UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	)))	Docket No. RM20-10-000

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Notice of Proposed Rulemaking issued March 20, 2020,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments.[3]

In regions with robust planning processes, like PJM, there is no reason to provide additional incentives for investment in transmission assets. PJM identifies projects needed, including for system reliability, and initiates the process to identify the specific project and developer. The opportunity to build transmission projects, particularly when recovered through cost of service rates, is inherently attractive because they are low risk and high profit. The challenge is not to encourage projects to be built; the challenge is make the selection that is required for the reliable operation of the system and best serves the public interest.

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1 *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204.

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

3 *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208 (March 21, 2019).

There is no evidence that any additional incentive to build is needed. The NOPRs explanation of the need for reform (at PP 24–33) provides reasons that system planning is challenging and why planners need to make better decisions. None of the reasons explain why, once a project has been identified, builders need an additional incentive to build it. No such evidence has been provided either in the NOPR or by market participants. The question of evidence does not appear to have been considered. Rather, it appears to simply be assumed that additional incentives are required. There are multiple parties interested in building transmission projects. The issue is not the need to pay more to get transmission projects built. The issue is how to structure competitive processes to ensure a reliable system is built at the least cost. Competitive processes create the best incentives.

There is no evidence that current incentives are not more than adequate to encourage the construction of transmission facilities. Existing transmission owners want to maintain their historical regulatory monopoly on the construction of transmission projects because current incentives are high. There is evidence that there are other entities willing to build identified transmission facilities if the existing transmission owners do not believe that incentives are adequate.

Transmission continues to occupy a complex spot in the continuum between regulation and competition. RTO/ISO planning should identify the need for all transmission facilities following explicit reliability criteria that are reviewed and approved by the Commission. Once the need has been identified, competitive market processes should be followed.

The use of competitive market processes will reveal the need for, or the lack of need for, additional incentives to build transmission. Competitive processes rely on a market mechanism rather than on administrative determinations of the cost of capital and adders to the cost of capital. The Commission should continue to apply Order No. 1000 and to expand the role of markets in order to ensure that needed transmission is built at the lowest possible cost.

A. Consistent with Section 219 of the Federal Power Act, Transmission Investment Should Be Attracted Through Competition.

The opportunity to build projects is an adequate incentive to build transmission projects. Regulation through competition is the best way to ensure that transmission projects are built and are built at lowest cost. Section 219 of the Federal Power Act does not require administrative adders to transmission rates to encourage the building of new transmission facilities.[4] That Section 219 encourages transmission infrastructure investment does not change the fundamental purpose of the Federal Power Act to protect consumers and ensure just and reasonable rates.[5] In PJM, regulation through competition protects the public interest in access to electric power at the lowest possible cost. Regulation through competition should be extended more completely to transmission investments.

Section 219 is entirely consistent with regulation through competition, and, properly interpreted and applied, promotes competition in the transmission sector. Section 219 does not require continued cost of service ratemaking in the transmission sector. Section 219 promotes incentive based and performance based ratemaking.[6] Incentive based and performance based alternatives to cost of service ratemaking are both consistent with regulation through competition. Competition offers the most efficient vehicle to provide incentives for new investment at the lowest cost.

Section 219 specifies only one form of incentive as an adjustment to transmission rates: the incentive for joining an ISO/RTO (Transmission Organization).[7] The inclusion of the incentive for ISO/RTO membership in an environment where such membership is not yet mandatory demonstrates statutory support for regulation through competition.

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4 *See* 16 U.S.C. § 824s (2005).

5 *See* 16 U.S.C. § 824s(d).

6 See 16 U.S.C. § 824(a).

7 *See* 16 U.S.C. § 824s(c).

Acceptance of the incentive should require a commitment to remain in an ISO/RTO indefinitely and to promote competitive market design and not narrow pecuniary interests in the stakeholder process.[8] Section 219 continues to require showing that rates inclusive of incentives are just and reasonable.[9]

ISO/RTOs represent the implementation of regulation through competition that successfully incorporates both the generation sector and the transmission sector. There has been substantial new investment in both generation and in transmission. The transmission sector has played a key role in ensuring the success of ISO/RTOs.

Section 219 specifically requires that the rules:

- "[P]romote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities."

- "[P]rovide a return on equity that attracts new investment in transmission facilities (including related transmission technologies)."

- "[E]ncourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities;

- "[A]llow recovery of— … all prudently incurred costs necessary to comply with mandatory reliability standards … and … related to transmission infrastructure development …"

The key provision concerning promoting new investment provides for a "return on equity that attracts new investment." This provision does not require incentives in the form of administrative adders to cost of service rates for transmission investment that would have occurred without such adders. The text of Section 219 makes clear that lower cost

8 See NOPR at P 93 ("the RTO-Participation Incentive also compensates transmitting utilities for the ongoing duties and responsibilities of RTO/ISO membership").

9 *See* 16 U.S.C. § 824s(d).

electric power and consumer protection remain the Federal Power Act's overriding objectives.[10]

The best way to determine the returns required to attract new investment is to create a competitive framework and let the market reveal the required level of returns. In PJM it is clear that nonincumbent transmission companies are willing to invest in new transmission facilities under Order No. 1000 and willing to make investments subject to cost cap provisions.

One provision of Section 219 worthy of special attention is the objective of "promoting capital investment… regardless of the ownership of the facilities." Competition is the best way to promote capital investment, and increased competition for the opportunity to finance facilities could help achieve the goals of Section 219. Competitive financing can be implemented without regard to ownership. Rules permitting competition to provide financing for PJM and other RTO transmission expansion projects could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. Such competition would reveal the actual, market based, cost of capital rather than the administratively determined cost of capital currently used.

B. The Role of Benefit/Cost Benefit Analysis

The NOPR includes benefit/cost analysis as a key determinant of incentive payments. But benefit/cost analysis is not clearly defined in the NOPR, and is incorrectly applied in PJM. The NOPR indicates that it is always a benefit to reduce congestion. That is not correct and ignores the tradeoffs between the cost of generation and transmission. If it

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10 *See* 16 U.S.C. §§ 824s(a) (rule must establish "incentive-based … rate treatments for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion"), 824(d) ("All rates approved under the rules adopted pursuant to this section, including any revisions to the rules, are subject to the requirements of sections 824d and 824e of this title that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential.").

were true that the correct approach is always to reduce congestion, then the goal of all transmission planning processes would be to build transmission everywhere, the copper plating strategy. But that, correctly, is not the goal of transmission planning. Copper plating, or eliminating congestion, is not and should not be the goal of transmission planning. By introducing benefit/cost analysis based on a misunderstanding of congestion, the NOPR would require a significant change in transmission planning criteria but without an explicit statement that the change is intended.

The goal of wholesale power market design should be to enhance competition and to ensure that competition is the driver for all the key elements of wholesale power markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The market efficiency approach does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service transmission regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. If there are incentive payments, benefit/cost analysis should not be the basis for incentive payments. The market efficiency approach is not efficient.

If benefit/cost analysis is used, there are significant issues that should be addressed. In PJM, the current benefit/cost analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from a transmission project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit/cost analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of significant cost increases for transmission projects should be incorporated in the cost benefit analysis.

C. Incentives for New Transmission Technologies

The NOPR (at 9) proposes to offer public utilities incentives for transmission technologies that, as deployed in certain circumstances, enhance reliability, efficiency, and capacity, and improve the operation of new or existing transmission facilities.

As stated by the Commission, grid-enhancing technologies (GETs) can increase the capacity, efficiency, or reliability of transmission facilities. The Commission can change regulatory approaches to GETs by addressing incentives or by direct requirements for the adoption of grid-enhancing technologies. For purposes of this discussion, GETs include, but are not limited to: (1) power flow control and transmission switching equipment; (2) storage technologies; and (3) advanced line rating management technologies.[11]

The transmission grid defines the network which permits the functioning of competitive wholesale power markets for energy, capacity and ancillary services. But the definition of competitive wholesale power markets also includes the transmission grid itself. As initiated in Order No. 1000, there is no reason to exempt the transmission grid from competition for innovative approaches to upgrades, expansions and improvements.

The capability of the transmission grid to transmit power affects every aspect of the energy and capacity markets. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, real-time nodal price differences, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new resources. These also include potential impacts on competition in the energy and capacity markets as the choice of where to place power flow technology and how to operate the technology will affect the economics of existing power plants. The impact of transmission facility capability on markets is a function, in part, of the actual capability of the facilities, of new technologies that may enhance that capability, of how the capability is measured (line ratings), of how the new technologies are used by the RTO/ISOs, and of the use or modification of measured capability by the RTO/ISOs. While the NOPR focuses on the technologies that can affect the capability of the transmission grid, the measurement of the impact on that capability, the

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11 FERC, Grid Enhancing Technologies, Docket AD19-19-000, Supplemental Notice of Workshop, November 11, 2019.

actual use of the technologies by the market operator and the impacts of those uses should also be examined.

For straightforward approaches like ambient adjusted line ratings (AAR), the Commission should require immediate adoption. Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real-time conditions and to help ensure that real-time prices are based on actual current line ratings.

For dynamic line rating (DLR) technologies, the Commission should require significant pilots and analysis of the results and the applicability of the results, to be completed within a defined time period. It is likely that some application of DLR should be required by the Commission in the near future. The Commission should open the provision of DLRs to competition with the result that the lowest cost provider would make the investment.

Given the weaknesses of the current transmission cost of service regulatory paradigm as a mechanism for competitive, efficient and flexible outcomes compared to a market approach, no new technologies should be included as transmission assets unless it is unavoidable. In the case of batteries, there is no reason to include batteries as transmission assets. There are market opportunities for batteries to compete and if batteries are economic, private investors will build batteries, take the associated risks and receive the associated rewards. Inclusion of batteries as a transmission asset will have a negative impact on competition to provide batteries.

The goal with respect to GETs should be to establish a regulatory approach that relies on Commission directives to require inclusion of the technologies when appropriate, and that, to the maximum extent possible, relies on competition and market incentives for the construction and operation of GETs. The fact that GETs are not already well established in U.S. wholesale power markets is evidence that the cost of service paradigm is not working to provide incentives for efficient, least cost solutions. The market paradigm does not rely on cost of service ratemaking, including paying higher rates of return to regulated utilities to encourage innovation. The cost of service approach is not well suited to providing incentives for cost cutting innovations. Under the cost of service approach, the regulated companies prefer higher levels of investment to lower levels of investment to reach the same goal because higher levels of investment lead to higher total returns for the regulated companies.

Simple math demonstrates that paying higher rates of return within the cost of service paradigm cannot and will not work to provide effective incentives to investment in efficient and least cost transmission solutions. By definition, if an investment in GETs costs significantly less than an investment in transmission facilities with a comparable impact on load carrying capability, a higher rate of return on the GETs investment, within any conceivably reasonable bounds, could never make a regulated transmission owner indifferent. Under cost of service regulation, the regulated transmission owner will always prefer a project with higher investment costs.

Paying above market returns to transmission owners to take actions which are not in their financial interests is not an efficient or effective approach to opening the system to new technology. As seen in the experience of generation development, the current world cost of capital is relatively low and well below regulated rates of return. Competitors are likely to be willing and able to make the investments at lower cost than a regulated transmission company, even if the competition were only to receive regulated revenues based on the competitive offer. Given that there is an incentive to not engage in the requested activities, paying higher returns is not the best way to have new technology implemented.

The market paradigm for GETs can be defined in a variety of ways and include a variety of dimensions. There is no final, clear answer on the best market design for GETs at the moment, but there a number of potential approaches that should not be considered as part of a market paradigm.

The market approach does not rely on counterfactual benefit sharing. It is not reasonable to rely on ongoing real-time counterfactual analysis of what price differences would have been, or how the markets would have cleared, but for the investment in power flow control technology, for example. Such counterfactual approaches are complex, subject to increasingly difficult interaction effects as more new investments are made, subject to subjective judgments and subject to significant measurement error as demonstrated by the measurement issues for demand side resources. Benefit sharing is a variant of the standard regulatory paradigm rather than a market approach, but without the benefit of a defined rate of return which would limit the excess compensation that is likely under this approach. The implied rates of return from the counterfactual benefit sharing approach are many multiples of the incentive rates of return considered for traditional transmission investments. Benefit sharing will result in significant overpayment for these technologies and payment well in excess of competitive rates of return.

The market approach does not rely on benefit/cost analysis or benefit sharing as the basis for compensation. Benefit sharing is speculative by definition and is based on expectations about an uncertain and unknowable future. Assuming that an appropriate metric for defining benefits were defined, benefit analysis cannot address the dynamic intertemporal variability of congestion or the dynamic locational variability of congestion or the more general changes in market dynamics over the likely life of the assets. In the case of power flow control, benefits are the result of the dynamic dispatch of the technology that can affect the market in unpredictable ways, including higher costs for some customers and lower costs for other customers. Benefit/cost benefit analysis as currently used to support transmission investment in PJM also includes subjective judgments, incomplete definitions of costs and benefits, and an incorrect definition of congestion. Benefit/cost analysis is a variant of the standard regulatory paradigm rather than a market approach, but without the benefit of a defined rate of return which would limit the excess compensation that will result from this approach.

Using a competitive, market based approach seems to be a straightforward solution to the incentives issue. But it is not. The optimal roles of market operators and market participants need to be defined. There are complexities in defining the metrics for where a technology should be located on the network. There are complexities in the interactions between competitors and existing transmission companies. There are complexities in defining how the technology should be dispatched once it is installed. There are complexities in defining exactly what is being bought and sold. For example, selling the rights to FTRs on a path is not a workable solution for compensating new power flow control technologies. One issue is that this approach would create incentives to not fully relieve the constraint. If the constraint were fully relieved, the FTR would have no value. The simple difference in prices between nodes is not a good measure of the need for a new investment. When FTRs are defined based solely on day-ahead price differences and ignore real-time price differences, FTR value is not a good metric of benefits.

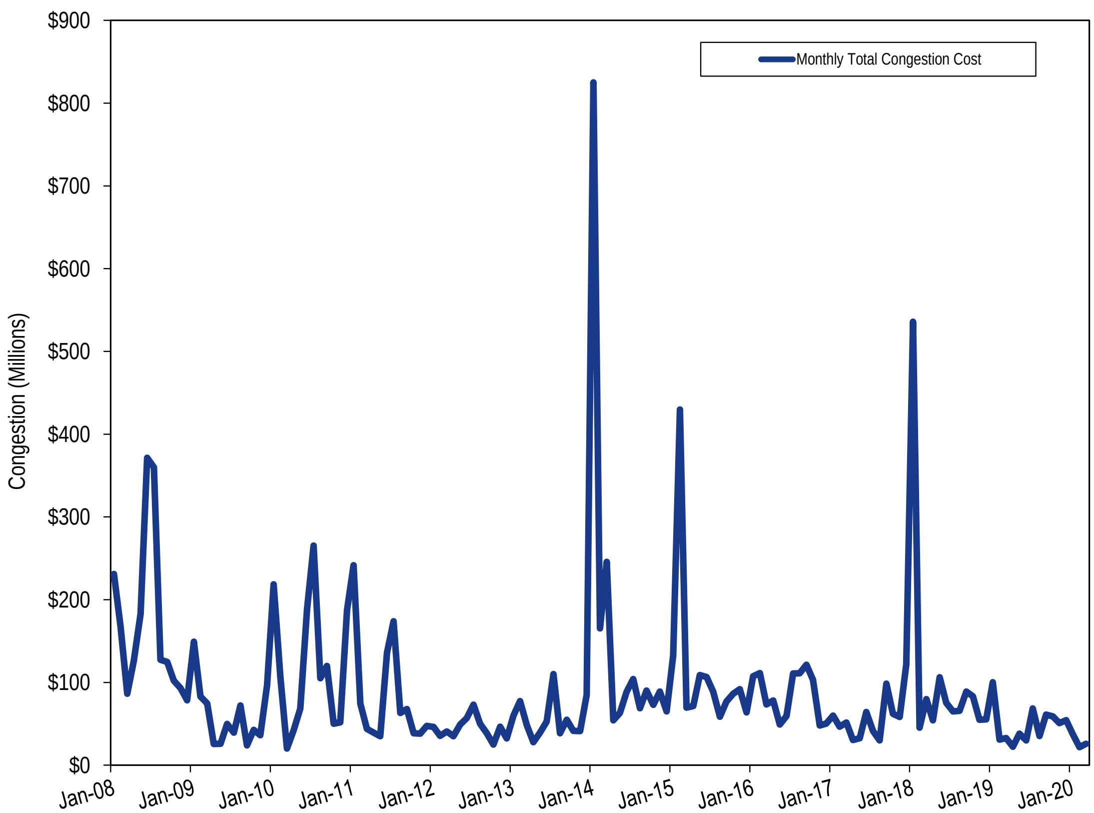
The Commission should support the market paradigm and focus on developing the details of a market approach for new transmission technologies rather than relying on inefficient and atavistic incentive approaches that will lead to overpayment and rates well in excess of the competitive and efficient level. There is no reason not to begin immediately. Any initial design should avoid the creation of vested interests that would inhibit the continued development of competition. A first step could be competing to receive regulated revenues for the relevant technology, e.g. DLR technologies. After a competition to determine the lowest offer to install a defined technology over its defined life, the winner would receive its competitive offer price for the asset over its life based on performance guarantees. This would be a significant step in the direction of more comprehensive market based solutions.

As an example of the complexities of defining the benefits of GETs, the reduction in congestion is frequently cited as a metric of benefits. Some reports cite to increasing congestion in PJM and elsewhere as a reason to invest in GETs. Some have proposed receiving a share of reduced congestion as an incentive for adding GETs.

Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid through GETs.

There is not a secular trend towards increasing congestion in PJM. Figure 1 shows actual monthly congestion in PJM from January 2008 through March 2020.[12]

Figure 1 PJM monthly total congestion cost: January 2008 through March 2020



12 *2019 Quarterly State of the Market Report for PJM: January through June,* Section 11, Congestion and Marginal Losses.

Figure 1 also shows that congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs. In 2018, congestion increased significantly for the entire year as a result of high gas costs associated with cold weather that occurred for only a relatively short period of time in the winter.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission or adding GETs to address one specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual GET investment, exacerbated by the addition of multiple GETs.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid through GETs.

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation while high cost generators are paid the high price at their bus and low cost generators are paid the low price at their bus.

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it resolves the issues raised in this proceeding.

Respectfully submitted,

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