Review Transmission Access Charge Structure

Issue Paper

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Market & Infrastructure Policy

Table of Contents

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1. Introduction and Scope of Initiative

In late 2015 the ISO started its Transmission Access Charge Options initiative in the context of potential expansion of the ISO balancing authority area (BAA) to integrate a large external BAA such as that of PacifiCorp. The focus of that initiative was limited to matters of transmission cost allocation over a larger BAA, including the costs of both existing transmission facilities that each member service area or “sub-region” would bring into the expanded BAA and new facilities that would be jointly planned through an integrated transmission planning process for the expanded BAA. That effort culminated in the Draft Regional Framework Proposal posted to the ISO web site on December 6, 2016.

During the Transmission Access Charge Options initiative, the Clean Coalition submitted a proposal to modify the procedure for collecting the Transmission Access Charge (TAC) to use as the billing determinant the hourly net load at each transmission-distribution (T-D) interface substation – referred to as “transmission energy downflow” or “TED” – instead of the current Gross Load billing determinant, which sums up the end-use metered load in each hour. In general, the TED at each T-D interface will be smaller than the corresponding Gross Load due to two factors: the energy output of generating resources connected to the distribution system on the utility side of the customer meter, and the output from behind-the-meter generation that is in excess of the corresponding end-use load during the same hour and is injected into the grid. These two factors comprise what this initiative will refer to as “distributed generation output” (“DG output”).

When the Clean Coalition first submitted this proposal, the ISO determined that it was outside the scope of the Transmission Access Charge Options initiative and proposed to address it through a separate initiative. In June 2016 the ISO opened the Review Transmission Access Charge Wholesale Billing Determinant initiative specifically to consider the Clean Coalition proposal. In the first round of stakeholder discussion and comments in that initiative several stakeholders argued against the narrow focus on the Clean Coalition proposal and urged the ISO to undertake a broader review of the structure of the TAC charge. Some stakeholders argued, for example, that the ISO should reconsider whether it is appropriate to maintain the current volumetric TAC charge or adopt a demand-based charge to align better with the cost drivers of transmission upgrades. The ISO agreed that a broader, holistic examination of the TAC structure would be preferable to a narrow change to the TAC billing determinant, but the ISO did not have bandwidth to devote to such an effort at that time and committed to re-opening the topic in 2017.

The present initiative is intended to take up where the summer 2016 initiative left off and to broaden the scope to a wider consideration of TAC structure. In anticipation of the present issue paper, in April 2017 the ISO published a background white paper titled "How transmission cost recovery through the transmission access charges works today" in order to provide a common understanding among stakeholders of how transmission cost allocation and recovery within the ISO works today.[1]

Through this initiative the ISO proposes to address at least two major TAC structure issues:

1. Whether to modify the TAC billing determinant to reduce TAC charges in PTO service areas for load offset by DG output as described above and, if so, what modification would be most appropriate, including but not limited to the Clean Coalition proposal.
2. Whether to modify the current volumetric structure of the TAC to consider, for example, using a demand-based charge, either instead of or in addition to a volumetric charge, or a time-of-use pricing structure.

At the same time, the ISO believes that this initiative must have some clear boundaries and therefore proposes to exclude the following topics from the scope:

- The current structure of regional and local transmission charges. The current approach uses a postage-stamp rate to recover the costs associated with all "regional" or high-voltage transmission facilities under ISO operational control (*i.e*., facilities rated at or above 200 kV), and utility-specific rates in each of the investor-owned utility (IOU) service areas to recover the costs of "local" or low-voltage facilities (*i.e*., facilities rated less than 200 kV) under ISO operational control. The ISO proposes not to consider changes to this aspect of TAC structure in this initiative.
- The ISO's role in collecting the TAC. Currently the ISO collects through its settlement system only the TAC charges associated with regional transmission facilities. Each of the IOUs collects the charges associated with local facilities. The ISO proposes not to consider changes to this aspect of TAC structure in this initiative.
- Regional cost allocation issues for an expanded BAA as discussed in the TAC Options initiative. The proposed scope stated above for the present initiative can be addressed independent of whether an expanded ISO BAA is created at some point in the future, and can logically be treated separately from regional cost allocation issues. The ISO believes that policy changes that result from the present initiative, if any, should be applicable in an expanded BAA that may be created in the future.
- Alternative types of transmission service. The ISO will review the approaches used by other ISOs and RTOs to recover transmission costs. Some of these other entities offer different transmission service options (*e.g*., point-to-point versus network integration service), whereas the CAISO offers only one form of service through our day-ahead and real-time markets. For a meaningful comparison with the TAC structures of other ISOs

[1] Available here: https://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf

and RTOs we will look at the service option in each of the other regions that most closely matches CAISO transmission service. This initiative will not consider expanding or modifying the types of transmission service we offer.

The ISO invites stakeholders to comment on the proposed scope of the initiative, including both the topics proposed for inclusion and those proposed for exclusion, and to suggest other topics they believe should be included in scope. If a stakeholder proposes a change to the proposed scope, the ISO requests an explanation of how the proposed change is linked with or important to resolving issues 1 and 2 identified above. The ISO will propose the final scope for this initiative in the context of a stakeholder working group meeting proposed for August 29, and will finalize the scope in the first straw proposal to be issued at the end of October.

2. Initiative Schedule

Table 1 below presents the schedule for this stakeholder initiative. The CAISO plans to present its proposal to the CAISO Board of Governors for approval in mid-2018, with the specific target date to be determined in early 2018 based on the CAISO's assessment at that time of how much additional work is needed to develop a final proposal.

Table 1 – Schedule for this Stakeholder Initiative

Step	Date	Milestone
Kick-off	Feb 6, 2017	Publish market notice announcing initiative beginning mid-year 2017
White Paper	Apr 12	Post background white paper
Issue Paper	Jun 30	Post issue paper
	Jul 12	Hold stakeholder meeting
	Jul 26	Stakeholder written comments due
Working Group	Aug 29	Hold stakeholder working group meeting to review and assess options
Straw Proposal	Oct 31	Post straw proposal
	Nov 15	Hold stakeholder meeting or call
	Dec 13	Stakeholder written comments due
Revised Straw Proposal	Feb 6, 2018	Post revised straw proposal
	Feb 20	Hold stakeholder meeting or call
	Mar 20	Stakeholder written comments due
Draft Final Proposal	May	Post draft final proposal
	May	Hold stakeholder meeting or call
	Jun	Stakeholder written comments due
Final Proposal	TBD	Present final proposal at CAISO Board meeting

3. Background

3.1. Review of previous initiatives

The ISO's 2016 "Review TAC Wholesale Billing Determinant" initiative considered whether it would be appropriate to revise the current method of billing transmission costs in the ISO's wholesale settlement process—specifically the use of end-use customer metered load (*i.e.*, Gross Load[2] as defined in the ISO tariff) in PTO service areas to bill the volumetric transmission access charge (TAC)—to reflect potential benefits from distributed generation in reducing or avoiding some transmission costs. The ISO settlement process also uses another volumetric rate, the wheeling access charge (WAC), to bill transmission charges for wheeling power to loads off the ISO controlled grid, including Non-PTO[3] loads and exports, but consideration of billing to these entities was not within the scope of the 2016 review. The June 2, 2016 issue paper and written stakeholder comments received in that initiative revealed a number of complex and controversial issues that would require more in-depth consideration and allocation of resources than the ISO could dedicate or most stakeholders would support at that time. The ISO therefore closed that initiative in September 2016 without reaching a conclusion and promised to open a more comprehensive assessment of TAC structure in 2017. This issue paper begins the new initiative, called "Review TAC Structure."

During 2016 the ISO also conducted and concluded the Transmission Access Charge Options initiative to consider possible ways to allocate the costs of transmission across a larger regional BAA that could be formed by expanding the current ISO BAA to include a large external BAA. The results of that initiative are contained in the ISO's December 6, 2016 Draft Regional Framework Proposal.[4] The ISO views the present initiative as logically separable from the 2016 TAC Options initiative, and therefore will not revisit or discuss the substance of the December 6 proposal in the context of the present initiative. The present initiative is needed regardless of whether the ISO expands the BAA regionally, and in fact these two initiatives do not overlap in substance. The TAC Options initiative focused narrowly on allocating costs across sub-regions of the expanded BAA and explicitly excluded consideration of the TAC structure issues that comprise the present scope. The ISO expects that any policy changes adopted here that are

[2] The term "Gross Load" may be somewhat confusing because some parties understand gross load to be the physical end-use consumption before its measurement at the meter is reduced by any behind-the-meter supply. Thus, in more common understanding one might say "metered load" or "net load" equals "gross load" minus "behind-the-meter supply." To be consistent with the ISO tariff definition, however, in this paper "Gross Load" means metered load. See ISO Tariff Appendix A for the exact definition.

[3] Non-PTOs are load-serving entities (LSEs) that receive power from the ISO grid but are not PTOs. All of these entities were electric utilities or other wholesale entities operating in the ISO footprint prior to the establishment of the ISO. Non-PTOs may own or have contractual entitlements to transmission facilities, but have chosen not to become PTOs.

[4] Available here: http://www.caiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf

approved by FERC and become part of the ISO tariff will then be part of the ISO's transmission cost recovery framework if and when regional BAA expansion is reopened.

3.2. How transmission cost recovery works today

As part of the background for this initiative, on April 12 the ISO posted a background white paper titled, "How transmission cost recovery through the transmission access charge works today."[5] The purpose of that paper was to address a need identified in the earlier initiatives for a clear and complete understanding of how transmission cost allocation and recovery within the ISO works today. The paper describes the role and function of the ISO's wholesale TAC settlement, the participating transmission owners' (PTOs) transmission filings at FERC, and the transmission cost recovery mechanisms that are outside the ISO's settlement process. For example, the PTOs collect revenues toward the costs of their local or low-voltage facilities directly rather than through an ISO settlement mechanism.

Rather than discuss the April 12 background paper here, the ISO recommends that stakeholders review the paper in preparation for the upcoming stakeholder meeting on July 12, where there will be an opportunity to ask questions and seek clarifications regarding its content. For convenience, the ISO presents here the key observations and conclusions that were stated at the end of the paper.

1. Recovery of the costs associated with building, owning, maintaining, and physically operating transmission facilities in the ISO Controlled Grid is a complex process with many steps, including PTOs filing TRRs with FERC, the ISO collecting a portion of the TRRs through the R-TAC [Regional TAC] and R-WAC [Regional WAC], and UDCs and other utilities collecting retail transmission charges from end-use customers.
2. The processes are somewhat different for each of the entities that has FERC-approved costs to recover; *i.e.*, the various PTOs in the ISO system.
3. The parties that receive shares of the revenues collected through the TAC and WAC (*i.e.*, the PTOs) are not always the same parties whose end-use customers pay these charges. There are some PTOs that do not have service areas and customers who pay transmission costs, and there are some UDCs and MSS whose customers pay transmission costs but do not contribute to the transmission costs collected for the ISO controlled grid.
4. The ISO's role in calculating and billing TAC and WAC charges and remitting the revenues to PTOs applies only to:
    a. The Regional or high-voltage facilities in the ISO Controlled Grid used by wholesale customers in the ISO's markets; and
    b. The Regional and Local facilities in the ISO Controlled Grid used for wholesale exports.

[5] The white paper is available here: http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf

5. The original structure based on a volumetric $/MWh rate was established to reflect the fact that the ISO market, through which use of the transmission system is allocated and scheduled, is an energy market, not a capacity market. In other words, use of the ISO controlled grid is scheduled based on the hourly MWh energy volumes for which market participants need transmission service, and the current volumetric TAC and WAC rate structure aligns with this market structure.

3.3. Principles of transmission rate design

The purpose of this section is to provide an overview of the principles and policies that have been articulated by the Federal Energy Regulatory Commission (FERC) regarding transmission cost allocation and pricing, as well as the more general and well-known Bonbright principles of electric utility ratemaking.

3.3.1. Principles of electric transmission cost allocation and pricing

In 1994, the Federal Energy Regulatory Commission (FERC) issued a Transmission Pricing Policy Statement.[6] The Transmission Pricing Policy Statement constitutes a complete description of FERC's general guidelines for assessing transmission pricing proposals. Section 2.22 of FERC's Regulations briefly summarizes the Transmission Pricing Policy Statement as follows:

> (b) The Commission endorses transmission pricing flexibility, consistent with the principles and procedures set forth in the Policy Statement. It will entertain transmission pricing proposals that do not conform to the traditional revenue requirement as well as proposals that conform to the traditional revenue requirement. The Commission will evaluate "conforming" transmission pricing proposals using the following five principles described more fully in the Policy Statement.
>
> (1) Transmission pricing must meet the traditional revenue requirement.
>
> (2) Transmission pricing must reflect comparability.
>
> (3) Transmission pricing should promote economic efficiency.[7]
>
> (4) Transmission pricing should promote fairness.

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6 *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,* 69 FERC 61,086 (1994)(Transmission Pricing Policy Statement).

7 In the Transmission Pricing Policy Statement, the Commission stated that this means that transmission pricing should promote good decision-making and foster efficient expansion of transmission capacity, efficient location of new generation and load, efficient use of existing transmission facilities, including the efficient allocation of constrained capacity through appropriate market clearing mechanisms, and efficient dispatch of existing generation.

(5) Transmission pricing should be practical.

> (c) Under these principles, the Commission will also evaluate "non-conforming" proposals which do not meet the traditional revenue requirement, and will require such proposals to conform to the comparability principle. Non-conforming proposals must include an open access comparability tariff and will not be allowed to go into effect prior to review and approval by the Commission under procedures described in the Policy Statement.[8]

FERC noted in the Transmission Pricing Policy Statement that the first two principles reflect fundamental requirements, whereas, the other three principles reflect goals that a public utility must try to meet, but that ultimately may need to be balanced against one another in FERC's determination of whether the proposed rates are just and reasonable.

These principles are not dissimilar to the traditionally recognized three primary principles of sound ratemaking – revenue adequacy, optimal use of service, and fairness. (Bonbright, Principles of Public Utility Rates, p. 292 (1961); see discussion in next sub-section).

Through the years, the Commission and the courts have offered general guidance regarding cost responsibility in a number of contexts. One overriding premise is that

> [a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to be an exact science.[9]

Traditionally, the courts and FERC have required that approved rates reflect to some degree the costs actually caused by a customer who must pay for them.[10] Stated differently, "cost responsibility should track cost causation."[11] This means that costs should be allocated to customers, where possible, based on customer benefits and cost incurrence.[12] This includes comparing the costs assessed against a party to the burdens imposed or benefits drawn by the party.[13] Courts have not required FERC to allocate costs with exact precision, and FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly.[14] Similarly, the courts and the Commission have recognized that there can be alternate rate designs that may be just and reasonable, or even superior to a proposed rate

8 18 C.F.R. §2.22.
9 *Colorado Interstate Gas Co. v. Federal Power Commission,* 324 U.S. 581, 589 (1945).
10 *See, e.g., KN Energy, Inc. v. FERC*, 968 F.2d 1295 (D.C. Cir. 1992); *Pacific Gas and Electric Company,* 113 FERC ¶61,084 at P 63 (2005).
11 *See, e.g., New England Power Pool*, 86 FERC ¶61,262 at 61,966 (1999).
12 *See, e.g.,* Pacific Gas and Electric Company v. FERC, 373 F. 3d 1315 (D.C. Cir, 2004).
13 *Illinois Commerce Commission v. FERC*, 576 F. 3d 470 (7th Cir. 2009), citing *Midwest ISO Transmission Owners v. FERC,* 373 F. 3d 1361, 1368 (D.C. Cir. 2004).
14 *Midwest ISO Transmission Owners v. FERC,* 373 F. 3d 1361, citing *Sithe/Independence Power Partners,L.P. v. FERC*, 285 F 3d 1,5 (D.C. Cir. 2002).

design, but a filing party is only required to prove that the proposed rate design is just and reasonable, not that it is the best rate design.[15]

In Order Nos. 890 and 1000, FERC enumerated principles regarding cost allocation for new transmission facilities. First, in Order No. 890, FERC concluded that it was appropriate to adopt specific principles regarding cost allocation for new transmission because the manner in which such costs are allocated is critical to the development of new infrastructure. Although FERC did not prescribe any specific cost allocation methodology, it enumerated the following factors to be considered in allocating transmission costs:

1. Whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them;
2. Whether a cost allocation proposal provides adequate incentives to construct new transmission; and
3. Whether the proposal is generally supported by state authorities and participants across the region.[16]

In Order No 1000, FERC adopted six general principles regarding the allocation of costs for new regional transmission facilities approved in a regional transmission planning process, including the following principles potentially relevant to this initiative:

> *Regional cost allocation principle 1:* The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.
>
> *Regional cost allocation principle 2:* Those that receive no benefit from transmission facilities either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.
>
> *Regional cost allocation principle 5:* The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to determine how they were applied to a proposed transmission facility.
>
> *Regional cost allocation principle 6:* A transmission planning region may choose to use a different cost allocation method for different types

15 *See, e.g., City of Bethany v. FERC,* 727 F. 2d 1131, 1136 (D.C. Cir. 1984, *cert. denied,* 469 U.S. 917 (1984); *New England Power Co., 52 FERC* ¶61, 090, 1t 61,336 (1990), *aff'd sub nom., Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992).

16 *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559 (emphasis added) (quoting *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945)), order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

transmission facilities in the regional transmission plan, such a transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[17]

3.3.2. The Bonbright principles of rate design

In considering efficient pricing and investment, rate design matters. Perhaps the most influential set of principles of rate design over the last half century are the Bonbright principles, laid out by James Bonbright in 1961.[18] These principles promote overall rate simplicity, stability, revenue recovery, fair distribution of costs among customers, and efficiency of energy use. Bonbright laid out the following principles regarding rate design:

1. The related, practical attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, within a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appropriateness of total costs of service among the different customers.
7. Avoidance of undue discrimination in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. In the control of the total amounts of service supplied by the company, and
    b. In the control of the relative uses of alternative types of service.

Generally, the Bonbright principles have been summarized as having three objectives: meeting the revenue requirement, fair apportionment of production costs among customers, and optimal efficiency. These principles have historically guided and influenced utility ratemaking, with the utility and its regulator deciding upon the appropriate balance among the principles based on the objectives and circumstances of the utility.

A fundamental guiding principle of cost allocation within rate design is cost causation – the concept that cost allocation should follow cost causation as closely as possible. This concept has been seen throughout the industry as promoting efficient production, consumption, and investment decisions through the sending of price signals.

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[17] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,061 (2011), order on *reh'g,* Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g,* Order No. 1000-B, 141 FERC ¶61,044 (2012), *aff'd sub nom, S.C. Pub. Serv. Auth. V. FERC,* 762 F. 3d 41 (D.C. Cir. 2014).

[18] James C. Bonbright, *Principles of Public Utility Rates* (Columbia University Press 1961).

The Bonbright principles were intended to apply to public utility rate setting in general, including but not limited to transmission cost recovery. In the specific context of transmission rate setting, the concept of cost causation has been relied upon to allocate the costs to customers based on their proportionate use of the transmission system, consistent with other principles the entity or utility may apply. FERC Order 1000 most recently reflects the principle of cost causation as it relates to cost allocation of regional transmission projects based on the amount of benefit the project provides to the respective regions or service areas within a region.

4. Structure of transmission cost recovery in other ISOs/RTOs

There is considerable rate design complexity among the ISOs/RTOs such that providing a comprehensive discussion of every detail of their rate designs would span hundreds of pages. Also, different ISOs/RTOs may provide different market services (*e.g.,* network integration service, firm point-to-point service, non-firm service), so a direct apples-to-apples comparison with the CAISO is challenging. These challenges are compounded by highly varying terms and definitions used in the various RTOs. This section provides a very high-level overview of how transmission charges are structured in other ISOs and RTOs for network transmission service so that it is intelligible and useful for the scope of this initiative.

Among the various ISOs and RTOs, it is fair to say that the CAISO uses the simplest billing determinant in its transmission rates: end-use customer metered load, namely, the MWh of UDCs and MSSs serving customers in the ISO area (or exports therefrom).[19] The CAISO is not alone in this approach. In the NYISO, transmission owners directly bill wholesale transmission customers a wholesale transmission service charge based upon the transmission owner's annual revenue requirement divided by its annual gross load (MWh), which is adjusted upward to include sub-transmission and distribution losses.[20]

Other ISOs and RTOs primarily use demand as the billing determinant in transmission cost recovery. FERC chose demand as the *pro forma* billing determinant in Order No. 888, finding that:

> Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its

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[19] *See generally* Section 26.1 of the CAISO tariff; CAISO Background White Paper, "How Transmission Cost Recovery through the Transmission Access Charge Works Today," https://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf.

[20] Section 14.1 of Appendix H to the NYISO tariff; *see also* Section 4.2 of the NYISO Transmission Services Manual, http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/tran_ser_mnl.pdf. The NYISO transmission service charge does not apply to a transmission owner's use of its own system to provide bundled retail service. *See* Section 14.1.1.3 of Appendix H to the NYISO tariff.

> generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning.[21]

FERC also noted that "alternative allocation proposals may have merit" and "welcome[d] their submittal by utilities in future rate applications."[22]

Consistent with Order No. 888, the Southwest Power Pool (SPP), ISO New England (ISO-NE), and Midcontinent Independent System Operator (MISO) all charge network customers based upon their monthly network load ratio share of transmission service, which is based upon their hourly load coincident with the monthly peak for each network zone or customer area.[23] All three RTOs have similar rules on what constitutes network load. ISO-NE, for example, states that:

> The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such nondesignated load.[24]

In addition to the demand-based charge for network service, MISO uses a volume-based charge for its Multi Value Projects (MVPs), which are regional transmission projects designed to

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21 *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

22 *Id*.

23 *See* Section 34.1 of the SPP tariff; Section II.21 of the ISO-NE tariff; and Schedule 9 of the MISO tariff; *see also* MISO Business Practice Manual No. 12, Transmission Settlements, at Section 3.1.1.3.

24 Regional Network Load, Section I.2.2 of the ISO-NE tariff. To avoid double recovery, where a transmission owner receives revenue pursuant to a service with a singular rate from facilities that support multiple services, that revenue reduces its transmission revenue requirement for the other services' rate calculations. *See, e.g.,* Section II.12.2 of the ISO-NE tariff. *See also* Order No. 890 at P 1619 ("transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load. We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters").

support public policy, provide economic value, or provide economic value and reliability.[25] The MVP rate is calculated separately based on MVP TRRs,[26] and charged to load, exports, and net actual energy withdrawals based on gross load (MWh usage). When it proposed this rate to FERC in 2010 (along with the entirety of its MVP tariff provisions), MISO explained that

> … the MVP is proposed to be applied on a usage (i.e., MWh) basis rather than a demand (i.e., MW) basis. . . . [A] usage-based charge is warranted because energy flows and the corresponding benefits will occur in all hours of the year, not just during peak demand. This is in contrast to many local facilities in existence today, which were constructed to meet the peak demand of the area in which they are located.
>
> Moreover . . . Load Serving Entities use the transmission system on a regional basis under the Midwest ISO's security constrained economic dispatch, which frequently results in transactions between Local Balancing Authorities within the Midwest ISO Balancing Authority Area. As detailed above, MVP-related reductions in production costs (e.g., congestion and losses) underscore the usage-based benefits of MVPs. Moreover, the MVP cost allocation proposal does not make an up-front allocation of costs based on an analysis of benefits and usage at a specific point in time, but instead allocates costs based on usage over time, which helps ensure that as usage and benefits change, cost allocation also will change accordingly.[27]

MISO further elaborated on this point in its supporting testimony:

> In considering the primary objectives of regional transmission infrastructure to enable public policy requirements and to provide regional economic benefits within the Midwest ISO market, it became apparent that a significant portion of the benefits associated with MVPs would occur at times other than the peak demand. That is, while many of the local transmission facilities already in existence today were constructed to meet the peak demand of the area in which they are located, regional facilities tend to be utilized throughout the year with a focus on energy delivery across the footprint during periods in addition to the peak demand. For example, if wind generation is used to help meet the energy requirements of RPSs, only a small percentage of the energy generated by wind will occur during periods of peak demand, *i.e*., the small percentage of hours that drive demand-type charges. Furthermore, it is expected that a significant portion of the economic value associated with MVPs will be the reduction of production

25 *See* https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx.

26 MISO also adjusts these figures throughout the year to account for the use of prior-year data. *See* Section 5 of Attachment MM to the MISO tariff.

27 *Midwest Independent Transmission System Operator Inc.*, Proposed Revisions, Docket No. ER10-1791-000 (July 15, 2010).

> costs, an energy based measure, during the year. For these reasons, a usage charge was selected as the preferred method for the recovery of costs of MVPs.[28]

ERCOT and PJM also charge for transmission service based upon demand, but with some variance from the Order No. 888 model used by SPP, ISO-NE, and MISO. As dictated by the Texas administrative code, ERCOT uses the average of coincident peak demand in June, July, August, and September, excluding the portion of coincident peak demand attributable to wholesale storage load.[29] Specifically, by December 1 of each year, ERCOT is required to file with the Texas PUC the year's average of the coincident peak demand of the four summer months for each distribution service provider, excluding the portion of coincident peak demand attributable to wholesale storage load. This figure is then used to bill transmission service for the next year. ERCOT calculates the average coincident peak demand of the four summer months by summing the coincident peak of all of the ERCOT distribution service providers, for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, and dividing by four. A distribution service provider's average demand is determined from the "total demand, coincident with the ERCOT [four summer months], of all customers connected to a distribution service provider, including load served at transmission voltage, but excluding the load of wholesale storage entities."[30]

PJM's rate structure is more complex. Although PJM defines network load similar to SPP, MISO, and ISO-NE, PJM charges a daily demand charge for network transmission service (aggregated into a monthly charge) based on the network customer's daily network service peak load contribution (including losses), coincident with the zonal peak for the 12 months ending October 31 of the preceding year.[31] For customers taking network transmission service under state-mandated retail access programs, peak load contributions may change daily, and are submitted to PJM by the associated distribution utilities 36 hours prior to the day being billed. These daily peak load contributions are then subtracted from that distribution company's fixed peak load contribution.[32]

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[28] *Id*., Prepared Direct Testimony of Jennifer Curran at pp. 12-13. MISO further emphasized, "The important point here is that regional economic dispatch, and the associated economic benefits, occurs throughout the year, not just during the peak hour(s). Furthermore, the benefits of a market-wide economic dispatch are often more significant during off-peak hours, because fewer generation resources are required and more opportunity exists to use generation in one region to serve load in another. In any event, any effort to reduce production costs through transmission expansion that allows for a greater level of regional dispatch must be allocated throughout the year rather than just during the system peak hour(s) in order for the cost allocation to appropriately align with benefits."

[29] *See* § 25.192 of the Texas Administrative Code.

[30] *Id*.

[31] *See* Section 34.1 of the PJM tariff; Section 5 of PJM Manual No. 27, Open Access Transmission Tariff Accounting.

[32] Network customers who are transmission owners do not actually pay themselves for use of their own facilities. Network demand charges are shown on their invoices only to identify their cost responsibility, and they are offset by an equal amount of network service credits. Section 5.2 of PJM Manual No. 27.

Further, under the PJM tariff, transmission owners (rather than PJM itself) have the right to determine how to calculate each of their customer's peak load contributions. For example, Atlantic City Electric Co. computes its customers' peak load contributions and then scales the contributions to sum the allocated PJM zonal peak following a four-step process:

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kWh quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kWh usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.
2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.
3. Each customer's loads are adjusted for losses, consistent with the customer's service agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.
4. The customer loads are then scaled so that the totals for the Atlantic zone matches the Atlantic unrestricted weather-normalized zonal peak on each of the five PJM unrestricted peak load days. The arithmetic average of these unrestricted hourly values for the five PJM peak hours is the customer's capacity peak load contribution. These contributions are again scaled so that the sum equals the zonal peak allocated by PJM.

Atlantic City aggregates the customer's peak load contribution on a daily basis, by suppliers, and reports the data to PJM and its retail customers. New customers who do not have data are assigned peak load contribution based on their profile class.[33]

For all network customers, the PJM tariff explicitly exempts load served by all "Behind The Meter Generation," and some "Non-Retail Behind The Meter Generation." In other words, customers do not incur transmission charges load served by these defined resources. The PJM tariff defines "Behind the Meter Generation" as:

> a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the

33 Additional peak load contribution calculation methods can be found in Attachment M-2 of the PJM tariff.

> distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Because this definition is limited to generation that uses neither the transmission system nor the distribution system (unless consent has been provided) and that is sold to another entity, it is safe to assume that most of this Behind The Meter Generation is rooftop solar or equivalent generation at the end user's location.

Through a settlement proceeding related to its demand response program, PJM also developed provisions for exempting some load served by "Non-Retail Behind the Meter Generation," which the PJM tariff defines as "Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load" and which complies with a number of PJM tariff provisions. For example, Non-Retail Behind the Meter Generation in PJM is "required to operate at its full output the first ten times between November 1 and October 31, that Maximum Generation Emergency conditions occur in the zone in which the Non-Retail Behind The Meter Generation resource is located."[34] For each instance a Non-Retail Behind The Meter Generation resource fails to operate, in whole or in part, as above, the amount of operating Non-Retail Behind The Meter Generation from such resource that is eligible for netting will be reduced.[35] Non-Retail Behind The Meter Generation also must report its output during these Maximum Generation Emergency events, and must submit outages according to standard generation requirements.

As decided by PJM's settlement proceeding, PJM imposed a 1,500 MW limit (for the entire PJM system) on the amount of load that could be netted by Non-Retail Behind The Meter Generation. This figure was increased proportional to load growth on an annual basis until it reached the 3,000 MW hard cap. Commenters on FERC Order No. 890 represented that this rule had "increased reliability and demand response opportunities on PJM's system."[36]

Table 2 below provides a concise summary of the various ISO/RTO approaches.

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34 *See* Schedule 15 of the PJM tariff.
35 *Id*.
36 Order No. 890 at P 1618.

Table 2. Summary of ISO/RTO approaches to transmission charges

	Volumetric	Demand		
Basis	MWh/Gross Load	Monthly peak	Annual peak	Variable
Examples	CAISO NYISO MISO MVPs	SPP NITS[37] ISO-NE NITS MISO NITS	ERCOT (4 summer months)	PJM NITS
Intent	Correlates with beneficiaries *ex post*: Customers benefit from transmission as they use it.	Correlates with cost causation ex ante: Transmission costs were incurred to provide customers reliable service during peak demand periods.		
Pros	- Mirrors energy-based (not capacity-based) market - Easily understandable - Reflects benefits all year - Correlates with RPS-driven construction benefits (e.g., carbon reduction, production cost savings)	- Customers only pay in relation to their contribution to peak conditions (no more, no less) - Historically more common		
Cons	Socializes costs incurred due to peak times and/or areas	- More complex than volumetric - Ignores benefits unrelated to peaks		

5. Treatment of load offset by distribution-connected resources

This section is intended to seek stakeholder input on the issues, considerations, and possible approaches regarding the treatment of load offset by DG output, as described in section 1 of this paper. The ISO will consider stakeholder input on these matters in developing and assessing potential proposals.

To consider the implications of DG or other distributed energy resources (DER) serving distribution-connected load it is helpful to first consider the range of services the transmission system provides and general cost allocation principles. Given the recurring principle expressed in both FERC Order No. 890 as referenced earlier *("Whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them")* as well as the Bonbright principles and other sources, the services to be considered generally include both those that increase the cost to provide service and also those that provide benefits without necessarily increasing the costs of the transmission system. Although this was largely unnecessary in an environment in which the ISO's current

[37] Network Integration Transmission Service.

energy volume-based high voltage transmission access charge was formulated, today's increasing range of technical choices, regulatory options, and policy objectives necessitate a more thorough consideration. Decisions to make changes should be made on an informed basis considering the baseline from which they are shifting.

5.1. Services provided by the transmission system

For purposes of exploring the range of services, whether potentially triggering additional transmission costs or not, this paper first sets out the causes of new transmission through the ISO's transmission planning process and then identifies services that may not cause new transmission costs.

5.1.1. Transmission needs addressed in the ISO's transmission planning process

The ISO's transmission planning process considers transmission needs to address reliability, public policy, and economic drivers for new transmission, which in effect entails providing reliable service and enabling transmission customers to access lower cost resources or resources necessary to achieve policy goals.

Reliability requirements can include providing thermal capacity and adequate voltage control, considering the range of stressed conditions on the system. In this regard, the maximum demands placed on the system by the distribution load is relevant, as well as demands placed at times when different transmission paths sourcing the load may be more heavily stressed. A broader range of potential transfer paths needs to be considered as the system evolves to more use-limited and highly variable energy resources backstopped by more flexible generation resources. For example, distribution-connected resources can offset the transmission needs to the extent their output coincides with this steadily increasing number of potentially stressed conditions. In its transmission planning studies, the ISO models the expected growth of distributed resources and their impacts on distribution-connected load over the 10-year planning horizon, as reflected in the CEC's IEPR demand forecast. Assessing both the volume and the profiles of these resources is becoming increasingly complex, but it is necessary to ensure the impacts and benefits are properly assessed.

The transmission planning studies also test dynamic system stability reliability issues, although more recently these factors less frequently drive the need for reinforcement. Relevant factors in considering these issues include overall system reliability, the volume and nature of the gross load, the magnitude, type, and control systems of all offsetting generation and whether the generation is connected to the transmission system, distribution system, or is behind-the-meter. The increasing amount of inverter-based generation and the economic disincentives to maintain "headroom" for inertia-like response will result in a greater focus on these issues moving forward. As long as the transmission-distribution interface is synchronous, *i.e.*, not connected through DC facilities, detailed information on the distribution-connected loads and resources will be necessary for accurate assessments. Planning studies are conducted on the basis that real-time information will also be available to operations staff for safe and reliable day-to-day operation. Distribution-connected resources may offset the transmission needs if their output coincides with the range of stressed conditions, and they effectively support or aid the specific dynamic conditions.

Policy and economic drivers share a common end effect – to allow access to a broader range of new or existing resources, albeit for different reasons. Policy-driven transmission has more generally focused on access to large volumes of transmission-connected renewable generation, typically in response to state policy direction and resulting in relatively quick transitions in the generation fleet and requiring proactive transmission investment. Although these policy goals have largely been energy-volume based (*e.g.*, to meet a renewable portfolio standard or RPS mandate), the transition from identifying the need to developing the most cost-effective transmission solution necessitates considering the capacity of the new resources and their output profiles. The corresponding output profiles of existing and anticipated distribution-connected resources need to be considered. For policy-driven transmission planning, the ISO relies on resource portfolios provided by the CPUC to specify areas of the system, including the distribution side, where resource procurement to meet policy directives is expected to occur.

Over time, and with less dramatic changes in the generation fleet, access to lower cost energy and capacity, rather than explicit policy goals, may drive new transmission. As with policy-driven transmission, considering distribution-connected resources to offset transmission needs involves considering specific profiles of the resources involved and the nature of the transmission constraints being addressed by a potential transmission project.

The above discussion focused on needs that can result, or have resulted, in new or increased transmission capacity being approved through the ISO's transmission planning process. Recently, more attention is being paid to transmission owner costs – and annual cost increases – associated with transmission expenditures that are not subject to the ISO's transmission planning process. Most of these costs are associated with activities to maintain the capabilities of the existing transmission grid, rather than expanding capacity for new services. These include activities such as like-for-like equipment replacement of aging or deteriorating equipment or improvements to meet new or existing design or safety standards. Although rate design considerations for these costs can be complex because they reflect costs associated with maintaining a range of both old and new equipment based on planning decisions spanning decades, they clearly relate to the services being provided by the grid as it exists today.

Other transmission owner-driven costs can be more complex to consider. New and more sophisticated control centers managing a broader range of operating parameters and increasing communications costs for data acquisition and system control do not as obviously translate only to the capacity and energy services contemplated above. Some of these are discussed below.

5.1.2. Other services provided by transmission

Transmission can be used to provide other services that are not traditionally addressed in the ISO's transmission planning process for purposes of driving new transmission reinforcements. For example, a reliable transmission system can enable backup service on an opportunity basis. The transmission system also enables balancing and frequency control services on a day-today, minute-to-minute, and second-to-second basis and provides inrush current for motor starting at commercial and industrial sites. In addition to the more traditional costs associated with upgrading and reinforcing transmission lines and substations, providing these services may also contribute to costs on the transmission system, for example, by needing to maintain or contributing to the need to increase capabilities such as short circuit duty. Also, the increased variability of operating conditions is driving a wider range of transient and dynamic power flow and voltage control conditions to be managed, which contribute to increased need for communication and upgraded control center SCADA. The ISO seeks stakeholder input regarding the impact of distribution-connected resources on these services and whether such resources can offset the need for these costs.

5.2. Distribution grid-connected and behind-the-meter generation

There are two types of distribution-connected resources to be considered, for both their potential similarities and differences: resources connected to the utility distribution system, and behind-the-meter (BTM) generation that is almost exclusively photovoltaic. The BTM generation initially offsets customer load on site, and then can inject into the grid when its output exceeds the load. In California, the structure of net energy metering (NEM) tariffs incentivizes the use of the grid to effectively provide storage for the excess production, so that the equivalent amount of energy will later be available to the end-use customer. Because distribution-connected resources on NEM tariffs is almost entirely solar PV, this storage service can affect both the transmission and distribution systems by contributing to the “duck curve” at the ISO system level[38] and replicating a similar load shape on distribution circuits that have high volumes of BTM solar. Solar PV generation on the utility side of the customer meter will have similar impacts, although utility-side PV does not utilize the grid storage service provided by NEM, and currently the volume of utility-side PV is much smaller than BTM PV. Regardless of the point of interconnection, PV distributed generation can worsen the duck curve unless combined or coordinated with additional devices such as storage that can shift excess supply to times when needed to meet demand.

5.3. Role of DER in offsetting new transmission costs

In considering the benefits distributed generation and other DER bring to the grid in reducing the need for future transmission additions and avoiding cost increases, the overall characteristics of the generation must be taken into account. In particular, one must consider how the DER output profiles relate to other sources of generation that backfill to meet demand when DERs are not producing energy, and how the combination of resources impacts or helps address the periods of maximum stress on the transmission system. As the specific profile takes into account scenarios of particular power output and peak loading on the grid, power transfer considerations

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[38] The “duck curve” is the common term used to denote a net demand profile at ISO system level that is driven by large volumes of solar generation in the system, and is characterized by significantly reduced demand in the middle of the day and significantly increased demand in early evening as energy usage increases and solar output declines.

(*i.e*., in MW and MVAR) are more relevant than overall energy considerations (i.e., MWh). Energy volume measures can still be useful billing determinants as a proxy, depending on the consistency of energy consumption profiles, both for ease of use and as approximations of coincidence impacts between different customer flows or T-D interface flows, but energy volumes alone do not reflect the bulk of transmission planning needs identification.

In considering the benefits DERs provide in offsetting the needs for new transmission capacity, the following should be considered:

1. Does the particular DER or group of DERs have an output profile that materially impacts the level of system stress across the entire range of planning conditions, offsetting the need for reliability driven reinforcements? It appears that some profiles can impact some of the stressed conditions, at least some of the time and especially on the more common thermal loading constraints. Reduced demands on the transmission system might eliminate or defer some level of transmission mitigation, or reduce the scope of otherwise-needed reinforcements.
2. Does the load served by use-limited DER (such as solar PV) also rely on other sources of transmission-connected generation to provide services at other times? Besides reliability-driven projects, does load also rely on policy-driven or economically-driven transmission to access lower cost resources when the DER output is not available?
3. Do the DERs utilize smart inverters that can provide reactive power support/Volt-VAR management along with other reliability functions? These functions would be independent of the DER output profiles, and in theory they can help the wholesale grid to some extent and potentially reduce or eliminate the need for some transmission upgrades. Are these operational functions more supportive of reliable distribution operation and power quality than direct benefits to the transmission system? Are they helping to mitigate distribution system issues that might otherwise be exported to and have adverse impacts on the transmission system. To what extent should they be considered services to the transmission system?

It appears there is some opportunity for DER to reduce the need for future transmission reinforcements, depending on the nature and output profile of the DER, the customer load itself including the level of BTM resources, and the nature of the limitations on the transmission system driving the potential need for reinforcement. The CAISO seeks stakeholder input on these questions.

One other issue worth addressing is how to quantify the benefits a particular DER or set of DERs is providing to the transmission system. For example, it may be relatively straightforward to associate an avoided cost with DER benefits in a situation where the transmission planning process has identified a specific needed upgrade and that upgrade is avoided or deferred by the addition of DER in the area. As the expansion of DER on the system continues, the transmission planning process will utilize estimated DER growth scenarios as an essential input, and on that basis may not identify specific upgrades and associated costs that are avoided by the addition of DER. In other words, as DERs proliferate on the system, it is less clear what the counterfactual would have been, *i.e.,* the specific transmission upgrades or reinforcements that may or may not have been needed absent the addition of the DERs. The ISO requests stakeholder input on how to measure DER benefits in such cases.

5.4. Implications for costs of existing transmission

The costs associated with transmission facilities already in service or that were planned and approved in prior transmission planning cycles and are under development are not avoidable. The TRR associated with these facilities, once approved by FERC, must be collected from ratepayers. What are the implications of this for cost allocation purposes? How should consideration of potential changes to the TAC structure take into account any potential shifting of the costs of existing transmission? The ISO requests stakeholder comments on these questions.