Review Transmission Access Charge Structure
Issue Paper

Comments by Department of Market Monitoring
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Summary

DMM appreciates the opportunity to comment on the Review Transmission Access Charge Structure Issue Paper. In this initiative, the ISO proposes to address at least two major issues of transmission access charge (TAC) structure. While details are not yet specified in the issue paper phase, DMM is supportive of TAC structural changes which remove incentives for load to incorporate fixed costs into their bids for marginal spot market energy. Historically, this has not been a major issue because most load has self-scheduled in real-time and was therefore not able to respond to price signals. However, this issue could become very significant for the efficiency of energy markets as load increasingly becomes able to respond to price signals in the low carbon energy network of tomorrow.

Additionally, DMM supports changes to TAC structure which may improve the alignment of TAC charges with the drivers of transmission investment. Any change to TAC structure should be based on principles of improving market efficiency and improving alignment of costs with the drivers of transmission investment. Changes in TAC structure should not be designed to incentivize a particular generation technology at the expense of market efficiency.

I. Alternatives to volumetric TAC structure

The current volumetric structure of TAC results in a charge to load on a per megawatt-hour (MWh) basis. This charge is incurred by participating load, as well as load serving entities (LSEs) which pass through to ratepayers, largely also on a per MWh basis. In a competitive market, the price of electricity faced by load should represent the marginal cost of delivered electricity. However, a fixed cost recovery mechanism for transmission does not represent a marginal cost of producing electricity, nor does it represent a marginal cost of providing transmission. This apparent marginal cost of transmission is simply a convenient means to allocate recovery of fixed costs associated with transmission assets.

Recovering fixed costs on the basis of marginal energy consumption results in load perceiving a spot market price of energy which exceeds the marginal cost of energy. This results in market inefficiency when load considers these non-marginal costs in the decision to consume incremental quantities of energy. Because these fixed costs are considered by load on a per MWh basis, participating load and exports will have

incentive to submit spot market bids which are lower than the true marginal willingness to pay for any quantity of incremental energy[1].

The regulated and static nature of retail electricity rates, as well as the point that TAC charges are indirectly charged to end users by LSEs, may itself introduce market inefficiencies by distorting price signals[2]. Any inclusion of fixed costs in incremental energy prices further contributes to these potential inefficiencies as the price realized by retail load increasingly departs from the marginal cost of energy. Market efficiency may improve to the extent that any fixed costs can be removed from retail and spot market energy prices realized by end users such that these prices more accurately reflect marginal cost of delivered electricity. For these reasons, DMM supports measures to remove fixed costs from the realized per MWh cost of purchasing spot market energy and would support a revised TAC structure which better reflects the nature of fixed costs.

Following the idea that realized costs should be aligned with the drivers of those costs, TAC structure improvements could be made to better align TAC charges with the drivers of transmission investment and related fixed costs. It may be useful to consider these changes in the context of three primary categories of transmission investment which may contribute to the overall transmission revenue requirement (TRR): reliability, economic, and policy projects.

- For reliability projects, a TAC structure which allocates fixed costs by utility distribution company (UDC) peak load may be appropriate to the extent that this peak load is a driver for transmission investment.

- For economic projects, DMM understands that investment in such projects is driven by the assessment that the *total* economic benefit realized over a period of time exceeds the total cost of the asset. Such benefits may be realized, for example, through access to lower cost generation resources and thus a reduction on total energy costs over a period of time. Although benefits may be realized at any given point in time through access to lower cost generation, there is no marginal cost of transmission to access these resources. The cost of investing in that transmission asset is sunk and fixed and should not be incurred by load on a marginal consumption basis. As such, TAC charges designed to recover TRR associated with economic transmission projects should not be recovered on a per MWh basis by which it appears as a marginal cost. Costs associated with these projects should instead be allocated by other means as a

[1] The consideration of wheeling export charges (WAC) applicable to exports is not included in the scope of the initiative as presented in the Issue Paper. However, DMM notes that considering a non-volumetric structure for WAC would also yield improvements to market efficiency.

[2] The method by which end-users realize TAC charges in retail rates need not be the same as that by which the ISO charges TAC. However, the TAC structure charged by the ISO may provide a logical basis for retail rate structures to recover those costs.

fixed cost that does not distort spot market energy prices. To align the allocation with the driver of the cost, this might be an allocation in proportion with projected total economic benefit, independent of marginal consumption at a point in time.

- For policy projects, there is also no marginal cost of transmission to be appropriately recovered as a volumetric charge. As with other types of transmission projects, costs associated with these projects are fixed and should not influence marginal energy consumption. Benefits of policy projects accrue to all ratepayers through the realization of a predetermined policy goal. Allocation of the fixed costs associated with these projects may largely be a question of equity. However, to maximize energy market efficiency, it remains important that the TAC structure chosen to recover these costs removes the influence of fixed cost recovery from the decision of marginal energy consumption.

As highlighted in the preceding text, aligning cost allocation with the drivers of transmission investment and fixed cost presents challenges, particularly for some drivers of transmission investment where quantifying benefits may be more difficult. While there may be a need for, and some benefit to, simplified approaches to TAC structure to recover these costs, it is detrimental to energy market efficiency to reflect any fixed cost as part of marginal energy cost. As the ISO works to lead the way to tomorrow's energy network, DMM recommends that the ISO consider revisions to the TAC structure in order to prevent fixed cost recovery from being reflected as a marginal cost in spot market prices realized by load. Historically, this has not been a major issue because most load has self-scheduled in real-time and was therefore not able to respond to price signals. However, this issue could become very significant for the efficiency of energy markets as load increasingly becomes able to respond to price signals in the low carbon energy network of tomorrow.

II. Treatment of load offset by distribution-connected resources

In addition to the question of a volumetric or demand based TAC structure, the ISO is considering whether or not it is appropriate to reduce TAC charges in PTO service areas for load offset by distributed generation (DG) output.

In general, if any technology offsets the need for transmission investment or otherwise reduces fixed costs in the TRR, that benefit should be realized by the entity that chooses to invest in that technology. This principle applies generally to any technology and should not be thought of as specific to DG capacity. The appropriate avoidance in TAC charges would be proportionate to transmission investment avoided as a result of the technology, and independent of incremental load served at a point in time. Only if serving load by DG offsets a marginal cost of transmission use would it be appropriate for load served by DG to realize a reduction in TAC costs on a per MWh basis. However,

as discussed above, TAC charges do not represent a marginal cost of transmission use. They represent recovery of a previously sunk fixed cost. Therefore there is no economic argument for exempting load served by DG from TAC charges on the basis that DG may reduce the number of MWhs using the transmission system.

Modifying the TAC structure to consider load at the transmission-distribution interface may be appropriate to help facilitate LSE realization of benefits of avoided transmission investment resulting from DG capacity. However, the extent to which this would actually improve the alignment of TAC charges with transmission cost drivers is unclear and depends upon the billing determinant design.

There is no direct link between incremental MWh of load served by DG and avoided marginal cost of transmission. Therefore exempting load served by DG from TAC charges on the basis of the current volumetric TAC does not appropriately align any type of avoided transmission cost with the benefits of DG capacity. Further, such an approach may result in shifting of sunk costs associated with existing transmission assets. This has potential to further increase inefficiency of spot market energy prices realized by load not served by DG.

Under a TAC structure based on an allocative measure independent of marginal consumption, considering load at the transmission-distribution interface would allow avoided transmission investment and fixed costs to be realized at the level of the UDC or metered sub system (MSS). For example, if TAC were charged based on peak load at the transmission-distribution interface, benefits would accrue at the UDC or MSS level to the extent that DG reduces peak load for the UDC or MSS. This translates directly to the LSE in the situation of only one LSE within the UDC or MSS.

If there is more than one LSE within the UDC, the UDC must then determine the portion of the lower TAC charge attributable to DG. This would be required to allocate the full benefit to the specific LSE which invested in the DG capacity. However, as DMM understands, allocation of TAC to LSEs within the UDC is carried out by the UDC rather than the ISO. The ISO implementing a non-volumetric TAC structure which considers load measured at the transmission-distribution interface may still be an appropriate step in the direction of better aligning DG benefits with the drivers of transmission investment while also removing energy market inefficiencies created by the volumetric TAC. Subsequent changes to the allocation of TAC within UDCs may follow as a future refinement, independent of ISO processes.