
1. FTR Forfeiture Rule

   a) When calculating the contribution a virtual transaction (INC, DEC, or UTC) has to power flowing across a given constraint, how should the injection/withdrawal points for the virtual transaction be identified? Should the defined “worst case” node be limited to the market participant’s own transactions? Additionally, should the impact threshold(s) used for triggering the forfeiture rule remain at 75 percent regardless of the injection/withdrawal points identified? Why or why not?

   **PJM Answer:** Since the Financial Transmission Right1 ("FTR") forfeiture rule2 was implemented, PJM has used a “worst case” assumption in order to identify the sink (withdrawal) point for an Increment Offer (“INC”)3 and the source (injection) point for a Decrement Bid (“DEC”)4 in the evaluation of the transaction’s impact on a given constraint. This means that for any given DEC withdrawal location, PJM will use the injection node that results in the greatest

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1 All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in PJM Open Access Transmission Tariff (“Tariff”) and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”).

2 The FTR forfeiture rule is described in detail in section 5.2.1 of Tariff, Attachment K-Appendix and the identical provisions of Schedule 1 of the Operating Agreement. As explained therein, if a FTR holder submits an INC or DEC at or near the source or sink location of one of its FTRs which in turn results in a higher LMP spread in the Day-ahead Energy Market than in the Real-time Energy Market, then the profit associated with that particular FTR will be forfeited. Attachment K-Appendix of the Tariff is identical to Schedule 1 of the Operating Agreement. For convenience, further references herein to Attachment K-Appendix of the Tariff shall apply equally to the identical provisions of Schedule 1 of the Operating Agreement.

3 INCS are defined in section 1.39A of Tariff, Attachment K-Appendix as: “an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.”

4 DECS are defined in section 1.3.1E of Tariff, Attachment K-Appendix as: “a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.”
impact on the constraint being evaluated, and for any given INC injection location, PJM will use the withdrawal node that results in the greatest impact on the constraint being evaluated.

The injection/withdrawal points for Virtual Transactions applied to the FTR forfeiture rule should be evaluated differently for INC sand DECs compared with Up-to Congestion Transactions (“UTCs”)\(^5\) because of the distinct nature of these three different types of transactions and their potential impact on the transmission system. Specifically, INCs and DECs are individual nodal offers and bids, respectively, and as such are evaluated individually by the Day-ahead Energy Market clearing algorithm. Thus, unlike the combined offer and bid UTC transactions, INCs and DECs cannot be submitted on the condition that they only clear if the other clears.

Since an INC and a DEC are independent and the clearing of one is not mutually dependent or conditioned on the clearing of the other, even if an INC and DEC are simultaneously submitted with the intention of them both clearing, there is still the possibility that only one transaction will clear, thus resulting in either a “long” or “short” position in the Day-ahead Energy Market for a Market Seller submitting both transactions. While the injections and withdrawals represented by the source and sink of UTCs induce the same flows on the transmission system in the Day-ahead Energy Market as any other injections and withdrawals on the system, and the distribution factors utilized to analyze these impacts are the same distribution factors utilized to evaluate the effects of any other injections and withdrawals, the paired nature of the source and sink of a UTC means that these transactions must be evaluated differently than INCs and DECs for the purpose of the FTR forfeiture rule as further discussed below.

Section 5.2.1(c) of Tariff, Attachment K-Appendix specifies that:

For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(emphasis added). Accordingly, the application of the FTR forfeiture rule requires that PJM make a determination of the expected impact of the energy that will be physically transferred from the source point where the energy from a cleared offer in the Day-ahead Energy Market is going to be injected onto the transmission system to the sink point where that energy is going to

\(^5\) UTCs are described in section 1.10.1A(c-1) of Tariff, Attachment K-Appendix as follows: “A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an Up-to Congestion Transaction.”
be withdrawn from the transmission system. Therefore, in order to develop an expected transmission path for cleared INCs and DECs, because INCs only have an identified source point and DECs only have an identified sink point, PJM must determine a sink point for the INC and a source point for the DEC. Because UTCs by definition have an identified transmission path that includes both a source and a sink, the direct impacts are measured by using the already identified source and sink path of the cleared UTC.

In other words, 100% of the injected megawatts at the source are always withdrawn at the sink location of the UTC, and flow across the transmission facilities between the source and the sink according to the characteristics of the transmission network. The same cannot be said for INCs and DECs since they are individual bids that are not required to be paired. The only time an INC and DEC will have the same impact on congestion and the day-ahead power flow model is if the cleared UTC and cleared INC and DEC are of equal megawatt quantity and at the same node pair (source and sink). However, since an INC and a DEC are bid separately and not as a paired transaction, they may both clear, neither clear, or only one may clear; whereas a UTC will always only clear as a paired source and sink. Therefore, the impact on the unit commitment and dispatch algorithms of UTCs can be very different when compared to INCs and DECs that do not have the same megawatt quantity, source and sink. These critical differences explain why the FTR forfeiture rule is applied to INCs and DECs separately.

In the current application of the FTR forfeiture rule to INCs and DECs, when PJM makes its determination of the sink point for the INC and the source point for the DEC, PJM measures the impact of the INC relative to the worst case DEC, and measures the DEC’s impact relative to the worst case INC. These worst case INCs or DECs do not need to be part of the same Market Participant’s portfolio. Thus, PJM’s evaluation can consider the impact of one Market Participant’s INCs and DECs against another Market Participant’s INCs and DECs on a particular constrained path between the subject FTR delivery and receipt buses in order to determine whether the FTR forfeiture rule should apply. PJM believes this “worst case” assumption should be modified.

Instead of the current analysis, PJM should use a generation-weighted reference to evaluate DEC bids and a load-weighted reference to evaluate INC offers. The generation-weighted reference would be calculated using the megawatts of all generators that cleared the Day-ahead Energy Market. The generation-weighted reference should be used as the source location for evaluating DEC bids for purposes of the FTR forfeiture rule instead of using the worst case location. The

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6 On an electric grid with no losses, the power injected must equal the power withdrawn. Therefore, every megawatt injected by all generators must be offset by a megawatt withdrawn at all load. If this power balance is not achieved then the system will have too much or too little frequency. PJM’s day-ahead model is a simulation representing the power on the system and this simulation will make sure power balance is achieved. The source of a UTC can be thought of as a generator and the sink as a load. The flow across the transmission system will move based on the impedance of the transmission lines, but where it is injected or withdrawn is based on the location of the generation or load (i.e. the source and sink of a UTC). PJM’s day-ahead modelling software will actually model a UTC by injecting the megawatts at the source and withdrawing at the sink. Thus, while the flow of the energy from the source to the sink will flow over transmission facilities according to the laws of physics, every megawatt of energy injected at the source will be withdrawn at the sink.
PJM load-weighted reference would be calculated using the megawatts of all load locations that cleared the Day-ahead Energy Market. The load-weighted reference should be used as the sink location for evaluating INC bids for purposes of the FTR forfeiture rule instead of using the worst case location. PJM believes using the generation and load weighted reference locations instead of the worst case scenario represents a more realistic model of the power flows on the system resulting from INC and DEC transactions than using a worst case assumption.

Using the worst case injection or withdrawal when such injection or withdrawal is part of another Market Participant’s portfolio is effectively evaluating one Market Participant’s activity against another’s. Thus, the worst case approach captures activity that should fall under the FTR forfeiture rule only if one assumes that the two Market Participants are colluding and submitting their bids and offers in a coordinated fashion in order to inflate the value of one or both Market Participants’ FTRs. Instead, the purpose of the FTR forfeiture rule is to find instances in which an individual Market Participant’s Virtual Transactions (or its Affiliate’s Virtual Transactions) are being used to improperly inflate its own (or its Affiliate’s) FTR values. Evaluating one Market Participant’s positions against another, non-Affiliate’s bids and offers therefore has the effect of “tripping” the rule when the individual Market Participant’s (or its Affiliate’s) INC and DEC positions would not, and results in FTR forfeitures that should not occur. For these reasons, PJM recommends the elimination of the “worst-case” assumption and replacing it with generation and load weighted reference locations as described herein.

Finally, PJM believes the current impact threshold of 75% is appropriate to trigger the FTR forfeiture rule regardless of the injection/withdrawal points because it represents a threshold that is not too limiting but still captures apparent market activities that impact FTR values. The purpose of the FTR forfeiture rule is to identify instances of Market Participant behavior where the impacts of virtual activity clearly affect that Market Participant’s (or its Affiliate’s) FTR values and where such activity is not merely coincidental. The 75% threshold is appropriate because virtual activity must significantly affect FTR paths before the rule is triggered. Using a lower threshold would result in FTR forfeitures where such impacts are merely coincidental given the networked nature of the transmission system.

b) As an alternative to the current approach of assessing one virtual transaction at a time, should the FTR forfeiture rule collectively assess the net impact of a market participant’s entire portfolio of INCs, DECs, and UTCs? Should it assess the net impact of all virtual transactions that clear the market? In addition to virtual transactions, should a market participant’s portfolio of physical transactions be considered? Why or why not? If a portfolio approach were adopted, should the impact threshold(s) continue to be 75 percent, as used in the past, or is a different threshold(s) more appropriate? How could a portfolio approach be implemented?

**PJM Answer:** The FTR forfeiture rule should not be applied on a portfolio basis. The FTR forfeiture rule was established to address observed Market Participant behavior as set forth in the following example:

1. Market Participant obtained 100 MWs of low cost FTRs along a radial path that is typically not congested.
2. The same Market Participant placed sufficient Virtual Transactions to cause the path to be constrained day-ahead.
   a. Significantly fewer Virtual Transactions, compared to FTRs, caused the path to become constrained, e.g., 40 MW of Virtual Transactions compared to 100 MW of FTRs.
   b. The 40 MW of Virtual Transactions lost money, but the losses were more than offset by the revenues from the 100 MW of FTRs.
   c. The Market Participant had the capability to set the price and control the profits on the 60 MW difference.
   d. The higher the bid on the demand side, i.e. the DEC to purchase power, the higher the overall net profits; thus the price signal was skewed as it rewarded the Market Participant buyer for not seeking the lowest price possible.

The expansion of the FTR forfeiture rule may reduce market efficiencies and convergence between the Day-ahead and Real-time Energy Markets by discouraging Virtual Transactions at locations where there is a small impact on a Market Participant’s FTR positions. PJM believes it is not in the best interest of the market to restrict legitimate market activity that provides market convergence and increases market efficiency.

In addition, market activity at the most liquid locations would be subject to forfeiture using the portfolio approach. For example, using the portfolio approach, Western Hub to Eastern Hub bids and offers would be included in the calculation. PJM believes that FTRs and Virtual Transactions between trading hubs should not be subject to FTR forfeitures because of the liquidity of these trading hubs. Due to the fact there are thousands of transactions that clear at these hubs, it is highly unlikely that individual Market Participants (or their Affiliates) could engage in behavior that would otherwise trip the FTR forfeiture rule.

For the same reasons PJM believes that it would be inappropriate for the FTR forfeiture rule to apply on a portfolio basis, PJM does not believe that physical transactions in the Day-ahead Energy Market should be considered for the purposes of applying the FTR forfeiture rule, nor should the rule assess the net impact of all Virtual Transactions that clear the Day-ahead Energy Market.

c) Should counter-flow FTRs and bids that relieve congestion remain exempt from FTR forfeiture rule calculations? Should financial transactions that improve day-ahead and real-time market price convergence be exempt from the forfeiture rule? Why or why not? How, if at all, would these exemptions differ when assessing the impact of a market participant’s portfolio as opposed to one INC, DEC, or UTC at a time? Are there any other currently exempt financial transactions that should be subject to FTR forfeiture calculations?

**PJM Answer:** The application of the FTR forfeiture rule to counterflow FTRs is appropriate. In order for a FTR holder to impact its profits for counterflow FTRs, the FTR holder can use
counterflow Virtual Transactions to reduce congestion and therefore have a smaller FTR obligation. For example, a FTR holder who is paid in an FTR Auction to take ownership of a FTR would be considered a counterflow FTR holder. This FTR holder would make a profit if the congestion cost on the FTR path in the Day-ahead Energy Market is less than the payment received from the FTR Auction. If the FTR holder was able to reduce congestion by using Virtual Transactions, it could increase its net FTR profit. This FTR profit would be forfeited if the counterflow position was subject to the FTR forfeiture rule. Typically, there is not a significant incentive to bid this way because virtual counterflow transactions can reduce congestion in the Day-ahead Energy Market and this congestion may still materialize in the Real-time Energy Market, thus resulting in less profitable Virtual Transactions. However, because the opportunity may exist for market manipulation, PJM supports application of the FTR forfeiture rule to counterflow FTRs utilizing the same criteria applied to the evaluation of Virtual Transactions on prevailing flow FTRs.

On the other hand, PJM believes it is appropriate to exempt Virtual Transactions that improve day-ahead and real-time market price convergence from the FTR forfeiture rule. This is because if these transactions are providing convergence, they are benefitting the market, and PJM does not believe such transactions should be penalized by the FTR forfeiture rule. The current design of the FTR forfeiture rule exempts Virtual Transactions from FTR forfeitures to the extent that the congestion on the FTR path in the Day-ahead Energy Market is less than the congestion on the FTR path in the Real-time Energy Market. Therefore, Virtual Transactions that increase congestion on an FTR path such that it is closer to what is actually observed in real time are not subject to FTR forfeitures. However, if such Virtual Transactions increase congestion in the Day-ahead Energy Market and such congestion exceeds the value observed in real time, then the FTR forfeiture rule would be applied on that path. PJM supports maintaining this beneficial aspect of the current FTR forfeiture rule design. PJM does not believe it is practical to assess whether a Market Participant’s Virtual Transactions improve convergence on a portfolio basis. Even if on average the prices at the locations where the Market Participant’s Virtual Transactions cleared are closer in day-ahead to real time than they otherwise would have been without the Virtual Transactions, the same may not be true for the individual locations themselves. Therefore, PJM continues to support applying the FTR forfeiture rule to individual transactions rather than on a portfolio basis.

Last, in PJM’s view, there are no other currently exempt financial transactions that should be subject to the FTR forfeiture rule.

    d) Should the application of the forfeiture rule to INCs, DECs and UTCs be revised in ways not addressed by these questions, and if so, describe in detail the proposed revision and justification for the change.

**PJM Answer:** There needs to be more clarity regarding the applicability of the FTR forfeiture rule. Currently, the FTR forfeiture rule is applicable to the “holder of a Financial Transmission Right”\(^7\) and “FTR holder”\(^8\), and PJM’s governing documents make numerous references to the

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\(^7\) Tariff, Attachment K-Appendix, sections 5.2.1(a) and (b).

\(^8\) Tariff, Attachment K-Appendix, section 5.2.1(d).
rule applying to the “holder of a Financial Transmission Right” and “FTR holders.” However, these terms are not defined in any of PJM’s governing documents, and there is some ambiguity as to when the FTR forfeiture rule should be applied. In practice, PJM has applied the FTR forfeiture rule to individual Market Participants and to their Affiliates, as defined in the Operating Agreement. This is because a Market Participant and its Affiliate could easily engage in manipulative behavior in which, for example, the Market Participant’s Virtual Transaction positions cause congestion in order to benefit the Affiliate’s FTR position, or vice versa.

However, after further consideration, PJM has determined that its current application of the FTR forfeiture rule to only individual Market Participants and their Affiliates may be inadequate to protect against the type of behavior the FTR forfeiture rule is designed to protect against—nearly, entities engaging in manipulative behavior that would cause congestion in order to benefit FTR positions. This is because the term Affiliate pertains to one entity “controlling” another entity, or entities being under “common control.” However, two entities could share common ownership but not be considered Affiliates under the Operating Agreement’s definition because such ownership may not constitute “control” under the definition. Further, because entities under common ownership are just as susceptible to having the opportunity to engage in the type of manipulative behavior that the FTR forfeiture rule is aimed at preventing as entities under common control, PJM would like to clarify, or expand, the FTR forfeiture rule so that it clearly states that the rule applies in instances of common ownership.

PJM believes that failing to clarify this issue could result in PJM Members creating entities that are not Affiliates of the Member company under the applicable PJM definition, but nonetheless share a common owner with the Member, solely in order to circumvent the FTR forfeiture rule’s application. PJM’s concern with this type of arrangement is that it leaves open the possibility of inappropriate behavior when the two related Member companies use common employees, common bidding strategies, or are familiar with each other’s bidding strategies. Without the application of the FTR forfeiture rule to these related entities, they have the opportunity to manipulate the market by one Member engaging in behavior to cause congestion in the Day-ahead Energy Market that would not otherwise occur in real-time in order to benefit the other related Member’s FTR positions.

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9 See Operating Agreement, section 1.2: “‘Affiliate’ shall mean any two or more entities, one of which controls the other or that are under common control. ‘Control’ shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of this Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.”

10 See id.
e) If you believe that changes to the current FTR Forfeiture Rule provisions of PJM’s tariff are necessary, propose appropriate tariff language that you believe addresses your concern.

**PJM Answer:** PJM recommends the following changes to section 5.2.1(c) of Attachment K-Appendix of the Tariff, which addresses the eligibility criteria for Transmission Congestion Credits. The proposed revisions would implement PJM’s proposal to replace the “worst case” assumption used in the FTR forfeiture rule for INCs and DECs, and instead would use either the PJM generation weighted LMP or the PJM load-weighted LMP, as described in PJM’s answer to question 1.a:

5.2 Transmission Congestion Credit Calculation

5.2.1 Eligibility.

(c) For purposes of Section 5.2.1(b), Cleared Increment Offers or Decrement Bids are considered to be at or near the Market Participant’s Financial Transmission Right if (i) any bus where the Market Participant has a cleared Increment Offer has a distribution factor relative to the distributed PJM load of seventy five percent or greater on the constrained path between the subject Financial Transmission Right delivery and receipt buses, or (ii) any bus where the Market Participant has a cleared Decrement Bid has a distribution factor relative to the distributed PJM generation of seventy five percent or greater on the constrained path between the subject Financial Transmission Right delivery and receipt buses. Cleared Up-to Congestion Transactions are considered to be at or near the Market Participant’s Financial Transmission Right if the net distribution factor of the source and sink locations of the Up-to Congestion Transaction is greater than or equal to seventy five percent on the constrained path between the subject Financial Transmission Right delivery and receipt buses. A bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

In addition, PJM proposes to incorporate definitions of FTR Holder and Effective FTR Holder in section 1.3 of Attachment K-Appendix of the Tariff. PJM proposes to insert the newly defined term “Effective FTR Holder” in place of references to “holder of an FTR,” “holder of a Financial Transmission Right,” and “FTR holder” in sections 5.2.1(b) and 5.2.1(d) of Attachment K-Appendix of the Tariff, and in Section VI of Attachment M-Appendix of the Tariff. PJM also proposes to replace references to “holder of an FTR,” “holder of a Financial Transmission Right,” and “FTR holder” with the newly defined term FTR Holder elsewhere in the Tariff and
“Effective FTR Holder” shall mean an FTR Holder, any Affiliate of the FTR Holder, and/or any other PJM Member that is under common ownership with the FTR Holder wherein the common owner possesses at least a 5% ownership interest in the FTR Holder and each such PJM Member.

“FTR Holder” shall mean the PJM Member that has acquired an FTR in an FTR Auction or by any other means.

2) Uplift

a) Should UTCs be assessed uplift? Explain why or why not. If so, how, if at all, should this allocation differ from the allocation to individual INCs and DECs and “paired” INCs and DECs? Should INCs and DECs continue to be required to pay uplift charges? What effect does imposing these charges have on the ability of virtual traders to arbitrage day-ahead and real-time price differences?

**PJM Answer:** PJM’s position is that UTCs should be allocated uplift. From a causality perspective, UTCs, like all other Virtual Transactions in the Day-ahead Energy Market, impact the commitment and dispatch of resources in that market, the flows on transmission lines, LMPs, and consequently the revenues that resources collect from the market and thus the level of uplift collected. From a beneficiary perspective, UTCs, like all other market transactions in the Day-ahead Energy Market, benefit from a reliable system and fair and efficient markets.

Uplift is a cost associated with the operation of an efficient power system and is a result of PJM’s market design, which is based on the minimization of bid production costs and the use of LMPs. It would be inappropriate to continue to arbitrarily exclude UTCs from being allocated uplift, and INCs and DECs should continue to pay uplift charges for the same reasons UTCs should be allocated these charges.

Under PJM’s current market rules, INCs and DECs can be allocated uplift in two different ways. First, all withdrawals in the Day-ahead Energy Market are allocated an equal share of the uplift incurred in the Day-ahead Energy Market. Day-ahead withdrawals include fixed Demand Bids, cleared price sensitive Demand Bids and DECs, and Export Transactions. The second way a Virtual Transaction can be allocated uplift is as a deviation between the day-ahead and real-time positions. For example, a cleared 10 megawatt INC in the Day-ahead Energy Market that has a 0 megawatt position in real-time is allocated a share of the real-time uplift charges because it is considered a deviation from the day-ahead position.

Currently, UTCs are not allocated any uplift because the transactions were originally created as a method to hedge real-time physical transactions in the Day-ahead Energy Market and as such, originally required a transmission service reservation in order to be used. Over time and through a series of market rule changes, the product evolved into a purely financial product used to arbitrage day-ahead and real-time price spreads. However, the emergence of UTCs as purely
financial products did not begin until after the latest major set of uplift allocation reforms PJM implemented in 2008.

In the PJM stakeholder process discussions at the Energy Market Uplift Senior Task Force (“EMUSTF”), PJM has proposed treating UTCs as a deviating transaction between day-ahead and real-time and charging them a share of the uplift on a daily basis. This market rule change would treat UTCs in the same manner as all other types of transactions (including INCs and DECs) that cause uplift, and would not change PJM’s existing uplift allocation mechanism except to include UTCs in the calculation. Under this model, the UTC would not receive an allocation of day-ahead uplift but would receive an allocation of the real-time uplift as if it were an import or export transaction that deviated between day-ahead and real-time. For example, if a Market Participant cleared a UTC between points A and B for 10 megawatts, the transaction would have a 0 megawatt position in real-time and would therefore be deviating by 10 megawatts. As a result, it would be allocated 10 megawatts worth of deviation charges. This approach keeps the method for allocating uplift to UTCs consistent with other transactions that are moving power between PJM and neighboring regions.

The most significant impact of allocating uplift to Virtual Transactions on virtual traders’ ability to arbitrage day-ahead and real-time price differences is that it creates a minimum, necessary price difference between the day-ahead and real-time LMPs in order for the transaction to be profitable. The profit earned by a Virtual Transaction is based upon the difference between the day-ahead LMP(s) at which the transaction clears and the Real-time Price at which the Virtual Transaction settles in the Real-time Energy Market. When an uplift charge is applied to Virtual Transactions, the difference between the day-ahead and real-time LMPs must be at least as great as the uplift charge in order for the Virtual Transaction to be profitable. Therefore, virtual traders will need to incorporate the expectation of the uplift charge into their bidding strategies in order for Virtual Transactions to have the highest probability of being profitable. The level of the uplift charge and whether it is known or unknown will determine how impactful it is to a virtual trader’s strategy. For example, if a virtual trader knows that it will be assessed a $1.00/MWh fee for each cleared virtual trade, that trader can submit its transactions and ensure that they only clear when they are expected to produce a profit of $1.00/MWh or more. This fact, combined with the analysis performed by the virtual trader, will identify which paths are viable for bidding. If the trader does not know the level of the charge that will be assessed, it adds an additional level of uncertainty to the trader’s strategy. This additional uncertainty will drive additional conservativism in the trader’s bidding strategy and likely lead to decreased volumes of Virtual Transactions in PJM’s markets.

While the uncertainty associated with an unknown uplift fee may appear on the surface to be an inefficient market design component, it is important to note that the level of uplift for any given day is not known until the market day is completed. Thus, if a certain segment of the market is only exposed to a fixed fee regardless of the level of uplift accrued for that day, the rest of the market will face all of the risk related to the allocation of uplift in excess of what is collected by the fixed fee. Stated more clearly, if Virtual Transactions are afforded a fixed uplift fee in order to minimize this uncertainty, all other Market Participants that are allocated uplift will face additional risk and these other Market Participants’ uncertainty will be increased because they would still be subject to a more variable uplift rate.
Fixing the uplift rate for all Market Participants is not advisable because this approach would result in a fixed collection of uplift fees each month from all Market Participants, yet the magnitude of the uplift costs themselves will almost certainly fluctuate each month. This approach would in turn routinely lead to over or under collections of uplift payments from Market Participants each month relative to the amount of uplift costs actually caused by such Market Participants.

b) Do UTCs impact unit commitment decisions? If so, how? Several views were expressed during the conference. For example, one panelist cited PJM documentation stating that UTCs are not included in commitment decisions. Other panelists expressed the view that both “paired” INCs and DECs and UTC’s impact unit commitment.

PJM Answer: Several studies conducted by PJM indicate that UTCs impact transmission flows on the system in the Day-ahead Energy Market and therefore impact congestion patterns and the commitment and dispatch of resources in congested areas. PJM confirmed this conclusion in a report filed with the Commission in 2014. In this report, PJM simulated what would have occurred in the Day-ahead Energy Market for several days if UTCs were removed from that market. As reflected in the report, the resulting evidence showed that UTCs do impact and change the dispatch and commitment of units in the Day-ahead Energy Market.

Moreover, when there are a large amount of cleared UTCs in the Day-ahead Energy Market, they can also significantly impact transmission system losses because they increase the loading of the Transmission System and therefore increase megawatt/hour losses across the system. When analyzing a single transaction on its own, the impact on losses is negligible. However, in aggregate they can be significant - on the order of thousands of megawatts. These megawatts must be replaced and therefore require the commitment of additional resources to compensate for the increased system losses.

c) Should market participants be allowed to net INC and DEC transactions for the purpose of uplift allocations? Why or why not? If yes, should netting within a market participant’s portfolio (intra-market participant) be allowed or should market-wide (inter-market participant) netting be allowed? Should physical assets be included in the netting process? Please discuss the advantages and disadvantages to both approaches.

PJM Answer: The answer to this question depends on the charges being allocated and the location of the INCs and DECs. For example, under PJM’s current uplift rules, which PJM is proposing to extend to UTCs, uplift charges accrued by resources committed to serve load and those that resolve transmission constraints are allocated using the same methodology. As a result, the uplift paid to resources serving load and those committed for constraint control are allocated via the same dollar per megawatt/hour charge ($/MWh), notwithstanding regional differences. Under this methodology, it does not make sense to allow netting of INC and DEC transactions at a less specific level than nodal. As a demonstrative example, if INC and DEC transactions were allowed to net zonally under PJM’s current rules, there could be INC and DEC transactions on either side of a transmission constraint that are wholly contained within a

 Transmission Zone that directly impact the flow, unit commitment, LMPs and uplift related to that transmission constraint, but would not be allocated a portion of uplift. Allowing INC and DEC transactions to net at a less specific level than nodal thus reduces the individual impact of each transaction at its injection and withdrawal point. This is inconsistent with the nodal dispatch and pricing of the Transmission System, and would incentivize bidding behavior that seeks to minimize the allocation of uplift, which in turn could undermine core market incentives. Thus, under PJM’s current and proposed uplift allocation methodology, no further netting should be allowed compared to what is allowed today in limited circumstances.

Moreover, any netting should be applied to both Market Sellers with physical energy transactions and Market Sellers with Virtual Transactions. Allowing an INC and a DEC position in the Day-ahead Energy Market to net but not a generation or load position would create an unfair advantage for virtual traders vis à vis Market Sellers with physical energy transactions in the Day-ahead Energy Market that are treated nearly identically but for the generator operating parameters.

Further, PJM does not believe netting should be permitted between one Market Participant’s portfolio and another Market Participant’s portfolio because doing so would likely significantly reduce the amount of day-ahead-to-real-time deviations such that the resulting uplift charges to the non-netted parties could be unmanageably high. It would also significantly overcomplicate the allocation because it would be difficult to determine who the remaining non-netted parties were if all portfolios were netted against each other.

In general, netting positions to allow certain transactions types or certain bidding behaviors to evade an allocation of uplift can further exacerbate the allocation of uplift to the remaining entities bearing the burden of the allocation. For example, if $1 million of uplift needs to be allocated and the total pool of transactions over which it is to be allocated is 1 million MWh, then each cleared MWh would pay $1/MWh. However, if 500,000 MWh were allowed to net, the remaining 500,000 MWh would need to pay $2/MWh instead of $1/MWh because the $1 million in uplift would be allocated to 500,000 MWh instead of 1 million MWh. Essentially, the more netting that is allowed, the more volatile the uplift rate will be for the remaining parties that are unable to net. This can impose a substantial risk on any Market Participant that is unable to fully net, which can in turn create a number of different risk-based bidding behaviors that would move Market Participant behavior away from core market incentives.

d) Are there other cost-causation approaches that should be considered? What advantages, disadvantages, and operational challenges would be associated with implementing such approaches in PJM?

PJM Answer: Cost-causation principles can only inform the method used to allocate uplift to a certain extent. Any market transaction that impacts the scheduling and dispatch of the power system impacts transmission flows and LMPs, and therefore uplift amounts. However, given the complexity of wholesale power markets, it is impossible to precisely assess the level at which each discrete transaction or category of transactions has contributed to uplift. Essentially, cost-causation principles can provide information on which types of market activities can impact and potentially cause uplift, but they cannot tell who uplift should be allocated to or in what amount. Therefore, once a category of market transactions (such as UTCs) has been determined to potentially cause uplift, there can either be a uniform allocation of uplift to all categories of
market transactions that cause uplift (as PJM proposes), or, additional factors must be considered in order to more directly allocate uplift. The uniform allocation of uplift has several benefits in that it does not favor any particular Market Participant sector or transaction type, and it attempts to allocate uplift across the broadest denominator possible in order to limit the impact to any specific party. The advantages, disadvantages and operational challenges of a more direct allocation will be largely governed by the principles used to define the more granular allocation.

e) If virtual transactions are assessed uplift, should the uplift be designed as a fixed amount known in advance to permit the traders to assess the costs of the trade versus the potential arbitrage differences between day-ahead and real-time?

**PJM Answer:** Virtual Transactions, including UTCs, should be afforded a fixed rate while other transactions face the risk of a variable rate. This is because it is impossible to determine the total contribution to uplift from any single transaction or class of transactions. To arbitrarily minimize the exposure to uplift for one segment of the market, in this case Virtual Transactions, and significantly increase it for Market Sellers with physical energy transactions, creates an unfair advantage to Market Sellers with Virtual Transactions without any justification. Without evidence showing that the amount of uplift created by Virtual Transactions is constant, a fixed fee to only Virtual Transactions is unjust and unreasonable.

f) If you believe that changes to the current Uplift provisions of PJM’s tariff are necessary, propose appropriate tariff language that you believe addresses your concern.

**PJM Answer:** Should the Commission agree with PJM that uplift should be allocated to UTCs in the same manner as all other types of transactions that cause uplift today, including INCs and DECs, PJM would need to review all applicable governing document provisions, propose changes to its stakeholders for consideration, and submit any appropriate revisions to implement such changes in a compliance filing. While PJM is not prepared to offer a complete set of specific revisions that would be needed at this time, PJM believes that at a minimum, revisions to sections 3.2.3(b) and 3.2.3(p) of Attachment K-Appendix of the Tariff would likely be needed.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Audubon, PA, this 29th day of May, 2015.

Steven Shparber
Attorney for
PJM Interconnection, L.L.C.
Attachment A


PJM Interconnection, L.L.C.
Docket No. ER13-1654-000
February 7, 2014

PJM Interconnection
February 2014
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Purpose

The purpose of this report is to fulfill the FERC compliance requirement ordered on August 9, 2013 in docket number ER13-1654-000 for PJM to, “provide an updated analysis of the impacts of UTC transactions and INCs/DECs on unit commitment, dispatch and operating reserve charges.” Just prior to receiving that order, PJM had already performed an analysis on the impact of Up-to Congestion transactions (UTC) on the PJM markets and operating reserves payments for a selection of days in May 2013. As a result of the Order, PJM performed a similar analysis on a set of days in December 2013 but in order to ensure a complete analysis, also included the impacts of increment offers (INCs) and decrement bids (DECs). This report will describe how each transaction works within the Day Ahead and Real-Time Energy Markets and how each can impact the unit commitment and dispatch of PJM. It will also discuss the results of both sets of analyses performed by PJM in May and December 2013.

For the purpose of this report, the term “Virtual Transaction” will include INCs, DECs and UTCs.

Background

Virtual Transactions are transactions that are used to both arbitrage price differences between the Day-Ahead and Real-Time Energy Markets and also to hedge financial exposure from physical positions. The transactions are called virtual because the Market Participant submitting a transaction that clears takes a financial position in the Day-Ahead Energy Market by agreeing to buy or sell energy at a specific location or locations that it then liquidates in the Real-Time Market. This occurs because the energy that is bought or sold in the Day-Ahead Energy Market is not provided in real-time and therefore creates an imbalance. The PJM two-settlement system settles all quantity (MW) deviations from the Day-Ahead Energy Market at the real-time spot price. Thus, Virtual Transactions can arbitrage price differences between the two markets.

The benefit of Virtual Transactions like INCs, DECs and UTCs is to provide price convergence between the Day-Ahead and Real-Time Energy Markets. Any pricing point on the system where the prices are different between the Day-Ahead and Real-Time Energy Markets provides an opportunity to make revenues using a Virtual Transaction. If the day-ahead price is higher than the real-time price, a Market Participant would want to submit an INC offer to sell energy at the high day ahead price and then buy out of that position at the lower real-time price. If the real-time price is higher, a DEC bid would be profitable. For price spreads between points, UTCs are used. Virtual Transactions can also be used to hedge physical positions in the Day-Ahead Energy Market in order to manage exposure to real-time prices. Virtual Transactions are regularly utilized by all types of PJM Market Participants for both purposes.

A consequence of allowing Virtual Transactions to compete with physical resources in the Day-Ahead Energy Market is that they may either displace, or cause additional scheduling of physical resources that may or may not be needed in the Real-Time Energy Market. Virtual Transactions may also impact the dispatch of physical supply resources and clearing price-sensitive demand bids, thus altering the outcome of the Day-Ahead Energy Market which is used to set an operating plan for the upcoming day.
**How Increment Offers Work**

INCs are offers submitted in the Day-Ahead Energy Market to sell some amount of energy at a specified location if the day ahead clearing price for that node exceeds the bid price. For example, if a 1 MW INC is submitted at node A with an offer price of $40/MWh, that offer would clear if the Locational Marginal Price (LMP) at that node was equal to or higher than $40/MWh. In this case, the Market Participant has agreed to sell 1 MW at the prevailing LMP in the Day-Ahead Energy Market.

In real time, the 1 MW injection from the INC offer does not exist and therefore it creates a MW deviation between the Day-Ahead and Real-Time Energy Markets. The Market Participant must purchase the 1 MW back from the Real-Time Energy Market at the real-time LMP.

Because the cleared INC offer is an injection in the Day-Ahead Energy Market that does not exist in real-time, it can create deviations between the resource plan cleared in the Day-Ahead Energy Market and what is actually needed for real-time operations the next Operating Day. In the case of an INC, it can displace economic resources that could have been scheduled in the Day-Ahead Energy Market. These deviations from the optimal unit commitment can result in uplift payments to resources scheduled outside of the Day-Ahead Energy Market in real time. Thus, under PJM’s current rules, cleared INC offers pay a share of these uplift charges as do cleared DEC bids, along with generator, load and transaction deviations. Therefore, absent administrative fees assessed to every bid type, an INC bid is profitable when the following equation is true:

\[
\text{Day-Ahead LMP ($/MWh) – Real-Time LMP ($/MWh) – Uplift Charge ($/MWh) > 0}
\]

**How Decrement Bids Work**

DEC bids are almost the exact opposite of INC offers. DECs are submitted into the Day-Ahead Energy Market as a bid to purchase energy at a price equal or less than some desired amount. For example, if a DEC bid of 1 MW is submitted at a price of $40/MWh into the Day-Ahead Energy Market, the Market Participant agrees to purchase 1 MW of energy at the location specified in the bid if the LMP at that location is less than or equal to $40/MWh.

In real time, like an INC, the 1 MW withdrawal caused by the DEC bid in the Day-Ahead Energy Market also does not exist and therefore creates a MW deviation between the Day-Ahead and Real-Time Energy Markets that must be settled at the real-time LMP. Unlike the INC, however, the Market Participant with a cleared DEC bid must sell their load position from the Day-Ahead Energy Market back at the real-time LMP.

Like an INC, a DEC creates a deviation between the Day-Ahead and Real-Time Energy Markets. Because a DEC acts like a load in the Day-Ahead Energy Market, it can cause the scheduling of additional resources in the Day-Ahead Energy Market that are not required for real-time operations, which can again result in out-of-market uplift payments. Additionally, DECs require the commitment of resources to serve load in the Day-Ahead Energy Market caused by a cleared DEC. As a result of a DEC being a causal factor for both the commitment of resources in the Day-Ahead Energy Market to cover the load caused by the cleared DEC, and the potential resulting uplift payments in real-time due to the MW deviation the DEC causes between the Day-Ahead and Real-Time Energy Markets, a
DEC is assessed an uplift charge in both the Day-Ahead and Real-Time Energy Markets. Absent administrative fees, a DEC is profitable when:

\[
\text{[Real-Time LMP ($/MWh) – Uplift Charge ($/MWh)] - [Day Ahead LMP ($/MWh) – Day Ahead Uplift Charge ($/MWh)] > 0}
\]

**How Up-To-Congestion Transactions Work**

A UTC is a bid in the Day-Ahead Energy Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Energy Market congestion or they can be in the counterflow direction where they are paid to take a position. In either case, like INCs and DECs, UTCs are bids that impose flow on the transmission network in the Day-Ahead Energy Market that do not exist in real-time and therefore classify as a Virtual Transaction. A major difference between an INC or DEC and a UTC is that an INC or a DEC is a discrete injection or withdrawal at a location whereas a UTC is an injection at a source point and a withdrawal at another point. Because a UTC is composed of an injection and a withdrawal, they are energy neutral and therefore, outside of their impact on losses, largely only impact the commitment and dispatch of the system for transmission constraints.

Like INCs and DECs, UTCs are Virtual Transactions in the Day-Ahead Energy Market that do not represent the physical delivery of power in real-time and therefore represent a deviation between MWs in the Day Ahead and Real-Time Energy Markets that is liquidated at the real-time LMP. The example provided in Appendix A of this report shows that a UTC is profitable when it drives congestion in the Day-Ahead Energy Market closer to what exists in real-time. More specifically, forward flow UTCs are profitable when they increase Day Ahead congestion such that it is closer to the congestion observed in real-time. In the counterflow direction, UTCs are profitable when they relieve Day Ahead congestion on a path that is less constrained in real-time. Because UTCs are profitable when they drive congestion between the Day Ahead and Real-Time Energy Markets closer to each other, they also work to converge prices between both markets.

While UTCs, like INCs and DECs, create deviations between the Day Ahead and Real-Time Energy Markets, they are not allocated a portion of the uplift costs like INCs and DECs are. This is likely more of a function of the way they have developed in the PJM market as opposed to their impact on the market itself. UTCs were originally day-ahead transactions used to hedge physical deliveries of energy in real-time. Because the original day-ahead transactions were nearly always firmed up in real-time with the actual delivery of power, there was no need to allocate them a share of the uplift charges because they did not create deviations between Day-Ahead and Real-Time Markets. Over time, and after a series of market rule changes, the UTC transaction type has evolved into a purely speculative transaction like an INC or a DEC that helps to converge the Day-Ahead and Real-Time Energy Market prices but can also create deviations between the two resulting in some amount of uplift costs. The volatility and magnitude of these costs are discussed in the following section.
Market Trends

The charts below show the market trends PJM has observed over time with regard to the use of Virtual Transactions in the Day-Ahead Energy Market. The fact most immediately apparent when looking at the use of the different types of Virtual Transactions is the decline in usage of INCs and DECs and the increase in use of UTCs. The increase in the use of the UTCs began in late 2010 following a market rule change that removed the requirement to make a transmission service reservation in order to submit a UTC transaction into the Day-Ahead Energy Market. By removing this requirement, it made the UTC transaction type a free transaction absent administrative charges as opposed to the INC and DEC bids that pay the same administrative fees, but also are assessed an allocation of uplift charges. From that period on, the use of UTCs has escalated significantly while a similar decline has occurred in the use of INCs and DECs.

Figure 1: PJM Up-To-Congestion Transactions – Total Volume
As can be seen from the figure below, the uplift charges assigned to INCs and DECs (referred to in the PJM market as “Deviation Charges”) can be very volatile and are therefore unpredictable by Market Participants. These volatile, unpredictable and sometimes significant charges can result in a strong disincentive to submit these types of transactions as opposed to UTCs which do not have these charges. The current methodology is to calculate different regional rates that are applied to cleared INCs and DECs depending on the location of the cleared bid. The East rate in PJM is typically the highest and most volatile as shown in the graph below.
For 2013, the East Deviations Rate ranged from between $0.02/MWh to $33.02/MWh, with a mean of $3.20/MWh, for each cleared MWh in the Day-Ahead Energy Market that deviated in real-time in the eastern portion of PJM. The West Deviations Rate ranged from $0.02/MWh to $16.43/MWh, with a mean of $1.56/MWh for deviations between the Day Ahead and Real-Time Energy Markets in the western portion of PJM. As shown, deviation charges in PJM can be significant and for a Market Participant submitting a virtual bid into PJM’s Day-Ahead Energy Market, they are always unknown and likely a barrier to participation at times.

The table below shows a comparison between the volumes, risk and profit margins of UTCs versus INCs and DECs. The ‘UTC Gross’ and ‘INC/DEC Gross’ columns show the bid-based revenue paid to cleared MWh for these bid types over the 2013 calendar year. The ‘UTC Net’ and ‘INC/DEC Net’ columns show the revenues for those bid types for the same time period but net of any administrative charges imposed on the bids. For UTCs this includes Schedule 91 charges that are assessed to all market bids and offers. For INCs and DECs, it includes the same

---

1 A Schedule 9 charge is a per MWh charge applied to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy Market Participants based on their accepted increment offers, decrement bids, and up-to-congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.
Schedule 9 charges and any uplift charges that are assessed to those bids under the current market rules in PJM.

<table>
<thead>
<tr>
<th></th>
<th>UTC Gross</th>
<th>UTC Net</th>
<th>INC/DEC Gross</th>
<th>INC/DEC Net</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cleared MWh</td>
<td>452,001,946</td>
<td>452,001,946</td>
<td>108,039,474</td>
<td>108,039,474</td>
</tr>
<tr>
<td>Average Daily Profit</td>
<td>$394,397</td>
<td>$389,828</td>
<td>$131,612</td>
<td>-$63,499</td>
</tr>
<tr>
<td>St Dev of Daily Profit</td>
<td>$1,266,783</td>
<td>$1,267,456</td>
<td>$783,490</td>
<td>$697,462</td>
</tr>
<tr>
<td>Average Profit/Cleared MWh</td>
<td>$0.32</td>
<td>$0.31</td>
<td>$0.44</td>
<td>-$0.21</td>
</tr>
<tr>
<td>% of Loss Days</td>
<td>39%</td>
<td>40%</td>
<td>53%</td>
<td>68%</td>
</tr>
</tbody>
</table>

*January 2013 through December 2013

Table 1: 2013 Gross and Net Financial Statistics for UTCs, INCs and DECs

The number of cleared MWh of UTC transactions outnumber those of INCs and DECs combined by a ratio of 4.2 to 1. This is consistent with the prior graphs showing the trend in bidding behavior migrating from INCs and DECs to UTCs. While the daily profits for UTCs far exceed those of INCs and DECs on both a gross and net basis, it is important to remember that there are over four times as many cleared MWh of UTCs on any given day as compared to INCs and DECs. A more relevant comparison is the average profit per cleared MWh shown in the second to last row of the table. In 2013, UTCs made a gross profit of about $.32/MWh while INCs and DECs made about $.44/MWh. However, the net outcomes tell a much different story. While it appears UTCs are not impacted but for the Schedule 9 charges applied, INCs and DECs are greatly impacted and on-average become net loss per cleared MWh of about $.21. A similar outcome exists when analyzing the percentage of times that each bid type net lost money over the course of the day. For UTCs those numbers are relatively constant but for INCs and DECs the percentage of days where those bids lost money markedly increases from about 53% to 68% after administrative fees and uplift charges are assessed.

Unit Commitment and Dispatch Analysis:

**INCs and DECs**

In order to assess the impact of INCs, DECs and UTCs on unit commitment and dispatch, PJM selected four Day-Ahead Energy Market cases from various days in December 2013. The days themselves were chosen at random. The month of December 2013 was used only because the FERC compliance directive requires the use of the most recent market data. PJM re-cleared the Day-Ahead Energy Market for those days two additional times. In the first iteration, PJM removed INCs and DECs from the solution and documented unit commitment changes from the actual market solutions for that day. In the second iteration, PJM removed UTCs and again documented unit commitment changes from the base case.
Table 2: Simulation Results Removing INCs and DECs

The prior chart shows the outcome of this analysis when INCs and DECs are removed. The outcome can be interpreted for the date of December 10, 2013 as demonstrating the following.

- On December 10, 2013, the Day-Ahead Energy Market committed a total of 634 generating units.
- When INCs and DECs were removed, 39 generating units were de-committed and 0 additional generators were committed.
- The net commitment difference is therefore the sum of the 39 units that were de-committed plus the 0 units committed, for a total of 39.

Based on this analysis, it is evident that INCs and DECs can and do impact unit commitment. Because they are injections and withdrawals on the system at various locations and can impact the commitment of units on the system, by definition they will also impact the dispatch of units on the system. As a result, it follows that they can contribute to the uplift caused by scheduling additional supply resources in the Day-Ahead Energy Market that are consequently not needed in real-time, or conversely, displacing economic, physical supply resources in the Day-Ahead Energy Market causing the scheduling of less economic resources in real-time that may require uplift payments. While the principle that INCs and DECs can impact the commitment and dispatch of supply resources in the Day-Ahead Energy Market and subsequently in real-time is clear, determining the exact cost of those impacts and assigning those costs to a specific transaction or transaction type is virtually impossible. This is because of the complexity of the Day-Ahead Energy Market and the interaction of the various transaction types such as generation offers (including startup and min run times), fixed demand bids, price-sensitive demand bids, UTCs, etc. The critical conclusion is that these transaction types can impact resource commitment and therefore should, and today do, share some of the uplift costs associated with their impact on commitment and dispatch.

UTCs

The same analysis described for INCs and DECs was also performed for UTCs. For the same four days in December 2013, PJM reran the Day-Ahead Energy Market removing UTC bids to gauge the impacts on resource commitment and dispatch. The nature of the UTC bid is such that it is an injection and a withdrawal at a specified location so that absent its impact on system losses, it is energy neutral. However, the UTC can impose flows on transmission facilities in the Day-Ahead Energy Market that can either cause or relieve congestion resulting in the
commitment or de-commitment of supply resources for congestion management. The table below summarizes the results for UTCs.

<table>
<thead>
<tr>
<th></th>
<th>12/10/13</th>
<th>12/14/13</th>
<th>12/18/13</th>
<th>12/23/13</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case Units Committed</td>
<td>634</td>
<td>565</td>
<td>596</td>
<td>532</td>
</tr>
<tr>
<td>Units De-committed Without UTCs</td>
<td>10</td>
<td>7</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Units Committed Without UTCs</td>
<td>10</td>
<td>13</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Total Commitment Difference</td>
<td>20</td>
<td>20</td>
<td>11</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 3: Simulation Results Removing UTCs

Based on these studies, it can be concluded that UTCs also impact the commitment of supply resources in the Day-Ahead Energy Market. The major difference between the UTC results and those of INCs and DECs is that removing UTCs leads to the de-commitment of certain units that are then replaced via the commitment of other units. In other words, while the net change in the number of units committed can be very small when UTCs are removed, the total number of changes of specific units committed can be larger. For example, on December 10, 2013, when UTCs were removed from the Day-Ahead Energy Market solution, 10 units that were originally committed were de-committed and replaced with 10 different units. This is consistent with the energy neutrality of UTCs. However, there is not always a one-to-one tradeoff between committed and de-committed units when UTCs are removed, and the cost of the units being swapped are not always identical. In some cases UTCs may be driving the commitment of lower cost resources in the Day-Ahead Energy Market because they are in the counterflow direction of transmission constraints and are therefore relieving congestion. In other cases the opposite will occur, and UTCs will impose forward flow on a facility in the Day-Ahead Energy Market and cause increased congestion and out-of-merit commitment and dispatch for constraint management.

Similar to INCs and DECs, whether or not UTCs drive a more optimal solution in the Day-Ahead Energy Market will change on a daily basis and a precise determination of the direction and impact on resource commitment and dispatch by UTCs is virtually impossible due to the complexity of the Day-Ahead Energy Market and the interactions of the various different types of transactions. What is important to note is that these transaction types can and do impact the commitment, and therefore also the dispatch, of supply resources in the Day-Ahead Energy Market. Under today’s rules these transaction types do not receive an allocation of the uplift costs associated with those impacts.

**Conclusion**

Any injection or withdrawal on the power system can have some impact on the resource commitment and dispatch of the system because it can change the flow of power. An injection or withdrawal can come from any type of Virtual Transaction, a generation or demand resource, an import or export transaction, or changes in the load profile. In other words, anything that has the ability to alter the flow of power on the system can impact resource commitment and dispatch. Determining what the consequence of an injection or withdrawal was for a discrete transaction, or
class of transactions, becomes much more difficult and to some extent is subjective given the complexity of the power system and PJM’s markets. Notwithstanding the impacts on uplift costs that Virtual Transactions may cause, they do provide value to the overall market by providing financial incentives for Market Participants to arbitrage price differences between the Day Ahead and Real-Time Energy Markets that in aggregate result in price convergence between the two markets.

Currently, PJM stakeholders are discussing the allocation of uplift costs and how to apply cost causality principles to the allocation of those costs. Under today’s market rules, INCs and DECs are allocated a share of these costs because of their obvious impact on resource commitment and dispatch. At the time rules for INCs and DECs were put in place, UTCs were not used in the speculative manner in which they are today and therefore were not included in the allocation of such charges. However, given how the use of UTCs has evolved, it is evident, based on the fact that UTCs can shift the flow of power on the system, that they also can impact the resource commitment and dispatch of the system and consequently should be allocated a share of the applicable costs in addition to INCs, DECs and other bid and offer types that have similar impacts on the power system. Given this, PJM believes that the outcome of the stakeholder process should:

- Allocate uplift charges to parties who contribute to system uplift by impacting the scheduling and dispatch of the system.
- Minimize the per cleared MWh impact of these charges by allocating the charges across as a broad a set of market transactions as possible.
- Establish a known fixed fee for virtual bids and offers (including UTCs) submitted in the Day-Ahead Energy Market. This would allow for a collection of some of the costs of uplift from these transactions while not deterring the use of them due to an unknown, after-the-fact uplift charge as is the case today. As shown in figure 3 above, the uplift charges currently assessed to INCs and DECs can be very volatile and unpredictable, thereby causing a strong disincentive to utilize these types of transactions. Fixing these charges at a reasonable level and applying that charge to all transaction types would remove this disincentive and appropriately apply them to all Virtual Transaction types.
Appendix A: Example UTC Clearing

- UTCs are submitted in the Day-Ahead Market and take a position on the price separation between two points
- For UTCs in the direction of congestion, they are profitable when real-time congestion > day-ahead congestion
- In the counter-flow direction, they are profitable when real-time congestion < day-ahead congestion

Example DA Settlement – Forward Flow

100 MWh UTC cleared between points A and B

\[
\begin{align*}
\text{Node A:} & \quad \text{DA LMP} = \$50 \\
\text{Node B:} & \quad \text{DA LMP} = \$75
\end{align*}
\]

\[
\text{UTC (A to B) = (Sink LMP – Source LMP) * Cleared MWh}
\]

\[
\text{UTC (A to B) = ($75 - $50) * 100 MWh = $2,500 (charge)}
\]

Example Balancing Settlement

100 MWh UTC cleared between points A and B

\[
\begin{align*}
\text{Node A:} & \quad \text{RT LMP} = \$45 \\
\text{Node B:} & \quad \text{RT LMP} = \$80
\end{align*}
\]

\[
\text{UTC (A to B) = (Sink LMP – Source LMP) * Cleared MWh}
\]

\[
\text{UTC (A to B) = ($80 - $45) * 100 MWh = $3,500 (credit)}
\]

\[
\text{Profit = RT Position – DA Position = $3,500 - $2,500 = $1,000}
\]

Alternative Balancing Settlement

100 MWh UTC cleared between points A and B

\[
\begin{align*}
\text{Node A:} & \quad \text{RT LMP} = \$45 \\
\text{Node B:} & \quad \text{RT LMP} = \$60
\end{align*}
\]

\[
\text{UTC (A to B) = (Sink LMP – Source LMP) * Cleared MWh}
\]

\[
\text{UTC (A to B) = ($60 - $45) * 100 MWh = $1,500 (credit)}
\]

\[
\text{Loss = RT Position – DA Position = $1,500 - $2,500 = -$1,000}
\]
• UTCs profit when they contribute to convergence of day-ahead and real-time congestion
• When they increase congestion in day-ahead drawing it closer to real-time, they make money
• When they create congestion in day-ahead that does exist in real-time, they lose money
• This principle applies for both prevailing and counter-flow congestion
• Therefore, the economic incentive for UTCs is to provide price convergence
FERC rendition of the electronically filed tariff records in Docket No. ER13-01654-000
Filing Data:
CID: C000030
Filing Title: Informational Filing re Up-to-Congestion & Virtual Transactions
Company Filing Identifier: 1257
Type of Filing Code: 150
Associated Filing Identifier: 1014
Tariff Title: Intra-PJM Tariffs
Tariff ID: 23
Payment Confirmation:
Suspension Motion:

Tariff Record Data: