2724	89743574	PAC Merchant	08/22/19	08/23/19	East	NT	Received	PACE	PACE	3.000	12/31/19	12/31/34		
2725	89766944	PAC Merchant	08/26/19	08/27/19	East	NT	Confirmed 9/20/19	NUT	NUT	34.000	08/27/19	01/01/28		
2726	89767013/94369279	PAC Merchant	08/26/19	08/27/19	East	NT	Confirmed 11/2/21	NUT	NUT	3.163	10/09/19	10/09/34		
2727	89777488	PAC Merchant	08/28/19	08/29/19	East	NT	Received	NUT	NUT	1.242	11/29/19	11/29/34		
2728	89778069	PAC Merchant	08/28/19	08/29/19	East	NT	Confirmed 12/12/19	NUT	NUT	1.604	09/30/19	09/30/34		
2730	89854560	PAC Merchant	09/09/19	09/10/19	West	NT	Received	PACW	PACW	1.134	12/09/19	12/09/34		
2731	89913961	PAC Merchant	09/19/19	09/19/19	East	NT	Confirmed 12/31/201	NUT	NUT	6.000	09/20/19	12/01/34		
2733	89861357	UAMPS	09/10/19	09/25/19	East	NT	Confirmed 9/26/19	GSHN	GSHN	4.000	10/01/19	10/01/21		
2734	89897995	UAMPS	09/16/19	09/25/19	East	NT	Confirmed 9/26/19	GSHN	GSHN	4.000	10/01/19	10/01/21		
2736	89991833	PAC Merchant	10/01/19	10/02/19	East	NT	Confirmed 1/3/20	WYOEAST	WYOEAST	1.100	11/29/19	11/29/34		
2737	90004432	PAC Merchant	10/03/19	10/07/19	East	NT	Confirmed 12/6/19	WYOEAST	WYOEAST	6.000	11/15/19	11/15/34		
2738	90029973	PAC Merchant	10/08/19	10/10/19	East	NT	Confirmed 11/13/19	WYOEAST	WYOEAST	25.900	10/09/19	10/09/34		
2739	90037025	PAC Merchant	10/09/19	10/10/19	East	NT	Confirmed 12/6/19	NUT	NUT	7.000	10/10/19	10/10/34		
2740	90038133	PAC Merchant	10/09/19	10/14/19	East	NT	Recieived	WYOEAST	WYOEAST	400.000	06/14/20	11/30/40		
2741	90038181	PAC Merchant	10/09/19	10/14/19	East	NT	Recieived	WYOEAST	WYOEAST	520.000	11/01/20	11/30/40		
2742	90044072	PAC Merchant	10/10/19	10/14/19	East	NT	Confirmed 10/10/19	PACE	REDBL	31.000	10/11/19	10/11/39		
2745	90173763	PAC Merchant	10/11/19	10/14/19	West	NT	Confirmed 10/31/201	HOODRIVER	HOODRIVERPA	43.000	11/01/19	11/01/24		
2746	90065266	PAC Merchant	10/14/19	10/15/19	East	NT	Recieived	PACW	PACW	120.000	10/01/22	10/01/37		
2747	90065289	PAC Merchant	10/14/19	10/16/19	East	PTP	Confirmed 1/2/2018	PACE	REDB	100.000	11/01/20	11/01/25		
2748	90068771	PAC Merchant	10/15/19	10/16/19	East	PTP	Confirmed 1/2/2018	PACE	BRDY	100.000	11/01/20	11/01/25		
2749	90069092	PAC Merchant	10/15/19	10/16/19	East	PTP	Confirmed 1/2/2018	PACE	REDBL	3.000	11/01/20	11/01/25		
2750	90071380	PAC Merchant	10/15/19	10/16/19	East	NT	Received	NUT	NUT	2.000	01/01/20	01/01/35		
2753	90082740	PAC Merchant	10/17/19	10/22/19	East	PTP	Confirmed 1/2/2018	PACE	FOURCORNE34	530.000	11/01/20	11/01/25		
2754	90082880	PAC Merchant	10/17/19	10/22/19	East	PTP	Confirmed 1/2/2018	BORA	PACE	250.000	11/01/20	11/01/25		
2755	90083017	PAC Merchant	10/17/19	10/22/19	East	PTP	Confirmed 1/2/2018	GLENCANYO	PACE	95.000	11/01/20	11/01/25		
2756	90083056	PAC Merchant	10/17/19	10/22/19	East	PTP	Confirmed 1/2/2018	BRDY	PACE	250.000	11/01/20	11/01/25		
2757	90083637	PAC Merchant	10/17/19	10/22/19	West	NT	Received	PACW	PACW	40.000	12/31/20	12/31/40		
2759	90172031	Powerex	10/31/19	10/31/19	West	PTP	Confirmed 12/4/19	BPAT.PACW	CRAG	80.000	11/01/20	11/01/25		
2760	90200031	PAC Merchant	11/04/19	11/06/19	East	NT	Confirmed 12/6/2019	PACE	PACE	58.000	06/01/20	12/31/45		
2761	90200049	PAC Merchant	11/04/19	11/06/19	East	NT	Confirmed 12/6/2019	PACE	PACE	122.000	04/01/20	10/31/45		
2762	90203731	PAC Merchant	11/05/19	11/06/19	East	NT	Confirmed 12/6/19	WYOEAST	WYOEAST	1.500	11/06/19	11/06/35		
2763	90206576	PAC Merchant	11/05/19	11/06/19	East	NT	Received	NUT	NUT	5.000	02/28/20	02/28/35		
2764	90212216	PAC Merchant	11/06/19	11/07/19	East	NT	Confirmed 12/6/19	NUT	NUT	3.720	11/07/19	11/07/34		
2765	90295960	BPA	11/19/19	11/19/19	East	NT	Confirmed 12/2/19	GSHN	TMK	30.000	12/01/19	10/01/28		
2766	90309153	UMPA	11/21/19	11/13/19	East	NT	Confirmed 12/20/19	GLENCANYO	PACE	8.000	01/01/20	01/01/35		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2768	90302844	Garrett Solar	11/20/19	11/21/19	West	PTP	Confirmed 11/27/19	PACW	PACW.PGE	10.000	12/01/19	12/01/24		
2769	90181511	PAC Merchant	11/01/19	12/02/19	West	NT	JDY/Deemed withdra	NEWPOINT	NEWPOINT	176.000	11/02/19	11/02/49	SIS	
2770	90384777	AIR1	12/03/19	11/26/19	West	PTP	Confirmed 12/20/201	PACW	PACW.PGE	50.000	01/01/20	01/01/25		
2771	90404546	PAC Merchant	12/06/19	12/09/19	West	NT	Confirmed 1/3/20	PACW	PACW	3.700	01/01/20	01/01/35		
2772	90404737	PAC Merchant	12/06/19	12/09/19	West	NT	Received	PACW	PACW	1.050	01/30/20	01/30/35		
2773	90310153/94369279	PAC Merchant	11/21/19	12/10/19	East	NT	Confirmed 10/28/21	NUT	NUT	8.000	10/31/20	10/31/35		
2775	90462892	PAC Merchant	12/16/19	12/17/19	West	PTP	Confirmed 12/22/202	JOHNDAY	PACW	100.000	01/01/21	01/01/26		
2777	90488583	PAC Merchant	12/20/19	12/23/19	East	NT	Accepted 3/3/20	TRONA	TRONA	61.000	12/21/19	12/21/34		
2778	90568041	BPA	01/03/20	01/03/20	West	NT	Confirmed 9/14/2020	BPAT.PACW	PACW	2.000	02/01/20	10/01/28		
2779	90585810	PAC Merchant	01/06/20	01/07/20	East	NT	Confirmed 2/11/20	NUT	NUT	1.050	01/07/20	11/06/34		
2780	90599893	BPA	01/08/20	01/08/20	West	NT	Confirmed 2/6/20	BPAT.PACW	PACW	2.000	01/09/20	10/01/28		
2782	90604052	PAC Merchant	01/09/20	01/10/20	East	NT	STUDY	NUT	NUT	80.000	12/31/21	01/01/37	SIS	
2783	90611952	PAC Merchant	01/10/20	01/13/20	West	NT	Received	PACW	PACW	6.190	05/01/20	05/01/35		
2786	90678677	PAC Merchant	01/21/20	01/28/20	West	NT	Confirmed 2/25/20	ROUNDBUT	COVEPACW	120.000	01/22/20	01/01/27		
2787	90678681	PAC Merchant	01/21/20	01/28/20	West	NT	Confirmed 2/25/20	ROUNDBUT	COVEPACW	2.000	01/22/20	06/30/28		
2788	90737779	PAC Merchant	01/30/20	01/31/20	East	NT	Confirmed 2/26/20	NUT	NUT	7.500	01/31/20	01/31/35		
2789	90896800	PAC Merchant	02/24/20	02/27/20	East	NT	Received	NUT	NUT	75.000	02/25/20	10/30/47		
2790	90896802	PAC Merchant	02/24/20	02/27/20	East	NT	STUDY	NUT	NUT	80.000	02/25/20	10/30/47	SIS	
2791	90900391	PAC Merchant	02/25/20	02/27/20	East	NT	Received	WYOEAST	WYOEAST	3.000	05/14/20	05/14/35		
2792	90908943	PAC Merchant	02/26/20	02/27/20	East	NT	Received	PACE	PACE	1.500	03/30/20	03/30/35		
2793	90923510	PAC Merchant	02/28/20	02/28/20	West	NT	Confirmed 2/28/20	COVEPACW	ROUNDBUTTE	10.000	03/01/20	03/31/37		
2794	90923515	PAC Merchant	02/28/20	02/28/20	West	NT	Confirmed 2/28/20	COVEPACW	ROUNDBUTTE	2.000	04/01/20	03/31/37		
2795	90949914	PAC Merchant	03/03/20	03/04/20	East	NT	Received	NUT	NUT	1.300	07/25/20	07/25/35		
2796	90956227/94369279	PAC Merchant	03/04/20	03/06/20	East	NT	Confirmed 11/2/21	NUT	NUT	3.804	06/19/20	06/19/35		
2797	90957065	PAC Merchant	03/04/20	03/06/20	East	NT	Confirmed 4/9/20	NUT	NUT	1.250	03/05/20	03/05/35		
2798	90985557	PAC Merchant	03/09/20	03/10/20	East	NT	Received	NUT	NUT	1.400	06/29/20	06/29/35		
2802	91184599	PAC Merchant	04/09/20	04/16/20	West	NT	Confirmed 12/4/2020	MCNARY	WALLAWALLA	375.000	01/01/21	01/01/36		
2803	91191016	PAC Merchant	04/10/20	04/16/20	West	NT	Confirmed 12/22/202	MIDC	WALLAWALLA	265.000	01/01/21	01/01/31		
2804	91223004	PAC Merchant	04/16/20	04/16/20	West	NT	Received	PACW	PACW	55.000	11/30/22	02/27/43		
2805	91224323	PAC Merchant	04/16/20	04/17/20	East	NT	Confirmed 5/26/2020	NUT	NUT	2.800	04/16/20	04/16/35		
2806	91529876	Tri-State	04/17/20	04/17/20	East	NT	Received	PACE		2.000	12/15/20	12/15/30		
2807	91321405	PAC Merchant	05/01/20	05/04/20	East	NT	Confirmed 7/16/2020	PACE	PACE	0.900	05/31/20	12/28/21		
2808	91321593	PAC Merchant	05/01/20	05/04/20	East	NT	Received	NUT	NUT	1.250	05/01/20	05/01/35		
2809	91350430	PAC Merchant	05/06/20	05/08/20	East	NT	Confirmed 7/16/2020	PACE	PACE	604.000	06/30/20	06/30/40		
2810	91448426	EDP Renewables (HZ	05/21/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2811	91455093	EDP Renewables (HZ	05/22/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2812	91455159	EDP Renewables (HZ	05/22/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2813	91455168	EDP Renewables (HZ	05/22/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2814	91455178	EDP Renewables (HZ	05/22/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2815	91455186	EDP Renewables (HZ	05/22/20	05/28/20	West	PTP	Confirmed 7/10/20	PACW	PACW.PGE	10.000	05/31/21	05/31/26		
2819	91493879	Tri-State	05/28/20	05/28/20	East	NT	Study 10/28/20	DJ		47 MW	06/30/21	06/30/31	SIS	
2820	91495116	Tri-State	05/28/20	05/28/20	East	NT	Received		WYOCENTRAL	12.000	06/30/21	06/30/31		
2821	91495822	Tri-State	05/28/20	05/28/20	East	NT	Received		WYONORTH	15.000	06/30/21	06/30/31		
2822	91496374	Tri-State	05/28/20	05/28/20	East	NT	Received		WYOEAST	19.000	06/30/21	06/30/31		
2823	91496774	Tri-State	05/28/20	05/28/20	East	NT	Confirmed 6/30/21		PINTO	1.000	06/30/21	06/30/31		
2825	91496882	Tri-State	05/28/20	05/28/20	East	NT	Received	FOURCORNE	345	2.000	06/30/21	06/30/31		
2826	91568878	PAC Merchant	06/08/20	06/08/20	East	NT	Confirmed 12/22/202	GLENCANYO	PACE	95.000	01/01/21	01/01/31		
2827	91598111	BPA	06/12/20	06/15/20	East	NT	Confirm 5/10/21	MDWP	GSHN	125.000	07/01/21	6/31/2026		
2830	91643443	PAC Merchant	06/19/20	06/22/20	West	NT	Received	PACW	PACW	7.000	07/01/20	03/31/22		
2831	91668584	BPA	06/23/20	06/24/20	West	NT	Received	KPRT	GSHN	100.000	06/30/21	06/30/26		
2832	91668597	BPA	06/23/20	06/24/20	West	NT	Received	KPRT	GSHN	100.000	06/30/21	06/30/26		
2833	91668613	BPA	06/23/20	06/24/20	West	NT	Received	BPAT.PACW	M500	100.000	06/30/21	06/30/26		
2834	91668618	BPA	06/23/20	06/24/20	West	NT	Received	BPAT.PACW	SMLK	100.000	06/30/21	06/30/26		
2835	91765965	PAC Merchant	07/07/20	07/13/20	East	NT	Received	GSHN	GSHN	2.650	04/01/22	04/01/42		
2836	91806834	PAC Merchant	07/13/20	07/13/20	East	NT	Confirmed 3/30/21	GSHN	GSHN	7.450	04/01/21	04/01/41		
2837	91862892	Tri-State	07/22/20	07/13/20	East	NT	Received	PACE	WYOEAST	5.000	11/01/20	06/30/31	SIS	
2838	91806183	PAC Merchant	07/13/20	07/23/20	West	NT	Received	PACW	PACW	6.250	08/01/20	08/01/25		
2839	91872684	EDP Renewables (HZ	07/23/20	07/24/20	West	PTP	Confirmed 3/1/21	PACW	ALVEYPAC	10.000	05/31/21	05/31/26		
2840	91965563	Powerex	08/06/20	08/06/20	West	PTP	Confirmed 9/25/20	MALIN500	RDM500	100.000	01/01/21	01/01/26		
2841	91965565	Powerex	08/06/20	08/06/20	West	PTP	Confirmed 9/25/20	MALIN500	RDM500	100.000	01/01/21	01/01/26		
2842	91968600	PAC Merchant	08/06/20	08/11/20	East	NT	Confirmed 9/2/20	PACE	NAPLES	25.000	08/06/20	08/06/35		
2843	91998230	PAC Merchant	08/11/20	08/12/20	East	NT	Confirmed 9/2/20	PACE		25.000	08/07/20	08/07/35		
2844	91811287	Tri-State	07/14/20	08/14/20	East	NT	Study 10/28/20	DJ		2.000	11/30/20	06/30/31	SIS	
2845	92200965	PAC Merchant	09/09/20	09/09/20	West	NT	Received	PACW		2.700	09/30/21	12/31/41		
2846	92214284	UAMPS	09/11/20	09/11/20	East	NT	Study 11/4/20	PACE		40.000	12/30/22	12/30/47	SIS	
2847	92117931	Powerex	08/28/20	09/01/20	West	PTP	Withdrawn 2/9/21	MCNARY	WALLAWALLA	100.000	04/01/21	01/01/26	SIS	
2848	92248009	PAC Merchant	09/17/20	09/23/20	East	NT	Received	AEOLUS		42.000	01/01/16	08/31/32		
2849	92236592	PAC Merchant	09/15/20	10/01/20	East	NT	Received	WYOEAST	JBSN	848.000	09/20/20	09/20/40		
2850	92236648	PAC Merchant	09/15/20	10/01/20	East	NT	Received	WYOEAST	WYOCENTRAL	888.000	09/20/20	09/20/40		
2851	92246422	PAC Merchant	09/17/20	10/01/20	East	NT	Received	BOWLER	WYONORTH	240.000	09/20/20	09/20/40		
2852	92247352	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS	WYOEAST	1,203.000	10/06/20	10/06/40		
2853	92247622	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		111.000	10/01/20	09/29/29		
2854	92247992	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		99.000	10/01/20	01/01/35		
2855	92247998	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		29.000	10/01/20	10/31/29		
2856	92248000	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		102.000	10/01/20	08/31/31		
2857	92248003	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		21.000	10/01/20	08/31/31		
2858	92248089	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		49.000	10/01/20	06/30/32		
2859	92248490	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		250.000	10/01/20	09/30/40		
2860	92248513	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		250.000	10/01/20	09/30/40		
2861	92248655	PAC Merchant	09/17/20	10/01/20	East	NT	Received	AEOLUS		250.000	10/01/20	09/30/40		
2862	92254087	PAC Merchant	09/18/20	10/01/20	East	NT	Received	BOWLER		240.000	10/01/20	09/30/40		
2863	92292162	PAC Merchant	09/25/20	10/01/20	East	NT	Received	WYOEAST		80.000	10/01/20	07/01/36		
2864	92321552	PAC Merchant	10/01/20	10/01/20	East	NT	Received	WYOEAST		520.000	09/30/20	09/30/40		
2865	92291087	PAC Merchant	09/25/20	10/02/20	East	NT	Received	NUT	NUT	70.000	12/31/22	12/31/47	SIS	FS
2866	92291135	PAC Merchant	09/25/20	10/02/20	East	NT	Received	NUT		11.000	12/31/22	12/31/42	SIS	
2867	92327610	PAC Merchant	10/02/20	10/02/20	East	NT	Received	PACE		20.000	12/31/21	12/31/46	SIS	FS
2870	92405443	Black Hills Power	10/14/20	n/a	East	PTP	Confirmed 4/9/21	JBSN	WYODAK	50.000	01/01/21	01/01/24		
2871	92406152	PAC Merchant	10/14/20	10/15/20	East	NT	Received	WYONORTH		1.000	11/01/20	10/30/25		
2872	92421409	PAC Merchant	10/16/20	10/19/20	East	NT	Received	PACE		80.000	09/29/23	09/29/43	SIS	
2873	92421441	PAC Merchant	10/16/20	10/19/20	East	NT	Received	PACE		120.000	09/29/23	09/29/43	SIS	
2876	92411494	PAC Merchant	10/15/20	10/20/20	East	NT	Received	WYONORTH	WYOEAST	303.000	10/14/20	10/14/40		
2877	92421752	PAC Merchant	10/16/20	10/20/20	East	NT	Received	NUT		7.540	01/01/16	01/01/22		
2878	92421790	PAC Merchant	10/16/20	10/20/20	East	NT	Received	NUT		31.800	01/01/16	01/01/22		
2879	92486315	Hornshadow Solar	10/26/20	10/22/20	East	PTP	Confirmed 3/1/21	PACE	PACE	200.000	01/01/24	01/01/29	SIS	
2880	92461343	PAC Merchant	10/22/20	10/28/20	East	NT	Received	FOURCORN	PACE	200.000	01/01/21	01/01/22		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
2882	92414020	PAC Merchant	10/15/20	10/29/20	East	NT	Received	NUT	Nut	25.000	01/01/21	01/01/22		
2883	92515832	PAC Merchant	10/30/20	10/30/20	East	PTP	Received	PACE	BORA	100.000	10/31/21	10/31/26		
2884	92591674	PAC Merchant	11/10/20	11/13/20	East	NT	Received	AEOLUS		49.000	10/01/20	11/07/21		
2885	92720062	Calpine Energy	11/30/20	11/30/20	West	NT	Confirmed 12/22/202	BPAT.PACW	PACW	19.000	01/01/21	12/31/21		
2886	92683121	PAC Merchant	11/24/20	12/03/20	East	NT	Received	GSHN		1.000	01/01/22	01/01/23		
2888	92808511	BPA	12/04/20	12/10/20	West	NT	Received	BPAT.PACW	PACW	1.000	12/15/20	08/31/28		
2889	92809214	Constellation Energy	12/14/20	12/14/20	West	NT	Received	BPAT.PACW	PACW	1.000	01/01/21	12/31/21		
2890	92837595	PAC Merchant	12/18/20	12/22/20	West	NT	Confirmed 3/15/2021	PACW		5.000	01/01/21	01/01/22		
2891	92863796	PAC Merchant	12/22/20	12/22/20	West	NT	Received	PONDEROSA	PAC	40.000	12/21/20	12/31/40		
2892	93639339	PAC Merchant	12/22/20	12/22/20	West	NT	Confirmed 9/10/21	PONDEROSA	PAC	60.000	12/21/20	12/31/45		
2893	92863449	PAC Merchant	12/22/20	12/23/20	West	PTP	Confirmed 9/29/21	PACW	JOHNDAY	70.000	01/01/22	01/01/27		
2894	92863731	PAC Merchant	12/22/20	12/23/20	West	NT	Confirmed 3/15/2021	PACW		1.460	01/01/21	01/01/31		
2895	92864707	PAC Merchant	12/22/20	12/23/20	West	NT	Confirmed 3/15/2021	PACW		2.000	01/01/21	01/01/31		
2896	92864615	PAC Merchant	12/22/20	12/24/20	West	NT	Received	PACW	PACW.PGE	2.000	01/01/21	01/01/26		
2897	92914794	PAC Merchant	12/30/20	12/30/20	West	NT	Received	PACW	BPAT.PACW	663.000	01/01/21	01/01/31		
2898	92914819	PAC Merchant	12/30/20	12/30/20	East	NT	Received	WYOEAST	DJ	152.000	01/01/21	01/01/31		
2899	92972411	PAC Merchant	01/08/21	01/12/20	East	NT	Confirmed 3/15/2021	TRONA	TRONA	107.400	01/01/21	01/01/22		
2901	93016525/94370705	Powerex	01/15/21	01/15/21	East	PTP	Confirmed 6/29/21	BORA	REDB	100.000	03/31/21	03/31/24	SIS	
2902	93016526/94370716	Powerex	01/15/21	01/15/21	East	PTP	Confirmed 6/29/21	BORA	REDB	100.000	03/31/21	03/31/24	SIS	
2904	93083559	MCPI	01/26/21	01/26/21	East	PTP	STUDY 4/19/21	VNL	FOURCORNE34	75.000	06/30/21	06/30/22	SIS	
2905	93186533	PAC Merchant	02/10/21	02/12/21	West	NT	Received		WALLAWALLA	6.000	05/15/21	05/15/31		
2906	93186602	PAC Merchant	02/10/21	02/12/21	East	NT	Received		PACE	25-45	02/01/21	01/01/00		
2907	93261270	PAC Merchant	02/19/21	02/22/21	West	NT	Received		PACW	14-21.6	02/19/21	01/01/00		
2913	93301364	Powerex	02/25/21	02/25/21	East	PTP	STUDY 4/19/21	BORA	REDB	100.000	04/30/21	04/30/26	SIS	FS
2914	93301365	Powerex	02/25/21	02/25/21	East	PTP	STUDY 4/19/21	BORA	REDB	100.000	04/30/21	04/30/26	SIS	FS
2915	93301880	PAC Merchant	02/25/21	03/01/21	West	NT	Confirmed 4/5/21	BPAT.PACW		1.000	01/01/22	01/01/37		
2916	93351090	Tri-State	03/05/21	03/05/21	East	NT	Received	WYOEAST		11.000	04/01/23	06/30/31		
2917	93345957	PAC Merchant	03/04/21	03/09/21	East	NT	STUDY 4/19/21	GSHN	GSHN	2.000	03/31/21	03/31/41	SIS	
2922	93412783	PAC Merchant	03/15/21	03/19/21	West	NT	Received	MIDC		168.600	01/01/21	01/01/22		
2925	93507657	Powerex	03/30/21	03/30/21	West	PTP	Confirmed 6/9/21	MALIN500	RDM230	100.000	03/31/22	03/31/27		
2926	93507668	Powerex	03/30/21	03/30/21	West	PTP	Confirmed 6/9/21	MALIN500	RDM230	100.000	03/31/22	03/31/27		
2927	93507673	Powerex	03/30/21	03/30/21	West	PTP	Confirmed 6/9/21	MALIN500	RDM230	100.000	03/31/22	03/31/27		
2928	93506754	PAC Merchant	03/30/21	04/01/21	East	NT	Confirmed 5/3/2021	GSHN		0.450	05/01/21	05/01/41		
2929	93529819	SMUD	04/02/21	04/02/54	West	PTP	Received	MALIN230	MALIN500	19.000	07/01/22	07/01/27		
2930	93369063	BPA	03/08/21	04/07/21	West	NT	Confirmed 4/30/21	PACW	PACW	18.000	04/30/21	09/30/28		
2931	93502144	BPA	03/29/21	04/07/21	West	NT	Confirmed 4/30/21	PACW	ALVEYPAC	18.000	04/30/21	09/30/28		
2932	93560629	BPA	04/07/21	04/07/21	West	NT	Confirmed 4/30/21	PACW	PACW	18.000	04/30/21	09/30/28		
2933	93566799	PAC Merchant	04/08/21	04/08/21	East	NT	Confirmed 5/14/2021	GSHN		7.450	03/31/21	03/31/41		
2934	93959095	PAC Merchant	04/09/21	04/12/21	East	NT	Received	GSHN		0.900	02/28/21	12/01/36		
2935	93521708	PAC Merchant	04/01/21	04/13/21	East	NT	Received	GSHN		0.330	03/31/21	03/31/22		
2936	93696978	Lucky Star Wind	04/22/21	04/23/21	East	PTP	Study 6/15/21	WYOEAST	REDB	390.000	01/01/24	01/01/29	SIS	FS
2938	95152148	BPA	03/12/21	04/27/21	East	NT	Confirmed 10/20/21	PACE		0.450	01/01/16	12/31/99		
2939	93840919	PAC Merchant	04/27/21	04/29/21	East	NT	Study 6/15/21	PACE		20.000	06/30/22	06/30/42	SIS	
2940	93853254	UAMPS	04/27/21	05/03/21	East	NT	Received	PACE	MDWP	65.000	04/30/21	01/01/30		
2941	93853267	UAMPS	04/27/21	05/03/21	East	NT	Received	PACE	MDGT	65.000	04/30/21	01/01/30		
2942	93853272	UAMPS	04/27/21	05/03/21	East	NT	Received	MDGT	MDWP	65.000	04/30/21	01/01/30		
2943	93983949	PAC Merchant	05/06/21	05/07/21	East	NT	Received	GSHN		3.400	04/30/22	04/30/42		
2947	93891187	Powerex	04/28/21	05/03/21	East	PTP	Study 6/22/21	BORA	GLENCANYON	125.000	03/31/24	03/31/29	SIS	
2948	93891191	Powerex	04/28/21	05/03/21	East	PTP	Study 6/22/21	BORA	GLENCANYON	125.000	03/31/24	03/31/29	SIS	
2949	93891201	Powerex	04/28/21	05/03/21	East	PTP	Study 6/22/21	BORA	FOURCORNE34	100.000	03/31/24	03/31/29	SIS	
2950	93891203	Powerex	04/28/21	05/03/21	East	PTP	Study 6/22/21	BORA	FOURCORNE34	100.000	03/31/24	03/31/29	SIS	
2951	94016341	UMPA	05/11/21	04/21/21	East	NT	Accepted 10/20/21		PACE	6.048	07/01/22	01/01/00	SIS	
2952	94016367	UMPA	05/11/21	04/21/21	East	NT	Accepted 10/20/21		PACE	6.048	07/01/22	01/01/00	SIS	
2953	93961888	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	ALVEYPAC	10.000	05/31/22	05/31/27		
2954	93961900	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	PACW.PGE	10.000	05/31/22	05/31/27		
2955	93961904	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	PACW.PGE	10.000	05/31/22	05/31/27		
2956	93961907	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	PACW.PGE	10.000	05/31/22	05/31/27		
2957	93961910	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	PACW.PGE	10.000	05/31/22	05/31/27		
2958	93961920	EDP Renewables (HZ	05/03/21	05/12/21	West	PTP	Received	PACW	PACW.PGE	10.000	05/31/22	05/31/27		
2960	93989467	Idaho Power	05/07/21	05/13/21	West	PTP	Received	MCNARY	WALLAWALLA	80.000	01/01/23	01/01/28		
2961	94011027	UMPA	05/10/21	06/07/21	East	NT	Received		DRYCREEK	12.048	07/01/22	01/01/00		
2962	94165470	PAC Merchant	06/02/21	06/07/21	East	NT	Confirmed 7/15/2021	GSHN		2.950	03/31/22	03/31/42		
2963	93602511	Tri-State	04/21/21	06/11/21	East	NT	Received		PACE	11.000	04/01/23	06/30/31	SIS	
2964	93960507	Tri-State	05/03/21	06/11/21	East	NT	Received	DJ	WYOCENTRAL	47.000	06/30/21	06/30/31	SIS	
2965	94262842	PAC Merchant	06/15/21	06/15/21	West	NT	Confirmed 7/15/2021	PACW		0.065	07/01/21	07/01/24		
2966	94419903	PAC Merchant	07/06/21	07/08/21	East	NT	Received		WYOEAST	`6-15	10/31/21	01/01/00		
2971	94604557	PAC Merchant	07/29/21	07/30/21	West	NT	Received	PACW		1.000	08/15/21	08/15/41		
2973	94762576	PAC Merchant	08/17/21	08/20/21	West	NT	Received	PACW		1.010	08/17/21	01/01/00		
2976	94928141	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	ALVEYPAC	PACW	523.000	09/14/21	09/30/26		
2977	94928232	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	SANTIAMPA	SANTIAMPAC	40.000	09/14/21	09/30/26		
2978	94928246	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	ALBANYPAC	ALBANYPAC	170.000	09/14/21	09/30/26		
2979	94928258	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	CLATSOPPA	CLATSOPPAC	76.000	09/14/21	09/30/26		
2980	94928292	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	BUCKLEY	PONDEROSA50	140.000	09/14/21	04/30/35		
2981	94928306	PAC Merchant	09/07/21	09/21/21	West	NT	Confirmed 10/08/21	BUCKLEY	PONDEROSA50	200.000	09/14/21	07/14/39		
2982	95033161	PAC Merchant	09/21/21	09/21/21	West	NT	Confirmed 10/08/21	ALBANYPAC	ALBANYPAC	11.000	09/26/21	09/30/26		
2983	95080281	PAC Merchant	09/28/21	10/01/21	West	NT	Confirmed 11/17/21	MIDC		206.000	01/01/22	01/01/23		
2984	95127011	PAC Merchant	10/05/21	10/21/21	East	NT	Received	AEOLUS		49.000	01/01/16	12/01/21		
2985	95298122	NextEra	10/27/21	10/27/21	West	PTP	Confirmed 12/15/21	WALLULA	MIDC	`99/80	12/01/22	12/01/27		
2986	95288159	PAC Merchant	10/26/21	10/28/21	East	NT	Received	TRONA		107.400	01/01/22	01/01/23		
2987	95357855	PAC Merchant	11/04/21	11/05/21	West	NT	Received		PACW	1.001	11/01/21	01/01/00		
2988	95387486	PAC Merchant	11/08/21	11/10/21	East	NT	Received		PACE	6.000	11/08/21	01/01/00		
2989	95387899	PAC Merchant	11/08/21	11/10/21	East	NT	Received		PACE	1.162	11/08/21	01/01/00		
2990	95402530	PAC Merchant	11/10/21	11/15/21	West	NT	Received	PACW		0.050	12/15/21	12/15/35		
2991	95418165	PAC Merchant	11/12/21	11/16/21	West	NT	Received		PACW	2.235	02/01/22	01/01/00		
2992	95418417	PAC Merchant	11/12/21	11/16/21	West	NT	Received		PACW	1.524	11/12/21	08/19/31		
2993	95441229	PAC Merchant	11/15/21	11/16/21	West	NT	Received	MIDC		85.000	01/01/22	01/01/23		
2994	95449897	PAC Merchant	11/16/21	11/16/21	West	NT	Received	PACW		4.990	09/30/23	11/07/36		
2995	95466147	PAC Merchant	11/18/21	11/22/21	East	NT	Received		PACE	1.663	09/30/21	12/31/99		
2997	95468219	PAC Merchant	11/18/21	11/22/21	East	NT	Received		PACE	1.365	11/18/22	12/31/99		
2998	95468410	PAC Merchant	11/18/21	11/22/21	East	NT	Received		PACE	3.000	09/30/21	12/31/99		
2999	95459196	PAC Merchant	11/17/21	11/23/21	East	NT	Received	NUT		7.540	01/01/22	01/01/23		
3000	95459242	PAC Merchant	11/17/21	11/23/21	East	NT	Received	NUT		31.800	01/01/22	01/01/23		
3001	95468259	PAC Merchant	11/18/21	11/23/21	West	NT	Received	PACW		0.800	01/01/22	04/14/22		
3002	95443072	Powerex	11/15/21	11/15/21	East	PTP	Withdrawn 12/21/21	GON.PAV	REDB	100.000	04/30/22	09/30/23		
3003	95443074	Powerex	11/15/21	11/15/21	West	PTP	Withdrawn 12/21/21	MALIN500	MALIN230	100.000	04/30/22	09/30/23		

PacifiCorp Transmission Services
Long Term Firm Request Queue (Active Requests)

1/7/2022

Queue	OASIS AREF	Company	OASIS Request Received	Written Application Received	Control Area	Product	OASIS Status	POR	POD	MW	Start	End	SIS	FS
3004	95443108	Powerex	11/15/21	11/15/21	East	PTP	Received	GON.PAV	REDB	10.000	04/30/22	09/30/23		
3005	95443112	Powerex	11/15/21	11/15/21	West	PTP	Received	BPAT.PACW	SMLK	10.000	04/30/22	09/30/23		
3006	95771200	Calpine Energy	11/30/21	11/30/21	West	NT	Confirmed 12/27/21	BPAT.PACW		19.000	01/01/16	12/30/99		
3007	95585001	PAC Merchant	12/06/21	12/07/21	West	NT	Received	PACW		0.360	12/07/21	01/01/42		
3008	95662025	Constellation Energy	12/13/21	12/10/21	West	NT	Confirmed 12/30/21	PACW		1.000	01/01/22	12/31/22		
3009	95678951	PAC Merchant	12/15/21	12/15/21	East	NT	Received		PACE	1.500	09/30/21	12/31/99		
3010	95694286	PAC Merchant	12/17/21	12/17/21	West	NT	Received		PACW	6.000	01/01/22	01/01/25		
3011	95686100	PAC Merchant	12/16/21	12/20/21	East	NT	Received	PACE		0.260	02/01/22	02/01/23		
3012	95686725	PAC Merchant	12/16/21	12/20/21	East	NT	Received		PACE	7.455	12/16/21	12/31/99		
3013	95686884	PAC Merchant	12/16/21	12/20/21	East	NT	Received		PACE	1.494	09/30/21	12/31/99		
3014	95686920	PAC Merchant	12/16/21	12/20/21	East	NT	Received		PACE	2.500	09/30/21	12/31/99		
3015	95686635	PAC Merchant	12/16/21	12/21/21	East	NT	Received		PACE	2.222	09/30/21	12/31/99		
3016	95725568	PAC Merchant	12/21/21	12/22/21	East	NT	Received	NUT		25.000	01/01/22	01/01/23		
3017	95725597	PAC Merchant	12/21/21	12/22/21	West	NT	Received	PACW		5.000	01/01/22	01/01/23		
3018	95693645	PAC Merchant	12/17/21	12/27/21	East	NT	Received		PACE	1.547	12/17/21	12/31/99		
3019	95694117	PAC Merchant	12/17/21	12/27/21	East	NT	Receoved		PACE	20.500	12/30/21	12/31/99		
3020	95740603	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	2.470	12/23/21	12/31/99		
3021	95740704	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	1.105	12/23/21	12/31/99		
3022	95740855	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	3.418	01/01/22	12/31/99		
3023	95740924	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	1.380	12/23/21	12/31/99		
3024	95741021	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	13.300	01/01/22	01/01/23		
3025	95741171	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	1.878	12/23/21	12/31/99		
3026	95741343	PAC Merchant	12/23/21	12/27/21	East	NT	Receoved		PACE	1.050	09/30/21	12/31/99		
3027	95741514	PAC Merchant	12/23/21	12/27/21	West	NT	Receoved		PACW	0.720	01/01/22	01/01/23		
3028	95741898	PAC Merchant	12/23/21	12/27/21	East	NT	Received		PACE	1.225	02/22/22	02/22/37		
3029	95742349	PAC Merchant	12/23/21	12/27/21	East	NT	Received		PACE	1.890	09/30/21	12/31/99		
3030	95742463	PAC Merchant	12/23/21	12/27/21	East	NT	Received		PACE	3.500	09/30/21	12/31/99		
3031	95742640	PAC Merchant	12/23/21	12/27/21	East	NT	Received		PACE	5.277	09/30/21	12/31/99		
3032	95749101	EOU	12/24/21	12/28/21	East	PTP	Received	NUT	NUT	50.000	12/01/25	12/01/30		
3033	95749731	EOU	12/24/21	12/28/21	East	PTP	Received	NUT	NUT	29.000	12/01/24	12/01/30		
3034	95749736	EOU	12/24/21	12/28/21	East	PTP	Received	NUT	NUT	80.000	12/01/25	12/01/31		

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/405

TRANSMISSION PLANNING FOR THE 21ST CENTURY: PROVEN PRACTICES THAT INCREASE VALUE AND REDUCE COSTS, *THE BRATTLE GROUP AND GRID STRATEGIES* (OCTOBER 2021)

January 19, 2022

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

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OCTOBER 2021

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NOTICE

This report was prepared with funding from the American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative, and the Natural Resource Defense Council (NRDC).

The report also incorporates research from our prior client engagements and public reports, including:

- Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* January 2021.
- Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.
- Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, prepared for WIRES May 2016.
- Gramlich and REBA Institute, *Designing the 21st Century Electricity System*, for Renewable Buyers Alliance Institute, March 2021.
- Caspary, Goggin, Gramlich, Schneider, Disconnected: The Need for a New Generator Interconnection Policy, for Americans for a Clean Energy Grid, January 2021.
- Pfeifenberger, Chang, and Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.
- Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's or Grid Strategies' clients or other consultants. There are no third party beneficiaries with respect to this report, and neither the Brattle Group nor Grid Strategies accepts any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

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Executive Summary

The U.S. is at a critical juncture in transmission network planning. System vulnerabilities to severe weather are illuminating the need and opportunity for transmission to enable power sharing across and between regions. Existing transmission infrastructure, mostly constructed in the 1960s and 1970s, is nearing the end of its useful life, and decisions today about how this aging infrastructure is replaced will have long-lasting impacts on system costs and reliability. At the same time, public policy mandates, customer preferences, and the power generation mix necessary to address these needs are rapidly changing, causing a need for various types of transmission in different locations to maintain reliable and efficient service.

While the current transmission system and grid planning processes have functioned adequately in the past, they are failing to address these diverse 21st century needs. Current transmission planning processes routinely ignore realistic projections of the future resource mix, how the transmission system is utilized during severe weather events, and the economies of scale and scope that can reduce total costs. Today's planning is overwhelmingly reactive and focused on addressing near-term needs and business-as-usual trends.

The large majority of current transmission investments are narrowly focused on network reliability and what is needed to connect the next group of generators in interconnection queues, ignoring the efficiencies that occur when simultaneously and proactively planning for multiple future needs and benefits across the system. Even if Planning Authorities look beyond reliability-driven needs, they typically compartmentalize transmission into individual planning efforts that separately examine reliability, economic, public policy, and generator-interconnection driven transmission projects—instead of conducting multi-value planning that optimizes investments across all reliability, economic, public policy, or generator interconnection needs. The current approaches also lack a proactive scenario-based outlook that explicitly recognizes long-term planning uncertainties.

Together, these deficiencies yield an inefficient patchwork of incremental transmission projects and they limit the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks. The inevitable outcome of such reactive and siloed planning is unreasonably high overall system costs and risks, which are ultimately passed on to electricity customers and can deter the development of low-cost generation resources.

Fortunately, there have been exceptions to the rule. Effective transmission planning efforts have proven repeatedly that proactive, multi-value, scenario-based planning delivers greater benefits to the entire electric system at lower overall costs and risks. These holistic transmission planning efforts have led to well-documented, highly beneficial transmission investments across the United States.

The available industry experience thus points to the following proven planning practices and core principles with which transmission planning can achieve reliable and efficient solutions capable of meeting the needs of the evolving 21st century power system at a lower total system cost:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

As set forth in greater detail in the remainder of this report, these principles form the standard for efficient transmission planning that can maintain a reliable grid while more cost-effectively meeting all other transmission-related needs to avoid unreasonably high electricity costs. Policymakers and planners need to reform current transmission planning requirements to avoid unreasonably high system-wide costs that result from the current planning approaches, thereby enabling customers to pay just and reasonable rates by implementing these principles.

I. Today's Transmission Planning Results in Unreasonably High Electricity Costs

This report focuses on improving transmission planning, including for generation interconnection, which consists of identifying transmission needs and evaluating and selecting solutions to address these needs. We recognize, however, that successful approval and development of planned transmission infrastructure also requires improvements to cost allocation and approval (including permitting) processes. Creating a more effective transmission planning and development process to build a grid that can cost-effectively meet 21st Century needs will require improving every phase of this process, as illustrated in the figure below. Improvements will have to specifically focus on: (1) expanding initial needs assessment and project identification; (2) improving the analyses of transmission solutions and their costs and benefits to determine the which are most effective from a total system-wide cost perspective; (3) refining project cost recovery (*i.e.*, cost allocation) to be roughly commensurate with benefits; and (4) presenting the needs, benefits, and proposed cost recovery to obtain approvals from the various federal and state permitting and regulatory agencies.

FIGURE 1. TRANSMISSION PLANNING PROCESS

Electricity costs consist of three major components: generation, transmission, and distribution costs. Transmission, the focus of this report, consists of the electrical wires and other equipment that transports electricity from generators to local distribution utilities. In many regions, including some served by regional transmission organizations (RTOs) or independent system operators (ISOs), these three functions are provided by one vertically integrated entity. Even in RTO areas with disaggregated generation and distribution ownership, transmission owners (TOs) are still primarily monopolies and affiliates of other utility entities.

Transmission currently accounts for about 13% of the total national average electricity costs, while generation accounts for 56% of the total.[1] Well-planned transmission investment reduces the total system-wide cost of electricity by allowing more electricity to be generated from lower-cost resources and making more efficient use of available generation resources. Unfortunately, current transmission planning processes fail to achieve the efficient quantity or type of investment needed to realize maximum reductions in generation costs and lowest total costs, which results in unreasonably high system-wide costs.

While the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid,[2] most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other, local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010.

1 U.S. Energy Information Administration, *Annual Energy Outlook 2021*, 2021, p4.

2 See slide 2 of Pfeifenberger, Tsoukalis, *Transmission Investment Needs and Challenges*, JP Morgan Renewables and Grid Transformation Series, June 1, 2021.

TABLE 1. MISO MTEP APPROVED INVESTMENT BY PROJECT TYPE[3]

Year	Baseline Reliability Projects (BRP) ($ million)	Market Efficiency Projects (MEP) ($ million)	Multi-Value Projects (MVP) ($ million)	Other (local) ($ million)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800
2020	755	-	-	2,800

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The narrowly focused current approaches do not identify opportunities to take advantage of the large economies of scale in transmission that come from "up-sizing" reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals. Neither do the narrowly focused approaches identify investments that create option value by increasing flexibility to respond to changing market and system conditions. For example, in-kind replacement of aging existing facilities misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies. And the current piecemeal approach certainly does not yield any larger regional or interregional solutions, such as transmission overlays, that could more cost-effectively address the nation's public policy needs. In short, and as shown through examples below, the current approach systematically results in inefficient infrastructure and excessive electricity costs.

The current lack of proactive, multi-value, and scenario-based planning for future generation and policy needs in most of the U.S. creates a situation where we are essentially trying to plan

[3] Years 2010 through 2019 from Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, Section 206 Complaint and Request for Fast Track Processing, January 21, 2020 at 31–32. 2020 figures from *MTEP20* at p 15. See MISO, *MTEP 20 Full Report.*

an integrated and shared network through the generator interconnection, local upgrades, and reliability planning processes. The lack of proactive, multi-value planning also overburdens generators in the interconnection queue by making them responsible for network upgrades that provide large system-wide benefits.

A recent ICF study showed that generation developers essentially bear the entire cost of regional network upgrades required to interconnect generators, even though these upgrades often provide broad system-wide benefits.[4] PJM's proactive 2021 off-shore wind integration study (discussed below) shows the same: upgrades to accommodate generation interconnection requests provide broad system-wide benefits.[5] This cost allocation consequently is not roughly commensurate with benefits; having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests even if the network upgrade provides substantial regional benefits that exceed costs—resulting in inefficient outcomes and higher system-wide costs. In addition, many of the current generation interconnection processes do not provide interconnection options that rely on non-firm, energy-only injections that take advantage of generation re-dispatch or other solutions. Reforms consequently are needed to ensure cost-effective solutions that more fairly allocate transmission costs.

The higher system-wide costs and inefficiencies associated with the current planning approaches are evident when compared to different planning methods that have been applied to the same needs. For example, comparing the results of PJM's 2021 offshore wind integration analysis with the results of individual PJM generation interconnection studies shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the transmission-related interconnection costs of offshore wind generation compared to a more proactive, regional study process. Under PJM's current queue-based generation interconnection study process, the total costs of necessary onshore PJM network upgrades identified within individual PJM feasibility and system impact studies related

[4] ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, prepared for American Council of Renewable Energy (ACORE), September 9, 2021. As the study notes, in SPP, 100% of the interconnection costs are assigned directly to generators in SPP. In MISO, generators are responsible for 90% of the cost for upgrades 345 kV and higher, with 10% allocated regionally

[5] PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021. See slide 24 for a discussion of the system-wide benefits associated with the network upgrades identified in this proactive study for interconnecting offshore wind generation.

to integrating 15.5 GW of offshore wind equals $6.4 billion.[6] This results in PJM onshore network upgrade costs that adds over $400/kW to the cost of the offshore generation (including offshore transmission), or roughly 13% of offshore generation capital costs.[7,8] By contrast, PJM's 2021 proactive region-wide study holistically evaluated onshore transmission investment needs to connect up to a cumulative 17 GW of offshore wind generation to its footprint (which reflects the offshore wind resource interconnection needs of multiple states' offshore wind plans).[9] This proactive regional study estimated only $3.2 billion in PJM onshore network upgrade costs would be needed for interconnecting 17 GW of offshore wind generation—less than half the costs identified through the individual interconnection request studies. This reduces average interconnection costs to $188/kW-wind, which is only 45% of the over $400/kW cost associated with the current reactive, incremental interconnection study approach. In addition, the regional PJM study found that these identified $3.2 billion in onshore network upgrades result in substantial additional regional benefits in the form of congestion relief, customer load LMP reduction, and reduced renewable generation curtailments that would not be realized using reactive interconnection methods.[10]

Thus, the July 2021 PJM offshore wind study shows that the reliability upgrades necessary to interconnect offshore wind generation needed to meet states' public policy goals also provide substantial benefits to a large portion of the PJM footprint beyond addressing interconnection-related reliability needs, thereby further reducing overall customer costs beyond the 50% of onshore transmission investment cost savings. Contrasting PJM's July 2021 study results to the results of its current interconnection study process demonstrates the inefficiency and excessive costs associated with the current reactive, interconnection- and reliability-driven planning process. The July 2021 PJM study is just one of many similar examples demonstrating the unreasonable expense and lost benefits associated with transmission planning processes that are not proactive and multi-value based.

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6 Based on costs from PJM's feasibility and system impact studies for individual generation interconnection requests as reported in Burke and Goggin, *Offshore Wind Transmission Whitepaper*, October 2020 at p. 40.

7 Reported global project data suggest a decline of the weighted average capital cost of offshore wind capacity to $3,000/kW by the mid-2020s. National Renewable Energy Laboratory, *Offshore Wind Market Report: 2021 Edition*, prepared for U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, DOE/GO-102021-5614, August 2021.

8 If offshore wind generators accept the allocation of these onshore upgrade costs, they will need to pass them on to their wholesale customers, which then pass them on to retail customers, increasing electricity rates.

9 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to ISAC, July 29, 2021. Across six scenarios studied by PJM, the identified onshore upgrade costs range from $627 million to $3.2 billion for OSW injections ranging from 6.4 GW to 17 GW.

10 *Id*., slide 24.

Similarly, the optimized transmission plans produced as part of PJM's 2014 renewable generation integration study to accommodate large additions of wind, offshore wind, and solar resources also find lower interconnection costs than the individual PJM's interconnection studies. That 2014 study identified transmission costs of $106/kW of renewable generation to integrate the then-projected 35 GW of additional wind and solar capacity needed to meet the PJM-wide RPS requirements of 14%. For a 20% PJM-wide RPS requirement, the cost ranged from $57–$74/kW of new renewable capacity, depending on the mix of wind, offshore wind, and solar capacity.[11] The fact that renewable generation-related interconnection costs are so much lower in the 20% RPS cases than the 14% RPS case confirms the large economies of scale that are captured from a more proactive regional evaluation of transmission needs, further bolstering the case for proactive regional planning for public policy needs rather than relying on incremental reactive upgrades through the generation interconnection process.

Comparing the proactive 2021 and 2014 PJM studies with the results from PJM's individual generation interconnection studies clearly highlight how the current generator interconnection process is unreasonable in two ways. First, the current interconnection process leads to much higher-cost solutions for achieving state clean energy policies, which unreasonably increases overall electricity costs. Second, given the identified system-wide benefits, allocating 100% of the identified interconnection project costs to the interconnecting generators or participant funding does not yield an outcome in which all beneficiaries pay costs that are roughly commensurate to the benefits they receive. Allocating the entire costs of the interconnection-related network upgrades to generators, ignores that PJM's own studies found large benefits associated with these upgrades accrue to other PJM market participants and customers.

Across all FERC-jurisdictional ISO/RTOs, the current approach of identifying and funding network upgrades through the generator interconnection process is becoming unworkable as costs and queue backlogs increase. Grid Strategies' January 2021 report on interconnection

[11] Transmission costs obtained from PJM scenarios were divided by the wind and solar capacity added in each RPS scenario (minus 5,122 MW of existing wind and 72 MW of existing solar. *PJM Renewable Integration Study, Task 3A Part C*, GE Energy Consulting prepared for PJM Interconnection, March 31, 2014, p 16. *Final Report: Task 2 Scenario Development and Analysis*, GE Energy Consulting prepared for PJM Interconnection, January 26, 2012.

Note that these projected costs of future upgrades, however, are still higher than the average of historical upgrade costs of generation interconnection request (in large part taking advantage of existing grid capabilities) as documented by the Lawrence Berkeley National Laboratory as reported in Will Gorman, Andrew Mills, Ryan Wiser, *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*, preprint version of a journal article published in *Energy Policy*. DOI: https://doi.org/10.1016/j.enpol.2019.110994, October 2019, p 12.

queues shows that recent network upgrade costs are 2 to 5 times higher now that the existing transmission capacity has been fully subscribed.[12] For example, the identified upgrade costs for recent entrants into the interconnection queue in western MISO now exceed $750/kW.[13] In contrast, the cost per kW for proactive regionally planned network solutions in these areas has been much lower. For example, the interconnection costs associated with MISO's Multi Value Projects (MVPs) was only approximately $400/kW in today's dollars even before netting out any system-wide benefits.[14] As quantified in the next section, the MVP projects and other comprehensive network solutions designed with multi-value planning approaches provide many other quantified benefits in addition to interconnecting generation, thereby reducing the net cost of generator interconnection.[15]

Since MISO approved its portfolio of MVPs a decade ago, MISO's 2014 MRITS study documented that even lower generation interconnection costs can be achieved if planned regionally rather than integrating renewable generation through the current interconnection process. This 2014 study found that MISO-wide transmission expansion of $2.567 billion would allow the interconnection of 17,245 MW of new wind capacity, at a cost of only $149/kW of wind.[16] The cost per kW may be lower because, unlike the MVP study, this study was not attempting to co-optimize regional economic and reliability benefits, which may yield lower transmission costs but higher net costs. However, comparing the $149/kW cost from the 2014 MRITS study to the $750/kW costs identified for the current interconnection queue in western MISO shows that proactively planned network additions are superior to incremental upgrades through the generation interconnection process. Given that MISO's 2014 Study yielded a plan that made extensive use of 345-kV transmission lines, it is not surprising that it could have achieved economies of scale and produced significant savings relative to the cost of incremental upgrades identified through the interconnection queue—documenting the high cost of the current planning process and the significant savings that could be realized through

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[12] J. Caspary, M. Goggin, R. Gramlich, J. Schneider, *Disconnected: The Need for New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 14, 2021, at pp 8–11

[13] For example, the average cost for wind projects in MISO's August 2017 Definitive Planning Phase 2, West was $756/kW.

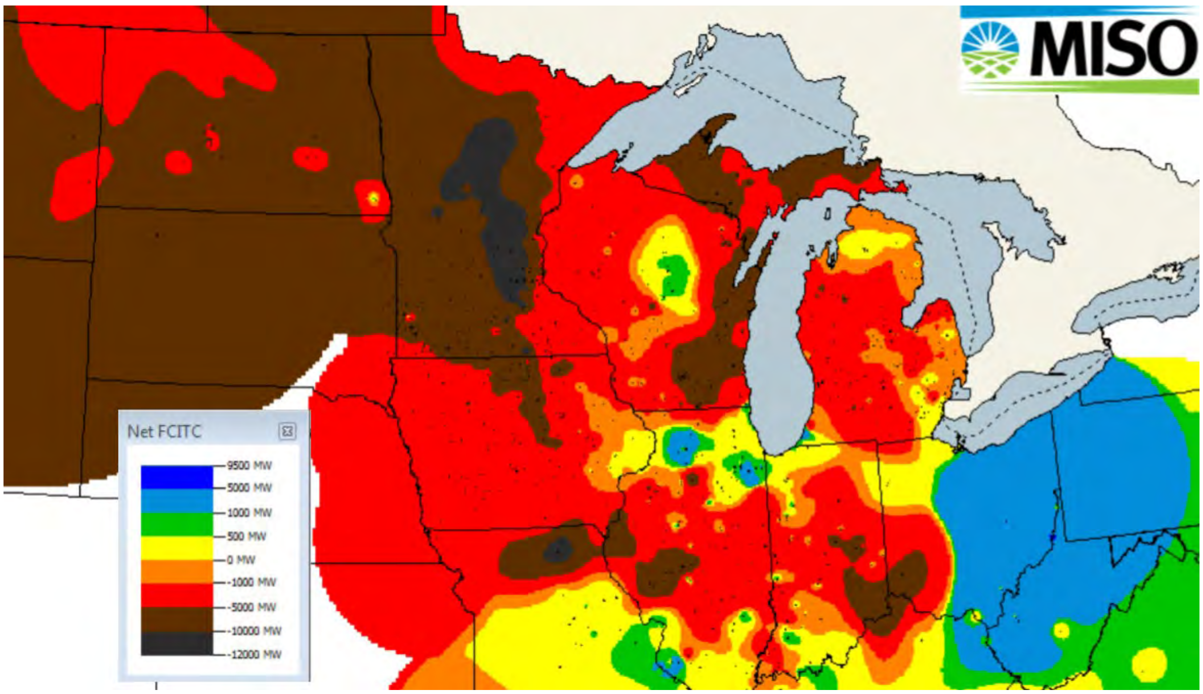
[14] The MVP lines cost $6.57 billion, per MISO, *Regionally Cost Allocated Project Reporting Analysis, MVP Project Status July 2021*, and were designed to interconnect 15,949 MW of wind, per MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017, which yields $412/kW of wind.

[15] MISO's quantification of MVP-related benefits estimated that the total benefits of the transmission portfolio exceeds its total cost by a factor of 2.2-3.4. *Id.* at p 4.

[16] GE Energy Consulting with MISO, *Minnesota Renewable Energy Integration and Transmission Study: Final Report*, October 31, 2014 at pp 4–21.

more proactive regional planning. Given MISO's analysis showing most of western MISO has a "transmission capacity deficit" of between 5,000 and 10,000 MW,[17] the brown areas in the map below, it is not surprising that the incremental upgrades produced through the current planning process are insufficient and unreasonably expensive solution to address regional transmission needs.

FIGURE 2. TRANSMISSION INTERCONNECTION CAPACITY DEFICIT IN MISO



Source: MISO, 2018.

Cost savings from regionally planned networks are confirmed by a 2009 analysis from Lawrence Berkeley National Laboratory (LBNL). The 2009 study reviewed 40 detailed transmission planning analyses for interconnecting wind generation and found the median cost of planned regional transmission was $300 per kW of wind (roughly $400/kW in today's dollars),[18] almost identical to the cost of the MISO MVP lines. That study also found strong evidence of cost reductions from comprehensive regional planning of transmission solutions that take into consideration a broad set of benefits (compared to relying on piecemeal upgrades planned

17 MISO, *August 2017 Definitive Planning Phase Model for Central, MI, ATC, and South regions. August 2016 model for West region*, July 11, 2018.

18 Andrew Mills, Ryan Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-1471E, February 2009; $300/kW corresponds to $383/kW today based on the increase in the consumer price index from 2009 to 2021.

solely for the interconnection of new wind resources). As the authors conclude from their review of 40 studies:

> we find that transmission designed to accommodate the full nameplate capacity of all new generation during peak periods on sparsely interconnected transmission lines appears to have a higher cost than transmission designed to reduce congestion costs caused by new wind generation based on an economic dispatch of an interconnected transmission network. This finding may have implications for future transmission planning efforts oriented toward accessing additional wind energy.[19]

The LBNL authors argue that the median transmission cost per kilowatt of wind across these studies likely overstates the true cost by not reflecting the system-wide benefits of interconnecting wind through comprehensive transmission planning. As they explain, their "methodology assigns the full cost of the transmission line to the wind plant without taking into account the other benefits of the transmission line," after noting that "in reality, however, studies frequently point to the additional reliability benefits and congestion relief that new transmission will provide. In these cases, our methodology overstates the transmission costs that are attributable specifically to wind."[20]

While this LBNL study was conducted 12 years ago, the fundamental economic and physical factors driving the economies of scale and broader benefits of comprehensive, regionally planned network upgrades are the same today.[21] Recent analysis, such as the savings identified in PJM's proactive offshore wind plan relative to PJM's interconnection queue results, as discussed above, also confirms the high cost of the current reactive planning process and the cost savings and larger benefits of proactively planned transmission compared to the cost of incremental additions designed to address specific needs like generator interconnection.

While it is surely true that in some cases an incremental single project designed to address a specific need may be more efficient than a larger-scale regional solution, the efficiency of the choice will be known if the planning process quantifies and considers all the benefits and costs of the alternatives. Such a benefits-and-cost-based planning process is important for developing

[19] *Id.,* at xii

[20] *Id.,* at 27

[21] For a more comprehensive discussion of these underlying factors, see pp 3–5 and 29–30 at American Wind Energy Association (AWEA), *Grid Vision: The Electric Highway to a 21st Century Economy*, May 2019.

cost-effective transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. Any least-regrets planning approach, however, needs to consider *both* (1) the possible regret that a project may not be cost effective in a particular future; *and* (2) the possible regret that customers may face excessive costs due to an insufficiently robust transmission grid in other futures.[22] A recent example of system planners failing to adequately consider the implications of insufficient expansion of interregional transfer capability to address extreme market conditions is the August 2020 blackouts in California. The final root cause analysis released by California policymakers concluded that "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint" and "more energy was available in the north than could be physically delivered."[23] CAISO had similarly concluded after the 2000−01 California power crisis, that the crisis and its extremely high costs could have been avoided if more interregional transmission capability had been available to the state.[24]

Even if the share of transmission relative to the total electricity cost increases above today's level, that is not an indication of inefficiency or consumer harm. To the contrary, well-planned transmission investments can have a significant impact on reducing overall costs of delivering reliable electricity. As generation costs continue to fall and transmission needs to provide resilience, reliability, and system efficiency rises, transmission costs may rise as a percentage of total electricity system costs, but system-wide total costs will be lower than they would be with less transmission investment.

Many recent studies that apply proactive, multi-value planning principles have shown the large benefits and overall cost reductions that a more robust transmission system can provide for the

[22] For a more detailed discussion on how transmission planners can use scenarios proactively to consider long-term uncertainties and the potentially high cost of insufficient infrastructure and associated risk mitigation benefit in transmission planning, see Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9−19 and Appendix B.

[23] California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC), *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, Final, January 13, 2021, p 48.

[24] CAISO 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 CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004, p ES-9.

nation's future power system. Some studies show the need for a doubling[25] or tripling[26] of the nation's existing transmission capacity over the next several decades. These studies evaluate the location and timing of output from load and generation and co-optimize across generation and transmission. They find that transmission investments typically enable significant savings in generation costs. Numerous additional studies, listed in Appendix A, show that for varying resource-mix scenarios, large expansion of transmission is needed to achieve cost-effective outcomes, particularly investment in transmission facilities that enable long distance large-volume transfers of energy across regions and across the country and continent. While the cost of these transmission investments would be significant, it only makes up a small portion of total electricity system investment needs (likely under ten percent of total cost).

One such study finds that well-planned transmission expansion results in additional transmission costs of about a half a cent per kWh on average (well under ten percent of total cost) but—in combination with a national policy goal for a zero carbon grid— would result in system-wide cost reductions of over 40% compared to relying on transmission-limited regional and state-level solutions.[27] Figure 3 below displays transmission costs, shown as the gray slice near the top of the bars (and the cost of wind, solar, and storage resources shown as the blue, orange, and green slices below), of decarbonizing the U.S. electricity grid. Another study finds transmission costs of about a quarter cent per kWh, or well under 5% of the total cost of electricity, even with a large-scale buildout of transmission.[28]

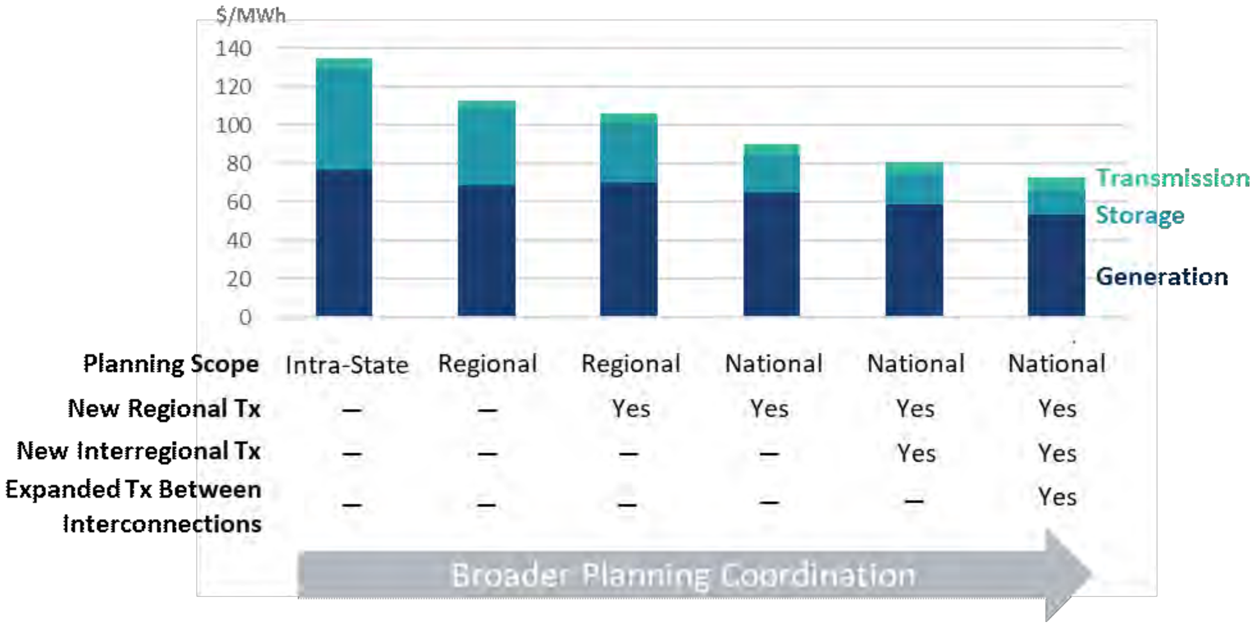
[25] P. R. Brown and A. Botterud, "*The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*," *Joule*, Vol. 5, No. 1, p115–134, January 20, 2021.

[26] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, interim report, Princeton University, Princeton, NJ, December 15, 2020.

[27] P. R. Brown and A. Botterud, *op. cit.*

[28] C.T.M. Clack (Vibrant Clean Energy LLC), M. Goggin (Grid Strategies LLC), *et al.*, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S*, Americans for a Clean Energy Grid, October 2020., at 9.

FIGURE 3. ELECTRICITY SYSTEM COSTS BY TYPE AND TRANSMISSION PLANNING SCENARIO



Source: Figure displays from data provided by MIT researchers Peter R. Brown and Audun Botterud based on their work modeling the decarbonization of the U.S. electricity system. Scenarios vary by the three planning parameters: (1) geographical scope, (2) whether new regional DC transmission is allowed, (3) whether new interregional DC transmission is allowed, and (4) whether new interconnectional transmission between East, WECC, and ERCOT is allowed.

It is clear that most of the current transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some examples of better transmission planning, using existing and readily available tools, exist. While these experiences with improved planning process account for only a small portion of nation-wide transmission investments, they provide models for planning processes that, if broadly adopted by the nation's transmission planners, would yield better transmission solutions and lower system-wide costs.

II. Current Planning Generally Fails to Incorporate All Benefits, Scenarios, Portfolios, and Future Needs

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The table below shows which Planning Authorities are actually implementing these more-efficient planning methods, based on their most recent approved plans. While some of these entities are exploring improvements and have been performing relevant studies, in most cases their approved plans do not reflect these methods.

Table 2 shows the planning authorities' lack of use of proactive, scenario-based, multi-value processes. NYISO is applying this type of comprehensive planning framework in its public policy transmission planning process, but does not do so for addressing generation interconnection or reliability needs. CAISO has utilized such comprehensive planning when applying its TEAM approach, which reflects a multi-value transmission benefit framework that can effectively utilize scenarios, but the scope of benefits the CAISO considers outside of this process is limited. Similarly, MISO's MVP transmission planning benefit-cost analysis was an encouraging example of a comprehensive planning effort. However, since the MVPs were approved a decade ago, MISO's planning process has focused primarily on generation-interconnection and other reliability needs, a few minor market-efficiency projects based on narrowly defined benefits, and no other projects that were planned using MISO's multi-value approach.[29] While PJM has a "multi-driver" option in its planning process, it has never been used. PJM continues to rely primarily on its generation interconnection and reliability planning processes, which we showed in prior sections is much more costly than a comprehensive and proactive approach to build transmission. PJM's planning process for "market efficiency" projects considers only a narrow set of traditional production cost (load LMP) metrics and capacity market impact—which has yielded few such projects. Lastly, ISO-NE, Florida, Southeast Regional, and South Carolina Regional rank very low among the regional planning authorities, having rarely (if ever), applied any of the available comprehensive practices in their planning effort.

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[29] Within MISO, American Transmission Company quantified a broad set of transmission benefits for range of different futures, but this process was used only for transmission siting cases before the Wisconsin Public Service Commission. MISO is also currently applying a proactive, scenario-based, multi-value planning framework in it RIIA effort, but has not yet approved any transmission projects based on it.

We offer the following criteria for the five efficient planning practices included in Table 2 below:

- **Proactively plan for future generation and load:** Incorporates a proactive perspective on reasonably anticipated load levels, load profiles, and generation mix over the lifespan of the transmission. Planning inputs extend beyond generic, baseline projections or considerations of such factors and actually include in the plans knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets, which are used to evaluate the need, impacts, and benefits of the transmission.
- **Apply a <u>multi-value</u> planning framework to all transmission projects**: Accounts for a full range of transmission needs rather than separately assessing reliability, economic, and public policy needs. Quantifies and assesses a broad range of benefits, rather than narrow analyses based on traditional production cost savings.
- **Use <u>scenario-based</u> planning to address uncertainties**: Evaluates a set of distinct scenarios representing plausible futures (beyond the status-quo needs) that address the range of long-term uncertainties and also consider high-stress grid conditions. Incorporates plausible ranges of fuel price trends, locations and size of future load and generation, economic and public policy-driven changes to future market rules or industry structure, and/or technological changes to assess transmission effectiveness in multiple futures and any possible modifications needed from scenario differences.
- **Capture portfolio-synergy and use <u>portfolio-based</u> cost recovery**: Considers comprehensive portfolios of synergistic transmission projects to address system needs. Assesses benefits more accurately by taking into account network interactions, as well as other resources such as storage and other technologies. Applies portfolio-based cost recovery rather than a project-by-project cost-recovery approach.
- **Perform <u>joint interregional</u> planning:** Uses joint modeling and analysis of adjacent regions that jointly evaluates transmission regional and interregional needs and analyzes benefits based on multi-value framework, rather than being focused solely on each regions' needs and solutions independently of interregional needs and synergies.

TABLE 2. PLANNING AUTHORITIES CURRENT USE OF EFFICIENT PRACTICES

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[30]	Joint Interregional Planning
ISO-NE[31]	✗	✗	✗	✓	✗
NYISO[32,33]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[34.35]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[36]	✗	✗	✗	✗	✗
SPP (ITP)[37,38]	✗	✓	✗	✓	✗
CAISO[39,40]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[41]	✗	✗	✗	✗	✗

30 Includes portfolio-based cost recovery for projects approved by ISO-NE, NYISO, SPP, and CAISO. SPP also performs portfolio-based planning through its Integrated Transmission Planning (ITP) process.

31 ISO-NE transmission planning has been based solely on generation interconnection and network reliability needs. Cost recovery of network transmission costs, however, is broadly based on the entire ISO-NE portfolio (*i.e.*, utilizing postage stamp cost recovery)

32 NYISO applies proactive, multi-value, scenario-based planning only for the purpose of its Public Policy Transmission Planning Process (PPTPP). All other New York planning efforts, including for generation interconnection, remain solely reliability focused and individual (incremental) needs. In the most recent (2019) public policy transmission plan, transmission lines were studied using a base case, as well as a Clean Energy Standard + Retirement Scenario. See New York ISO (NYISO), *AC Transmission Public Policy Transmission Plan*, April 8, 2019, at p 14.

33 In the most recent (2019) public policy transmission plan, transmission lines were studied using: (1) a base case, (2) a Clean Energy Standard + Retirement Scenario, (3) a Clean Energy Standard +Retirement case with CO_2 emissions priced at the social cost of carbon. In a separate extended analysis, the NYISO studied two scenarios: (1) a base case, and (2) a case in which the capacity zones are reconstituted due to pending changes to the resource mix and the construction of the AC Transmission projects. See NYISO, *id.,* at pp 14, 19, and 25.

34 PJM's transmission planning manual has documentation on how PJM can develop a multi-driver approach. See PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 49*, effective date: June 23, 2021, at p 32.

35 PJM and MISO Boards approved the first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV line – based on a competitive planning process. See PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, at p 2. The project has yet to be included in a MISO MTEP plan.

36 MISO's transmission planning manual has documentation on how to develop multi-value projects. See MISO, *Business Practices Manual: Transmission Planning*, Manual No. 020, BPM-020-r24, effective date, May 1, 2021,

To date, only a small portion of transmission spending is justified on economic criteria and full analysis of broader regional and interregional benefits and costs. Table 3 below shows what types of transmission are being planned based on recent spending as they report it (though in a number of cases the information was not readily available in time for publication of this report). As the table shows, the current planning processes do not consider the multiple values and wide-ranging benefits that well-planning transmission projects would be able to provide, which unreasonably increases system-wide costs.

at 160. MISO's transmission planning manual has documentation on constructing portfolios, and has approved and constructed MVP portfolios in the past. See MISO, *Ibid.*

Note that MISO has experience with pro-active, multi-value, scenario-based planning through its MVP and RIIA planning processes. However, no transmission projects have been approved through RIIA at this point and no MVPs were planned or approved by MISO in the last decade.

[37] SPP's multi-benefit Integrated Transmission Planning (ITP) process does not apply to generation interconnection. In SPP's screening of individual economic transmission projects, ITP projects are evaluated under only two "futures:" a reference case and an emerging technologies case. See SPP Engineering, *2020 Integrated Transmission Planning Assessment Report*, Version 1.0, October 27, 2020, at p 11.

[38] While SPP groups transmission into a "consolidated portfolio," all screened reliability projects are automatically included without further analysis. Economic projects are chosen based on the results of cost-benefit analyses; however, they are studied individually and the analysis does not account for the impacts of other economic lines in the portfolio. See SPP Engineering, *Id.*, p 81.

[39] CAISO's multi-value TEAM planning process is not utilized to address generation interconnection and network reliability needs. "CAISO's policy-driven transmission studies were based on a 60 percent RPS policy base portfolio provided by the CPUC, together with sensitivity portfolios based on higher approximately 71 percent – RPS levels." California ISO (CAISO), *2020–2021 Transmission Plan*, approved March 24, 2021, p 1.

[40] CAISO selects for approval of transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios: "1) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (2) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity." CAISO, *Id.*, p 27.

[41] NothernGrid's 2020-2021 draft (and first ever) transmission plan has not yet been approved, but does offer a portfolio-based approach and includes a handful of proposed interregional lines. See Northern Grid, *Draft Regional Transmission Plan for the 2020–2021 NorthernGrid Planning Cycle*, n.d., pp 9 and 13.

TABLE 3. PLANNING AUTHORITIES'S RECENTLY APPROVED TRANSMISSION SPENDING FOR DIFFERENT TYPES OF PROJECTS ($ MILLION)

	Local Reliability	Regional Reliability	Economic	Generator Interconnection	Multi-Value Projects
ISO-NE	n/a	$437[42]	$0[43]	n/a	$0
NYISO[44]	n/a	n/a	n/a	n/a	n/a
PJM	$4,106[45]	$388.31[46]	$24.69[47]	$101[48]	$0
Florida	n/a	$0[49]	$0[50]	n/a	$0
Southeastern Regional	n/a	n/a	n/a	n/a	n/a
S Carolina Regional	n/a	n/a	n/a	n/a	n/a
MISO	$2,800[51]	$755[52]	$0[53]	$606[54]	$0
SPP	n/a	$213.5[55]	$318.8[56]	n/a	$0
CAISO	n/a	$3.6[57]	$0[58]	n/a	$0
WestConnect	n/a	n/a	n/a	n/a	n/a
NorthernGrid	n/a	n/a	n/a	n/a	n/a

42 See the list of transmission included under the most recent regional system plan (2019). The cost figure has been calculated for transmission defined as "planned." See ISO-New England, October 2019 ISO-New England Project Listing Update (Draft)–ISO-NE Public, Excel spreadsheet, October 2019. It is possible that some local reliability projects are included under this category, and likely that ISO-NE does not track local reliability projects in general.

43 "To date, the ISO has not identified the need for separate market-efficiency transmission upgrades (METUs), primarily designed to reduce the total net production cost to supply the system load." See ISO New England, *2019 Regional System Plan*, October 31, 2019 at 7.

44 NYISO does not report approved transmission investment cost figures.

45 PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, p 259.

46 *Id*., p 259. Of the $413 million in baseline projects approved under the 2020 PJM Regional Transmission Expansion Plan, one interregional market efficiency project at a total estimated cost of $24.69 million was approved. See *Id.*, p 75.

47 *Id., p* 75.

48 *Id.*, p 2.

49 "The Regional Projects Subcommittee (RPS) has completed its proactive planning analysis per the Biennial Transmission Planning Process (BTPP). In summary, no potential [Cost Effective or Efficient Regional Transmission Solutions] CEERTS Projects have been identified." See Florida Reliability Coordinating Council, Inc. (FRCC), FRCC Proactive Planning Results and CEERTS Proposal Solicitation Announcement, April 21, 2021.

50 *Ibid.*

51 MISO, *MTEP 20*, n.d., full report, p 15.

52 *Ibid.*

53 *Ibid.* No market efficiency projects were approved.

PJM's recent offshore wind generation study (discussed earlier in the report) shows that this absence of a multi-value framework in the generation interconnection process means that costs are higher than they would be under a proactive planning framework and, in the case of generation interconnections, they are unfairly placed on generators when large benefits accrue to the system as a whole. Fair treatment would align cost allocation for generation-interconnection-related network upgrades with benefits. If under such a multi-value framework there are generator interconnection-related network upgrades that do not show material benefits for load, generators would still be responsible for these costs.[59] However, many generation-interconnection-related network upgrades do provide economic and reliability benefits to load. A multi-value framework would correctly allocate a commensurate share of project costs to load.

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[54] *Ibid.*

[55] SPP offers the project cost figures for approved reliability projects. See SPP Engineering, *op. cit.*, pp 4–5. It is possible that some local reliability projects are included under this category, and likely that SPP does not track local reliability projects in general.

[56] SPP offers the project costs of approved economic projects. See SPP Engineering, *op. cit.*, pp 4-5.

[57] CAISO, *op. cit.*, p 440 –higher end of cost estimates chosen for each. It is possible that some local reliability projects are included under this category, and likely that CAISO does not track local reliability projects in general.

[58] *Ibid*.

[59] GIR are responsible for network upgrades needed to accommodate the full output of the generator on a non-firm, energy-only basis (N-0 conditions with optimal re-dispatch).

III. Market and Regulatory Failures Cause Under-Investment in Regional and Interregional Transmission

The lack of planning for and investment in the type of cost-effective, beneficial transmission that is needed to achieve reasonable electricity costs is caused by structural and regulatory problems in the electric industry. Below we comment on several of these problems.

1. Small utility planning areas encourage local transmission planning while discouraging regional transmission planning

There are 329 transmission owners (TOs) in the country, each of which evolved out of the early industry structure of local utilities serving local load with local generation resources.[60] Nearly all of these utilities were vertically integrated for most of their history and many remain so. Under this model, transmission was only built to serve the load and generation of the owner.[61] It was not until the late 1990s that regional operation and planning was introduced with the FERC Order 888 and the advent of RTOs and ISOs, and mandatory Planning Authorities were not established until FERC Order 1000 was issued in 2011.

Despite the formation of ISOs, RTOs, and regional Planning Authorities, much decision-making power over transmission planning and investments remains with the individual transmission owners. Planning authority over "local transmission" (which constitutes about half of the nation's transmission grid and is specifically exempt from regional planning requirements) has been retained by the individual transmission owners, which created barriers to coordinated planning over a larger regional footprint. Additionally, the regional planning efforts in the RTOs are collaborative processes that require broad consensus, as RTO membership is voluntary and individual members who do not support regional or interregional transmission investments

60 See NERC, Compliance Registry Matrix, tab "NCR Summary," under heading "TO." Accessed 10/2/2021

61 Vertically integrated utilities are generally monopoly entities that get full cost recovery through regulated, commission-approved rates.

have the option to leave the RTO. Regional planning outside of RTO areas is minimal to nonexistent.

2. Differing TO incentives between local transmission and regional plans leads to inefficient levels of each

TOs are allowed under current federal regulations to plan and install upgrades on their local systems without regional planning oversight; this also allows them to grow their transmission rate base on which they earn commission-approved rates of return, including incentive returns. While local transmission investment is necessary to replace aging infrastructure, regionally planned investments that address local needs may provide larger system-wide benefits. Some of these regionally planned projects may be bid out competitively, in which case incumbent TOs have to compete with independent third parties and are much less likely to end up owning the asset. Even where the incumbent TO wins a regional transmission project bid, the investment cost may be capped and the rate of return may have been reduced through the competitive bidding process. No such competitive pressure exists for local transmission facilities and many types of regional transmission, including any transmission that is not subject to regional cost sharing or that is located in states that (often at the urging of incumbent transmission owners) have prevented competitive bidding through their right of first refusal (ROFR). This creates a bias against larger regional solutions even if they are more innovative and cost-effective, but would involve cost sharing and competitive processes.

Current FERC regulations cause this regulatory failure. If there were not such a different ability to own and profit from regional vs local transmission, this bias would not exist.

3. Economies of scale cause inefficiently small investments unless mitigated through regulations

A very common “market failure” that is standard across regulated industries is the declining average cost at larger quantities of production, known as economies of scale. This physical and economic feature causes what is known as a “natural monopoly” in which the most efficient structure is to build and own large assets by a single company, with an economic regulator to determine the efficient level of investment and with cost recovery spread across all consumers. Economies of scale still exist in transmission such that the costs of high-capacity lines are much lower per unit of delivered energy than the cost of lower capacity lines. These economies mean that large regional lines would need to be planned through a regulatory process to achieve sufficient scale, rather than left to market forces alone or to processes where only small incremental upgrades are made by the local transmission owners. This regional planning process needs to function as intended to actually determine the most cost-effective scale of transmission investment, based on future needs over the life of the assets. This would require that the regional planning evaluate local transmission solutions and reject them if more cost effective regional solutions are available. The current planning processes, however, mostly accept the local transmission solutions (implemented by transmission owners outside the regional planning processes) and only add regional projects to address specific remaining needs, which are mostly reliability-only needs.

The current planning processes thus unreasonably lead to inefficiently small investments and higher system-wide costs by forgoing the economies of scale that regional projects would offer.

4. Economies of scope cause inefficient plans unless mitigated through regulations

When the production of one product reduces the cost of other products, there are "economies of scope." An apple orchard might sell both apple sauce and apples, for example, using the same inputs to production. In the case of transmission, there are a variety of uses and benefits that all come from the existence of high capacity transmission facilities. For example, transmission used to cover for the loss of generation due to extreme weather by sending power in the direction of the shortfall is also used to connect low-cost generation and reduce congestion costs, and vice versa. When transmission planning is based only on identifying least-cost transmission solutions for single drivers—such as generation interconnection and other reliability needs, economic and market efficiency needs, or public policy needs—these economies of scope provided by larger regional projects capable of simultaneously addressing multiple needs at both the regional and local transmission system levels are not captured, unreasonably raising system-wide electricity costs and rates.

Economies of scope can be captured only if multi-value/multi-driver planning is performed. Public policy that achieves cost-effective outcomes needs to require regional multi-value/multi-driver planning, particularly if the planning outcomes are not in the economic interest of TOs.

5. Externalities cause inefficient plans unless mitigated through regulations

When parties beyond the buyer and seller of a product are impacted, positively or negatively, from the transaction, that third-party impact is an "externality" of the transaction. Achieving efficient outcomes requires that the value of these externalities be taken into account. In transmission, electricity flows across the entire alternating-current network according to the laws of physics, which send power along the path of least electrical resistance (a function of the voltage levels, design, and length of transmission lines). For this reason, individual transactions and uses on the system impact all other transactions and uses. An expansion of transmission capacity to accommodate one transaction (or purpose) will thus increase or decrease capacity for other uses. The interactions of power flows across grid facilities also means that synergistic portfolios of transmission facilities can provide system-wide value that exceeds the value of the individual facilities.

Given the prevalence of network externalities, it is generally inefficient to plan transmission one line at a time and for one local (or even regional) system at a time. Efficiency requires planning a full portfolio of network assets together, across a wide geographic area. A transmission planning process that results in little regional (or interregional) capacity and only plans local or incremental regional upgrades at a time—and in response to a specific generator interconnection request or a single other need—will result in inefficient solutions that are unreasonably expensive from a system-wide perspective.

6. Horizontal market power

Another market failure in transmission relates to the exercise of horizontal market power, which is the power to withhold service to raise prices. Avoiding the exercise of such market power is a standard feature of the regulation of natural monopolies. Withholding is prevented by regulators requiring that all capacity is provided to any customer willing to pay the cost. For example, FERC's open access transmission regulations require that all "Available Transmission Capability" be provided to market participants. And the ability of entities with market power to raise prices is prevented by regulators establishing rates that are "just and reasonable," usually as a function of the total cost of providing the service. Thus, horizontal market power is largely addressed in the electric transmission industry through FERC regulations—but not completely.

Horizontal market power can still exist in electric transmission systems. When efficient transmission investments are not made by a TO with the power to determine which type of investments to make, then system-wide costs are increased. In the U.S. electric transmission industry, when more efficient regional and interregional transmission investments are not made due to barriers and biases in the planning processes such that less-efficient local and small regional upgrades are made instead, it is a form of unmitigated horizontal market power. A regulatory requirement to plan the efficient amount and scale of transmission, and charge only rates based on the cost of the efficient investment, is necessary to mitigate this market power.

7. Vertical market power

The ability to withhold service in one stage of production to increase profit in another stage of production is called vertical market power. Regulations that prevent the exercise of vertical market power are common in the electricity industry. If there were no such regulations related to the electric transmission system, TOs could withhold transmission and interconnection service from other market participants in order to increase the value of and the profits from their own generation. FERC open access rules introduced in 1996 through Order No. 888 and interconnection rules in Order No. 2003 are intended to mitigate the exercise of this type of vertical market power. But, again, these regulations are imperfect.

In the current electricity system, when interconnection and transmission planning processes are inefficient or even dysfunctional, then valuable transmission service is withheld, disadvantaging third party consumers and sellers, potentially advantaging a TO's owned generation, and unreasonably increasing system-wide costs. Most TOs in the country still own generation and thus have incentives to underinvest in regional transmission and prefer less efficient local transmission solutions. Transmission planning requirements thus need to ensure that remaining opportunities to exercise vertical market power are removed.

Overall, these barriers and incentives serve to bias transmission planning against more innovative and cost-effective regional and interregional solutions to address the identified (multiple) transmission needs, the result of which is an inefficient outcome with higher system-wide costs.

IV. Adoption of Pro-Active, Scenario-Based, Multi-Value, and Portfolio-Based Transmission Planning Practices Is Necessary to Avoid Unreasonably High Electricity Costs

As discussed in prior sections, structural and regulatory problems in the electric industry have resulted in a lack of comprehensive planning for and investment in the type of transmission that offers the most cost-effective system-wide results. Fortunately, significant experience exists with proactive, scenario-based transmission planning that quantifies the wide range of economic, reliability, and public policy ("multi-value") benefits of transmission investments, whether it be individual projects or synergistic portfolios. This experience shows that proactive, scenario-based, multi-value planning yields infrastructure that lowers the overall, system-wide costs of supplying and delivering electricity.

In the cases when such comprehensive transmission planning processes have been used, the outcomes have yielded lower-cost results (even though without explicit but-for analysis, this difference in costs cannot always be quantified precisely). One example is Texas' proactive Competitive Renewable Energy Zone (CREZ) project. Recognizing the economic potential of connecting western Texas' sparsely populated wind-rich areas to load, the Texas legislature passed a bill in 2005 that ordered that the Public Utility Commission of Texas to develop a transmission plan to deliver renewable power to customers. The $7 billion effort was designed to interconnect around 11.5 GW of new wind generation capacity. After its 2013 completion, wind curtailment fell from a previous high of 17% to 0.5%.[62] Unforeseen at the time it was planned, interest in developing solar capacity in West Texas, as well as load growth from shale oil and gas production in the region, has further elevated the benefits of the projects.

Similarly, MISO's multi-value projects serve as another planning success story. Over 10 years ago, MISO began proactively planning in anticipation of the development of wind generation capacity to meet the state-by-state Renewable Portfolio Standards in its territory. Diverging from the standard planning processes, the MVP planning process identified a comprehensive

[62] ERCOT, *The Texas Competitive Renewable Energy Zone Process*, September 2017.

set of upgrades across its footprint that would provide a mix of reliability, policy, and economic benefits to the system under a range of scenarios. The resulting transmission infrastructure offers a broad range of regional benefits and has allowed over 11 GW of wind to be interconnected and delivered, with total benefits that are estimated to exceed project costs by $7 to $39 billion over the next 20–40 years.[63] In other words, without the proactively and regionally planned MVP portfolio, MISO's system-wide costs would be $7–$39 billion higher.

The California Independent System Operator (CAISO) also has extensive experience with evaluating a broad range of benefits for transmission projects as documented in CAISO's case study of the Palo Verde to Devers No. 2 project, which is discussed in more detail below. Nevertheless, this multi-value transmission planning experience has not been broadly applied in the CAISO's recent planning efforts. Rather, candidates for economically justified transmission projects have been evaluated based mostly on their impacts on wholesale market prices or their ability to reduce congestion charges based on either historically observed congestion charges or the congestion cost observed in base-case production cost simulations.

The Southwest Power Pool (SPP) has similarly found that the transmission upgrades it installed between 2012 and 2014 through its integrated planning process (ITP) yield a broad range of benefits that exceed $4.6 billion of project costs by nearly $12 billion over the next 40 years.[64] The $16.6 billion in total benefits is higher than SPP's multi-value transmission planning models had initially estimated, and 3.5 times greater than the cost of the transmission upgrades. SPP is the only RTO which regularly quantifies a broad range of transmission-related benefits in its planning and cost allocation process. In contrast, for example, while PJM also has experience quantifying a wide range of benefits for transmission projects,[65] it has not been utilizing any of this experience in its transmission planning process.

NYISO has recently added a multi-value planning framework through its Public Policy Transmission Planning Process (PPTPP), which has yielded a number of transmission projects with benefits in excess of project costs, thereby reducing system-wide costs.[66] However, NYISO is not applying this multi-value planning framework to its generation interconnection and reliability-driven planning efforts.

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63 MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017

64 Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016.

65 PJM Interconnection, *The Benefits of the PJM Transmission System*, April 16, 2019.

66 NYISO, AC Transmission Public Policy Transmission Plan. April 8, 2019. Potomac Economic, *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects*, February 2019.

Proactive, multi-value, scenario-based planning approaches have also been successfully utilized in other countries. For example, the Australian Electricity Market Operator (AEMO) has used scenario-based planning for a number of years after an independent review found that Australian transmission planning processes needed to be improved.[67] In the latest "Integrated System Plan" (ISP), the AEMO drew upon an extensive stakeholder engagement and internal and external industry and power system expertise to develop a blueprint that maximises consumer benefits through a transition period of great complexity and uncertainty.[68] The ISP serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision makers and consumers.[69] As the AEMO explains, the ISP is based on the following principles:

- *Whole-of-system plan:* A plan to maximize net market benefits and deliver low cost, secure, and reliable energy through a complex and comprehensive range of plausible energy futures. It identifies the optimal development path for the National Electricity Market (NEM), consisting of ISP projects and development opportunities, as well as necessary regulatory and market reforms.
- *Consultation and scenario modelling:* AEMO developed the ISP using cost-benefit analysis, least-regret scenario modelling, and detailed engineering analysis, covering five scenarios, four discrete market event sensitivities, and two additional sensitivities with materially different inputs. The scenarios, sensitivities, and assumptions have been developed in close consultation with a broad range of energy stakeholders.
- *Least-regret energy system:* This analysis identified the least system cost investments needed for Australia's future energy system. These are distributed energy resources (DER), variable renewable energy (VRE), supporting dispatchable resources, and power system services. Significant market and regulatory reforms will be needed to bring the right resources into the system in a timely fashion.

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67 A. Finkel, K. Moses, C. Munro, T. Effeney, and M. O'Kane, "*Independent Review into the Future Security of the National Electricity Market—Blueprint for the Future*," energy.gov.au, June 1, 2017, find that "Incremental planning and investment decision making based on the next marginal investment required is unlikely to produce the best outcomes for consumers or for the system as a whole over the long-term or support a smooth transition. Proactively planning key elements of the network now in order to create the flexibility to respond to changing technologies and preferences has the potential to reduce the cost of the system over the long-term" (at p 123)

68 AEMO, *2020 Integrated System Plan*, July 30, 2020.

69 Australian Energy Market Operator (AEMO), *Our 20-year plan for the National Electricity Market*, 2020. See also Transgrid, *Energy Vision 2050: A Clean Energy Future for Australia*, October 2020, as an example of a long-term, scenario-based energy industry and transmission grid analysis by one of the Australian transmission owners and developers, which explores alternative futures and their transmission implications through 2050.

- *Projects to augment the transmission grid:* The analysis identified targeted augmentations of the NEM transmission grid, and considered sets of investments that together with the non-grid developments could be considered candidate development paths for the ISP.
- *Optimal development path:* A path needed for Australia's energy system, with decision signposts to deliver the affordability, security, reliability and emissions outcome for consumers throughout the energy transition.
- *Benefits:* When implemented, these investments will create a modern and efficient energy system that is expected to deliver $11 billion in net market benefits and meets the system's reliability and security needs through its transition, while also satisfying existing competition, affordability, and emissions policies.

As we have shown with the examples in the prior section of this report, the current incremental and reactive transmission planning processes result in higher system-wide electricity costs than more proactive planning processes that simultaneously consider multiple needs and quantify a broad range of transmission benefits. The industry experience with such more effective planning and cost-allocation processes, where utilized, points to several core principles for transmission planning that can avoid these higher-cost traditional planning solutions.[70] The already-available experience with improved planning processes points to the following five core principles for efficient transmission planning:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

[70] While this report focuses on the need to improve transmission planning processes, we recognize that addressing cost allocation challenges will also be an important element to the development of just and reasonable transmission solutions. For recommendations on improving cost allocation frameworks, see slides 25–30 of Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021. See also P.L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

The remaining section provides a more detailed examination of how these core planning principles work in practice.

1. Proactively Plan for Future Generation and Load

Most of today's transmission planning processes ignore the location, types, and quantities of the future generation mix needed to meet federal, state, utility, and customer clean energy goals, and thus do not consider how system needs will change as the grid continues to evolve. Looking further into the future to include knowable information about already enacted public policy mandates, publicly stated utility goals, and consumer preferences can identify more cost-effective grid solutions. From a system-wide cost perspective, the lack of proactive planning can lead to numerous piece-meal transmission upgrades that fail to holistically consider what is most cost-effective for the system over the 40–50 year life of the investments. Incorporating proactive forward-looking planning, identifies more efficient, integrated network solutions that cost significantly less than the sum of the often piecemeal upgrades identified through current planning processes.

As noted above, the recent PJM offshore wind integration study shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the onshore transmission costs of integrating offshore wind generation compared to a proactive planning process.

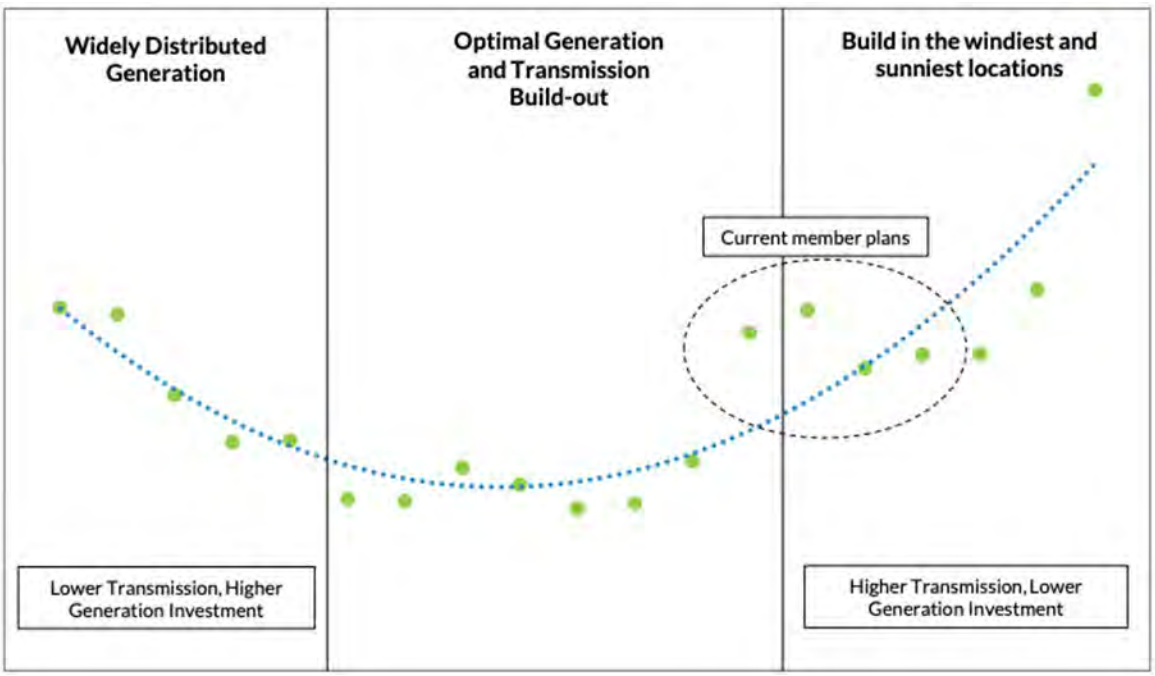
The MISO MVPs present another example of proactive forward-looking planning that resulted in transmission solutions that reduce system wide costs. The MVPs were the result of MISO's proactive planning effort prior to 2010, the Regional Generation Outlet Study (RGOS).[71] RGOS performed proactive planning and identified so-called "RGOS start projects." These projects were estimated to be beneficial in all scenarios evaluated by the study. These "no-regrets" RGOS start projects turned into the MVP portfolio that has allowed over 11 GW of wind to be integrated and delivered with system-wide cost savings (economic net-benefits) of $12–$53

71 Midwest ISO (MISO), *RGOS: RGOS: Regional Generation Outlet Study*, November 19, 2010.

billion over the next 20–40 years.[72] MISO has found through its updated studies that the net benefits of the MVP portfolio exceed MISO's initial estimates.

Proactive planning also identifies transmission upgrades that guide the market towards the optimal mix of local and remote generation that can be delivered through the transmission grid. Local renewable generation can serve customers with less regional transmission but is often more expensive. Remote generation often has lower generation cost but requires more regional transmission. The trade-off can be evaluated through scenario-based proactive studies that consider generation in different locations and their transmission cost. The MISO "smile curve" illustrates this trade-off (Figure 4).

FIGURE 4. TOTAL MISO PROJECT GENERATION AND TRANSMISSION COSTS



Source: MISO Planning Advisory Committee, *Long Range Transmission Planning - Preparing for the Evolving Future Grid*, August 12, 2020, pg. 7.

Similarly, NYISO analyses of transmission projects evaluated under its public policy transmission planning processes (PPTPP) show significant benefits from placing up-sized public policy projects on the rights-of-way of aging existing transmission facilities, thereby avoiding the cost of the otherwise needed replacement of these existing facilities.[73] In fact, the avoided costs of

72 MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017.

73 Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

aging facility replacement was one of the largest benefits identified for some of the public policy projected studied in in New York.

2. Account for the Full Range of Transmission Project Benefits, and use Multi-Value Planning to Comprehensively Identify Investments that address all Categories of Needs and Benefits

To identify solutions that result in lower overall costs to customers, planning needs to consider the multiple values (system-wide cost reductions) offered by transmission investments, irrespective of whether the primary driver of transmission infrastructure is based on reliability, public policy, or economic needs. For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective. Multi-value transmission planning identifies these lower-total-cost solutions, by quantifying and considering a larger portion of total transmission-related benefits. Multi-value transmission planning can also inform policymakers about the system-wide costs of not investing in transmission to provide a more comprehensive picture of overall costs and benefits beyond transmission project costs.

Table 4 summarizes the benefits quantified and considered in four RTOs' multi-value transmission planning efforts. In addition to this RTO experience, many industry and academic studies have discussed the cost savings that transmission investments can provide and how to quantify them.[74] Most current transmission planning processes, however, do not consider these benefits. And even the few transmission projects approved under RTOs' "economic" (or "market efficiency") planning processes have been evaluated solely based on a very narrow set of benefits, such as production cost savings simulated under highly normalized system conditions. As the multi-value planning examples of RTOs and industry studies show, however, there already is much experience in quantifying a larger set of transmission benefits using existing evaluation tools.

[74] For example, see: Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021.

Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.

Chang, Pfeifenberger, Hagerty, *The Benefits of electric Transmission Identifying and Analyzing the Value of Investments*, presentation prepared for WIRES, July 31, 2013.

TABLE 4. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified 1. **production cost savings** value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	**Quantified** 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	**Quantified** 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	**Quantified** 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
Not Quantified 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	**Not Quantified** 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO2 emissions 11. decreased wind volatility 12. increased local investment and job creation	**Not Quantified** 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	**Not Quantified** 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

Sources: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity; Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

Unfortunately, most existing planning processes do not take advantage of the available experience or consider the multiple values proposed transmission investment can provide beyond addressing specific drivers and needs. If a project is driven by reliability needs, the broader economic and public policy benefits provided by the project are usually not quantified and considered. If a project is categorized as an economic or public policy project, but simultaneously provides reliability benefits without addressing a specific reliability violation, that reliability benefit usually is not considered either. This particular "compartmentalized" or "siloed" planning approach leads to an understatement of transmission-related system benefits and a significant under-appreciation of the costs and risks imposed on customers by an insufficiently robust and flexible transmission infrastructure.

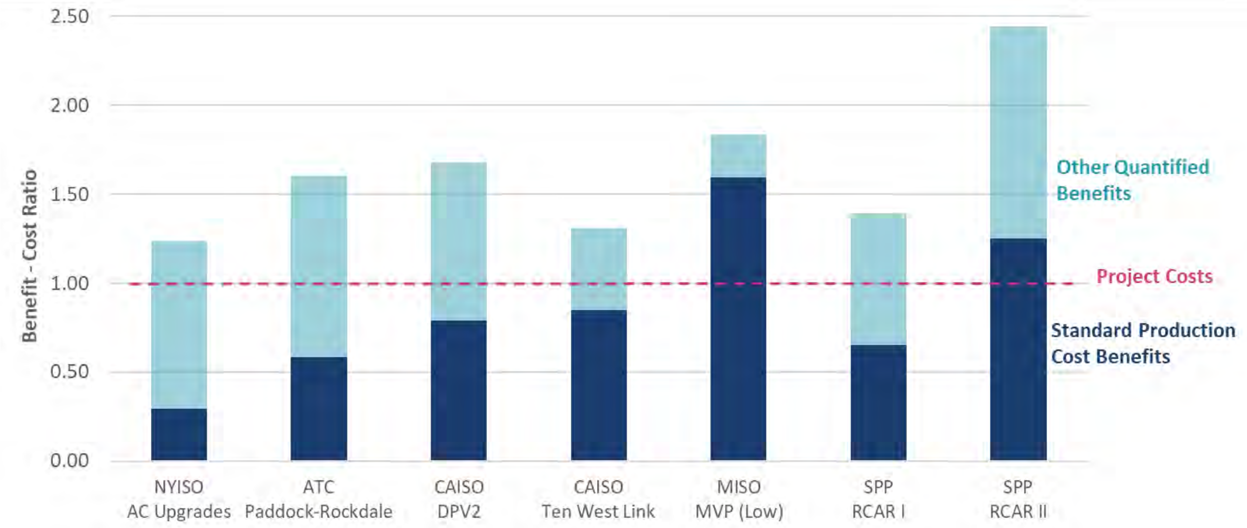
While not all proposed transmission investments provide benefits that exceed project costs, overlooking benefits because traditional tools and processes do not automatically capture these benefits leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure. Many beneficial projects that have been built would not have passed cost-benefit ratios when only considering limited benefits, such as the traditionally quantified production cost benefits as shown in Figure 5 below. This leads to planning outcomes that impose unreasonable costs on customers.

Even though some of transmission-related benefits have been classified “unquantifiable” or “difficult to quantify,” such as increased liquidity, the available industry experience shows that this is not the case. Many of these (frequently not quantified) transmission-related benefits can be readily estimated using existing planning and market simulation tools as the RTO examples in Table 4 and industry reports clearly show.

Quantifying a broader range of transmission benefits for individual projects or a portfolio of synergistic transmission upgrades will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejecting beneficial investments that would reduce system-wide costs. Not quantifying these transmission-related benefits where they likely exist, results in unreasonably imposing additional costs on customers.

An effective multi-value planning process would: (1) consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (*e.g.*, as shown in Table 5); (2) identify the set of benefits that plausibly exist and may be significant for that particular project or portfolio; and (3) then focus on quantifying those benefits. This will yield a clear list of all benefits considered and quantified (along with those considered only qualitatively), akin to the list of quantified and not quantified benefits shown in industry examples of effective planning processes as summarized in Table 4 above.

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



Sources: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015. ATC uses expected benefits under “high environmental scenario.” American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007. CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005. Testimony of Yi Zhang on Behalf of the California Independent System Operator, In the Matter of the Application of DCR Transmission, LLC for a Certificate of Public Convenience and Necessity for the Ten West Link Project, submitted to California Public Utilities Commission, Application 16-10-012, December 20, 2019. MISO, MTEP19 MVP Limited Review Report, 2019. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR I), October 8, 2013. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR II), July 11, 2016.

We continue this section with a review of the types of transmission-related benefits and how they can and have been quantified. We then describe efforts to integrate them into multi-benefit planning.

a. Types of Transmission Benefits

Most economic analyses used in transmission planning rely primarily on traditional applications of production cost simulations to determine whether the “adjusted production cost savings” (typically simulated only for highly normalized system conditions) offered by a transmission project exceed the project’s costs. These production cost savings, adjusted for wholesale purchases and sales (or imports and exports), are mostly composed of fuel cost savings. The many RTO planning processes that are focused on traditional production cost savings do not examine or quantify the expanded set of well-known and tested transmission-related benefits, including (but not limited to): other production cost savings (*e.g.*, lower line losses and operating reserves), greater reliability and resilience, greater resource adequacy through reduced planning reserves and higher capacity value, and market benefits.[75] Compiled from the available RTO and industry experience, a full set of transmission-related benefits is listed in Table 5 and discussed further below.

TABLE 5. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Benefits unrelated to electricity costs, such as jobs supported jobs supported, economic growth, and public health are shown in Table 6.[76]

[75] Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for The WIRES Group. July 2013.

[76] We are not including these types of benefits, but rather limit the discussion to benefits that affect system-wide electricity costs as measure of whether rates paid by consumers are just and reasonable, which we understand is the main focus of FERC and the Federal Power Act.

TABLE 6. TRANSMISSION BENEFITS BEYOND ELECTRICITY SYSTEM IMPACTS

Benefit Category	Transmission Benefit
9. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
10. Increased Health Benefits	Lower fossil-fuel burn can result in better air quality

1. Traditional Production Cost Savings

The most commonly used metric for measuring the economic benefits of transmission investments is the reduction 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.

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 individual regions or utility service areas. This is because the cost of serving these regions and areas will depend not only 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 Cost (APC).

APC for an individual utility is 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.[77] The traditional method for estimating the changes

[77] 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

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."

2. Additional Production Cost 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 quite limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. As an example, failure to consider transmission's value of diversifying uncertain renewable generation through the transmission system can significantly under-estimate benefits.[78]

This is problematic, as 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;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Only weather-normalized peak loads and monthly energy (*i.e.*, no typical heat waves, typical cold snaps, or more extreme weather conditions);
- Perfect foresight of all real-time market conditions (*i.e.*, no day-ahead and intra-day forecasting uncertainty of load and renewable generation);
- Incomplete cycling costs of conventional generation;
- Over-simplified modeling of ancillary service-related costs (*e.g.*, assuming all operating reserves are deliverable);

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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).

[78] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

- Incomplete simulation of reliability must-run conditions; and
- Unrealistically optimal system dispatch in non-RTO and "Day-1" markets.

Appendix B provides additional discussion regarding how to quantify the additional production cost savings (items 2.i through 2.x in Table 5 above) that are traditionally missed due to these simplifications.

3. Reliability and Resource Adequacy Benefits

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, additional transmission investments made to improve market efficiency and meet public policy goals also 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.

i. Benefits from Avoided or Deferred Reliability Projects and Aging Infrastructure Replacement

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 or replace aging facilities may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the incremental cost of the planned economic or public-policy projects. These benefits can be estimated by comparing the revenue requirements of reliability-based transmission upgrades without the proposed projects (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed projects 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.[79] 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.[80] This method has also been used by MISO, which 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.[81] Similarly, NYISO has found that public policy projects that utilize the right of way of aging existing transmission facilities, often offer the significant benefit of avoiding having to replace the aging facility in the future.[82]

ii. Reduced Loss of Load Probability

Transmission provides tremendous flexibility to ensure reliable service through many situations, both predictable and unpredictable. 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 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 high-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.

Today, North American Reliability Corporation (NERC) sets the minimum requirements of transmission needed to comply with NERC reliability criteria. That is essentially the reliability planning that all transmission owners and planning authorities perform today.

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79 Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 3.3.

80 Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 77-78.

81 Midwest ISO (MISO), Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 42-44.

82 Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

However, many 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. Additional transmission investments made for market efficiency and public policy goals help to 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. Transmission's reduction in the required planning reserve margin accounted for a large share of the quantified transmission benefits in the MISO, SPP, and PJM studies discussed earlier in this section. These reliability benefits are not captured in production cost simulations, but can be estimated separately.

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).[83] 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.[84]

London Economics performed a similar study for hypothetical lines in the Western and Eastern Interconnects.[85] The study found over a single year period, under constrained system operating conditions, electric consumers are projected to save as much as $1.3 billion in PJM and $740

[83] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 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.

[84] American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009.

[85] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018.

million in MISO with the 1,300 MW Eastern Interconnect project. This is equal to savings of about $20 (in MISO) to $40 (PJM) on a typical household's annual electricity utility bill in the affected regions. As the authors note, "Although benefits of transmission investment are based on a simulation, they are nevertheless measurable and quantifiable."[86]

iii. Lower Planning Reserve Margins

When a transmission investment reduces the loss of load probabilities, system operators can 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.[87]

Using transmission to aggregate diverse loads allows peak electricity demand to be met with less generating capacity, as localized peaks in demand can be met using surplus generating capacity from other areas that are not experiencing peak demand at the same time. For example, the June 2021 West Coast heat wave was quantified as a 1-in-1000 year event in the Pacific Northwest,[88] yet grid operators were able to keep the lights on because the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region that were only possible because of sufficient transmission interconnection.

Load diversity is primarily driven by regional differences in weather and climate, and to some extent by time zone diversity across very large east-west aggregations of load. Climate diversity benefits occur in all regions, but are particularly pronounced in regions, like the Northwest and

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[86] *Id.* p 43.

[87] 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.

[88] R. Lindsey, "*Preliminary analysis concludes Pacific Northwest heat wave was a 1,000-year event…hopefully*," *Climate.gov*, July 20, 2021.

Southeast, that contain both winter-peaking and summer-peaking power systems. Transmission's ability to access weather diversity is also very valuable, particularly during severe weather events that tend to be at their most extreme across a relatively small footprint.[89] There are inherent diversity benefits from larger aggregations of load, as the variability in usage from even very large industrial loads is cancelled out.

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 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.[90] This benefit was similarly recognized by the SPP Metrics Task Force,[91] 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%.[92]

As shown below, SPP's Value of Transmission report found its recent transmission investments provide an assumed two percent reduction in SPP's planning reserve margin, yielding 40-year net present value savings of $1.34 billion from reduced generating capacity costs, in addition to $92 million in net present value from a reduced need for generating capacity due to lower on-peak transmission losses.[93] MISO analysis shows that a lower need for capacity due to load diversity saves $1.9–$2.5 billion annually, nearly two-thirds of the RTO's total value proposition of $3.1–$3.9 billion annually.[94] Notably, this is 4–5 times larger than the roughly $500 million

[89] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[90] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 34-36.

[91] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.1.

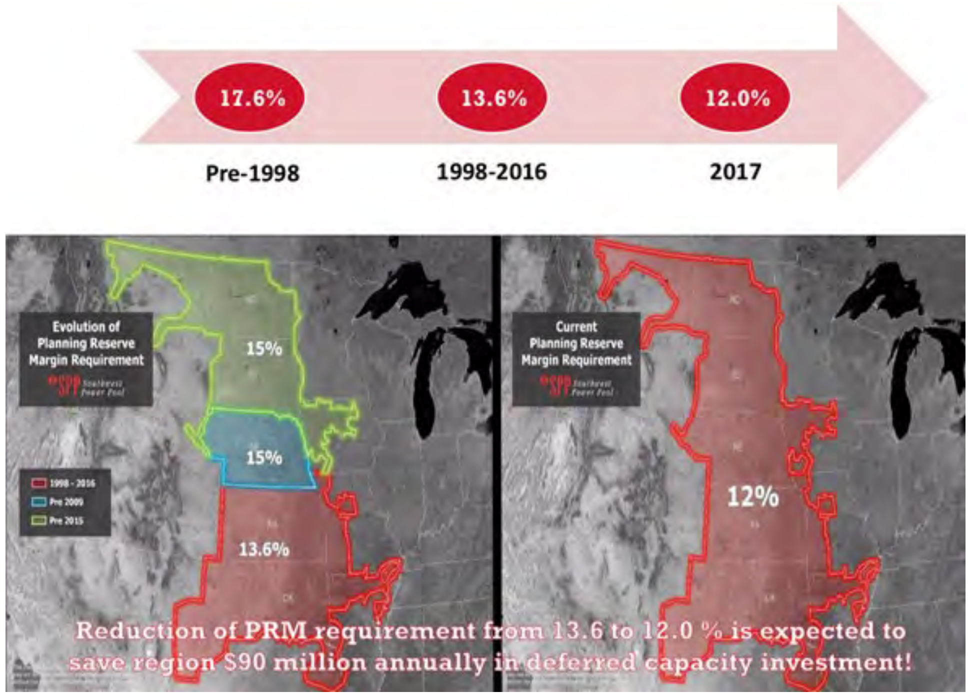
[92] Public Service Commission (PSC) of Wisconsin (WI), *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5. Two other changes that contributed to 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.

[93] Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, p. 16.

[94] MISO, *MISO Value Proposition 2020*, Detailed Circulation Description, n.d., p. 22.

annual benefit from being able to make use of higher quality wind resources. Similarly, PJM finds annual savings of $1.2–$1.8 billion from regional load diversity.[95]

FIGURE 6. SPP RESERVE MARGIN EVOLUTION



Source: L. Nickell (SPP), *Resource Adequacy in SPP*, Spring 2017 Joint CREPC-WIRAB Meeting, April 2017, slides 10 and 14.

As noted above, there is additional benefit when considering severe weather and unusual grid situations. For example, this year's winter storm Uri presented a situation where a variety of generation sources in the Central region were incapacitated. MISO was able to import 13 GW from the East and deliver some of that to SPP to the West. Both of those regions largely avoided blackouts. Interestingly, the lines that were used to ship power from the East to the West were the MISO MVP lines that had originally been justified and cost allocated on the assumption of West-to-East prevailing flow, illustrating the broad reliability benefits that result from interregional transmission. ERCOT which covers most of Texas, on the other hand, had only a maximum of 0.8 GW of import capability, which limited its ability to import power, to catastrophic effect.

Another way to quantify reliability benefit is to look back to an extreme event where reliability was compromised and consider the value of hypothetical lines. In a recent example, one such

[95] PJM, *Value Proposition*, 2019, p 2.

study found that an additional GW of delivery capacity into Texas during winter storm Uri would have fully paid for itself over the course of the four-day event.[96] The same study found that an additional GW of capacity into MISO from the East would have earned $100 million during that short period of time.

Transmission also provides a reliability benefit in the form of dynamic stability. The MISO RIIA study, for example, evaluated dynamic stability needs at a range of renewable energy penetration levels.[97] At 40% renewables, MISO found weak grid issues. As synchronous generators retire, significant HVDC was added to mitigate these issues.

4. Generation Capacity Value

Transmission investments can 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.

i. 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

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[96] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[97] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summary Report, February 2021.

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.[98]

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 $92 million in net present value capacity savings from reduced losses, or 3% of total project costs.[99]
- 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.[100]
- MISO 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.[101]
- 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.[102]

ii. 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

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[98] 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.

[99] Southwest Power Pool, *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, p 26.

[100] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4, 63.

[101] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 27.

[102] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 58-59.

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.[103] 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.

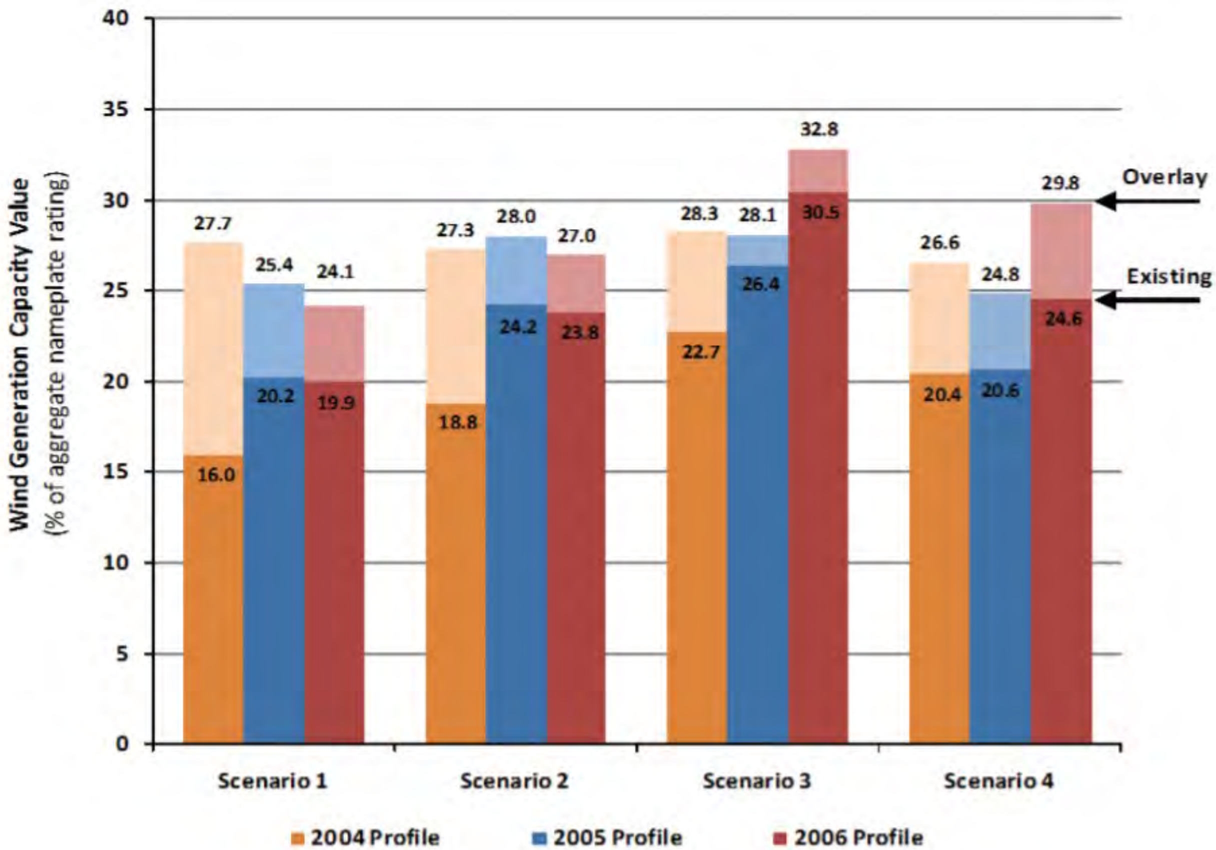
Transmission can increase the capacity value of existing resources, particularly wind and solar resources due to their geographic diversity. Higher capacity values reduce system (generation plus transmission) costs and increase net benefits. In the chart below from the Eastern Wind Integration and Transmission Study (EWITS),[104] higher wind capacity values of a few percentage points are achievable with the transmission "overlay" versus the "existing" grid. Other studies indicate even larger resource adequacy benefits from aggregating diverse renewable resources and loads.[105]

[103] *Id.*, pp 69.

[104] Enernex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (U.S. Department of Energy), NREL/SR-550-47078, January 2010.

[105] Energy and Environmental Economics, Inc., *Resource Adequacy in the Pacific Northwest*, March 2019.

FIGURE 7. ELCC RESULTS FOR HIGH PENETRATION SCENARIOS, WITH AND WITHOUT TRANSMISSION OVERLAYS



Source: EnerNex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (NREL), Revised February 2011, p 54

iii. 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.[106] 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.[107] 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.

Access to a lower-cost generation option can significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits," the MISO 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 transmission investment.[108] 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 provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable

[106] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 25-26.

[107] American Transmission Company LLC (ATC) (2007), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007, pp 54-55.

[108] Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

5. Market Benefits

Transmission expands the geographic reach of electric power markets, increasing competition, and reducing system costs. Transmission projects 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. As noted by Dr. Frank Wolak of Stanford University:

> Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade...With the exception of the U.S., most countries re-structured at a time when they had significant excess transmission capacity, so the issue of how to expand the transmission network to serve the best interests of wholesale market participants has not yet become significant. In the U.S., determining how to expand the transmission network to serve the needs of wholesale market participants has been a major stumbling block to realizing the expected benefits of electricity industry re-structuring.[109]

i. 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 markups 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.[110]

[109] F. A. Wolak, "*Managing Unilateral Market Power in Electricity*," Policy Research Working Paper; No. 3691. World Bank, Washington, DC, 2005.p 8.

[110] 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

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.[111] 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."[112]

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.[113] 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.[114] 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.[115]

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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.

[111] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp ES-9.

[112] Federal Energy Regulatory Commission, *2011 Performance Metrics for Independent System Operators and Regional Transmission Organizations*, A Report to Congress in Response to Recommendations of the United States Government Accountability Office, April 7, 2011.

[113] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 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.

[114] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004.

[115] Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008; and American Transmission Company LLC

ii. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets 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.[116] 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.

6. 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-emissions generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emissions 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

(ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598C), pp 44-47.

116 Pfeifenberger, Oral Testimony on behalf of Southern California Edison Company re economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, September and October, 2006

expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emissions 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.[117] 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.[118] That estimated emissions reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

7. 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 to the investment costs of wind generation in locations with a 30% capacity factor.[119]

[117] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 26.

[118] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 83.

[119] Burns & McDonnell Engineering Company, Inc., *Wind Energy Transmission Economics Assessment*, prepared for WPPI Energy, Project No. 55056, March 2010, pp 1–2, Figure 2.

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 MISO 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.[120] 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 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's initial analysis 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.[121] 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.[122]

Additional transmission investment can 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 operation (which includes a variable cost reduction). If less generating capacity from conventional generation is

[120] Midwest ISO (MISO), *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

[121] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 38-41.

[122] American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009, p 7.

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 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.[123] 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.

8. Other 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 and wild-fire resilience, 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 benefits, increased resource planning and system operational flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Please see Appendix C for more details.

b. Multi-Value Planning Examples

As Table 4 has summarized in the beginning of this section, significant experience with multi-value transmission planning already exists within SPP, MISO, CAISO, and NYISO.

[123] 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 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.

1. SPP Integrated Transmission Planning (ITP), Metrics Task Force (MTF), and Regional Cost Allocation Review (RCAR)

The ITP efforts by SPP have moved toward examining a range of transmission-related benefits in its transmission project evaluations, which included: production cost savings, reduced transmission losses, wind revenue impacts, natural gas market benefits, reliability benefits, and economic stimulus benefits of transmission and wind generation construction. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group 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, societal economic benefits.

Later, to support cost allocation efforts, SPP's MTF 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. SPP's MTF 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.

SPP's Regional Cost Allocation Review has further expanded the scope of benefits to include avoided or delayed reliability projects, capacity savings due to reduced on-peak transmission losses, transmission outage cost savings, and marginal energy loss benefits.[124]

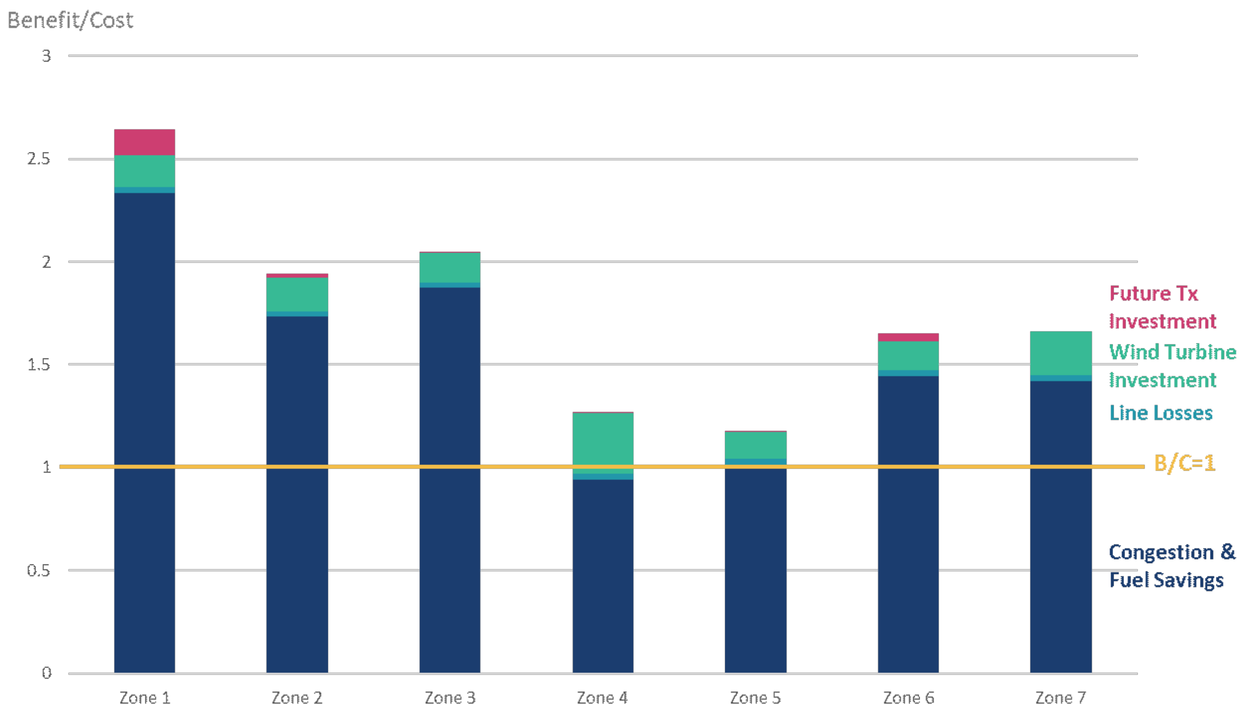
2. MISO Multi Value Projects (MVP)

MISO's evaluation and development of its MVP portfolio is a good example of a pro-active planning process that considered multiple benefits. The quantified benefits included: (1) congestion and fuel cost savings; (2) reduced costs of operating reserves; (3) reduced planning reserve margin requirements; (4) deferred generation investment needs due to

[124] Southwest Power Pool (SPP), *Regional Cost Allocation Review (RCAR II)*, July 11, 2016.

reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; and (6) reduced other future transmission investments. When approving projects in 2011, the MISO board of directors based their approval on the need to support a variety of state energy policies, to maintain reliability, and to obtain economic benefits in excess of costs. The $6.6 billion worth of MVP projects that resulted are now estimated to provide economic net-benefits of $7.3 to $39 billion over the next 20 to 40 years, which (as shown in Figure 8) produces net benefits in each of MISO's planning zones.[125]

FIGURE 8. MISO MVP BENEFITS BY ZONE



Source: Low range 20 year NPV from MISO, MTEP19 MVP Limited Review Report, 2019.

3. New York Public Policy Transmission Planning Process

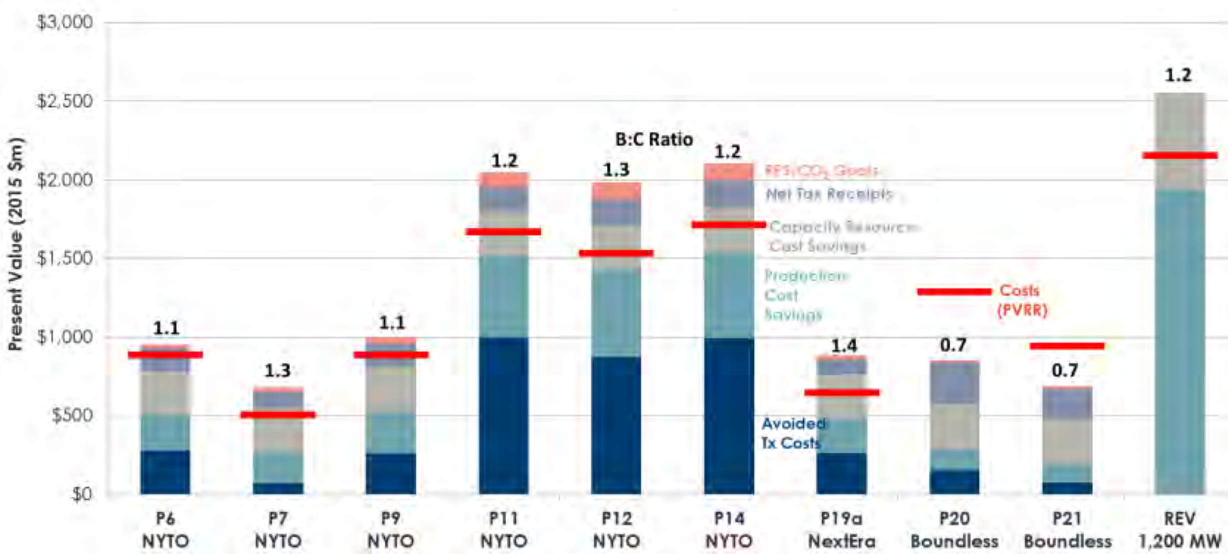
In New York, NYISO implemented a multi-value "public policy" transmission planning process after the New York Public Service Commission (PSC) mandated that approach in 2015. Prior, the existing approach for identifying "economic" projects through the NYISO Congestion Assessment and Resource Integration Study (CARIS) failed to identify regional projects to be built due to its limited scope of benefits considered: it focused solely on adjusted production

125 MISO, *MTEP19 MVP Limited Review Report*, 2019.

cost savings over a 10-year period.[126] The PPTPP starts with the suggestions of public policy transmission needs (PPTN) by market participations. After the PSC approves specific needs, the NYISO solicits solutions from market participations, which are then being evaluated based on a multi-value framework that recognizes and quantifies the broad set of benefits that the proposed solutions may provide.

Considering the broader range of benefits that transmission provides, and that a large portion of total benefits are the avoided costs of not having to upgrade the aging infrastructure later (due to facilities nearing the end of their useful life), seven portfolios of initially proposed projects and the Reforming the Energy Vision (REV) resources were found to provide net societal benefits as (see Figure 9) and two upgrades were ultimately approved.

FIGURE 9. SUMMARY OF NEW YORK SOCIETAL BENEFIT-COST ANALYSIS



Source: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Trans9ission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015.

[126] Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

4. CAISO Transmission Economic Assessment Methodology (TEAM)

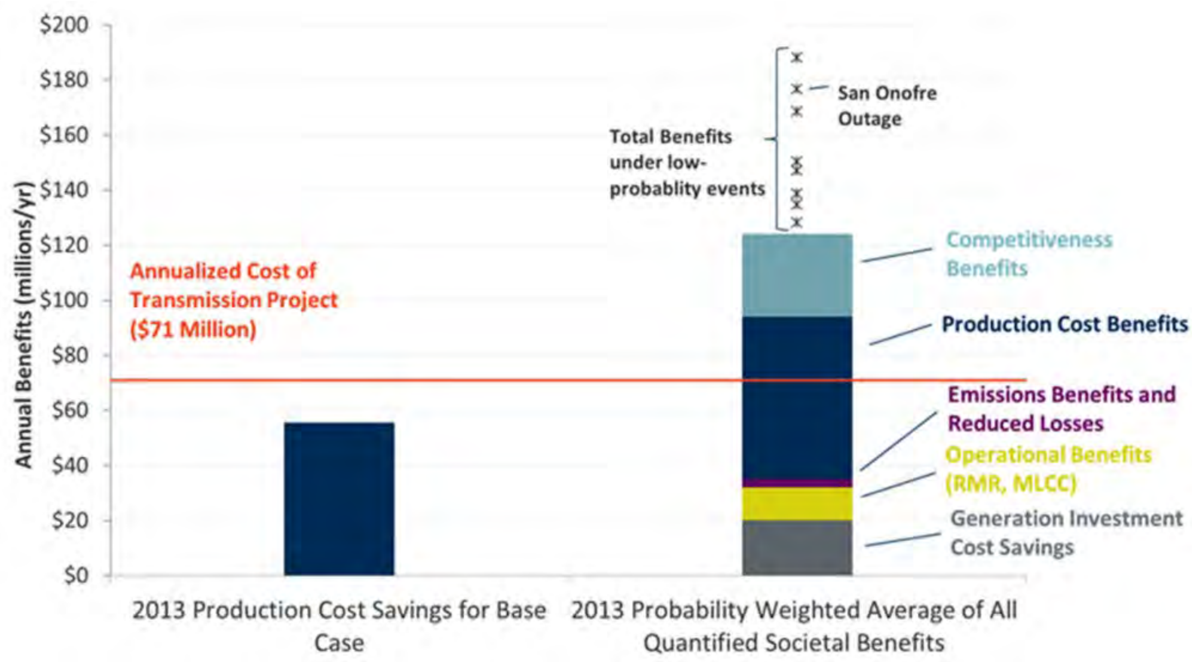
CAISO has occasionally utilized its TEAM approach in its transmission planning effort, which considers multiple benefits.[127] When initially evaluating CAISO's Palo Verde-Devers 2 (PVD2) line, the California Public Utility Commission (CPUC) relied on results from the TEAM approach.[128] Quantified benefits included production cost benefits, operational benefits, generation investment cost savings, reduced losses, competitiveness benefits, and emissions benefits.[129] This proved critical, as the PVD2 project benefits exceeded project costs by more than 50%, but only if multiple benefits were quantified (Figure 10). Thus, traditional planning approaches would have rejected the PVD2 transmission investment despite the fact that the CAISO's more comprehensive analysis shows it offered overall costs savings in excess of the project costs including significant risk mitigation benefits. In contrast, the CAISO TEAM analysis of PVD2 went beyond a base-case production cost analysis to identify a much broader range of transmission-related benefits and estimated the value associated with them more comprehensively than what most economic analyses of transmission projects do today.

[127] CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

[128] CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005.

[129] The CAISO identified a number of project-related benefits that were not quantified for the purpose of comparing benefits and costs. These unquantified benefits included: increased operational flexibility (providing the system operator with more options for responding to transmission and generation outages); facilitation of the retirement of aging power plants; encouraging fuel diversity; improved reserve sharing; and increased voltage support.

FIGURE 10. PVD2 ANNUAL BENEFITS IN COMPARISON TO COSTS



However, despite its experience with TEAM, most of CAISO's recent planning efforts focus solely on reliability needs or impacts on wholesale market prices, congestion, and production costs. We are aware of only two recent transmission projects—the Harry Allen to Eldorado 500 kV line and the Delaney to Colorado River 500 kV line (the successor of the PVD2 project first evaluated in 2004)—which the CAISO justified and approved based on quantification of multiple economic benefits.

3. Address Uncertainties and High-Stress Conditions Explicitly through Scenario-Based Planning

While proactive planning improves planning beyond considering status-quo needs or reliability needs (including those created by generation interconnection requests), it may still only consider a single "base case" scenario (as was done in the PJM offshore wind study). Scenario-based planning takes the planning process a step further by explicitly recognizing that planning for the future requires dealing with uncertainty. Because the industry, its market conditions, and even its regulations are invariably uncertain, today's conditions or current trends should not be the primary scenario, let alone the exclusive basis, for how the industry plans transmission facilities in the next decade or two for service 20, 30, or 40 years in the future. This type of scenario-based long-term planning is widely used by other industries, such as the oil and gas, utility planning, and many other industries.[130] Such scenario-based planning using existing tools and proven methods can be deployed to identify robust solutions that are beneficial across a range of scenarios.

Reactive planning to meet near-term reliability or interconnection needs often completely ignores uncertainty, as other future needs are not even considered in the planning effort. Uncertainties about future regulations, industry structure, or generation technology (and associated investments and retirements) can substantially affect the need and size of future transmission projects. A well-planned, flexible transmission system can insure against the risks of high-cost outcomes in the future ("insurance value"). Because future outcomes are highly uncertain, it is important to plan in such a way to minimise "regret" in all plausible scenarios and consider "option value." Without considering a range of plausible scenarios, planning procedures do not address the risk of leaving customers with few options beyond a cost-ineffective set of infrastructure that results in very high system-wide costs. Factors to consider in scenario-based planning include (but not limited to):

- Public Policy Mandates and Goals
- Electrification and Efficiency Adoption
- Economic Growth
- Commodity Costs
- Technology Costs & Availability
- Generation Type and Location
- Future Weather/Climate Conditions, including Extreme Weather Frequency
- Resource Adequacy and Reserve Needs
- Customer Preferences

Finding efficient solutions under conditions of uncertainty is a well-established field of economic policy. One methodological approach relies on the concept of "expected value," which is a calculation of the (probability-weighted) average of multiple potential outcomes in the future. In transmission planning, this methodology is very important because transmission can be extremely valuable in scenarios that can occur in reality but are often not considered in current planning processes' analyses. For example during winter storm Uri in February 2021, additional transmission lines into Texas would have provided so many benefits that they would

[130] Royal Dutch Shell plc, *New Lens Scenarios: A Shift in Perspective for a World in Transition*, March 2013; Wilkinson, Angela and Roland Kupers, "*Living in the Futures*," Harvard Business Review, May 2013.

have fully paid for themselves in 2.5 days, and an additional Gigawatt of transmission capacity into MISO would have provided $100 million in benefit over the event.[131] Prospectively, such scenarios can be considered with proper weighting for the likelihood or probability of such events. For example, even if only one such extreme event can be expected in any decade, the probability weighted annual average would be 1/10th of the benefits the transmission is estimated to provide. However, the distribution of possible outcomes needs to be considered beyond the probability-weighted expected value, since two projects with the same expected value may have vastly different risk profile—with one project significantly reducing the risk of very high cost outcomes relative to the other project.

A frequently voiced concern is that effective transmission planning is not possible until key uncertainties are resolved. This concern has effectively stalled regional and interregional planning processes. However, delaying long-term planning because the future is uncertain will necessarily limit transmission upgrades and miss opportunities to capture higher values through investments that could address longer-term needs more cost effectively. While objectively determining a reasonable set of scenarios that captures possible future market conditions requires careful considerations, it will be much more efficient to do that than ignore uncertainties all together or wait for uncertainties to resolve themselves.

Evaluating long-term uncertainties by defining various distinctive (and equally plausible) “futures” is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can then be used to: (1) identify “least-regrets” projects that mitigate the risk of high-cost outcomes and whose value would be robust across most futures;[132] and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values

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[131] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[132] For least regret’s planning to deliver robust planning choices, it is important to consider how transmission projects can reduce the risk that some future outcomes may lead to either (a) the regret that the cost of building the project significantly exceeds the project’s benefits, or (b) the regret that not building the project results in very-high-cost outcomes that far exceed the project’s cost. Reducing the cost of both types of regrettable outcomes is necessary to reduce the project’s overall risk in light of an uncertain future.

of economic transmission projects under the various scenarios can be used both to assess the robustness of a project's cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

For example, a scenario-based long-term transmission planning study was first presented to the Public Service Commission of Wisconsin by American Transmission Company (ATC) in 2007.[133] In its Planning Analysis of the Paddock-Rockdale Project, ATC evaluated the benefit that the project would provide under seven plausible futures. That ATC study, which evaluated a wide range of transmission-related benefits, found that while the 40-year present value of the project's customer benefits fell short of the project's revenue requirement in the "Slow Growth" future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. The other scenarios also showed that not investing in the project could leave customers as much as $700 million worse off. Overall, the Paddock-Rockdale analysis showed that understanding the potential impact of projects across plausible futures is necessary for transmission planning under uncertainties and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid.

In 2014, ERCOT improved their stakeholder-driven long-term transmission planning process by applying a scenario-based planning framework to identify the key trends, uncertainties, and drivers of long-term transmission needs in ERCOT.[134] ERCOT converted the detailed scenario descriptions (developed jointly by stakeholders) into transmission planning assumptions, which differed in their projections for load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions. Following that, ERCOT performed initial planning analyses for ten scenarios—including projections of likely locations and magnitudes of generation investments and retirements—and identified four scenarios that covered the most distinct range of possible futures to carry forward for detailed long-term system modeling analyses.

MISO's MVP planning effort, noted for its proactive planning in the prior section, also utilized a scenario-based approach to identify the selected projects. In MISO's original RGOS process, three scenarios were considered and the projects that yielded beneficial outcomes in all scenarios eventually went on to become the MVP projects.

[133] Before the Public Service Commission of Wisconsin, Docket 137-CE-149, Planning Analysis of the Paddock-Rockdale Project, American Transmission Company, April 5, 2007.

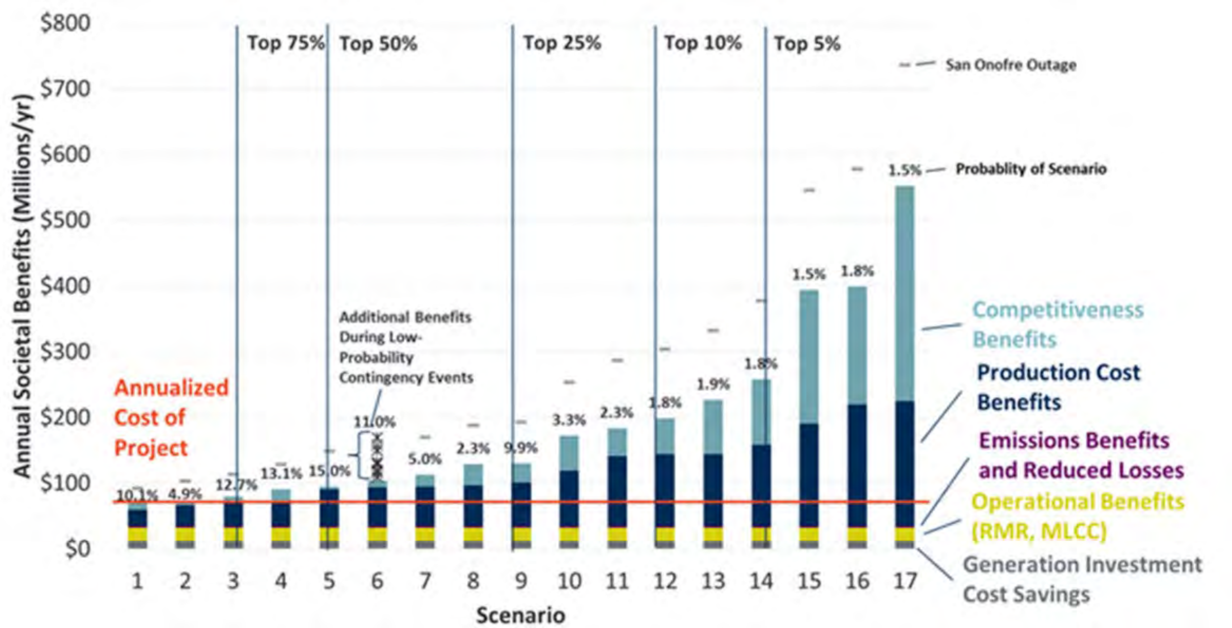
[134] ERCOT, *2014 Long-Term System Assessment for the ERCOT Region*, December, 2014; Chang, Pfiefenberger and Hagerty (The Brattle Group), *Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment,* September 30, 2014.

California's planners similarly have applied scenario-based approaches in the past. CAISO's 2004 analysis of its Palo Verde to Devers (PVD2) project considered seventeen plausible scenarios and a number of long-term contingencies (which could happen in any of the scenarios) to show that base-case results still significantly understated the overall cost-reductions and risk mitigation offered by the project.[135] Based on the range of scenarios, CAISO showed that the probability-weighted average of the project benefits exceeded the savings estimated in the base-case scenario, which did not have benefits that exceeded costs (Figure 11). Thus, most economic transmission planning processes that focus solely on such base-case benefit and cost comparisons would have rejected the PVD2 transmission project because the quantified benefits do not appear to justify the project's costs.

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

[135] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005.

FIGURE 11. RANGE OF PROJECTED SOCIETAL BENEFITS OF PVD2 PROJECT COMPARED TO PROJECT COSTS



Source: Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

Thus, while proactive planning already offers a significant improvement over current planning processes, it may understate project benefits if only a “base case” is evaluated. This risks projects not moving forward due to a lack of understanding of possible benefits in an uncertain future. In addition, the lack of scenarios can result in an inadequate understanding of the potentially high costs of not pursing the project. Recognizing the uncertainties about the future with the use of scenario-based planning can improve current transmission planning processes that are focused solely (or mostly) on a “base case” that reflects the status quo or current trends.

One scenario that is increasingly more likely to be reflective of future market conditions is one with stringent state or federal clean-energy regulation. Over the last decade, numerous and ambitious state clean energy standards have already changed system needs. It is possible, if not likely, that there will be additional significant state or federal clean energy or climate policies. Even if such policies are outside the confines of electricity regulation, they impact the generation mix, power flows, and the value of transmission that has to be expected. Even if some such policies are not yet implemented, it is prudent to consider the possibility of such future policies through scenario-based planning (along with scenarios that envision a future that may not impose such policies). Of course, once such policies are passed they should be considered proactively in “base case” planning scenarios and transmission plans.

A London Economics report described scenario planning this way:

> Utilizing scenario analysis can help decision makers to better understand and quantify the expected range of benefits over the long term. Scenario analysis can capture the impact of uncertainty or the magnitude and longevity of benefits, and even identify beneficiaries that were not anticipated under a "base case" or most likely forecast. In some cases, scenario analysis can also show that benefits may arise irrespective to future market outcomes.[136]

A Brattle Group report for WIRES contains a more detailed discussion on the use of scenarios (to address long-term future uncertainties) and sensitivities (to address short term uncertainties that can happen in each scenario of future market conditions)[137]

4. Use Portfolios of Transmission Projects

Planning a portfolio of synergistic transmission projects can reduce electricity costs by identifying solutions that are more valuable than the sum of the individual projects' value. A synergistic portfolio of projects might also consider both storage and other technologies. Studies that co-optimize storage and transmission tend to find that they are complementary components and not substitutes. There is usually a "sweet spot" where the optimal amount of both storage and transmission lead to the lowest system cost.

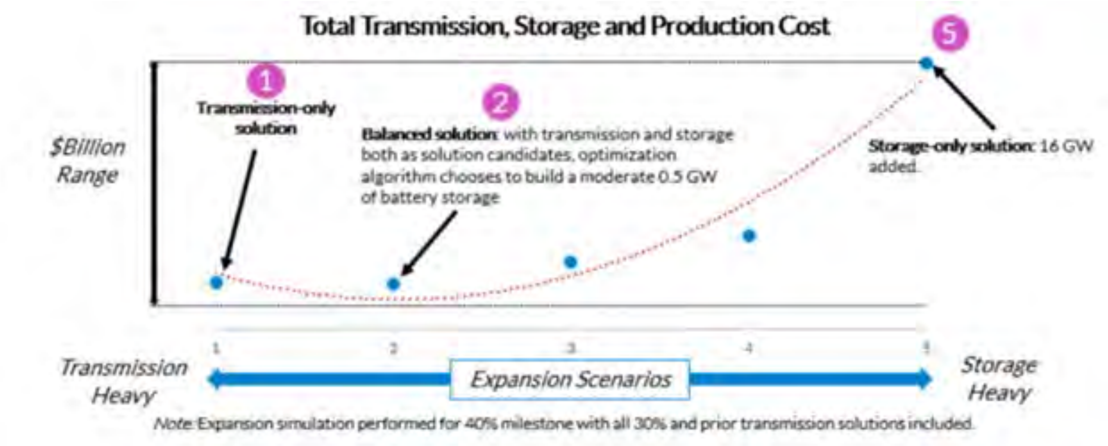
For example, MISO evaluated both transmission and storage in its RIIA study.[138] In this study, if the model was allowed to optimize transmission and storage it selected 0.5 GW of storage plus significant additional transmission. If it was allowed to build only storage without additional transmission, the model selected 16 GW at a much higher total system-wide cost. The combined transmission and storage solution achieved a lower system-wide cost than either transmission or storage alone. The graph below shows this "sweet spot" of an optimal combination of transmission and storage.

[136] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018, p 46.

[137] Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9−19 and Appendix B.

[138] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021.

FIGURE 12. COSTS FOR SCENARIOS VARYING IN TRANSMISSION AND STORAGE EXPANSION



Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 93.

Similarly, portfolio-based planning can consider and co-optimize transmission and distributed energy resources (DERs). Studies that co-optimize DERs, transmission, and small and large generation sources can achieve a lower system-wide cost than those that focus on one over the others. Notably, such studies (even with high levels of DERs) still find transmission system expansion to be very valuable. In fact, in one recent study that considered a high DER scenario, 10 million more MW-miles more transmission is required to minimize system-wide costs due to the complementarity (not substitutability) of DERs and transmission.[139]

For the purpose of cost allocation, however, considering even larger portfolios offers additional advantages—it will reduce the contentiousness of cost allocations since the benefits of larger transmission portfolios will be more evenly distributed and stable over time.[140] Such portfolio-wide cost allocation approach is widely used for other infrastructure, including roads or electric distribution systems.

Because the benefits of a portfolio of transmission projects will generally be more evenly distributed and stable than for a single project, portfolio-based cost recovery allows for less complex (and contentious) cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received. While the SPP highway-byway and MISO MVP examples demonstrate that the benefits of portfolio of projects are

[139] C. T. M. Clack, A. Choukulkar, B. Coté, and S. A. McKee (Vibrant Clean Energy LLC), *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid*, Technical Report, December 1, 2020.

[140] See, for example, *Transmission Cost Allocation: Principles, Methodologies, and Recommendations*, presentation to the OMS Cost Allocation Principles Committee, November 16, 2020.

roughly commensurate with allocated costs, the MVP cost allocation approach would not meet that standard for individual ITP and MVP projects.[141]

5. Jointly Plan Neighboring Interregional Systems

Improving interregional transmission planning is the subject of several other reports.[142] We address this topic here only briefly. Interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs, as already discussed for several examples above. Similar to regional transmission planning, however, interregional planning also suffers from lack of pro-active, multi-value, and scenario-based analysis.

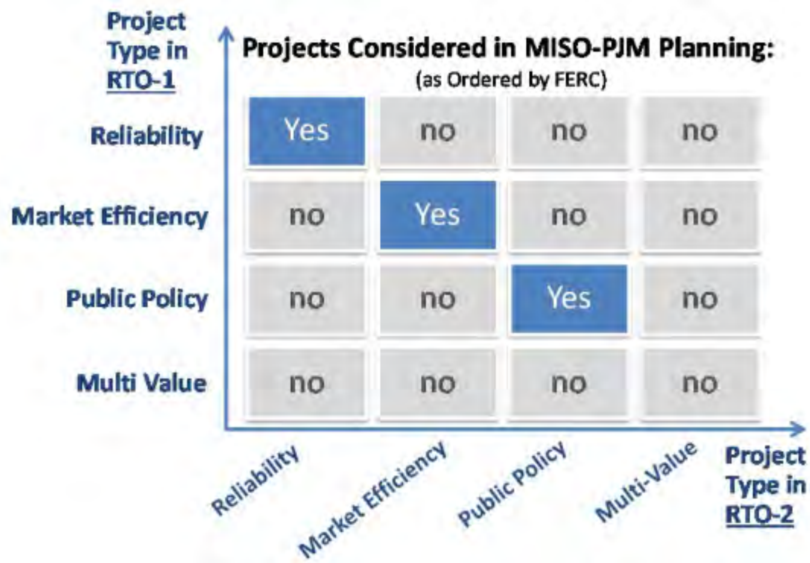
Most of the existing joint interregional planning processes (such as the PJM-MISO interregional planning process) allow only for the evaluation of transmission needs that are of the same type (*i.e.*, reliability, market efficiency, or public policy) in both regions. As illustrated in Figure 13,[143] these types of interregional planning processes may not allow for the evaluation of needs that differ across the regions, which can disqualify from consideration many valuable interregional projects.

[141] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been applied, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for the postage-stamp-based cost allocation of its portfolio of Multi-Value Projects (MVP). While SPP and MISO have demonstrated that the benefits of portfolio of projects are roughly commensurate with allocated costs, the cost allocation approach would not meet that standard for individual ITP and MVP projects. Note, however, that the approval of individual projects (or synergistic groups of projects) still needs to be based on the need for and total benefits of the individual projects.

[142] Southwest Power Pool, *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012; Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

[143] For a summary of the PJM-MISO interregional planning process, see Appendix C of Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Prepared for WIRES Group, April 2015.

FIGURE 13. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH RTO

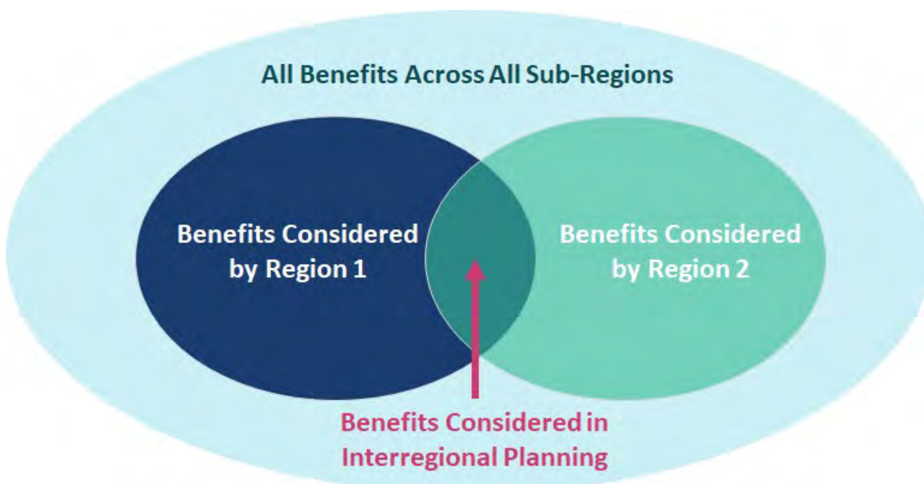


By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs in the neighboring region. Unless the two adjacent regions categorize the interregional project in exactly the same way, the regions' interregional planning rules do not exist or may outright reject evaluating the project. More often than not, however, a transmission project will provide multiple types of benefits and these benefits may differ across regions. Finding and approving transmission solutions solely based on reliability needs can, thus, lead to missed opportunities to build lower-cost or higher-value transmission projects that could provide benefits beyond meeting reliability needs to reduce the overall costs and risks to customers in both regions.

The geographic scope of regional and interregional RTO planning processes tends to be narrowly focused in its consideration of the transmission-related benefits geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to their own region without considering the broader set of interregional benefits. Projects near the regional boundaries, such as an upgrade to a shared flowgate, can address the needs of neighboring regions and need to be considered if the goal is to determine the infrastructure that most lowers cost. Without considering this, quantified benefits will be understated and even "regional" projects near RTO seams could fail to meet applicable benefit-cost thresholds for regional market-efficiency and public policy needs simply because the planning process ignores the benefits that accrue on the other side of the seam. This limitation has been addressed in some interregional planning processes (*e.g.*, PJM-MISO and MISO-SPP joint interregional planning[144]), but is often not considered in regional planning for projects located entirely within one of the RTOs.

This approach tends to disadvantage interregional projects because the jointly agreed-upon criteria and metrics generally will tend to represent the "*least common denominator*" subset of the criteria and metrics used in the adjoining regions. Worse, as show, the range of benefits considered for interregional projects tends be more limited than the narrow scope of benefits considered in intra-regional planning processes, reducing the set of benefits to the least-common denominator of benefits considered in planning within each of the two regions. Similarly, interregional planning processes do not recognize the unique benefits often offered by an expanded interregional transmission system, which include increased load and resource diversity.[145]

FIGURE 14. THE "LEAST COMMON DENOMINATOR" CHALLENGE OF BENEFIT-COST ANALYSIS FOR INTERREGIONAL PROJECTS



In addition, barriers can be created due to the disjointed nature of the existing interregional and regional planning processes. For example, interregional transmission projects may be subjected to three separate benefit-cost thresholds: a joint interregional benefit-cost threshold as well as each of the two neighboring region's individual internal planning criteria. This means, for example, that projects that pass each RTO's individual benefit-cost thresholds may fail the threshold imposed through the least-common denominator approach to interregional planning;

[144] SPP-MISO and MISO-PJM Joint Operating Agreements available at MISO, *Interregional Coordination*.

[145] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

or projects that pass the benefit-cost threshold of the interregional planning process may be rejected because they may fail one of the individual RTOs' planning criteria. In combination with evaluating only a subset of benefits of a few scenarios of future market conditions, this adds to the challenge of approving even very valuable projects.

Interregional planning also lacks proactive scenario-based analyses. This is partly caused by the lack of inputs from states on how they plan on achieving clean energy goals. States generally have specific goals for local renewable energy resource development that are not well articulated or challenging to incorporate into regional and interregional planning processes. One of the key drivers of the MISO MVP process was that state representatives were requesting that MISO evaluate transmission solutions that could cost-effectively meet the region's combined state-level renewable portfolio standards by integrating a combination of local and regional renewable resources. A high-level outlook of how states wish to pursue meeting their goals, or a more detailed set of scenarios, would greatly improve the ability of RTOs to plan their future system without having to develop a specific portfolio of resources to do so.

6. Summary of Examples of Proven Efficient Planning Studies and Methods

As described above, there are many examples where efficient transmission planning methods have been performed. The following table lists transmission studies and analyses and shows what type of planning method was performed (Table 7). Table 7 classifies proactive as considering beyond status-quo scenarios, multi-benefit as considering a comprehensive set of benefits (*i.e.*, not just a couple), and scenario-based planning to reflect a broad set of divergent futures.

TABLE 7. EXAMPLES USING PROVEN EFFICIENT PLANNING METHODS

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

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146 CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

147 American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007.

148 D. Woodfin (ERCOT), *CREZ Transmission Optimization Study Summary*, presented to the ERCOT Board of Directors, April 15, 2008.

149 Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010.

150 See *Eastern Interconnection Planning Collaborative*, including Phase I and Phase II planning reports

151 GE Energy Consulting, *PJM Renewable Integration Study, Task 3A Part C: Transmission Analysis*, March 31, 2014.

152 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019.

153 ERCOT, *2020 LTSA Review*, December 15, 2020 and *2020 Long-Term System Assessment for the ERCOT Region*, December 20202, as posted at: Planning (ercot.com).

154 SPP, *2020 Integrated Transmission Planning Report*, October 27, 2020. As noted in the report (at p 8), the (multi-value) objectives of the SPP ITP process are to: resolve reliability criteria violations; Improve access to markets; Improve interconnections with SPP neighbors; meet expected load-growth demands; facilitate or respond to expected facility retirements; synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes; address persistent operational issues as defined in the scope; Facilitate continuity in the overall transmission expansion plan; and facilitate a cost-effective, responsive, and flexible transmission network.

155 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021.

156 Midwest ISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, February 2021.

157 AEMO, *2020 Integrated System Plan*, July 30, 2020.

158 Transgrid, *Energy Vision: A Clean Energy Future for Australia*, October 2021.

V. Summary and Conclusions

The currently predominant use of reactive, single-driver approaches to transmission planning is systematically failing to identify and implement transmission options that offer the lowest system-wide costs and highest benefits for customers. A set of market and regulatory failures create perverse incentives that lead to under-investment in the type of regional and interregional transmission that would increase reliability and system-wide efficiency.

This failure is widespread across the country, and present to a greater or lesser extent in all 11 Planning Authority regions. These transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some proven examples of more effective transmission planning, using existing and readily available tools, exist. Continuing current practices without reforms will mean higher-than-necessary electricity costs. Existing experience with effective planning and cost-allocation processes shows that transmission planners have the tools needed to significantly reduce system-wide electricity costs. To do so, effective planning process need to:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Policymakers and planners need to reform transmission planning requirements to avoid the unreasonably high system-wide costs that result from the current planning approaches and enable customers to pay just and reasonable rates by implementing these principles.

Appendix A – Evidence of the Need for Regional and Interregional Transmission Infrastructure to Lower Costs

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and large regional and interregional transmission expansion is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA) found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[159]
- The NREL Interconnections Seam Study shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[160] The study found a need for 40–60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by ScottMadden Management Consultants on behalf of WIRES, concluded that as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[161]

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[159] Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526-531, January 25, 2016.

[160] Aaron Bloom, *Interconnections Seam Study*, August 2018.

[161] Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, January 2020.

- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[162]
- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[163]
- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[164]
- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30–70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[165]
- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[166]
- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state

[162] Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020. See also Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

[163] FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 39, June 2020.

[164] Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

[165] J. Michael Hagerty, Johannes Pfeifenberger, and Judy Chang, *Transmission Planning Strategies to Accommodate Renewables*, at 17, September 11, 2017.

[166] Eric Larson, *et al.*, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

approach.[167] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5× transmission cost'' case there are substantial transmission additions."[168]

- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[169] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%.[170]
- The Brattle Group analysts find that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[171]
- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[172]
- MISO's Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV, and 640 circuit-miles of HVDC.[173]

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[167] P. R. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

[168] *Id.*, at 12.

[169] B. A. Frew, *et al.*, *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65-78, April 15, 2016.

[170] *Ibid*.

[171] Dr. J. Weiss, J. M. Hagerty, and M. Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

[172] Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016

[173] Wind Solar Alliance, *Renewable Integration Impact Assessment Finding Integration Inflection Points of Increasing Renewable Energy*, January 21, 2020.

- The Brattle Group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[174]
- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[175]
- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[176]
- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[177]
- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[178]
- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS

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174 Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

175 MISO, *HVDC Network Concept*, at 3, January 7, 2014.

176 A. Liu, *et al.*, *Co-optimization of Transmission and Other Supply Resources*, September 2013.

177 SPP, *The Value of Transmission*, at 5, January 26, 2016.

178 MISO, *MTEP19*, 2019.

standard would reduce generation costs by $163–$197 billion compared to traditional planning approaches.[179]

- Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98 billion.[180] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.
- A study comparing proactive planning to reactive planning found significant benefits to proactive planning because it is able to co-optimize generation and transmission. "Transmission planning has traditionally followed a "generation first" or "reactive" logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by "proactive" transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment."[181]

[179] Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

[180] Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

[181] E. Spyrou, J. L. Ho, B. F. Hobbs, R. M. Johnson, and J. D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

Appendix B – Quantifying the Additional Production Cost Savings of Transmission Investments

As noted in the main report, RTOs and transmission planners are increasingly recognizing that traditional production cost simulations and the traditional "adjusted production cost" metrics are quite limited in their ability to estimate the full congestion relief and production cost benefits. Below we describe the quantification of additional production-cost-related savings (*i.e.*, beyond the production cost savings traditionally quantified) that need to be considered when evaluating the full range of transmission benefits.

TABLE 8. ADDITOINAL PRODUCTION COST SAVING CATEGORIES

i. Impact of generation outages and A/S unit designations
ii. Reduced transmission energy losses
iii. Reduced congestion due to transmission outages
iv. Reduced production cost during extreme events and system contingencies
v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
vii. Reduced cost of cycling power plants
viii. Reduced amounts and costs of operating reserves and other ancillary services
ix. Mitigation of reliability-must-run (RMR) conditions
x. More realistic "Day 1" market representation

B.1 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.[182] 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 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.[183] 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.[184] 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.[185]

B.2 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

[182] For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008.

[183] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4 (project cost) and 63 (losses benefit).

[184] Pioneer Transmission, LLC, Letter from David B. Raskin and Steven J. Ross (Steptoe & Johnson) to Hon. Kimberly D. Bose (FERC) Re: Formula Rate and Incentive Rate Filing, Pioneer Transmission LLC, Docket No. ER09-75-000, no attachments, January, 26, 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.

[185] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[186]

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.[187] 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.[188] 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 account for unmodelled events such as unplanned transmission outages and loop flows.[189] 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

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[186] For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see Southwest Power Pool (SPP), *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, 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.

[187] PJM Interconnection (PJM), *FTR Revenue Stakeholder Report*, April 30, 2012, p 32.

[188] D. Patton, "*2010 State of the Market Report: Midwest ISO*," presented by Midwest ISO Independent Market Monitor, Potomac Economics, May 2011. (Patton, 2011) Posted at https://www.potomaceconomics.com/wp-content/uploads/2017/02/2010-State-of-the-Market-Presentation.pdf, 2011.

[189] See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manual 4. Posted at: https://cdn.misoenergy.org//BPM%20004%20-%20FTR%20and%20ARR49548.zip.

west-east price differentials.[190] 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.[191]

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 period.[192] The TSM report also showed that, for the five most constrained flowgates on the

[190] Pfeifenberger and S. Newell, "*Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models*," Energy (Brattle Group Newsletter) No. 1, 2006.

[191] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[192] Potomac Economics, Quarterly Transmission Service Monitoring Report on Entergy Services, Inc.¸ December 2012 through March 2013, April 30, 2013.

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 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.

B.3 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.[193]

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.[194] 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.[195]

Further, the analysis of high-impact, low-probability events 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.[196]

In a recent example, one such study found that the development of an additional 1,000 MW of transmission capacity into Texas during would have fully paid for itself over the course of four days during winter storm Uri.[197] The same study found that an additional 1,000 MW of transmission capacity into MISO from the East would have saved $100 million during that short period of time.

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[193] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598, p 4 (project cost) and 50-53 (insurance benefit).

[194] California Public Utilities Commission (CPUC), Decision 07-01-040: *Opinion Granting a Certificate of Public Convenience and Necessity*, in the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (filed April 11, 2005), January 25, 2007, pp 37–41.

[195] M. L. Wald, "Nuclear Power Plant in Limbo Decides to Close, *The New York Times*, June 7, 2013.

[196] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, p 24.

[197] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

B.4 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.[198]

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.[199] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions. 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.[200]

198 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.

199 Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 9.6.

200 Energy Reliability Council of Texas (ERCOT), *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting*, March 4, 2011, p10. 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.

Mitigating the variability and uncertainty of renewable generation by diversifying it over geographic areas that exceed in size the scale of typical weather system has also been shown to provide substantial economic benefits, but requires the explicit simulation of both renewable generation variability and the day-ahead and intra-day uncertainty associated with intra-hour real-time generation as discussed in more detail in the subsection below.[201]

B.5 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.[202] 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.

[201] Pfeifenberger, Ruiz, and Van Horn, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, BU-ISE Working Paper, September 2020.

[202] Pfeifenberger and Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

In a recent study, analysts at The Brattle Group and researchers at Boston University estimated the value of diversifying uncertain renewable generation through the transmission system.[203] The analysis indicates that the benefits of transmission expansion between areas with diverse renewable generation resources are greater than typically estimated, with significant reductions in system-wide costs and renewable generation curtailments in both hourly day-ahead and intra-hour power market operations. For renewable generation levels from 10% to 60% of annual energy consumption, interconnecting two power market sub-regions with different wind regimes through transmission investments can reduce annual production costs by between 2% and 23% and annual renewable curtailments by 45% to 90%. When real-time uncertainties of renewable generation and loads relative to their day-ahead forecasts are taken into consideration, the benefit of geographic diversification through the transmission grid are 2 to 20 times higher than benefits typically quantified based only on “perfect forecasts.”

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.[204] These benefits will generally be more significant if transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-

[203] Pfeifenberger, *Ruiz, Van Horn.*, The Value of Diversifying Uncertain Renewable Generation through the Transmission System: Cost Savings Associated with Interconnecting Systems with High Renewables Generation: Cost Savings Associated with Interconnecting Systems with High Renewables Penetration, presented for Boston University Institute for Sustainable Energy Webinar Series, October 14, 2020.

[204] 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 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 $5.74/MWh of wind energy injected. ($/MWh in US$2024). EnerNex Corporation, prepared for National Renewable Energy Laboratory (NREL), NREL/SR-5500-47078, Revised February 2013.

rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[205]

B.6 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

[205] For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see F. D. Munoz, B. F. Hobbs, J. Ho, and S. Kasina, "*An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study*," Working Paper, JHU, March 2013;
A. H. Van Der Weijde, B. F. Hobbs, "*The Economics of Planning Electricity Transmission to Accommodate Renewables: Using Two-Stage Optimisation to Evaluate Flexibility and the Cost of Disregarding Uncertainty*," *Energy Economics*, 34(5). 2089-2101.
H. Park and R. Baldick, "Transmission Planning Under Uncertainties of Wind and Load: Sequential Approximation Approach," *IEEE Transactions on Power Systems*, vol. PP, no.99, March 22, 2013 pp1–8.

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.[206]

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,[207] this is an area where standard analytical methodology still needs to be developed.

B.7 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,

[206] N. Kumar, *et al.*, Power Plant Cycling Costs, AES 12047831-2-1, prepared by Intertek APTECH for National Renewable Energy Laboratory and Western Electricity Coordinating Council, April 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.

[207] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012,, Section 9.4.

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.[208] 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 may require specialized (but available) simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements.[209] Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

FIGURE 15. DELIVERABILITY CAPACITY NEEDS AT 40% RENEWABLE ENERGY

Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 99.

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.

[208] Midwest ISO, *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011. , pp 29-33.

[209] For an example of the quantification of these benefits, see Pfeifenberger, Ruiz, Van Horn, The Value of Diversifying Uncertain Renewable Generation through the Transmission System, BU-ISE, October 14, 2020.

B.8 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.[210] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

B.9 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

[210] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 et al., September 24, 2012.

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.[211] 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 compared to the flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch.[212]

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.

[211] U.S. Department of Energy, Report to Congress, *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, DOE/S-0138, April 30, 2003, pp 7-8 and 41-42.

[212] R.R. McNamara, Affidavit on behalf of Midwest ISO before the Federal Energy Regulatory Commission, Docket ER04-691-000, on June 25, 2004, p 14.

Appendix C – 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 loadserving 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.

C.1 Storm Hardening and Wildfire Resilience

In regions that experience storm- or wild-fire induced transmission outages, certain transmission upgrades can improve the resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where production cost impacts and the value of lost load can be very 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.[213] Adding transmission on geographically sufficiently separate rights of ways will mitigate risks even if each of the transmission paths face equal risks of storm or wild-fire induced outages.

C.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

[213] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 79–80.

market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[214]

C.3 Synergies with Future Transmission Projects and Asset Replacement Needs

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.[215] 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.[216] 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. Finally, as discussed in the main body of this report, New York's Public Policy Transmission Projects, built on the right of way of aging transmission facilities that would need to be replaced within the next decade, offer significant cost savings by avoiding having to replace the aging facilities in the future.[217] These benefit of synergies with the replacement of aging facilities on scarce and valuable rights of way is particularly important because as PJM explains, for example:

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[214] For example, see *id.*, p 80.

[215] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp 9–21. Tehachapi region referred to as Kern County.

[216] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[217] Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

> The regional high-voltage transmission system is aging. Many facilities were placed in service in the 1960s or earlier and are deteriorating and reaching the end of their useful lives. Within PJM, nearly two-thirds of all bulk electric system assets are more than 40 years old and more than one third are more than 50 years old. Some local lower-voltage equipment, especially below 230 kV, is approaching 90 years old.[218]

C.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 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.

[218] PJM “*The Benefits of the PJM Transmission System*” PJM Interconnection at 5 (April 16, 2019). See also see also Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty in FERC Docket ER20-2308-000, on behalf of LS Power, July 23, 2020.

C.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.

C.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.[219]

C.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

[219] V. Budhraja, J. Balance, J. Dyer, and F. Mobasher, *Transmission Benefit Quantification, Cost Allocation and Cost Recovery*, Final Project Report prepared for CIEE by Lawrence Berkeley National Laboratory and CERTS, Proj. Mgr. J. Eto, June 2008, pp 43-44.

deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant 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.[220] SPP has also estimated that the additional export capability created by its portfolio of ITP projects increases SPP wheeling-out revenues, which offsets the present value of its transmission revenue requirements by over $600 million, thereby offsetting a meaningful portion of the costs of SPP regional transmission project, even though these projects were not specifically planned to increase export capability.[221]

C.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.[222] 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

[220] For example, see Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 73-76.

[221] SPP, *RCAR 2 Report* (spp.org), July 11, 2016, Figure 7.1

[222] 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).

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.[223]

C.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;[224] (2) supply voltage and frequency support;[225] (3) improve transient stability[226] and reactive performance;[227] (4) provide AC system damping;[228] (5) serve as a "firewall" to limit the spread of system disturbances;[229] (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;[230] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of

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[223] Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008, Appendix A.

[224] M. P. Bahrman, "HVDC Transmission Overview," *Transmission and Distribution Conference and Exposition, 2008*. T&D. IEEE/PES, April 21-24, 2008), p 5.

[225] S. Wang, J. Zhu, L. Trinh, and J Pan, "Economic Assessment of HVDC Project in Deregulated Energy Markets," *Electric Utility Deregulation and Restructuring and Power Technologies*, 2008. DRPT 2008. IEEE Third International Conference, pp18, 23, 6-9 April 2008, p 19.

[226] Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society (PES), *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

[227] As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, *Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas*, October 2010, p 51; (2) European Wind Energy Association, *Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource*, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A> Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

[228] Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society, *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

[229] Siemens, "HVDC PLUS (VSC Technology): Benefits," n.d. .

[230] L. P. Lazaridis, *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability*, Master's Thesis X-ETS/ESS-0505, Royal Institute of Technology Department of Electrical Engineering, 2005, p 34.

the network.[231] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[232] 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.[233]

[231] As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas, October 2010, p 51; (2) European Wind Energy Association, Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A. Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

[232] PJM Interconnection, "2008 RTEP — Reliability Analysis Update," Transmission Expansion Advisory Committee (TEAC) Meeting, October 15, 2008, pp 8-10.

[233] Pfeifenberger and S. A. Newell, Direct Testimony on behalf of The AWC Companies, before the Federal Energy Regulatory Commission, Docket No. EL11-13-000, December 20, 2010.

Appendix D – Approaches Used to Quantify Transmission Benefits

(Source: 2013 Brattle report for WIRES[234])

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1. Traditional Production Cost Savings – See Section IV.2.				
2. 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

[234] Chang, Pfeifenberger, and Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
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
3–4. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings				
Transmission Benefit		**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
3. 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)
4. 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

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
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

5–6. Market, Environmental and Public Policy

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
5. 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)
6. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emissions 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)	
7.	**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)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/406

DISCONNECTED: THE NEED FOR A NEW GENERATOR INTERCONNECTION POLICY, *AMERICANS FOR A CLEAN ENERGY GRID* (JANUARY 2021)

January 19, 2022

January 2021

Americans for a Clean Energy Grid

DISCONNECTED: THE NEED FOR A NEW GENERATOR INTERCONNECTION POLICY

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Report Sponsors

This report was sponsored by Americans for a Clean Energy Grid, with support from the Macro Grid Initiative.

About Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is the only non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high voltage grid.

Expanded high voltage transmission will make America's electric grid more affordable, reliable, and sustainable and allow America to tap all economic energy resources, overcome system management challenges, and create thousands of well-compensated jobs. But an insular, outdated and often short-sighted regional transmission planning and permitting system stands in the way of achieving those goals.

ACEG brings together the diverse support for an expanded and modernized grid from business, labor, consumer and environmental groups, and other transmission supporters to educate policymakers and key opinion leaders to support policy which recognizes the benefits of a robust transmission grid.

About the Macro Grid Initiative

The Macro Grid Initiative is a joint effort of the American Council on Renewable Energy and Americans for a Clean Energy Grid to promote investment in a 21st century transmission infrastructure that enhances reliability, improves efficiency and delivers more low-cost clean energy. The Initiative works closely with the American Wind Energy Association, the Solar Energy Industries Association, the Advanced Power Alliance and the Clean Grid Alliance to advance our shared goals.

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I. Executive Summary

America's system for planning and paying for the nation's transmission grid is causing a massive backlog and delay in the construction of new power projects. While locally produced electric power is gaining in popularity, most of the lowest cost new power production comes from projects which are located in rural areas and, thus, depend on new electricity lines to deliver power to the urban and suburban areas which use most of the nation's power. Project developers must apply for interconnection to the transmission network, and until the network capacity is expanded to accommodate the resources, the projects must wait in an "interconnection queue." At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.[1]

This massive backlog has multiple negative impacts on the nation. First, it needlessly increases electricity costs for America's homes and businesses in two ways: (1) it slows or prevents the adoption of new power sources which are cheaper than existing power generation; and (2) it also significantly increases the costs of each new power source. Americans for a Clean Energy Grid's (ACEG) recent study demonstrates that a comprehensive approach to building transmission to connect remote power resources to electricity load centers in the Eastern half of the U.S. can cut consumers electric bills by $100 billion and decrease the average electric bill rate by more than one-third, from over 9 cents/kWh today to around 6 cents/kWh by 2050,

Key Findings

- The current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient it is creating a huge backlog of unbuilt energy projects. At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.
- This backlog is needlessly increasing electricity costs for consumers by delaying the construction of new projects which are cheaper than existing electricity production.
- Because most of these projects are located in remote rural areas, this backlog is harming rural economic development and job creation.
- Almost 90 percent of the backlog is for wind, solar, and storage projects. The backlog may delay or prevent achievement of commitments that states, utilities, and Fortune 500 companies have made to scale up their renewable energy use or reduce their pollution.
- The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.
- Although Regional Transmission Orgizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have undertaken worthwhile attempts to alleviate interconnection backlogs, the interconnection queues remain costly, lengthy, and unpredictable.
- The current "participant funding "policy that places nearly all costs of shared large network upgrades on the interconnection customer violates FERC's "beneficiary pays" principle and is therefore no longer a "just and reasonable" policy and violates the Federal Power Act.

1 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

Key Recommendations

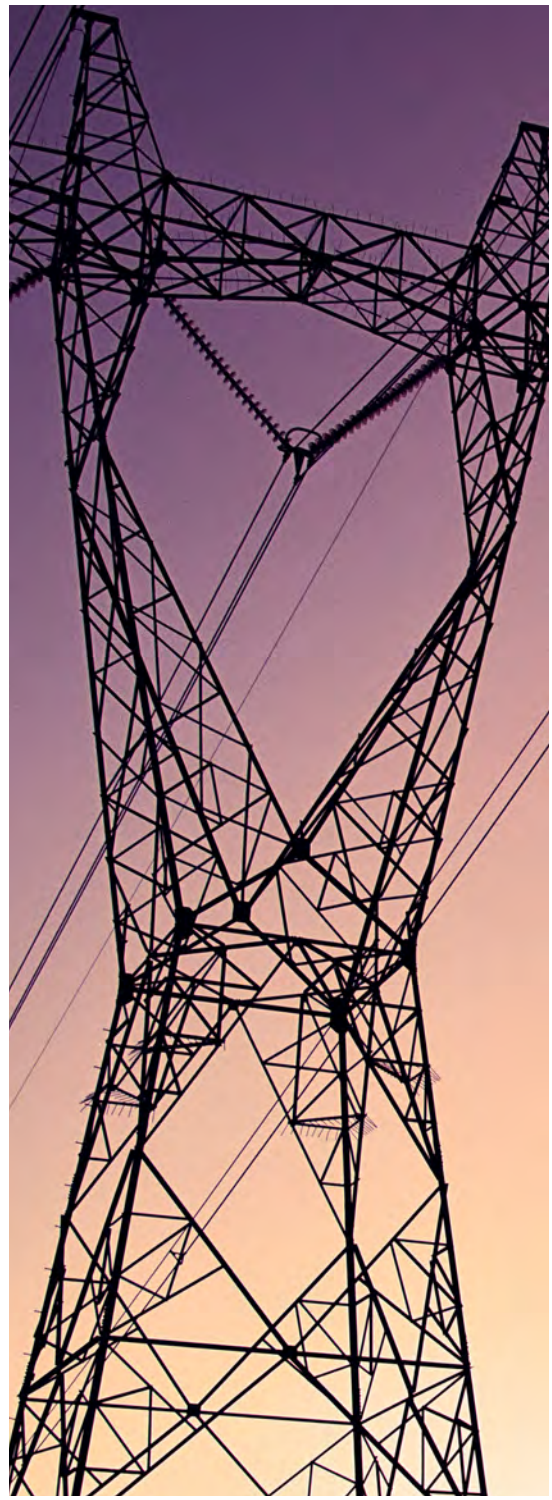
- FERC should discontinue the policy of participant funding for new generation. Shared network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be fully assigned to interconnection generators.
- FERC and planning authorities should expand and improve regional and inter-regional transmission planning processes to be pro-active, incorporating future generation additions and retirements and the multiple benefits, and spread costs to all beneficiaries.

saving a typical household more than $300 per year.[2]

Second, because the lowest cost proposed power projects are often located in rural areas, this backlog is blocking rural economic development and job creation. In addition, rural power projects expand the tax base of local communities and typically generate lease payments or other revenue for farmers and other landowners. New transmission in the Eastern half of the U.S. alone will unleash up to $7.8 trillion in investment in rural America and create more than 6 million net new domestic jobs.[3]

Third, almost 90 percent of the backlog is for wind and solar projects, thus blocking the resources which dominate new electricity production, reflecting the changing resource mix in the power sector and America's abundance of high-quality renewable resource areas where the sun shines bright and the wind blows strong.[4] The U.S. Energy Information Administration (EIA) projects wind and solar will account for 75 percent of new electricity generation in 2020.[5] Many states, utilities, Fortune 500 companies and other institutions have adopted large commitments or requirements to scale up their renewable energy use or reduce their carbon pollution and this backlog may delay or impede achievement of these commitments or requirements. In addition, delays in developing these projects unnecessarily exposes Americans, especially those in environmental justice communities, to the harmful impacts of smog, and nitrogen oxide, sulfur dioxide, fine particulate and carbon dioxide pollution.

Policies governing the interconnection of generators to the grid network stand in the way of accessing these remote resources. Interconnection policies and procedures governing transmission engineering studies, queuing, and allocating transmission upgrade costs are set by the Federal Energy Regulatory Commission (FERC) and implemented in



2 Christopher T.M. Clack et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, October 2020.

3 *Id.*

4 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

5 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

detail by all of the hundreds of transmission providers around the country including the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).[6]

Although FERC and the RTOs have undertaken worthwhile reforms to alleviate interconnection backlogs, the interconnection queues are costly, lengthy, and unpredictable. Power project developers are uncertain if their project will be approved and this risk significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.

The current process also places nearly all costs of network upgrades on the energy project developer, even though many others will benefit from the construction of the project. Until a few years ago, these interconnection charges for new renewable resources would comprise under 10 percent of the total project cost for most projects. In recent years - due to the lack of sufficient large-scale transmission build - these costs have dramatically risen and interconnection charges now can comprise as much as 50 to 100 percent of the generation project costs. The system has reached a breaking point recently as spare transmission has been used up. Presently in most regions, new network capacity is needed for almost all of the projects in the queues.

Participant funding for new grid connections is no longer a "just and reasonable" policy and violates FERC's "beneficiary pays" principle and the Federal Power Act. Relying on the interconnection process to identify needed transmission leads to a piecemeal approach and inefficiently small upgrades, raising costs to consumers. The incremental reforms at the RTO-level over the past decade have only served to treat symptoms of this fundamental issue – the lack of alignment between regional planning processes and the interconnection process.

There is a better way. RTOs could conduct comprehensive transmission planning which would identify the transmission lines to connect many new energy projects to the grid and deliver the greatest benefits for consumers. It is time for FERC and RTOs to undertake a fundamental re-thinking of interconnection and transmission planning policy based on different circumstances than those that existed when these policies were developed. Full participant funding should no longer be allowed in RTO or non-RTO areas.

More broadly, FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning.

This paper is structured as follows:

- Section II explains the origin of current interconnection policy;
- Section III describes implications of a different set of resources than those for which the policies were designed;
- Section IV provides evidence that the current policy no longer works for the current mix;
- Section V describes incremental solutions to those problems;
- Section VI argues that the real solution must involve broader transmission planning reform; and
- Section VII concludes.

[6] Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

II. Interconnection Queue Policy Inherited from a Bygone Era

Generator interconnection policy was established two decades ago when almost all new interconnecting generators were natural gas-fired. Gas generators can interconnect with transmission systems in a relatively wide variety of locations, allowing them to avoid transmission constraints. As a result, transmission planning is less important with gas generation, as locational wholesale market prices and network upgrade costs assigned to interconnecting generators are able to direct gas generation investment to economically efficient locations.

Our current interconnection policies are an increasingly obsolete vestige of that era. FERC Order No. 2003, issued in the year 2003, standardized Large Generator Interconnection Procedures (LGIPs) and Large Generator Interconnection Agreements (LGIAs). As part of the Order, FERC determined that RTOs may propose that interconnecting generators be solely responsible for paying for Generation Interconnection (GI) network upgrades—a cost allocation policy referred to as "participant funding."[7] The Commission reasoned that "...under the right circumstances, a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach."[8] The policy also included a serial approach to interconnection, wherein each generator was reviewed independently for its own impacts on the network in the order they enter the interconnection queue. The Commission's participant funding policy applied only to RTOs and not to utilities non-RTO areas.

That policy of a generator-by-generator transmission planning process and individual assignment of network upgrade costs worked reasonably well for the gas generation additions of the early 2000s. A whopping 191,745 megawatts (MW) of natural gas capacity was added between 2000 and 2005,

7 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 28, July 24, 2003. *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

8 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 695, July 24, 2003.

compared to 23,434 MW for the entire decade from 2010-2019.[9] After that gas generation boom, the resource mix of new interconnecting generators changed as interest in renewable energy grew among states and customers and the costs of utility-scale wind and solar projects continued to decline. Utility-scale wind and solar projects have dominated generating capacity additions over the last decade, with around 100,000 MW added, and they are expected to account for an even larger share of capacity additions going forward.

The transmission policy embodied in FERC Order 2003 that provided efficient incentives for the siting of gas generation has proven inefficient and unworkable for today's resource mix. Wind, and to a lesser extent solar generation, is heavily location-constrained, unlike gas generation. Wind turbines located near the best wind resources are several times more productive than wind turbines at a typical site selected at random, while the best solar resource sites are about twice as productive as less optimal sites, corresponding to a proportional impact on the cost of energy from renewable energy resources. Wind and solar are also scalable and benefit from economies of scale, so most projects are large and built in remote areas where large amounts of land are available at low cost.[10] As a result, these renewable projects often require larger transmission upgrades to serve load.

As wind capacity grew in the late 2000s, interconnection queues became overloaded in certain areas. When transmission capacity extending to good wind resource areas reached capacity, large network upgrade costs would be assigned to the next wind projects entering the queue. When these wind project owners saw the hefty price tag and the difference between what they were paying compared to their competitors that might have been just ahead of them or behind them in the queue, they would often drop out of the queue. Often one project would be assigned a high cost to upgrade the network, but then subsequent projects could utilize the capacity that project created, such that the subsequent project would be assigned a lower cost. When one project drops out, costs are typically shifted onto others, causing a domino effect of cancellations. Project developers, knowing there was a chance of getting lucky with a lower network upgrade cost assignment, had an incentive to enter multiple project proposals and multiple locations. Thus, many projects would enter queues, and many projects would cancel, leading to a cycle of continuous churn. RTOs are required to study all projects, leading to lengthy workloads and inevitable delays.

Over the years FERC and RTOs have noticed the problem and attempted to fix it with process changes. In 2008, FERC held a technical conference to discuss interconnection queue-related issues that arose after Order No. 2003, and issued an Order directing RTOs to develop solutions to address queue delays and backlogs.[11] RTOs held numerous interconnection queue reform stakeholder processes, many resulting in FERC filings and tariff changes. Some of these incremental reforms, as described in more detail below, helped to reduce the churn and the quantities of projects backlogged in the queue. MISO stakeholder fora such as the Interconnection Process Task Force and the Planning Advisory Committee, for example, developed a series of queue reforms between 2008 and 2012 to address queue delays and project cancellations.[12] In 2016, MISO proposed tariff revisions to minimize restudies and introduced new milestones to improve project readiness, among other revisions to improve process efficiency.[13] MISO later built upon these reforms in 2018 to reduce cancellations and logjams by eliminating fully refundable milestone payments and requiring site control demonstration.[14]

SPP, like MISO, experienced high renewable energy interconnection interest in the late 2000s and reformed its interconnection process to transition to an approach that discouraged speculative projects

9 Headwaters Economics, *U.S. Generation Capacity, 1950-2030*, Updated April 2020.

10 American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 30-42, May 2019.

11 *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, March 20, 2008.

12 MISO, *Filing of Revisions to the Open Access Transmission, Energy and Operating Reserve Markets Tariff to Reform MISO's Generator Interconnection Procedures*, at 5-6, December 31, 2015.

13 *Id.* at 3-4.

14 Jasmin Melvin, *FERC Clears MISO Interconnection Reforms Targeting Recent Influx in Speculative Projects*, December 4, 2019.

from proceeding through the queue. These reforms included a "first-ready, first served" policy and a greater use of cluster interconnection studies, among other measures.[15] In 2013, SPP further increased milestone requirements and required generators to post a financial milestone upon execution of a Generator Interconnection Agreement (GIA),[16] and in 2019 further refined its interconnection process to include a three-stage study process with financial deposits required at each stage.[17]

As renewable energy expanded into the Mid-Atlantic states in the 2010s, PJM began facing the same challenges. In 2012, FERC accepted PJM tariff modifications selected by the PJM Interconnection Process Senior Task Force, which among other changes, extended the length of the queue cluster to avoid queue study overlap and associated restudies.[18] The reforms also included an alternate queue for the hundreds of projects under 20 MW that were observed to drop out at higher rates and trigger constant restudies.

California proceeded down a similar policy evolution as MISO, SPP, and PJM. After transitioning to a cluster approach in 2008 and creating requirements to demonstrate project viability,[19] CAISO filed tariff revisions in 2010 to combine its small and large generator interconnection procedures in an attempt to streamline the processes.[20] Citing an increase in renewable generator interconnection requests due to renewable portfolio standards and related dropouts, CAISO later filed additional revisions in 2012 to integrate the transmission planning process and generation interconnection procedures.[21] In 2013, CAISO launched its first Interconnection Process Enhancement initiative, a stakeholder process to improve interconnection procedures.[22]

Despite these various incremental reforms at the RTO level, however, the fundamental problem driving the queue backlog, a reliance on participant funding and individual generators to build a large share of needed transmission upgrades, remains in place. The share of location-constrained relative to location-flexible generation continued rising through the 2010s, and increasingly affected solar generation as well as wind. Multiple RTOs continue to tinker with reforms to generator interconnection queue processes.[23]

FERC also acted again in 2016 by holding another technical conference[24] on generator interconnection issues partially in response to a 2015 request of formal rulemaking from the American Wind Energy Association to revise FERC's proforma LGIP and LGIAs.[25] The Commission later issued Order No. 845 in 2018,[26] which addressed queue interconnection procedure issues by revising FERC's pro forma LGIP and LGIA's to implement ten specific reforms. The Order was followed up by Order No. 845-A in 2019,[27] which left Order No. 845's major reforms intact, but amended the LGIP and LGIA in an attempt to further improve interconnection processes.

15 *Southwest Power Pool, Inc.*, 167 FERC ¶ 61,275, at P 4, June 28, 2019.

16 *Id.* at P 5.

17 *Id.* at P 11-13.

18 *PJM Interconnection L.L.C. Filing Via eTariff*, at 5, February 29, 2012.

19 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 28, January 2009.

20 *California Independent System Operator Corporation*, 140 FERC ¶ 61,070, at P 3, July 24, 2012.

21 *Id.*

22 *Reform of Generator Interconnection Procedures and Agreements*, Docket No. RM17-8, at 4, April 13, 2017.

23 MISO, for example, recently created the Coordinated Planning Process Task Team in November of 2019 to examine how MISO can better coordinate the separate studies underlying the generator interconnection process and the MISO transmission expansion plan. See Amanda Durish Cook, *MISO Floats Ideas on MTEP, Interconnection Coupling*, May 17, 2020. PJM is in the midst of holding interconnection process workshops to explore potential queue reforms that would allow for more renewable and storage resources to interconnect. See PJM, *Update: Interconnection Process Workshop Dates Announced*, October 6, 2020.

24 *Transcript of FERC Technical Conference on Generator Interconnection Agreements and Procedures and the American Wind Energy Association*, Docket No. RM16-12, May 13, 2016.

25 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, June 19, 2015.

26 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, April 19, 2018.

27 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137, February 21, 2019.

III. Implications of a Different Resource Mix

Interconnection policy must work for the resource being interconnected, and the resource mix is clearly changing.[28] Regardless of climate or clean energy policies, renewable energy growth is nearly certain because the costs of renewables have fallen so much to make them competitive with any other resource. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[29] As a result of falling costs, consumer preferences, and public policies, wind and solar resources now make up the majority of resources in interconnection queues across the country.[30] There were 734 GW of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90 percent of which were renewable and storage resources.[31] In 2019 alone, 168 GW of solar and 64 GW of wind projects entered interconnection queues, as shown in figure 1. The U.S. EIA forecasts that wind and solar will make up over 75 percent of new capacity additions in 2020.[32]

When an increasing amount of location-constrained generation applies for interconnection in the same area, the grid begins to require not only "driveway" type transmission facilities, but also bigger roads and highways. Much like a new community of homes requires a webwork of larger roads to connect to neighboring towns, a more regional network is needed for the U.S. power system. What we are observing is that interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades. This is a predictable dynamic.

The future resource mix is made up increasingly of wind and solar energy, which are location-constrained, so it is quite predictable that larger regional network upgrades will be identified in the interconnection processes. Unfortunately, large system upgrades are not efficiently planned or paid for by the interconnection process, which relies on generator-by-generator assessments and participant

28 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data* Update accompanying the slide deck.

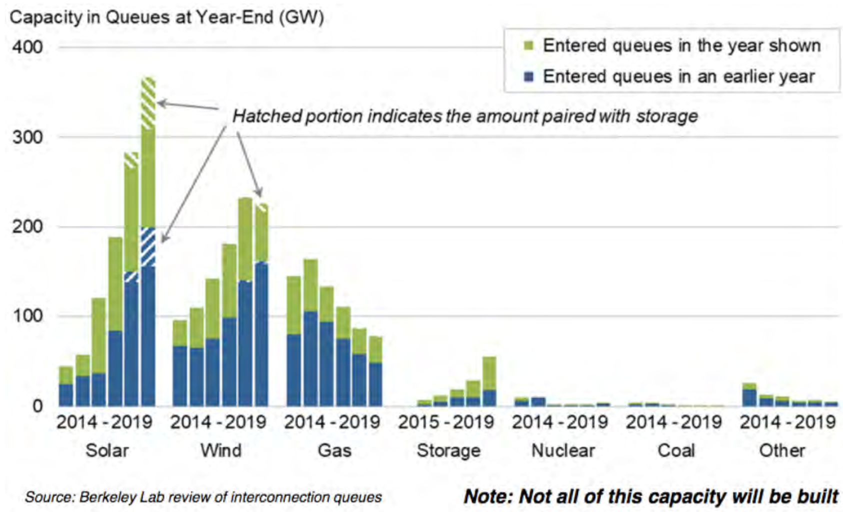
29 Lazard, Lazard's *Levelized Cost of Energy Analysis - Version 13.0*, a 8, November 2019.

30 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

31 *Id.*

32 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

Figure 1: Capacity in Queues at Year-End by Resource Type



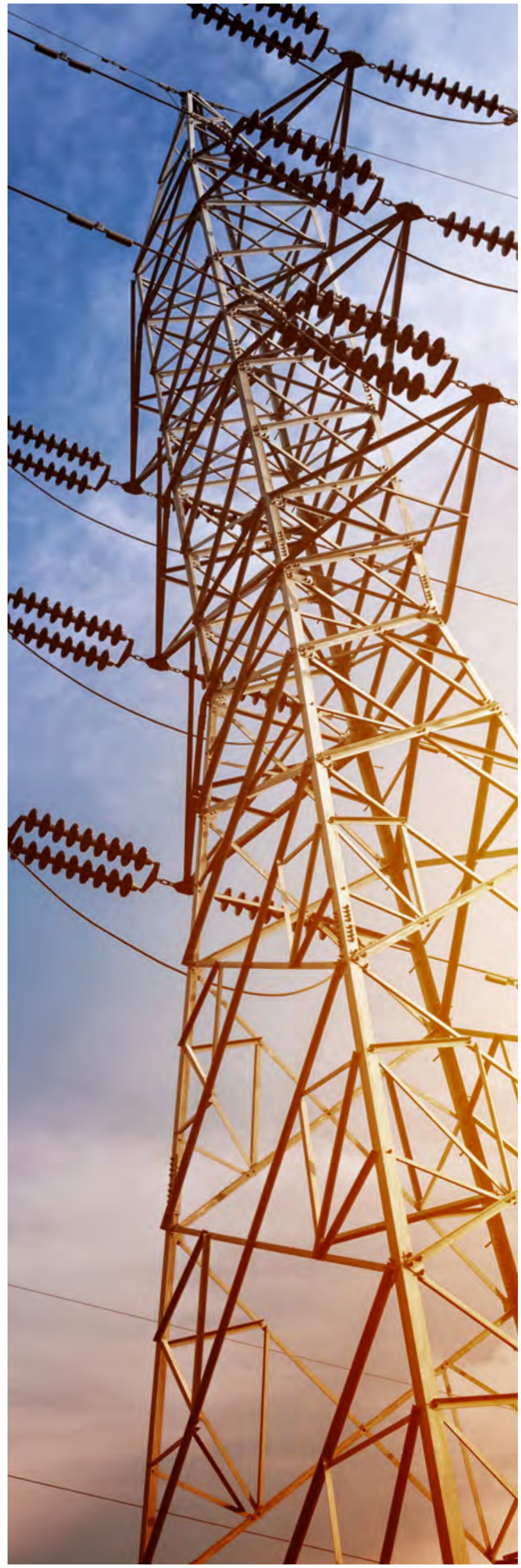
funding for network upgrades. Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are borne by the incoming generator.[33] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[34] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[35]

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and regional transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays. This problem could potentially be addressed by broader transmission planning reform to support holistic, proactive planning processes in conjunction with accompanying narrow Order No. 2003 reform eliminating participant funding.

33 See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

34 *Id.*

35 For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).



The current process also misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades. Given the broad benefits of large-scale regional transmission, it is a violation of FERC's "beneficiary pays" principle to place all the costs of large network upgrades on the interconnection customer. It is clear that the large upgrades being identified and assigned to generators in interconnection studies would provide benefits to users across the network, even if those may be difficult to quantify with certainty. FERC Commissioner LaFleur noted the challenges with the siloed study processes when she commented "...where does the interconnection process leave off and the transmission planning process start?"[36]

Transmission expansion planning for generator interconnections based on generator-by-generator assessments will not result in optimal plans as the resource mix continues to change. Moving to studying clusters of generators simultaneously, as some areas have done, is a step in the right direction. However, current cluster approaches are still based only on what is in the current queue rather than well-known information about what generation is coming and where it is likely to be, and still does not account for the economic and reliability benefits of the transmission expansion.

36 *See* transcript of FERC technical conference in the matter of *Review of Generator Interconnection Agreements and Procedures*, Docket No. RM16-12, at 47, May 13, 2020.

IV. Evidence of a Broken Interconnection Policy

a) Upgrade costs assigned to customers are high

Analysis by Lawrence Berkeley National Laboratory, shown in tables 1 and 2 below, indicates that the costs to integrate new resources, not just renewable projects, have reached levels that are unreasonably high for a developer to proceed in MISO and PJM. As expected, the costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than "driveway" type facilities are needed; larger roads and highways are required to alleviate the traffic. Table 1[37] below shows that historically, interconnecting wind projects have incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW. For reference, this is about 23 percent of the capital cost of building a wind project.

Table 1: MISO Interconnection Costs for Selected Utility-Scale Projects (as of 2018)

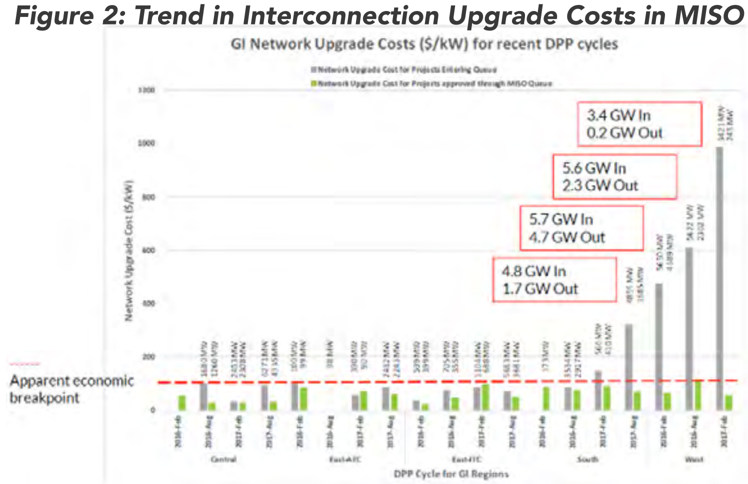
				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	55	$0.55	14,642	$38	$31	$55	$0.34	$0.28	$0.50
Wind	161	$4.51	23,232	$194	$66	$317	$2.48	$0.85	$4.05
Solar	33	$0.18	3,277	$56	$70	$53	$1.56	$1.95	$1.48
Coal	19	$0.01	2,991	$4	$4	NA	$0.03	$0.03	NA
Hydro	13	$0.06	4,234	$13	$13	NA	$0.18	$0.18	NA

[37] Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 10, October 2019.

New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total $307/kW, with upgrade costs for individual interconnection requests as high as $677/kW.[38]

The rapidly increasing cost of interconnection in recent years shows that the breaking point has been reached. MISO, for example, has reported that "…interconnection studies for new generation resources in MISO's West sub-region have indicated the need for network upgrades exceeding $3 billion to accommodate the initial queue volume, and a similar trend is expected to occur in other areas with high wind and solar potential, including MISO's Central and South sub-regions."[39] Figure 2[40] below illustrates the large increase in assigned network upgrade costs to generators in MISO West, from approximately $300/kW in 2016 to nearly $1,000/kW in 2017. The costs to build proposed wind projects will likely result in developers abandoning those resources as project integration costs exceed $100/kW.

Figure 2: Trend in Interconnection Upgrade Costs in MISO



The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were $0.25/MWh and $1.72/MWh, respectively, or $19.07 kW and $61.83/kW, respectively. As shown in Table 2,[41] upgrade costs for newly proposed wind and solar projects, however, have now risen to $0.69/MWh and $3.66/MWh, respectively, or $54/kW and $131.90/kW, respectively – more than a 100 percent increase.

Table 2: PJM Interconnection Costs for Selected Utility-Scale Projects (as of 2019)

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	98	$1.43	38,733	$36.92	$18.40	$76.63	$0.34	$0.17	$0.70
Wind	72	$0.25	10,859	$22.73	$19.07	$54.10	$0.30	$0.25	$0.69
Solar	134	$1.17	10,057	$116.17	$61.83	$131.90	$3.22	$1.72	$3.66
Coal	4	$0.05	1,303	$36.26	$36.26	NA	$0.25	$0.25	NA
Nuclear	2	$0.03	1,674	$19.63	$19.63	NA	$0.12	$0.12	NA

38 MISO, *Final MISO DPP 2019 Cycle 1 South Area Study Phase I Report*, at 8-15, July 16, 2020.

39 MISO, *MISO 2020 Interconnection Queue Outlook*, at 9, May 2020.

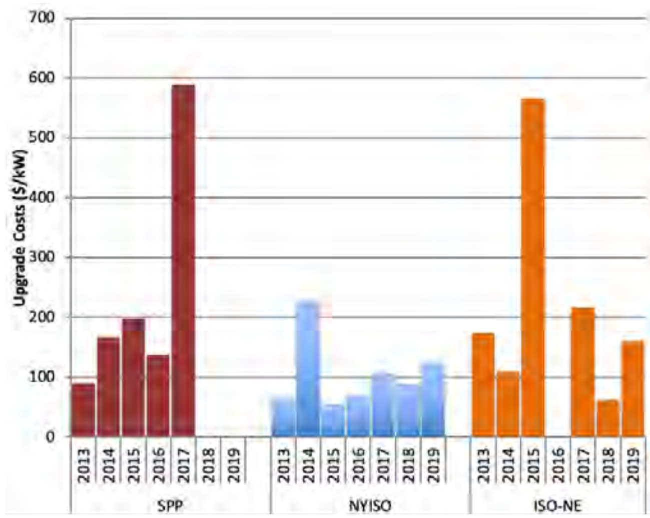
40 ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

41 Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 12, October 2019.

In 2019, one 120 MW solar plus storage project in southern Virginia was informed it could be required to pay as much as $1.5 billion, or $12,086/kW, in system upgrades in order to connect to the PJM grid.[42] Among the many upgrade costs associated with the GI request includes the demolition and rebuilding of a handful of 500kV lines.[43] The construction of large transmission lines required by some interconnection studies which leads to such high network upgrade costs are not isolated incidents. A number of offshore wind projects in PJM, for example, are expected to build long, 500kV lines that are clearly network elements that benefit the entire region and should be planned and paid for through the regional planning process.[44]

This trend of rising network upgrade costs is happening across RTOs as the ratio of location-constrained generation rises and the existing network in the renewable resource areas becomes constrained. The typical increase in costs over time associated with GI studies, as shown in Figure 3[45] below, are indicative that the assigned network upgrades are high enough that most projects will not proceed.

Figure 3: Trend in Generator Interconnection Network Upgrade Costs in SPP, NYISO, and ISO-NE ($/kW)



In SPP, GI-assigned network upgrade costs from the 2013 interconnection queue were roughly $89/kW while the most recent 2017 study costs approached $600/kW. Put differently, network upgrade costs increase from composing around 8 percent of the capital cost of wind generation, to over 43 percent.[46] The most recent 2017 SPP study upgrade costs included massive 765kV lines up to 165 miles long.[47]

42 PJM, *Generation Interconnection Feasibility Study Report for Queue Project AE1-135*, at 6, January 2019.

43 *Id.* at 18.

44 *See* PJM, *Generator Interconnection Feasibility Study Report for Queue Project AF2-193*, at 15, Revised August 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-251*, at 58, February 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-122*, at 28, February 2020.

45 *See* publicly available SPP, *Generator Interconnection Studies* (note that SPP is behind in processing impact studies). NYISO and ISO-NE generator interconnection studies are not available to the public and require a Critical Energy Infrastructure Information (CEII) non-disclosure agreement with the ISOs.

46 In 2019, installed wind power project costs were approximately $1,387/kW in the region that includes most of SPP and MISO. We use the range of network cost increases from SPP generator interconnection studies and the aforementioned cost of installed wind power projects to estimate network upgrade costs as a share of the cost of generation in 2013/2014 vs. 2016. See Ryan Wiser et al., *Wind Energy Technology Data Update: 2020* Edition, at 56, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

47 *See* tab titled "Assigned Upgrade Costs" in SPP *DISIS-2017-001 Phase One*, Revised, November 11, 2020.

NYISO has also experienced an increase in upgrade costs from $67/kW in 2013 to $124/kW in 2019. Experience in ISO-NE on the other hand, while not a linear display of upgrade cost increases, demonstrates how high the network upgrade costs can get in any given year with 2015 upgrade costs reaching $566/kWs. Upgrade costs for ISO-NE also increased by 160 percent from 2018 to 2019.

b) Paying for transmission through the interconnection process fails to capture efficiencies that benefit all users

The system of funding major transmission upgrades through the generation interconnection process is ineffective and violates the beneficiaries pays principle. Large new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others. MISO, for example, has estimated that its 17 Multi-Value Projects (MVPs) approved in 2011 will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, producing cost-to-benefit ratios ranging from 1.8 to 3.1.[48] Additionally, SPP's portfolio of transmission projects constructed between 2012 and 2014 is estimated to generate upwards of $12 billion in net benefits over the next 40 years, with a cost-to-benefit ratio of 3.5.[49] Charging only interconnecting generators for the construction of transmission additions that generate benefits similar to those found in MISO and SPP is a classic example of the "free rider" problem. This type of market failure found in various other economic sectors involving networks, such as water and sewage systems and highways, signals why it is more efficient to broadly allocate the cost of "public goods." If required to pay for upgrades that mostly benefit others, interconnecting generators tend to balk and drop out of the interconnection queue.

c) Interconnection queue project cancellations are rising

The interconnection process relies upon sequential studies that are highly unpredictable for participating generators who do not know whether their interconnection request

48 MISO, *MTEP19*, at 6-7, n.d.

49 SPP, *The Value of Transmission*, at 5, January 26, 2016.

will require large upgrades. The uncertainty of interconnection costs leads wind and solar developers to often submit multiple interconnection applications for the same generator, typically for different project sizes, configurations, and interconnection points, which leads to a queue with far more projects than will actually be developed. This is a rational strategy from the developer's perspective; however, the proliferation of projects only exacerbates the number of re-studies and the number of uncertainties that can affect every project. When studies reveal significant costs, those projects tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and often higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. That vicious cycle continues, with the next round of wind and solar projects submitting even more interconnection applications to protect against this uncertainty. Cancelled projects lead to a vicious reinforcing cycle increasing the potential of further cancellations.

The high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue, which exacerbates the uncertainty. Between January of 2016 and July of 2020, 245 clean energy projects in advanced stages of the MISO generator interconnection process chose to withdraw from the queue.[50] Interviews with the owners of these projects indicates that network upgrade costs were the primary reason for withdrawing.

Queue dropout rates are increasing. In 2019, approximately 3.5 of 5 GWs of renewable energy projects that had been a part of the MISO West 2017 study group dropped out of the interconnection queue due to high transmission upgrade costs. These projects, some of which already had power purchase agreements in place,[51] each faced transmission upgrade costs in the range of tens to hundreds of millions of dollars.[52] As of December of 2019, all but 250 MW of the 5,000 MWs had withdrawn from the queue. The remaining 250 MW was comprised of a 200 MW wind project and a 50 MW solar project; it is unlikely that the wind project will move forward as its engineering study showed the project would require transmission upgrades totaling $500 million.[53] This leaves the success rate at 1 percent for the MW in that queue study group.

Queue reform has attempted to reduce queue length and dropouts with larger financial deposits from interconnecting generators, yet queue backlogs continue to grow because queue reform has not addressed the fundamental problem of requiring interconnecting generators to pay for large network transmission elements that benefit the entire region.

d) Queue backlogs are large and growing

Interconnection queue timelines are increasing across the country due to the churn of re-studies and the high and unpredictable upgrade costs assignments, harming consumers' ability to access generation. Developers have said processing interconnection requests in PJM can take over two years, while processing in SPP can take nearly four years in some areas.[54] Currently, the MISO interconnection queue suggests processing times to be around three years, with the time it takes for a request to get through the process trending up over time.[55]

50 Sustainable FERC, *New Interactive Map Shows Clean Energy Projects Withdrawn from MISO Queue*, n.d.

51 Advanced Power Alliance, Clean Grid Alliance, and the American Wind Energy Association, *Comments to the SPP RSC and OMS Regarding Interregional Transmission Planning*, at 3, 2019.

52 Peder Mewis and Kelley Welf, *Clarion Call! Success has Brought Us to the Limits of the Current Transmission System*, November 12, 2019.

53 Jeffery Tomich, *Renewables 'Hit a Wall' in Saturated Upper Midwest Grid*, December 12, 2019.

54 Interviews with developers.

55 *See* MISO, *Interactive Queue*. We approximate the time it takes for an interconnection request to be processed by taking the difference between the "done date" of a request and the date the project entered the queue.

e) Interconnection challenges exist for offshore as well as onshore projects

Limitations of the current interconnection process hinder offshore wind development and state clean energy goals. Interconnection studies for offshore wind illustrate that most interconnection sites have a finite amount of capacity for new power injection before upgrade costs increase considerably, as the supply curve of available injection capacity among sites and at individual sites slopes steeply upward. According to upgrade costs estimated in PJM offshore wind interconnection studies and as shown in Appendix A, one can see that the first tranche of 605 MWs can be accommodated for an upgrade cost of around $275/kW at an interconnection site. The second tranche of 605 MW, however, incurs a marginal upgrade cost of over $1,100/kW, and the third tranche of 300 MWs incurs a marginal upgrade cost of over $1,300/kW. In this case, costs quadruple for projects later in the queue. The upgrades required for the later tranches involve rebuilding large segments of the transmission system. These investments benefit all interconnecting generators and consumers, who receive lower-cost and more reliable electricity from a stronger grid.

Appendix A also demonstrates that onshore transmission upgrade costs for interconnecting offshore generators tend to be very large. A review of 24 interconnection studies comprising 15,582 MWs of offshore wind capacity that have proposed to interconnect to PJM reveals $6.4 billion in total onshore grid upgrade costs for those projects, with an average of $413 per kW of offshore wind capacity.[56] Onshore grid upgrade costs for these offshore projects range from $10 per kW to $1,850 per kW.[57]

The status quo approach of relying on sequential interconnection studies with participant funding, without any pro-active regional planning, is leading to ballooning costs for offshore wind just like land-based renewables.

f) The problems occur mainly where participant funding is allowed—in RTOs and ISOs

FERC's interconnection policy as established in Order No. 2003 allowed participant funding inside RTOs and ISOs and not for transmission providers outside RTO/ISO areas. The problems described above are all in RTO/ISO areas. Where transmission upgrade costs are rolled into rates for all users, we do not find evidence of similar problems.

[56] Brandon W. Burke, Michael Goggin, and Rob Gramlich, *Offshore Wind Transmission White Paper*, at 14, October 2020.
[57] *Id.*

V. Incremental Solutions Can Help but Not Solve the Problem

a) Cluster study approaches have been a modest improvement

Some regions have implemented "cluster" interconnection studies, in which many interconnection requests are evaluated in the same study, as opposed to sequential project-by-project studies. The sequential processing approach is untenable for each new project that is the proverbial straw that breaks the camel's back and incurs a disproportionate share of upgrade costs. Clusters of similarly situated GI study requests, on the other hand, proved to be a preferred approach as transmission expansion is lumpy with large economies of scope and scale, so several developers in one area are able to pay a prorated share of the costs of required network upgrades. Additionally, grouping many interconnecting projects together instead of studying them individually allows for less queue reshuffling. Despite these advantages of a clustered approach, however, this does not solve the fundamental problem that all, or nearly all, costs are still assigned to interconnecting generators.

While clustering has helped in the past, it alone cannot solve the challenges associated with efficient and effective processing of generation interconnection queue requests. Current cluster sizes are extremely large in many cases, and planning for only one tranche of the future grid does not address the long-range needs, and certainly doesn't allow the capture of economies of scope and scale for large regional and interregional solutions to address aggregate network needs of resolving economic congestion and reliability concerns.

b) Eliminating participant funding would help

As part of FERC's Notice of Proposed Rulemaking (NOPR) for Order No. 2003, the Commission sought comment on whether or not they should retain their interconnection pricing policy.[58] At the time of the

[58] *Standardizing Generator Interconnection Agreements Procedures*, Notice of Proposed Rulemaking, Docket No. RM02-1, at 25, April 24, 2002.

NOPR, FERC's current policy required generators to pay 100 percent of the cost of "interconnection facilities" needed to establish the direct electrical connection between the generator and the existing transmission provider network. The costs of "network facilities," however – facilities at or beyond the point of interconnection to assist in accommodating the new generation facility (e.g. facilities needed for stability and short-circuit issues) – were borne initially by the generator and subsequently credited back to the generator through credits applied through transmission rates.[59]

In the final rule for Order No. 2003, FERC explained its reasoning for switching from such a "rolled-in" credit approach to one that is participant-funded.[60] One main reason included the credit approach's potential to provide price signals to direct developers to better locations from a network perspective. FERC argued at the time that a participant-funded pricing policy under which those who benefit from the project pay would help solve this problem.

FERC's decision to allow participant funding was based on the gas generation being added at the time. The Commission agreed with a number of commenters that objected to how the credit approach diminishes the incentive for interconnection customers to make efficient siting decisions while taking into account new network upgrade transmission costs, while effectively subsidizing interconnection customers who decide to sell output off-system.[61] The participant funding of network upgrades, FERC argued, would send more efficient price signals, more equally allocate costs, and potentially provide the framework necessary to allow incumbent transmission owners to overcome their reluctance to build much needed transmission.

The failure of the current system under the new resource mix, including excessive costs and risk, an inability to build needed transmission, and generators paying for large network upgrades that primarily benefit customers suggest that participant funding may no longer be a just and reasonable policy. Participant funding of network upgrades not only imposes costs on interconnection customers that are often exorbitant and rising, but is also not the solution to the inability to build large-scale transmission.

One policy solution would be to end participant funding for new generation. It is clear that major network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be direct assigned as a result of participant funding. The Commission can and should change this policy within the scope of interconnection policy.

c) Other incremental reforms to the interconnection process would help

The American Wind Energy Association (AWEA) petition for rulemaking in June of 2015 urged FERC to revise the pro forma LGIP and LGIA to alleviate "...unduly discriminatory and unreasonable barriers to generator market access."[62] AWEA's petition detailed a total of 14 recommendations and FERC later adopted 10 of the 14 under Order No. 845. The four recommendations FERC declined to adopt were regarding periodic restudies requirements, self-funding of network upgrades, publication of congestion and curtailment information, and the modeling of electric storage resources. In Order No. 845, FERC did not provide insight into what steps still needed to be taken to address these deficiencies in the current interconnection process.

59 *Standardizing Generator Interconnection Agreements Procedures*, Advance Notice of Proposed Rulemaking, Docket No. RM02-1, at 15, October 25, 2001. This was true unless the transmission provider elected to fund the network upgrades.

60 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 678, July 24, 2003.

61 *Id.* at P 695.

62 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, at 1, June 19, 2015.

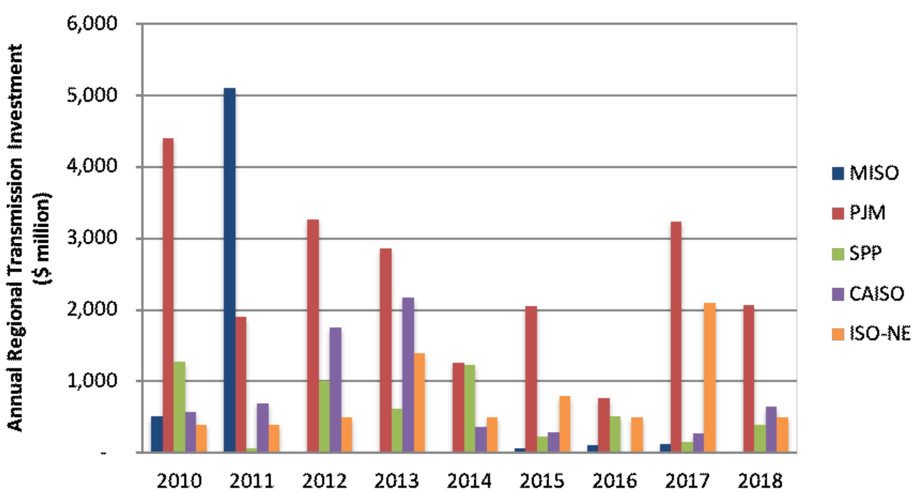
d) Interconnection process changes would still leave a shortage of efficient regional transmission

Even with the incremental changes above, there would be a continued lack of efficient regional transmission without more fundamental reforms. Integrated and comprehensive planning efforts to address to effectively integrate expected generation while also meeting economic and reliability needs have not happened since major initiatives such as Competitive Renewable Energy Zones (CREZ) in ERCOT, MVPs in MISO, and Priority Projects in SPP. Once those lines were fully subscribed, upgrade costs and queue backlogs quickly returned to unworkable levels.

While current transmission investment numbers are relatively high by historical standards, the majority of recent transmission investments have been small local projects, as demonstrated by Brattle: "[A]bout one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."[63]

Without sufficient regional and interregional transmission capacity to facilitate the integration of location-constrained resources onto the grid, the cost of constructing the network upgrades necessary to interconnect new wind and solar resources falls on generators as part of the interconnection process. As demonstrated in most RTO regional transmission planning statistics and reports, regionally planned transmission investment has decreased substantially since 2010. Specifically, between 2010 and 2018, total regionally planned transmission investment in RTOs decreased by 50 percent as shown in Figure 4.[64]

Figure 4: Annual Regionally Planned Transmission Investment in RTOs/ISOs ($ million)



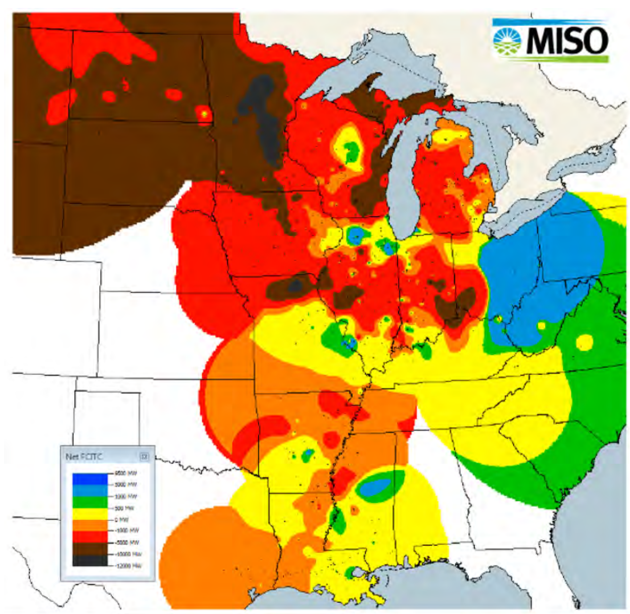
63 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 ("Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.")

64 Note: all RTOs/ISOs provide regional transmission investment information. Grid Strategies assembled data using the following sources to assemble figure 4: Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processin*g, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

There have been successful examples of region-wide coordination in planning and cost allocation achieving efficient levels of transmission investment. Transmission expansion efforts with pro-active multi-value planning and broad cost allocation, like the CREZ in ERCOT, MVPs in MISO, and Priority Projects in SPP, for example, have led to the large buildout of backbone transmission. These transmission expansion plans pro-actively incorporated wind and solar development assumptions, and also designed transmission upgrades that would maximize other economic and reliability benefits. Most importantly, these policies were successful because the costs of transmission were broadly allocated across the region, consistent with the benefits of the transmission being broadly spread across the region, instead of unworkably attempting to recover the costs through the generator interconnection process. However, these successful pro-active transmission planning efforts were not sustained. Subsequent renewable development requests in these areas have been burdened with unreasonable costs for interconnections, and queue backlogs have grown as a result.

The decline of regional plans is inconsistent with the evolving resource mix. Because the best locations for wind and solar resources are significantly different from those of retiring coal and other thermal resources, the current grid based on approved plans cannot be expected to support future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind. While almost all generation resources are location-constrained to some extent, wind and solar tend to be more constrained to areas with high-quality resources and therefore require more transmission.[65] Yet less transmission is being planned as wind and solar resources make up an increasing portion of the resource mix, which can severely constrain the amount of transmission transfer capacity out of renewable-heavy areas. Figure 5[66] below, for example, shows the majority of western MISO (highlighted in blue) had an estimated 5 GW or more deficit of transfer capacity to the rest of the region in 2016. This means that at least that amount of transmission capacity must be constructed across MISO and into the PJM region before any new generation can be added.

Figure 5: MISO West Transfer Capacity Deficit

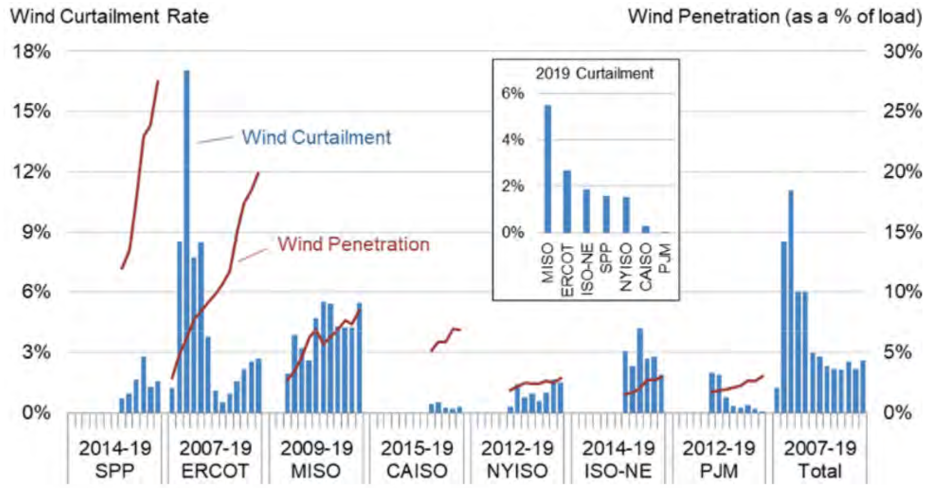


65 *See* American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 31, May 2019; Scott Madden, *Informing the Transmission Discussion*, at 29, January 2020; FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 12-14, June 2020.

66 *See* MISO transfer capacity contour map, available at https://cdn.misoenergy.org/GI-Contour_Map108143.pdf, July, 11, 2018.

Efficient regional transmission capacity for location-constrained renewables can help lower renewable curtailment levels. Average wind curtailment levels for the RTOs hovered around 2.6 percent in 2019, up from 2.2 percent in 2018, with the highest levels in MISO and ERCOT at 5.5 percent and 2.7 percent, respectively.[67] Regions with high wind curtailment levels, specifically in western MISO and northwestern ERCOT, benefitted from the construction of new, large regional transmission. As shown in Figure 6[68] below, wind curtailment in MISO decreased from 2015 through 2018 shortly after the completion of a number of MVPs in western MISO between 2013-2017.[69] Similarly, wind curtailment in ERCOT has declined dramatically since 2011 after the completion of CREZ transmission projects from 2010 through 2013 allowed more than 18,500 MWs of wind capacity to be transported throughout the state.[70]

Figure 6: Wind Curtailment and Penetration Rates by ISO



Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

67 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 49, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

68 Id.

69 MISO, *Regionally Cost Allocated Project Reporting Analysis*, October 2020.

70 ERCOT, *Report on Existing and Potential Electric System Constraints and Needs*, at iii, December 2018. U.S. Energy Information Administration, *Fewer Wind Curtailments and Negative Power Prices Seen in Texas After Major Grid Expansion*, June 24, 2014

VI. The Real Solution Must Be Regional and Inter-regional Planning Reforms

Transmission expansion needs to be driven by a multi-value plan to address overall system needs, including economics, reliability, and generator interconnection. Some regions have demonstrated success in integrated transmission plans to accommodate projected futures that resulted in very cost-effective transmission expansion. CREZ in ERCOT, MVPs in MISO and Priority Projects in SPP are case studies where loads, generators and stakeholders benefited from holistic planning efforts. SPP and MISO have found the benefits of that transmission expansion exceeded the cost by 2 to 3 times.[71]

The changing resource mix and electrification of the energy sector will have a profound impact on the future grid, yet in many cases those factors are not being included in regional and interregional planning efforts. Most recent regional planning studies have not included reasonable projections regarding the changing resource mix and expected retirements. State policies should also be accounted for in regional transmission planning process.

Network upgrades benefit everyone, and all costs ultimately flow to customers, so cost allocation needs to reflect that reality. Consumers benefit from minimizing costs and maximizing the benefits of transmission expansion. Customers are also harmed by the inefficient and unworkable status quo that attempts to force upgrade costs on interconnecting generators. This policy leads to a sub-optimal level of transmission investment, driving billions of dollars annually in unnecessary congestion and reliability costs, while the cost of energy offered to customers by generators is higher than necessary due to lengthy queue delays and risk and an inability to build generation in low-cost resource areas.

Transmission policy can and should include Grid-Enhancing Technologies (GETs), not just new infrastructure. As FERC has recognized, a set of GETs are now widely commercialized and deployable to address a number of transmission challenges speedily and at low cost. GETs can be incorporated into interconnection policy, transmission planning, and FERC incentives policy. As with infrastructure,

[71] *See* SPP, *The Value of Transmission*, at 5, January 26, 2016; MISO, *MTEP17 MVP Triennial Review*, at 4, September 2017.

addressing only interconnection policy will not be sufficient for GETs.

a) Generator lead lines should be incorporated into regional plan

In many cases, a lack of transmission capacity, queue backlogs, and excessive participant funding upgrade costs have forced renewable developers to build and own generator lead lines that are dozens of miles long. For example, wind projects such as Horse Hollow in ERCOT and Flat Ridge in SPP had in-service dates and commitments for deliveries that could not wait for approved, regionally funded Extra High Voltage (EHV) network upgrades. As a result, developers of these projects built long, high capacity EHV generator leads to integrate their projects into existing transmission facilities in advance of planned regionally funded upgrades. In the case of Horse Hollow, the developer constructed a private 345 kV line extending from West ERCOT to South ERCOT – a distance spanning ten Texas counties.[72] Often long generator leads reduce congestion and curtailments and become network elements benefitting everyone.

b) Affected system studies need to be part of improved interregional planning processes

Affected system studies occur when a generator interconnection in one RTO triggers a need for transmission upgrades in more than one RTO. These studies increase upgrade costs for generators. The fact that the transmission need is large enough to cross into another RTO clearly indicates that the transmission expansion benefits others, and therefore should be planned and paid for in a regional, and ideally inter-regional, process.

Planning is tough enough within an RTO, and the planning and cost allocation obstacles for building transmission between RTOs are currently insurmountable. Part of the problem is there is significant divergence among RTO planning processes, with different models, assumptions, benefit-cost thresholds, and timing. As a result, no large-scale transmission upgrades have been able to pass what is called the "triple hurdle," which requires an inter-regional transmission project to pass a benefit-cost ratio test in each RTO and for the entire region. The free rider problem is an even greater challenge for inter-regional cost allocation than it is within RTOs. However, the large need for inter-regional transmission will not be met without solving that problem, likely by broadly allocating the cost of inter-regional lines across those regions.

The voluntary nature of RTOs has resulted in footprints that create seams issues that stymie collaborative planning. Expansion of RTO footprints helps to mitigate seams issues to a large extent and needs to be strongly encouraged. The lack of transmission capabilities between zones of an RTO creates challenges that have plagued effective expansion planning. Transmission capabilities are critical to an efficient and effective bulk power system and electricity market, as transmission is the critical link to enabling and defining markets.

c) Regional planning studies and generation interconnection studies need better alignment

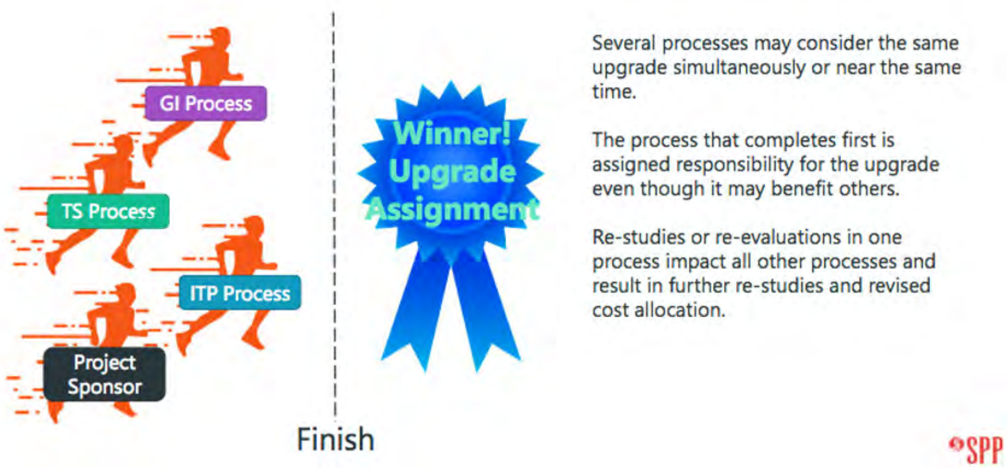
Planning entities often employ siloed study processes that consider reliability, economic, and public policy

72 Hillard Energy, *Horse Hollow Generation Tie*, Comfort, Texas, n.d.

transmission projects separately rather than considering all benefits at once under a holistic planning approach. The main factor driving siloed planning processes is that different cost allocation methods for each category of transmission project results in a race that no one wants to win, as it will result in them bearing the cost for the transmission upgrades. Said another way, each group of stakeholders attempts to free ride on other groups of stakeholders by failing to plan transmission that they would have to pay for, in the hope another group of stakeholders will plan and pay for it. Unfortunately, the typical result is that nobody builds the transmission, and all customers suffer from increased congested and reduced reliability.

A great case study that demonstrates this failure in action involves SPP's filing of an unexecuted GIA between SPP - the transmission provider, Oklahoma Gas & Electric (OG&E) Company - the transmission owner, and Frontier Windpower II - the interconnection customer.[73] After Frontier's GIA identified shared network upgrades including a new transmission line with a $62 million price tag, of which Frontier had been allocated 22.5 percent of the total cost, Frontier then asked SPP to file the GIA as an unexecuted agreement. When SPP later revised Frontier's GIA to remove all costs associated with the new transmission line, the back-and-forth continued as OG&E submitted a filing in protest of SPP's decision as they believed that because Frontier is imposing costs on the SPP system, they should bear their share of the cost so others, including OG&E, do not have to pay more.[74] SPP's Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) has identified this problem, as shown in Figure 7.[75]

Figure 7: Process Interaction



SPP is working on a solution, which builds on the successes achieved through pro-active transmission planning and broad cost allocation identified a decade ago with the ERCOT CREZ, MISO MVP, and SPP Priority Project lines. The new SCRIPT effort at SPP appears to be a positive step forward and may serve as a model for other RTOs. The scope of the SCRIPT at SPP is noteworthy in several respects. "The SCRIPT is tasked with developing policy recommendations that result in:

- Appropriate consolidation, modification, or elimination of SPP's transmission planning and study processes, in order to:
  - » Develop more optimal solutions that meet a broader set of customer needs

73 *Protest of Oklahoma Gas and Electric Company*, Docket No. ER19-2747-002, March 16, 2020.
74 Id. at 7-8.
75 *See* the minutes and meeting materials for SCRIPT's meeting held on October 9th, 2020 (attachment D at slide 49).

- » Synergize analysis so that beneficiaries and cost-causers can be identified in a holistic, uniform fashion
- » Improve planning efficiency, effectiveness and timeliness
- » Reduce the number of model sets needed
- » Reduce reliance on customer-requested, queue-driven studies

- Improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service
- Reduced dependence on queue-driven studies, with consideration given to development of proactive processes that identify and make transparent underutilized transmission capacity
- Utilization of processes and information needed to ensure decisions being made about future investment in transmission infrastructure are made with a high degree of confidence and quality
- Optimization of the existing and planned transmission network to most cost effectively meet future needs while providing maximum value to the region
- Facilitation of generation transfers in a way that will provide future net benefits to the SPP region
- Improved cost sharing among users of the transmission system that appropriately recognizes causers and beneficiaries of transmission investment decisions"

d) Both incremental and broader reforms would still be fuel-neutral

If FERC were to change its policies based in part on the evolving resource mix, that could still be a fuel neutral policy. FERC has always tried to be neutral, with no discrimination or preference to any particular resource, and that can remain true. Transmission policy necessarily takes into account the physical location of resources. For example, in 2007, FERC issued policies on interconnection and transmission service for "location-constrained" resources that differed from the Order 2003 approach in CAISO.[76] It was not a preference or any value judgment on the renewable resources, just the recognition that there was a large resource area that could be tapped with a higher voltage transmission lines than any one generator or group of generators could be assigned, leading to more just and reasonable rates for consumers. Transmission planning reforms could follow this general approach.

[76] See *California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007. See also Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

VII. Conclusion: Transmission Planning as Well as Interconnection Policy Reforms Are Needed

The current system of participant funding and network planning through the interconnection process is increasingly unworkable and inefficient. While participant funding and serial interconnection studies created workable signals for siting interconnecting gas plants, they create inefficiencies for interconnecting location-constrained renewable resources. Needed transmission remains unbuilt because the vast majority of new proposed projects drop out of the queue, lengthy queue backlogs create massive uncertainty and risk for generation developers, and congestion and reliability problems from a constrained grid impose billions of dollars per year in unnecessary costs on customers. All generation and transmission costs ultimately flow to electricity consumers, so there is no benefit from policies that seek to shift transmission costs from RTO customers exclusively to generators. The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers. The question for policymakers is how to create a workable and efficient system of planning and paying for transmission that minimizes customer costs.

Interconnection policy and transmission planning policy both need to fit the resource mix going forward. This paper provides evidence of how the interconnection policy is broken now, given the current and expected future resource mix. It proposes some recommendations within the scope of interconnection policy such as ending the policy of assigning all the costs of network upgrades just to generators. However, major progress requires improved transmission expansion policies in order to build out grid capacity to accommodate the future resource mix. Reform to regional transmission planning raises a number of issues that are beyond the scope of this paper. A companion paper from ACEG will address the need for planning reform, consider various policy options, and recommend a number of specific policy changes. It is clear that regional and inter-regional planning must be pro-active, consider future generation additions and retirements, consider multiple benefits, and spread costs to all beneficiaries. That is the only real solution to the broken interconnection processes around the country.

Appendix[77]

Queue Position	MW	Request Date	COD	Interconnection Point	State	County	Trans. Owner	Feasibility Study	System Impact Study	Facilities Study	$ upgrade cost	$/kW upgrade cost
Z1-035	18	7/5/13	9/30/17	Lake Road 11.5 kV	OH	Unknown	ATSI	Complete	Complete	Not required	$2,468,558	$137
AB1-056	255.1	8/31/15	10/31/21	Indian River 230kV I	DE	Sussex	DPL	Complete	Complete	Complete	$2,556,112	$10
AE1-020	816	5/22/18	6/1/23	Oyster Creek 230 kV	NJ	Ocean	JCPL	Complete	Complete	In Progress	$111,316,644	$136
AE1-104	432	9/6/18	6/1/23	BL England 138 kV	NJ	Cape May	AEC	Complete	Complete	In Progress	$65,050,000	$151
AE1-117	152	9/14/18	6/1/22	Bethany 138 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$9,698,945	$64
AE1-238	816	9/28/18	6/1/24	Oceanview Wind 230 kV	NJ	Monmouth	JCPL	Complete	Complete	In Progress	$13,498,200	$17
AE2-020	604.8	12/14/18	12/1/24	Cardiff 230 kV I	NJ	Atlantic	AEC	Complete	Complete	In Progress	$167,856,800	$278
AE2-021	604.8	12/14/18	12/1/25	Cardiff 230 kV II	NJ	Atlantic	AEC	Complete	Complete	In Progress	$668,716,213	$1,106
AE2-022	300	12/14/18	12/1/24	Cardiff 230 kV III	NJ	Atlantic	AEC	Complete	Complete	In Progress	$399,595,257	$1,332
AE2-024	882	12/14/18	12/1/25	Larrabee 230 kV I	NJ	Ocean	JCPL	Complete	Complete	In Progress	$179,417,245	$203
AE2-025	445.2	12/14/18	12/1/26	Larrabee 230 kV II	NJ	Ocean	JCPL	Complete	Complete	In Progress	$171,405,063	$385
AE2-122	800.1	2/28/19	12/31/25	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$304,108,327	$380
AE2-123	800.1	2/28/19	12/31/27	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$243,757,023	$305
AE2-124	800.1	2/28/19	12/31/29	Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$215,266,218	$269
AE2-222	300	3/22/19	6/1/23	Higbee 69 kV	NJ	Atlantic	AEC	Complete	Complete	In Progress	$285,840,760	$953
AE2-251	1200	3/26/19	6/1/24	Cardiff 230 kV	NJ	Monmouth	AEC	Complete	Complete	In Progress	$923,771,404	$770
AE2-257	120	3/27/19	6/1/22	Cedar Neck 69 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$105,062,883	$876
AF1-101	800	9/6/19	11/23/22	Oyster Creek 230 kV III	NJ	Atlantic	JCPL	Complete	Complete		$572,211,265	$715
AF1-123	880	9/17/19	12/31/25	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$76,200,000	$87
AF1-124	880	9/17/19	12/31/26	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$156,865,407	$178
AF1-125	880	9/17/19	12/31/24	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$149,505,894	$170
AF1-222	1326	9/27/19	12/30/25	Oceanview Wind 2 230 kV	NJ	Monmouth	JCPL	Complete	Complete		$131,556,667	$99
AF2-193	440	3/23/20	10/31/26	Indian River 230 kV I	DE	Sussex	DPL	Complete			$534,708,000	$1,215
AF2-194	880	3/23/20	10/31/26	Indian River 230 kV II	DE	Sussex	DPL	Complete			$664,582,000	$755
AF2-196	150	3/23/20	6/1/22	Cedar Neck 69 kV II	DE	Sussex	DPL	Complete			$277,459,000	$1,850
											$6,432,473,885	**$413/kW average**

[77] See PJM, New Services Queue. To gather the data found in Appendix A, we filtered the queue for offshore wind projects. Upgrade cost information was taken from the most recent interconnection study available for each request (e.g. feasibility study, system impact study, or facilities study).

Americans for a
Clean Energy Grid

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

REPLY TESTIMONY OF MARK BOISSEVAIN

January 19, 2022

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Mark Boissevain. I am currently employed as Solutions Director at Energy Automation Solutions Engineering – EASE LLC.

Q. Please describe your background and experience.

A. I have held positions in renewables companies and specifically the utility scale solar industry since 2007. My background is in embedded controls, Supervisory Control and Data Acquisition (SCADA), and North American Electric Reliability Corporation (NERC)/Critical Infrastructure Protection (CIP) plant operations center design and management, as well as solar project management in a variety of engineering and management roles during that time. While as a Senior Project Manager at Swinerton Renewable Energy from 2012 to 2017, I oversaw the teams of SCADA and network professionals who designed, installed and commissioned SCADA monitoring and control systems for over 2 gigawatts (GW) of photovoltaic (PV) solar facilities in the Western Electricity Coordinating Council (WECC) region and other operating regions in the US and Canada. This involved interacting with utility and independent system operator (ISO) operations staff, as well as facility owner and Operations and Maintenance (O&M) teams, to ensure utility data monitoring and control systems were installed and operating, as well as plant monitoring systems were configured properly to ensure compliance with utility specific transmission and generation operating standards, and also aligned with national standards imposed by NERC. This included control systems and operations to manage solar and storage system performance, facility communication with the grid operator, and control related to disconnecting or curtailing system output, including at the interconnection facilities. At present I own and operate a consulting company which caters to developers and facility operators such as NewSun Energy and renewable asset management clients which own and/or operate large scale solar and wind facilities in the US and Canada, and engineering, procurement and construction (EPC) firms which specialize in design and construction of such facilities.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of NewSun Energy LLC (NewSun).

Q. Please summarize your testimony.

A. My testimony responds to the reply testimony submitted by the Joint Utilities, the Oregon Public Utility Commission (Commission) Staff (Staff), and the Interconnection Customer Coalition on December 11, 2020.

In this reply testimony, I primarily would like to respond to the claims that there is no evidence to support the idea that all system users may benefit from Network Upgrades funded by qualifying facilities (QFs) or other investments in the transmission system and provide specific real-world examples.

II. TESTIMONY

Q. What is your understanding of the issues in this case?

A. I understand that the issues presented in this phase of the case include:

1. Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility? and
2. Should on-system QFs be required to interconnect to the host utility with Network Resource Interconnection (NRIS) or should QFs have the option to interconnect with

Energy Resource Interconnection Service (ERIS) or an interconnection service similar to ERIS?

Q. What specifically in Reply Testimony on these points that you would like to respond to?

A. Specifically, Joint Utilities fault NewSun for "provid[ing] no factual support" for the assumption that all system users may benefit from Network Upgrades or other investments in the transmission system.[1] Additionally, Staff notes that NewSun did not provide any evidence to support the assumptions that all Network Upgrades provide system-wide benefits.[2] I will not be responding to anything related to question number 2 in this testimony.

Q. Ok. And what is your response?

A. First, I would note that it is broadly understood in the industry that network upgrades provide broader benefits to the system, and noting that in my career experience, energizing facilities through WECC, has been that such network upgrades are broadly understood to provide benefits and are essentially always reimbursed to the interconnection customer. Second, I am aware of several examples where network upgrades provide benefits to the broader system by helping transmission system operations and reliability and specifically where an interconnected QF has constructed upgrades that benefit the broader system. This testimony is to provide a couple recent discrete examples, in particular Bonneville Power Administration (BPA) connected QFs which have used common interconnection related network upgrades to improve system

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[1] Joint Utilities/300, Wilding-Macfarlane-Williams/2.
[2] Staff/200, Moore/9.

management, benefit the grid, and benefit its unrelated customers, as well as those whom its operations might affect.

Q. Thank you, what would be a common example of a network upgrade that is associated with generator interconnection that provides broad system benefits.

A. A common type of network upgrades assigned by interconnecting utilities for new generator interconnections (including by BPA), in addition to increases to power line capacities, are new taps, switchyards, and related disconnects, breakers, and switches. These systems both connect the new generator to the grid, but also to provide the utility the ability to communicate with the facility and manage its interconnection status, including both to disconnect the facility and segment the line, such that the facility could deliver in one direction, but not the other.

Q. How does this provide a benefit to the system or other customers?

A. It provides a benefit because the transmission owner or grid operator can then manage their system in smaller pieces. Each substation would provide the means to disconnect the line on either side of the generator (or load), or disconnect the generator (or load) while keeping the line in service. This enables the ability, through this additional network upgrade facility and hardware (all of which works together), in the event of the need to take a forced outage or maintenance outage, to take down a *smaller* segment of their system. By direct correlation this means they have the ability to reduce the number of customers, as well as other connected systems, might be required to take an outage. This has many benefits in a variety of settings. For example, as in the case below, it might mean that line maintenance and repair work could be broken up into smaller successive portions of the line, rather than taking out an entire 50 or 100 mile section of line (and all the customers thereon). This could also reduce total outage time, by allowing work or inspections to be scheduled in smaller increments. It also means that in the event of damage or a trip on one part of the line that a smaller part is subject to outage, again reducing the number of affected customers. Another benefit is providing more flexibility for scheduling planned outage windows for maintenance and other upgrades, more modularity and more flexibility in terms of the number of affected customers, reduces the challenges securing outage windows by utilities needing to work on their systems. Conversely, if work has to be done, it either puts customers out of service, or puts workers in more dangerous "hot" working conditions.

Q. Have you seen examples of this for QFs built and interconnected in Oregon?

Yes. The new solar QFs interconnected by BPA via new taps built by BPA in 2019 and 2020 are good examples. These include these two new taps on the BPA 115 KV "Harney Line", which serves remote rural high desert loads in central and eastern Oregon running roughly 120-miles from Redmond Substation all the way to BPA's 115 KV Harney Substation. This very long line provides service to a handful of customers along the way, notably a couple Central Electric Cooperative (CEC) small substations to serve remote farming communities and irrigation loads in the middle (in Brothers and Hampton, for example) and a substation at the Brasada resort (30 miles east of Redmond), and primarily then to serve Harney Electric Cooperative (HEC). HEC takes service from BPA as a network (NT) "all requirements customer" of BPA's and is almost entirely dependent on BPA for electric service, except in contingency situations when it can sometimes feed backup outage power from Idaho Power's Hines Substation or via NV Energy in Nevada. But generally, HEC's primary service point at BPA's 115 KV

Harney Substation, with HEC serving 20-30 MW of mostly summer irrigation load across hundreds of miles 115 KV transmission and 24.9 KV distribution lines on the Oregon frontier via its BPA power contract. BPA also serves a couple separate remote feeders for HEC off the BPA line which are HEC's, but discontiguous from the rest of HEC's main transmission system. These local remote feeders are such as those serving the Riley and Silver Creek areas (roughly 20 miles west of Burns/Hines), which are similar to CEC's remote service feeders in places like Hampton and Brothers, also from the middle of this long Harney line.[3]

Operationally, when BPA requires an outage on the line, whether for maintenance or emergencies, it had very few options before the new Riley "Best Lane Tap" and the "Starvation Ridge Tap". Thus, BPA generally had to take down very large segments, such as the entire line down back to Hampton Substation (50 miles west of Harney Substation's disconnects) or to Brasada (100 miles west).

However, once BPA constructed the new Best Lane Tap to connect new QF solar generation facilities at that site (Riley Solar I and Suntex Solar), roughly 20 miles closer, and Starvation Ridge, BPA then had multiple new configurational options to segment the line (or "isolate" line sections) in multiple places. Thus, BPA could keep the Riley Silver Creek area in service (20-30 miles from Burns/Hines), if they needed to take an outage on the 50 miles between Best Lane and Hampton, for example, without taking down everyone in between. Or vice versa.

Q. Have these benefits been used?

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[3] NewSun/501.

A. Yes. Already in the two years since the QFs and taps were energized, BPA has used the disconnects at the Best Lane tap to only partially take down portions of the line more than once. This included wildfire maintenance work for which outages were required.

Q. What were the circumstances around which BPA was taking outages on all or parts of the Harney Line where these QF taps and network upgrades were installed?

A. BPA has system maintenance outages there. BPA also had its first ever preventative outage for wildfire risk, after it developed a new protocol for outages when fire conditions are very high. Their first ever such outage under this program was in 2020 and it was taken on the Harney Line.

Q. What Do these sorts of new "tap" and new substation type interconnections upgrades help with wildfire risks?

A. Yes, in more than one way. First, if part of a line is threatened with an actual wildfire, like occurred with various wildfires in Oregon this past summer, then additional disconnects and switching can allow a utility to keep other portions of a line in service while fire damaged or fire threatened line and system segments are isolated. Additionally, as noted above preventative outages can more easily be taken and better tailor to local conditions on smaller portions of the transmission owner's system.

Q. Do other network upgrades help with wildfire risk and management, such as those for new or upgrade power lines?

A. Yes, a reconductoring of an existing transmission (or distribution) line would allow for upgrades to equipment and modernizations that would reduce line fault risks, replace dangerous and old commitment, raise structure heights, and a variety of improvements, as well as line inspection opportunities, all of which might help avoid the type of situation in Pacific Gas & Electric territory with the Paradise Fire. Additionally larger throughput capacity also increases the safety ratings to operate at higher temperatures or better support alternate plans of service for outages elsewhere.

Q. What about monitoring and communications equipment?

A. Yes, these new interconnection facilities include network upgrades such as remote communication monitoring, controls, and protection systems that allow a utility to better understand the operations and safety of their facilities. This includes related and other protective equipment such as protection relays for substation equipment, line relays that monitor critical parts of transmission lines, specialized power quality meters which compute and monitor indicative metrics such as total harmonic distortion, flicker, and other values requiring digital signal processing, all on the on the high side of a generator step up (GSU) or Main Power Transformer (MPT) which can be remotely operated by the utility or transmission operator. Network upgrades also include communications equipment dedicated to pt-pt communications with the transmission operator (often the utility).

These upgrades benefit the transmission operator to provide near real-time monitoring of critical transmission line parameters such as voltage, current, and power, as well as the specialized parameters mentioned previously. These values allow for more insight to transmission operation and health during normal day to day operations, as well as provide for better understanding of transmission line voltage fluctuations, real and reactive power conditions, at additional specific points in a transmission network where qualifying facilities interconnect.

For example, during a fault condition, Phasor Measurement Units (smart microprocessor-controlled relays) can provide AC cycle by cycle breakdowns of grid events (faults) which can more quickly pinpoint causes and locations of issues so that the utility operator can quickly assess and effectively dispatch repair crews, increasing reliability to its customers.

QF facility network upgrade monitoring capabilities can also extend to increasing the safety of transmission line repair crews and, as mentioned, but better informed by real system data, also help with minimizing transmission outage segments, providing for better service to loads (customers).

Q. Have you seen examples of this with the QFs installed in Oregon?

A. Yes. BPA's Harney Line has long had voltage regulation issues affecting its service of customers and coops on this line. But it did not have data for mid-system performance. The new QF network upgrades have thus allowed BPA to improve its diagnostics in this area of the system and begin identifying other solutions to aid in serving its load customers. The taps and new disconnects will also, when it finally goes to install those upgrades, likely help to reduce outage windows and durations for the customers affected.

Q. Are getting outages for maintenance challenging? What other benefits are there to this?

A. Yes. When Starvation Solar I was being built, it getting an outage window that worked, even with BPA requesting it, was challenging due to other outages planned by Idaho Power, many of which had been previously scheduled and delayed for years, also delaying that utility (and its customers) from getting needed system improvements done. Indeed, PGE apparently refused a request re-scheduling the commercial operation date (COD) of the Starvation Solar despite these issues, causing a small crisis for these projects. Regardless the available outage windows were very limited. Thus, additional breakers, switches, and disconnects—i.e. new QF substations and taps and related network upgrades—also are likely to facilitate more successful interconnection of other facilities due to highly constrained outage windows often affecting lines, and which are competed for a variety of purposes, including wildfire maintenance, as noted above.

Q. Thank you. Are there other specific examples of where an interconnected QF has constructed upgrades the benefit the broader system?

A. Yes. The couple QF projects interconnected to Bonneville Power Administration's Fort Rock-LaPine 115 kV line (BPA Queue numbers G051, G0526) had similar benefits to the above, but also these facilities offered to create and implement special "hotline tag" settings in July of 2020 to increase the crew safety of scheduled BPA line repair personnel with more stringent safety limits on voltage levels and durations at these relays on either side of the POI to the transmission line. QF operations personnel installed and confirmed them in the facilities, which was possible due to the communications and other infrastructure related to the Connley tap and these generators monitoring requirements. The result of this effort increased operator personnel safety and allowed for less of the line to be part of the outage. For future needs, these tag settings can be re-implemented with the touch of a button.

Q. Thank you. So, at a high-level what are the benefits these upgrades provide to the system?

A. They offer increased safety and flexibility for the transmission owner's system, customers, operator personnel, field maintenance workers, construction, and for connected and affected systems, preserving and amplifying the reliability to serve load and customers, including safely, and reduce the liabilities for wildfire damage, both directly (from the system) and to protect the system and customers should wildfires or other system emergencies damage or threaten a portion of the system elsewhere. They also aid with maintenance activities that are critical to avoiding damage and outages and financial liabilities as well (to the utility and its ratepayers).

Q. You mention these QF facilities are interconnected with BPA's system. Who the ultimate purchaser of the QF power?

A. Portland General Electric Company.

Q. Ok, so if the purchase arrangements were different and the QF was selling its power to its directly interconnected utility but made the same upgrades under the same conditions, would the benefits to the system be any different?

A. No. I see no reason why it would make a difference whether the QF is selling its power to its directly interconnected utility or wheeling to another utility. The same upgrades if made under the same conditions, would provide the same benefit to whichever system it is interconnected.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

EXHIBIT NEWSUN/501

MAP

January 19, 2022

Docket No. UM 2032

NewSun/501
Boissevain/1