UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentives Policy	**Docket No. PL19-3-000**

COMMENTS OF POTOMAC ECONOMICS, LTD.

Pursuant to the above-captioned Notice of Inquiry initiated by the Federal Energy Regulatory Commission (the "Commission"), Potomac Economics hereby submits these comments. The Commission seeks comments on the scope and implementation of its electric transmission incentives regulations and policy. Potomac Economics appreciates the Commission's focus and recognition of the importance of incentives in this area to help ensure reliability and reduce the cost of delivered power by reducing congestion.

The Commission's inquiry is broad, including a broad set of potential incentive designs to meet many objectives and covering both new and existing transmission facilities. Potomac Economics' comments address many of these objectives but are particularly focused on the areas where our monitoring roles provide useful insight on the potential for gains in economic efficiency through increased transmission utilization and improved market signals for new investment. We believe our analyses and recommendations in the areas of transmission utilization and investment are highly instructive and we provide these comments to the Commission to help further the discussion.

Potomac Economics is the Independent Market Monitor ("IMM") for Midcontinent ISO ("MISO") and ERCOT, the Market Monitoring Unit for the New York ISO ("NYISO"), and the External Market Monitoring Unit ("EMMU") for ISO New England. In these roles, we are responsible for monitoring and evaluating the performance of each RTO's energy and operating reserve markets. In these roles we also recommend market design changes to improve the performance of the markets and evaluate design changes proposed by the RTOs or market participants.

Potomac Economics' monitoring role and supporting analyses provide insight into how transmission is utilized in RTO markets through the range of time horizons from planning horizon addressing investment and construction to the intermediate time horizons up to real-time operating horizon where 5-minute dispatch and Reliability Coordination delivers electricity to consumers.   Each of these distinct time horizons impacts whether the grid operates reliably and efficiently, but none is more significant than the real-time.

I. NOTICE AND COMMUNICATIONS

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II. INTRODUCTION

Potomac Economics' roles as market monitor in several of RTOs/ISOs and the attendant responsibility to analyze market and operating data provides us with unique insight regarding how transmission is utilized in RTO/ISO markets.   The Commission's inquiry covers both New and Existing Transmission. The focus of most of the Commission's current policies on incentives has been on new transmission investment and generally rate of return incentives. While the planning horizon in which new transmission construction decisions are made is vitally important, much less attention has been paid to maximizing the utilization and efficiency of transmission in the shorter horizons including the real-time (5-minute dispatch and reliability coordination) where the physical operation of the grid impacts efficiency and actual production costs. In the sections below, we separately address incentives for existing transmission facilities and operations and for new investment in transmission. We believe new market-based incentives, incentivizing increased grid capacity, facility ratings, and efficient grid utilization rather than specific technologies will provide flexibility to transmission owners and other market participants and best achieve the Commission's goals.

III. INCENTIVES FOR EXISTING TRANSMISSION FACILITIES

Much of the focus of prior incentives has been on rate of return on new transmission facilities, which recognizes that new transmission facilities can provide substantial benefits by relieving key bottlenecks. In the same way, operating transmission facilities in a manner that allows greater network flows can produce sizable benefits with little or no capital investment. The Commission has, to a lesser extent, provided rate-based incentives for decisions that would improve the operation of transmission by increasing the allowable return on equity (ROE) for transmission owners that choose to join an RTO.

While we believe it is generally true that joining an RTO will improve the utilization of transmission by increasing coordination of injections into and withdrawals from the transmission network, RTO membership alone does not ensure full utilization of transmission. As the market monitor for four of the nation's RTOs, we have identified a number of shortcomings in the operation of transmission facilities that limit the utilization of the network and increase congestion. We attribute many of these operational shortcomings to a lack of efficient incentives for transmission owners to take actions that increase the utilization of the exiting network. In this section, we discuss market-based incentives for transmission owners to maximize the utilization of existing transmission facilities, including:

- Providing dynamic ratings;
- Scheduling outages to minimize congestion; and
- Optimizing the operation of transmission equipment.

We will discuss recommended incentives in each of these areas and identify potential benefits of making these improvements.

A. Background on Exiting Transmission Ratings

Facility ratings are used in virtually every aspect of electricity market and system operations, from the planning horizon to real-time operations. A rating simply reflects the amount of power that can safely and reliably flow through a transmission facility (e.g., a line or a transformer). Normal ratings are an amount that can flow indefinitely, while a short-term emergency rating is an amount that can be safely accommodated for short periods, generally only 2 to 4 hours. These ratings are the basis for the transmission limits used by the RTO market models.

Using ratings that are understated (below facilities' design criteria or actual capability) will cause the RTO to operate inefficiently and lead to:

- Higher congestion costs for RTO customers;
- Reduced availability of transmission service;
- Higher local resource adequacy and transmission security requirements; and

- Increased need to invest in new transmission facilities.

1. Calculation of Transmission Ratings

Transmission owners in the Eastern Interconnection are obligated under NERC Standard FAC-008-3 Facility Ratings "to ensure that Facility Ratings used in the reliable planning and operations of the Bulk Electric System are determined based on technically sound principles." Likewise, Reliability Coordinators in the Eastern Interconnection are obligated under NERC Standard FAC-011-3 System Operating Limits Methodology for the Operations Horizon "to ensure that System Operating Limits used in the reliable operation of the Bulk Electric System are determined based on an established methodology or methodologies."

Ratings for conductors and other related types of facilities depend on ambient conditions.[1] Seasonal static ratings are calculated assuming appropriately conservative weather conditions. However, in any hour, if calculated dynamically using current temperatures, wind speeds and direction, and humidity, the rating would be more accurate. Since the seasonal ratings are based on conservative assumptions (e.g., high temperatures and low wind speeds), these dynamic transmission ratings are generally higher than the seasonal ratings.

In general, transmission owners have the authority to determine the transmission ratings. Ideally, transmission owners would provide dynamic hourly transmission ratings based on current ambient conditions since these ratings can be substantially higher than seasonal ratings. Additionally, RTOs should typically use emergency ratings (which are typically 10 percent or more higher than normal ratings) for most constraints that are "contingent constraints". These constraints are managed with limits that allow for the additional flows that will result if the most

[1] The standard used by the industry to establish overhead line ratings is IEEE Standard 738-2012. This standard identifies a methodology based on a set of inputs (ambient temperature, conductor temperature, wind speed and direction with respect to the conductor, type of conductor, sun/no sun, emissivity index, absorptivity index, longitude/latitude, etc.) that go into the heat balance equation to determine the ampacity limit of the conductor.

significant contingency occurs. Emergency ratings are appropriate for these constraints because this flow will only occur after the contingency occurs and RTOs generally have actions that can be taken after the contingency to reduce the flow back down to the normal rating.

Transmission modeling and associated facility ratings are used in many distinct time horizons that have important implications, including:

- Transmission and resource planning
- Financial Transmission Rights
- Transmission service administration and AFC calculation
- Outage coordination
- Day-ahead market and reliability assessment
- Market-to-market coordination and settlement
- Real-time market dispatch and operations

The ratings used in all these time horizons are important, but none more so than the ratings used in the real-time market dispatch. In this timeframe, transmission owners can have accurate information on temperature, wind speed/direction, and other factors that allow them to calculate dynamic transmission ratings. In practice, however, very few transmission owners provide such ratings.

Some RTOs have worked to facilitate the provision of dynamic ratings and a limited number of transmission owners are working to provide them. For example, Potomac Economics (as the IMM for MISO) has worked with Entergy (Entergy Services, LLC) and MISO for the past several years on a program under which Entergy provides short-term emergency ratings and temperature adjusted ratings for selected transmission facilities. We have identified facilities for this program based on past congestion or expected future congestion. As Entergy reported, it has realized an average ratings increase of 11% when applying temperature-adjusted ratings, and 13% when applying short-term emergency ratings.[2] While not all of Entergy's transmission facilities are in the program, Entergy, MISO, and the IMM continue to evaluate additional facilities for inclusion in the program. At the RTO level, both MISO and PJM have instituted processes to allow all transmission owners to submit ratings that are adjusted for temperature changes, including the ability to provided multiple ratings that correspond to different temperatures. This allows the RTO to utilize the appropriate temperature-adjusted rating without the transmission owner having to calculate and provide updated ratings on an ongoing basis. In MISO and many other RTOs, however, very few transmission owners utilize these capabilities, likely because they lack the incentive to provide temperature-adjusted ratings as discussed in the following subsection.

2. Current Incentives to Provide Dynamic and Emergency Ratings

Since transmission owners are guaranteed recovery of their costs, their revenues are generally unaffected by the rating levels of their facilities. Transmission owners do have incentives to satisfy reliability standards, protect against loss of load, and protect against equipment damage and degradation/loss of life. These incentives generally result in *lower* ratings. To the extent that the transmission owner owns generation or serves load in a load pocket served by its transmission facilities, the transmission owner may have an incentive to provide *higher* or *lower* ratings depending on how prices in the load pocket affect its net revenues and costs.

As the NOI recognizes, increases in ratings for existing facilities may be achieved through O&M expenses on which there may be no return on investment, which reduces the

2 https://cdn.misoenergy.org/20181213%20MSC%20Item%2004a%20Entergy%20Presentation%20Dyanmic%20Line%20Ratings300974.pdf.

incentive to incur these expenses and ultimately *lowers* ratings. Finally, improvements in ratings for existing facilities may compete with new transmission that are a source of increased revenues for transmission owners. This creates incentives for *lower* ratings for existing transmission facilities.

These existing incentives help explain why few transmission owners in RTO/ISO areas have provided dynamic ratings that would allow the RTO to maximize utilization of the transmission network, despite the enormous economic benefits of doing so. The best, and perhaps only, solution to this problem is to provide market-based incentives for transmission owners that allow them to realize some of the benefits of improving the utilization of the transmission network.

B. Market-Based Incentives for Transmission Owners to Provide Dynamic Ratings

1. Recommended Incentive for Dynamic Ratings

In MISO and likely in most other RTOs, transmission owners have the ability to provide dynamic transmission ratings (emergency ratings for contingent constraints) based on currently available information. This would a generate substantial benefits. Additional benefits could be achieved by installing equipment that provides better measurement and data on the status of transmission facilities and ambient conditions. Finally, further benefits could be achieved by making low-cost upgrades to equipment that prevent a constraint's rating from being adjusted upward as temperatures fall.

The NOI addresses these issues broadly in asking the question: *how to incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals?*

Our answer is that all of these actions would be facilitated by establishing market-based incentives that allow transmission owners to capture increased revenues that are directly related to the benefits of increasing transmission ratings. Providing market-based incentives will motivate the most cost-effective actions by transmission owners and RTOs/ISOs that can increase ratings and, ultimately, the utilization of the transmission network.

In the NOI The Commission has asked if the costs of technologies supporting dynamic line rating (DLR) technology are or should be recovered in rate base. We believe better incentives for DLR should be designed that allow for a better link between value of actions and the market value. The direct costs to provide DLR may involve investments in real-time measurements and ratings or more timely updates to ratings may require O&M involved with staff engineering. Regardless, recovering such costs through rate base is not sufficient to overcome other disincentives to providing more accurate (and less conservative) ratings. To establish market-based incentives, we recommend that RTOs *provide revenues to transmission owners equal to some or all of the congestion surpluses that result from the higher transmission ratings.* The congestion surplus would equal:

Shadow Price of the Constraint ($/MW) * (Dynamic Rating – Static Seasonal Rating)

This approach will provide an economic incentive to the transmission owners that is directly related to the benefits of the additional transmission capability. This is reasonable because using higher transmission ratings reduces congestion and the overall costs of managing the system. Even if all the surplus is paid to the transmission owner, loads will still benefit as:

- The shadow price falls and congestion costs decrease; and
- Fewer uplift costs are incurred to commit resources to manage congestion and address local reliability concerns.

Since the FTR markets generally limit flows to the static seasonal ratings, use of temperature-adjusted day-ahead ratings will result in day-ahead congestion surpluses. As RTOs develop the tariff provisions, they would need to combine day-ahead congestion surpluses with real-time surplus in a manner that avoids any double counting.

As an alternative to simply providing a higher rating as temperatures fall, some RTO's may be able to use adjustments to constraint demand curves. If using the higher temperature-adjusted ratings have some costs, such that transmission owners would prefer to utilize the higher ratings only if the congestion is costly, the transmission owners could specify a price above which the additional capability could be used. This option would align their expectation of incremental risk/cost with potential surplus compensation. In practice, this would cause the RTO to insert an additional step in its transmission constraint demand curve (TCDC) rather than increasing the rating/limit, which would shift the entire TCDC. This would allow the flow to rise to the temperature-adjusted limit at a specified price/range, but only if the marginal value (shadow price) exceeds the value provided by the transmission owner.

In addition to utilizing temperature-adjusted savings in real-time operations, additional savings can be achieved by using predictive ratings in the day-ahead market based on forecasted temperatures and wind speeds. The incentive described above would be appropriate to motivate the use of predictive ratings, but it would likely require some work by the RTOs/ISOs to calculate such ratings.

The Commission also asked about the appropriateness of rate-based incentives for transmission owners to install equipment that would improve the utilization of the existing transmission system. Market-based incentives, like those recommended above, are far more effective that rate-based incentives. Therefore, we recommend the Commission issue a rulemaking that encourages RTOs/ISOs to develop market-based incentives to utilize dynamic transmission ratings, including the use of emergency ratings on contingent constraints. The benefits of such rules would be very large, which we have estimated for MISO and discuss in the next subsection.

2. Estimated Benefits of Dynamic and Short-Term Emergency Ratings

Potomac Economics has estimated the direct benefits of transmission owners providing more accurate temperature-adjusted ratings and short-term emergency ratings. Most transmission owners in MISO do not actively adjust their facility ratings to reflect ambient temperatures and wind speeds or other ambient factors. As a result, MISO uses more conservative seasonal ratings, which reduces MISO's utilization of the true network capability. In our State of the Market Report analysis we estimate MISO could have saved more than $145 million in production costs in 2018 by using temperature-adjusted and short-term emergency ratings.

Our analysis used temperature and engineering data to estimate the increase in transmission ratings that would result from temperature-adjustments. To estimate the effects of using emergency ratings for facilities for which only normal rates have been provided, we assume that the emergency ratings are 10 percent higher than the normal ratings. This is consistent with the data for other facilities for which transmission owners submit emergency ratings. We then estimated the value of these increases (both the temperature-based increases and the emergency rating increases) based on the shadow prices of the constraints. This analysis is described in detail in Section VI.E of the Analytic Appendix of our SOM and summarized in the following Table.

Benefits of Temperature-Adjusted and Emergency Ratings
2017-2018

		Savings ($ Millions)				
		Temp. Adj. Ratings	Emergency Ratings	Total	# of Facilities for 2/3 Savings	Share of Congestion
Total Estimated Benefits						
2018	Midwest	$70.9	$50.92	$121.8	22	12.4%
	South	$7.0	$16.86	$23.9	2	6.7%
	Total	**$77.9**	**$67.8**	**$145.7**	**24**	**10.9%**
2017	Midwest	$83.8	$38.83	$122.7	20	11.7%
	South	$10.0	$23.07	$33.1	3	8.9%
	Total	**$93.9**	**$61.9**	**$155.8**	**23**	**10.9%**

The results across the two years show consistent benefits equal to 11 percent of the real-time congestion value, including $80 to $95 million per year for temperature-adjusting the ratings and $60 to $70 million per year for using emergency ratings. As may be expected, the benefits of temperature adjustments accrue primarily outside the summer months when static ratings are most understated.

We have also estimated the savings that are currently being achieved by two transmission owners that do regularly provide daily or hourly updates to ratings. These benefits are estimated by multiplying the rating increases (from the static rating level) by the prevailing shadow prices. This methodology is a conservative estimate of savings, given that the shadow price would increase if the market was controlling to a lower, non-adjusted rating.

From 2017 to 2018, the actual savings totaled almost $51 million – almost 9 percent of the congestion on the transmission facilities. Over $37 million of the savings were on Entergy's transmission facilities in the South – 9 percent of congestion on those facilities. These savings estimates are conservative because the costs of managing to a lower limit would increase.

Estimated Achieved Savings by Two Transmission Owners
2017-2018

	Savings ($ Millions)	Share of Congestion
Midwest	$14.0	5.4%
South	$37.3	9.0%
Total	**$51.3**	**7.6%**

Our estimates of the potential benefits for transmission owners in MISO to provide dynamic and emergency ratings, as well as our estimates of the actual benefits being achieved by two of MISO's transmission owners strongly support the value of FERC's incentive inquiry. We encourage the Commission to proceed to a rulemaking to facilitate achieving these benefits in all the RTO/ISO markets.

C. Incentives for Improved Outage Coordination

In MISO and other RTO/ISOs, the responsibility and authority for scheduling transmission facilities outages resides with transmission owners. The grid is greatly impacted by transmission outages, both planned and forced. MISO's role is limited to disapproving planned outages proposed by transmission owners that cannot be managed reliably. There is no authority or mechanism for MISO to optimize planned outage schedules to avoid congestion or reduce production costs.

Unfortunately, like the incentive to provide dynamic ratings, transmission owners have little incentive to optimize the scheduling of outages and minimizing their duration. A rulemaking by the Commission could also provide effective market-based incentives to optimize outages by allocating some of the costs of the reduced transmission capability to the transmission owners. A form of this incentive exists in New York where the ISO allocates Transmission Congestion Contracts (TCCs) shortfalls to transmission owners when their outages cause the ISO to be revenue insufficient. This occurs when the capability of the network in the day-ahead market is less than the quantity of TCCs issued by the ISO. This is a reasonable approach that could be expanded to other RTOs. We encourage the Commission to explore this form of market-based incentive in a rulemaking.

D. Incentives for Transmission System Optimization

In addition to facility ratings and outage planning, transmission congestion costs are impacted by the transmission topology (i.e. it may be possible to reduce line flows and reduce the amount of congestion by altering the topology of the transmission system in response to real-time conditions). For example, RTOs/ISOs may develop operating guides with transmission owners to implement a reconfiguration of the system under specified operating conditions (i.e. based on line loadings, contingencies, load levels) to reduce flows on highly-congested facilities.

Flexible transmission system operation or topology optimization options could be expanded or enhanced to include the use of other existing controllable devices such as the use of phase angle regulators (PARs) that can be used to control flows. Since some of these options could put load at risk or result in wear and tear on equipment, they may require capital investment (i.e. to enhance controls, telemetry). Again, transmission owners generally have no market-based incentives to make these investments or make topology changes to reduce congestion costs.

Consequently, the Commission should explore the development of market-based incentives in this area as well. These incentives may be less straightforward than the incentives we recommended above and may require additional research. In general, we believe market-based incentives are more appropriate in this area than rate-based incentives. Finally, we note that expanded use of grid management technologies and reconfiguration options in the operating horizon by RTOs may be limited without significant changes and increases in RTO operational control over transmission assets.

E. Complementary Changes in RTO Processes and Authority

To facilitate the benefits we describe above, we believe RTOs will need additional authority to validate and potentially calculate facility ratings, and to review and coordinate outages. MISO, for example, generally has no specific information on how the ratings are calculated or the limiting elements associated with the ratings provided by the transmission owners. This limits its ability to appropriately implement the market-based incentives we describe above and can result in less reliable real-time operations.

Transmission owners must retain primary responsibility for determining ratings and must approve the parameters and methodologies, but RTOs/ISOs should have more visibility into the ratings and transmission limits, particularly if they administer market-based incentive settlements with the transmission owners.

The new authority would be more in line with existing authority to gather and validate information on generation resources. Although both generation and transmission can significantly affect prices in the RTO markets, RTOs generally have far less visibility, testing and verification, and authority over transmission facilities than generating resources.

Therefore, as the Commission considers potential improvements in the incentives for transmission owners and RTOs to take actions to utilize transmission facilities more completely, we encourage the Commission to consider requiring the RTO's to expand their operational authority over transmission facilities, which should include additional authority in the areas of rating obligations and verification, outage scheduling, and facility testing requirements.

IV. IMPROVING INCENTIVES FOR NEW TRANSMISSION FACILITIES

Investment in new transmission projects has traditionally occurred under a regulated cost-of-service framework. Although there are several areas where additional transmission can significantly alleviate grid congestion and enhance reliability, there has been relatively little market-based investment in transmission projects. This is unfortunate because the markets have the potential to provide powerful incentives to identify the most cost-effective investments. In this section, we discuss the barriers to merchant investment in transmission, design of market-based incentives, and illustrate the impact of market-based incentives on investment decisions for new transmission projects.

A. Background

As the Commission recognizes through its questions on benefits that would warrant incentives, new transmission projects can benefit the system in multiple ways.[3] Two primary benefits of new transmission projects are: (a) reducing grid congestion and (b) enhancing reliability by lowering planning reserve requirements. A significant portion of both these benefits can be measured and priced through the markets. However, transmission projects generally receive little or no market-based compensation for the benefits they provide. For instance, in NYISO, investment in transmission projects can reduce the required installed capacity reserve margins, but they are not compensated for their reliability value through the capacity markets.

Consequently, developers are likely to rely on incentives from regulators to invest in and develop new projects. The absence of market-based compensation has hindered merchant

[3] For example, see questions 17, 22, 24, 26, and 47 from the NOI.

investment in transmission projects. Even with additional rate-based incentives, compensation for the most valuable investments is likely to be far less than their benefits. In addition to the efficiency benefits, merchant investment in transmission is valuable because it shifts the project risk from consumers to private investors, and leverages competition between transmission developers and generation, to unlock consumer savings.

B. Market-based Incentives for Transmission Investment

A key step in providing market-based incentives for private investment in transmission is to create and allocate economic property rights to the investor that capture all the benefits it provides. We believe that this should include allocating:

- Financial Transmission Rights (FTRs) that would provide payments in accordance with the LMP differentials between two points; and
- Financial Capacity Transfer Rights (or "FCTRs") that would provide revenues for reducing the capacity requirements to new transmission projects and provide strong incentives to merchant developers.

The provisions governing the allocation of these rights are very important. Some of the existing rules related to the allocation of FTRs may cause transmission projects to be undercompensated relative to the value they provide to the system.[4]

Adopting a framework that provides transparent market-based incentives for transmission projects would produce a variety of benefits over the long term. These benefits include:

[4] For instance, in NYISO, the Transmission Congestions Contracts ("TCCs" which are analogous to FTRs in other markets) are (a) sold only for day-ahead congestion and none are sold for real-time market congestion, (b) allocated based on assumed congestion patterns, which could differ substantially from actual market outcomes, and (c) awarded for only 10 years, which is well below the likely economic life of a new transmission line. Consequently, the compensation to TCC holders is likely to be much lower relative to their value to the system.

- Directing transmission investment to areas with large congestion and/or reliability needs that would result in overall production and investment cost savings.
- Compensating transmission projects in a manner that is comparable to generation that would support efficient allocation of investment across the two resource types.
- Enabling 'right sizing' of investment in new transmission projects. A merchant developer would size the transmission project at a level where the marginal cost of expansion would equal the marginal benefit from increased revenue rights.

When paired with allowing investment from non-incumbents in existing facilities, this will also impose competitive discipline on incumbents and result in lower costs for consumers. Recent Order 1000 transmission processes in NYISO have demonstrated that non-incumbents can often propose more cost-efficient transmission solutions.

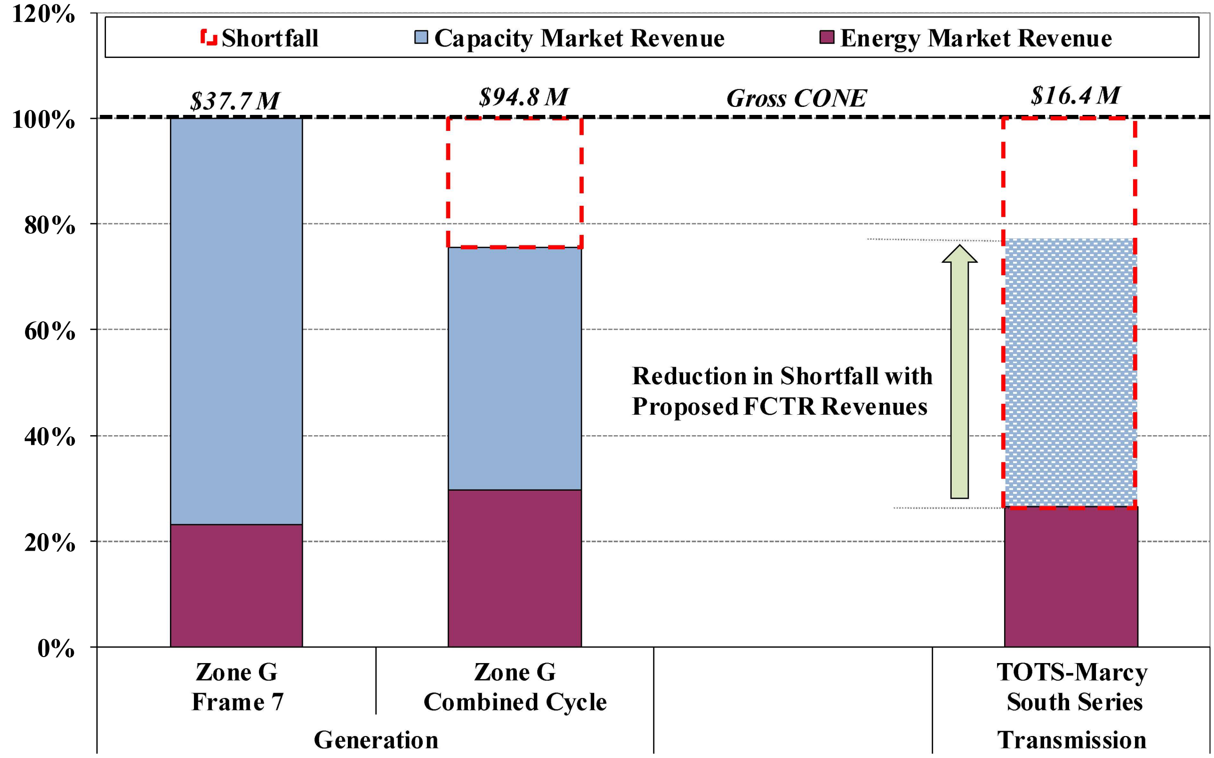
To illustrate the significance of providing market-based compensation for new transmission projects, we present the impact of FCTRs on the investment signals for a transmission project in the NYISO footprint that was completed in 2016. The value of the FCTRs in our illustration are based on how much installed capacity requirements are reduced by the upgrade.

The figure below compares the breakdown of capacity and energy revenues for two hypothetical new generators (Frame CT and a combined cycle) in Zone G of NYISO with the revenue breakdown for a transmission project (the Marcy-South Series Compensation or the "MSSC" project). [5] For the MSSC project, the figure shows the Incremental TCC revenues

[5] The FCTR revenues for the MSSC project equal the product of the following three inputs: (a) the effect on the UPNY-SENY transfer limit of adding the new facility to the as-found system, (b) the improvement in LOLE by increasing the transfer limit of UNPY-SENY by 1 MW, and (c) the value of reliability in dollars per unit of LOLE. Based on the results of the GE-MARS simulations, (c) is assumed to be $2.9 million per 0.001 events change in

received by the project under "Energy Market Revenue." The figure reports the capacity value (i.e., the revenue that a generator or demand response resource would receive for having the same effect on LOLE) of increased transfer capability in the resource adequacy model under "Capacity Market Revenue." Transmission projects do not receive actual revenue for this capacity value. The figure also compares the net revenues for these projects against their gross CONE and highlights the reduction in shortfall of revenues due to the proposed FCTRs.

Valuation of Generation and Transmission Projects
Annualized Cost of New Entry vs. Revenue



The results illustrate the disadvantages that transmission projects have relative to generation in receiving market-based compensation for the benefits they provide. Capacity

LOLE. The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the MSSC project.

markets provide a critical portion of the incentive (up to 77 percent) for a new generator in Zone G. In the absence of analogous FCTR rights to the MSSC project, the project would recoup only 27 percent of its annualized gross CONE. However, granting FCTRs to the project based on its capacity value would have provided an additional 51 percent of the annualized gross CONE, thus significantly increasing the incentive for merchant transmission developers.

This analysis illustrates the potential effects on investment decisions of providing market-based compensation for the reliability services provided by transmission projects in NYISO and other RTOs. Market-based investments in transmission will be under-compensated if transmission developers cannot receive capacity market compensation. Consequently, the shortfall in revenues for any new transmission investment will have to be recovered through cost-of-service mechanisms.

C. Recommendation

Overall, the market compensation to transmission projects is currently lower than their marginal benefits to the system. Designing transparent markets that would compensate these resources in accordance with their benefits would provide efficient incentives for private transmission investment and ultimately result in large consumer cost savings.

Therefore, in addition to pursuing potential rate-based incentives, we recommend the Commission incorporate in its rulemaking a proposal that would capture:

- the energy and ancillary services markets benefits of transmission through enhancements to the FTR/TCC rules, and
- the planning value of transmission by providing compensation through the allocation of capacity transfer rights.

V. CONCLUSIONS

We strongly support the Commission's interest in incentives for new and existing transmission. However, we recommend the Commission focus on the creation and expansion of market-based incentives in both these areas. In particular, we recommend that the Commission issue a rulemaking that:

- Provides market-based incentives for transmission owners to provide increased capability through dynamic ratings by allocating the congestion surplus to the transmission owners;
- Improves transmission outage scheduling and coordination by allocating the costs of outages to transmission owners and expanding RTO outage coordination authority;
- Considers possible market-based incentives for topology optimization; and
- Provides market-based incentives for investment in new transmission by allocating rights related to the congestion benefits and capacity market benefits associated with the new transmission.

Respectfully submitted,

/s/ David B. Patton

David Patton
President
Potomac Economics, Ltd.

June 25, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 25th day of June 2019 in Fairfax, VA.

/s/ David B. Patton