SPP Southwest Power Pool
MARKET MONITORING UNIT

COORDINATED TRANSACTION SCHEDULING (CTS) STUDY

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1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit (MMU) and Potomac Economics (external Independent Market Monitor (IMM) for the Midcontinent Independent System Operator (MISO)) are in the process of studying several seams issues at the request of the SPP Regional State Committee (RSC) and Organization of MISO States (OMS) Liaison Committee. The issues were broken out into three tiers. Coordinated Transaction Scheduling, also known as Interchange Optimization, was one of the three items in the second tier:

- Coordinated Transaction Scheduling (Interchange Optimization)
- Regional Directional Transfer Limit
- Interface Pricing

The MMU took the lead on the coordinated transaction scheduling study for the SPP/MISO seam. This analysis includes a qualitative assessment of existing coordinated transaction scheduling processes in place between other markets. Quantitative analysis estimates volume changes in imports and exports stemming from a coordinated transaction scheduling process and benefits the market might obtain from those increased volumes.

The MMU also inquired with other RTOs about the cost of implementing such a product and performed a cost benefit analysis using that information. This report presents the approach, assumptions, and results of the total projected volume changes on imports and exports obtainable from the implementation of a coordinated transaction schedule process on the SPP/MISO seam, as well as the benefits and harms that both markets could incur from the product. The period analyzed in this study was from July 2018 through June 2019.

The results of the analysis showed that a CTS product may not be cost effective with current fee structures, price fluctuations, and inaccuracy in price forecasts. However, that does not mean that a CTS product would not have value and could be beneficial with the total removal of fees for CTS transactions, improvements in forecasting, and better controls over price swings. With changes to improve price forecasts or clear near real-time, remove fees from CTS transactions, and tie ramp constraints for CTS to the markets' abilities to provide ramp, the benefits of CTS can be unlocked.

1.1 INTRODUCTION

In March 2019, the RSC and OMS Liaison Committee requested the SPP MMU and Potomac Economics provide a list[1] of seams issues to help identify and prioritize the scope of seams issues for analysis. In May 2019, the SPP MMU and Potomac Economics submitted a scoping plan[2] that provided further details of efforts involved in analyzing each issue along with recommended priorities by each market monitor. The Liaison Committee separated the issues into three tiers. The MMU provided a work outline in January 2020 that included scope, milestones, and constraints for the coordinated transaction scheduling analysis.

Currently, market participants cannot place price-based interchange offers between SPP and MISO in the real-time market. Instead, they must place a fixed schedule to export, import, or flow though the market. In SPP, market participants must submit these transactions 30 minutes prior to the hour to be eligible for clearing. Prior to clearing, market participants are required to clear ramp and transmission service for the interchange transactions. Transmission reservations are required separately in both markets and can be time consuming for the interchange participants to acquire. In addition, because the transmission has to be cleared in two different markets, the participant can end up clearing a partial path for the transmission when the transmission clears in one market and not the other. When this happens, the participant will not be able to transact the import or export, but still have to pay for the partial path of transmission. Participants combat this by trying to obtain cheap market import service on the importing side, before obtaining expensive transmission on the exporting side.

CTS would simplify this, as it would provide a one-stop shop approach allowing market participants to place a spread offer to clear against forecasted price spreads between the two

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[1] SPP MMU Response on Seams Issues and MISO Market Monitor (Potomac Economics) Response on Seams Issues

[2] SPP MMU and Potomac Economics Scoping Plan

markets. If the offer is in the money of the forecasted prices and there is available transmission the offer will be reserved for the CTS megawatts that are in the money. Then at the time of clearing, typically around 30 minutes prior to real-time, if the forecasted price spread is greater than the offer and ramp is available, the CTS product will clear and be settled at the real-time price spreads. This settled amount will likely differ from the forecasted price spread.[3] CTS participants must account for this price forecast risk in their offers.

A well-designed coordinated transaction scheduling process can increase the volumes of economic bids and offers across the seam, thus providing liquidity and helping to converge prices between the markets. It does this by providing three specific benefits to participants:

- The reduction of exogenous fees associated with imports and exports
- The reduction of administrative burdens
- The reduction of price uncertainty

The intent of this analysis is to estimate the net benefits a coordinated transaction scheduling process can bring to the SPP and MISO markets. To achieve this, the analysis uses both qualitative and quantitative methods. Qualitative methods include interviewing RTOs currently using CTS products and inquiring about their best practices and lessons learned. Quantitative methods include multiple steps, discussed in detail in the analysis section below.

The following were the main areas of focus for the quantitative analysis:

1) Increases in transaction volumes from fee removal, separate from CTS.

2) Price insensitive trading and the effects on a CTS product.

3) Constraints on interchange transactions and their effects on CTS.

4) Markets' abilities to accurately forecast prices at the interchange locations.

[3] This process is described in detail under Figure 1-1, below.

5) Predicting megawatt flows between the markets from a CTS process, using SPP and MISO's current price forecast and applying the clearing assumed from econometric regression models, as well as looking at trading patterns across other seams.

6) Analyzing consumer and producer surpluses in the SPP and MISO markets by analyzing the movements along each market's respective aggregated supply curves using predicted transactional flows.

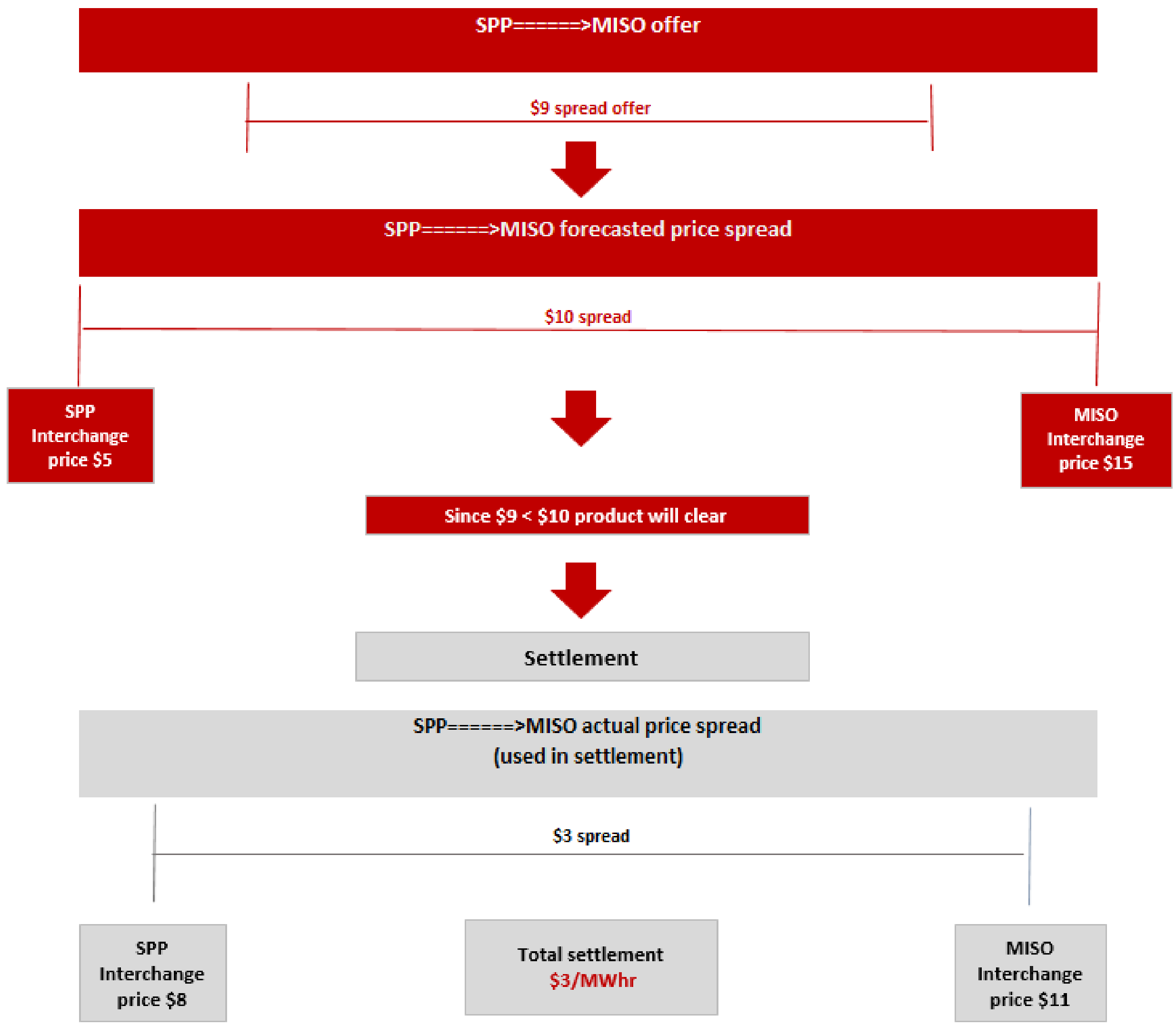
7) Calculating and extrapolating market benefits over the one-year analyzed and comparing those to the approximate cost other RTO's had in implementing their CTS products.

8) Through production runs, analyze the congestion impacts on a sample of intervals where CTS trading estimates are economical.

There are multiple designs and timelines used for coordinated transaction schedules across the markets. The following outlines the MMU's assumptions of how the typical processes currently work in other markets.

Prior to clearing, any bids or offers in the money of the forecasted prices receive transmission service for the entire schedule path, if the transmission service is available. After the procurement of transmission service, typically no earlier than 30 minutes prior to the interval, the systems compare the offers to the forecasted prices for clearing. If the forecasted price spread at this time is equal or greater than the price spread offered, the import or export schedule will clear. Regardless of clearing, there will be no charge to the CTS customer for the transmission service reserved. Once cleared the transaction is binding and the participant will settle at the difference of the real-time market prices between two RTOs trading hubs. Figure 1-1 is an example of how the coordinated transaction schedules will clear and settle for a given megawatt.

Figure 1–1 Coordinated transaction process flow (example)



If the forecasted price at the SPP interface going into MISO is $5/MWh and the MISO interface coming in from SPP is $15/MWh, a $9/MWh offer to export from SPP➔MISO will be eligible to clear. If the actual price, used for settlement, at the SPP interface going into MISO is $8/MWh and the MISO interface coming in from SPP is $11/MWh, the participant will be paid $3/MWh for the cleared CTS product. It is possible that prices in real-time could differ from forecasted prices enough to cause the transaction to be unprofitable, but over time offer behavior should shift to account for these risks. However, if these risks become too large, and the risk premium too great, usage of the CTS product may be stifled. This is why the markets' ability to forecast prices accurately is a very important factor in establishing a well-functioning CTS process and a key component of this analysis.

1.2 RESULTS

The MMU found that the historical price differences along the SPP and MISO seam represent a potential intermarket inefficiency estimated to be worth approximately $9.4 million to $11.2 million annually. In addition, a well-designed CTS product should be able to capture a significant portion of that inefficiency as total market benefit. However, multiple roadblocks and multiple criteria will need to be addressed to capture a portion of those potential benefits.

Fee removal will be a necessary component of a functional CTS product, as prices rarely diverge enough to cover both fees and historical risk premiums. Fee removal can allow new transactions to "fill in the gaps" of unused transmission facilities across the seam without affecting current transmission rates. However, to the extent stakeholders start using CTS for seams transactions for which they currently have Network or Point-to-Point service, transmission rates could change, resulting in a cost reallocation. While transmission fees are an externality and represent dead-weight loss to the market, they are appropriate for ensuring equal access and facilitating FERC Order Nos. 888 and 889. The SPP MMU is not taking a position on whether fee removal is appropriate for these markets, although the MISO IMM believes it is appropriate to eliminate these fees and have recommended they be eliminated on each of the MISO interfaces.

Assuming traders required a $5/MWh risk premium and the average transactional charges for importing and exporting were roughly $10/MWh, the CTS product would only clear in about 13 percent of the intervals studied. Because of this situation, this analysis assumed total fee removal when studying the effects of CTS trading. The MISO and PJM seam have seen similar issues with the application of fees to CTS as there is limited participation in the product.[4]

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[4] 2018 State of the Market Report for the MISO Electricity Markets, Potomac Economics, https://cdn.misoenergy.org/2018%20State%20of%20the%20Market%20Report364567.pdf, Page 82. Part of this issue is associated with the fact that transmission reservations may clear for the CTS product, but the schedule may not be in the money, leaving the customer paying for a transmission reservation and no schedule.

In addition to fee removal, the current price volatility in SPP will need to be reduced or more accurately predicted. The average price spread change from interval to interval during our study was $9.26/MWh and the median change was $1.75/MWh. Of note, both MISO and SPP price forecasts had difficulty predicting swings in price spreads. This was especially true when one market experienced extremely high prices or negative prices.

The MMU found there is benefit to this product when prices are forecasted accurately; however, the inability to forecast these extremes will constitute a larger risk premium for CTS participants to avoid uneconomic megawatt flows that harm the markets and the CTS participants. Left unresolved, these increased premiums will likely stifle the CTS volumes transacted. Our analysis found that the current 30-minute look-ahead models forecasted inaccurately enough to reduce the benefits to a range between a $1.4 million benefit to a net harm of $647,000 per year, because it either predicted a significantly larger price spread than actually occurred or predicted the price spread in the wrong direction. The MMU also evaluated the benefits under 5minute lagging price spreads. Including analysis under the benefits seen when one market's price is lagged, but the other market's price is current. Lagging SPP's price 5-minutes while holding MISO's price current produced the largest benefits, with net benefits estimated to be between $4 million and $3.2 million. This shows that the closer the CTS product can clear to real-time the greater the benefits for the market.

SPP has designed a ramp product, with expected implementation in 2021. SPP is also designing an uncertainty product. These two products, if implemented, should help improve price forecasting by reducing some of the price spikes seen in the analysis that interfere with a CTS product's ability to maximize benefit. However, the reduction in price spikes will also likely reduce some of the higher price spreads, which will also reduce some of the $9.4 million to $11.2 million overall potential benefit. If these new products function well in reducing price swings and/or price forecasting becomes better, they will increase the efficiency of a CTS product and provide benefit by supplying the cheapest generation between the markets. However, changes to the current market constructs need to occur in order to unlock the value of a CTS product as participants will likely transact in small volumes because of current fees and forecast errors.

2 CTS ANALYSIS

2.1 EFFECTS OF FEE REMOVAL

Interchange transactions currently incur transmission and market charges per megawatt reserved. The MMU conducted the CTS analysis under the presumption that no market or transmission fees apply to these transactions. The MMU removed the fees because the price spreads between the markets typically are not enough to incent participation with the fees applied, and limits potential benefit to the markets. Using these assumptions also simplifies the modeling and shows the full benefits that a CTS process can bring if not encumbered by external fees. This is similar to the implementation of CTS at the New York ISO/ISO New England seam, which produces the most transactional volume and generates the most benefit of all current CTS processes.

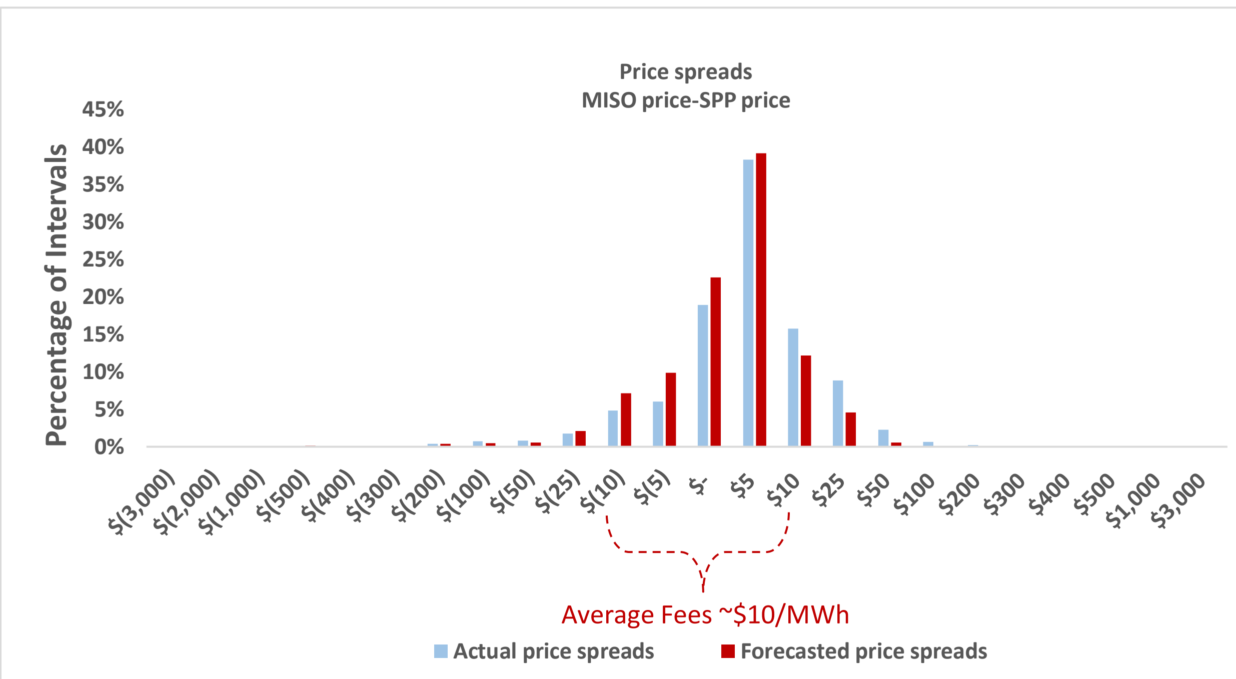
It is important to note that the CTS process has the potential of displacing current transmission fees and creating additional market uplift. The removal of fees such as make-whole payment distribution, revenue neutrality uplift, and transmission fees from participants of the CTS product may require any displaced or additional fees to be allocated to non-CTS transactions. For transmission, this may require adjustments to transmission rates. If implemented, the MMU views the redistribution of those charges as a cost-versus-benefit-based stakeholder decision best handled through stakeholder processes.

In an effort to delineate the effects of fee removal from the effects of the CTS product, the MMU ran econometric models to estimate the influx of transmission trading across the SPP/MISO seam if fee removal occurred with the current SPP/MISO interchange process. The estimates show that fee removal had relatively small impacts on transactional volumes, when using the current interchange process. During our study period of July 2018 through June 2019, we found that removing all of the market and transmission fees leads to an average hourly increase of 24 MW from SPP to MISO and 3 MW from MISO to SPP. These estimates are based on historical trading patterns and sensitivities to price changes. These low numbers represent the fact that much of the trading across the seam is price insensitive.

During the study period, market and transmission charges averaged just over $10/MWh. This fee was calculated by weighted averaging the on-peak and off-peak per megawatt transmission rates charged by SPP and MISO and adding the annual average market fees currently applied to interchange transactions. It was presumed that most CTS participants would take advantage of market-import service on the importing side of the transaction in either market. These market import fees are typically less than a $1/MWh. However, on the exporting side it was presumed the full transmission fee would be applied, similar to what currently happens. The average cost of the combined transmission fees was over $7/MWh. The average market charges for both parties were estimated to be $2.77/MWh. For simplicity, these combined numbers were rounded to $10/MWh.

As can be seen in Figure 2–1, price spreads between SPP and MISO are not consistently wide enough for participants without existing transmission service to cover the additional cost of acquiring transmission service in most intervals.

Figure 2–1 Forecasted and actual price spreads



Based on offer structures seen at the New York ISO/ISO New England seam and the price volatility on the SPP/MISO seam, the MMU assumes that very low volumes would transact at price spreads less than $5/MWh. Roughly, 57 percent of the intervals studied had price spreads less than $5/MWh. If CTS participants had to account for the approximately $10/MWh average costs of fees, we find that the intervals without an adequate price spread for trading expanded to 87 percent of all intervals. In fact, in Potomac Economics' 2018 Annual State of the Market Report on MISO Electricity Markets they cite fees as a key issue to the low volumes transacted at the MISO/PJM seam. The report states: "Since its inception, there has been almost no participation in CTS. The average quantity of CTS transactions offered and cleared in 2018 were 2.9 MW and 0.32 MW, respectively. We have previously asserted that high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling." [5] The MMU believes the effects will likely be similar at the SPP/MISO seam, if fees are applied for market charges and transmission reservations.

2.2 CONSTRAINTS ON CTS TRADING

This analysis capped the CTS megawatts available for clearing at 500 MW. This is currently the market-ramp constraint in the SPP market for net schedule interchange. It limits net schedule interchange to 500 MW of change every 10 minutes in the up or down direction. The maximum observed interchange across the SPP/MISO seam was about 2,600 MW. However, this was still subject to the 500 MW ramp constraint. Since CTS clears on a 10-minute basis, it would not be practical to clear more than the ramp requirement, as it would force CTS transactions to clear uneconomically when ramp constrained. For instance, assume the CTS trading incremented up 500 MW every 10 minutes to reach 2,600 MW of transactions, then prices spreads flipped and all 2,600 MW of CTS transactions became uneconomic. The markets will flow these uneconomic transactions while ramping them back down in 500 MW blocks every 10 minutes. This means that CTS trading could be inefficient for 50 minutes until they were able to ramp back to an economical position. The MMU performed analysis using both the 500 MW ramp limit and the 2,600 MW capacity limit. The 500 MW limit turned out to be more beneficial for the market and the CTS participants, because the price variations between intervals, using the 2,600 MW limit

[5] 2018 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS, Potomac Economics, https://cdn.misoenergy.org/2018%20State%20of%20the%20Market%20Report364567.pdf, Page 82.

caused CTS trading above the 500 MW ramp limit to be uneconomical too frequently to be cost effective.

The New York ISO and ISO New England seam has the highest CTS volumes of all seams. It has a similar ramp constraint, but it is limited to 300 MW and is only constrained to the interchange location and not the market as a whole.

2.3 RAMP AVAILABILITY AND PRICE SIGNALS

It is important to note that the net-interchange schedule ramp constraint is independent of the actual ramp available in the markets. SPP has an initiative on their roadmap to assess aligning the net-schedule interchange ramp requirement to the physical ramp limits of the market. Without having the net-schedule interchange ramp requirements tied to physical ramp-constraints in the market, there is the risk that CTS can create and exacerbate scarcity events under certain scenarios.

In our analysis we observed that roughly 16 percent of the intervals had a higher interchange-ramp capacity limit than the ramp available in the SPP market and five percent of the intervals did not have adequate ramp in the SPP market to support the CTS transactions, based off the assumed offers.[6] CTS can hinder reliability to either market by using ramp needed to serve load and meet reserve requirements. In addition, this can hinder market efficiencies by restricting the CTS flow to an amount less than the market's capabilities. Connecting the net-schedule interchange ramp requirement to the actual ramp limitations in the market is a key area that needs to be addressed before implementing a CTS product.

The MMU also observed another issue with the market's ability to signal ramp shortages through price formation. SPP uses violation relaxation limits (VRL) for spinning-reserve scarcity events. The VRL allows the market to redispatch in an attempt to acquire spinning-reserves up until the redispatch cost reaches $200/MWh. At that point, it reduces the limit to what it could

[6] The ramp adequacy was only analyzed in the SPP market. It is possible that it could be short in the MSO market, but this was not reviewed as part of this analysis

acquire for less than $200/MWh and sets the price at the highest cleared spin offer. Often times, this price might be $2 or less.[7] The CTS product relies solely on participants' offers and the prices between the markets to clear CTS megawatts. If those prices do not truly reflect the markets' needs, conflicts can occur between the CTS clearing and the market needs. During the analysis, spin was short just under 200 intervals where actual price spreads were high enough to warrant CTS trading. A demand curve would better reflect the true price of the scarcity event and provide better signaling for the CTS clearing. The MMU has recommended that SPP improve price formation during scarcity events as part of its 2019 annual report.[8]

2.4 FORECASTING PRICES AND BIDDING BEHAVIORS

As stated above, one component of a well-functioning CTS process is the RTOs' abilities to forecast prices. In order to predict the usage of a CTS process it is imperative to understand the RTOs' abilities to forecast price spreads. For this analysis, the SPP price forecasts at the "MISO" interchange location came from the pre real-time market runs known as pre-RTBM runs, performed 30 minutes prior to the interval. The MISO "SWPP" interface price came from the ~30 minute prior forecasted amounts, used by MISO for its CTS coordination with PJM.

Just under 2 percent of the intervals did not have forecasted prices for either SPP or MISO. During these intervals, no CTS volumes were considered for clearing in the study. This is analogous to what happens when forecast errors occur with current CTS processes.

With properly forecasted prices and no exogenous fees applied, if MISO's price was lower than SPP's price, CTS participants should import into SPP. Conversely, if SPP's price was lower than MISO's price, then CTS participants should import into MISO, barring any other constraints.

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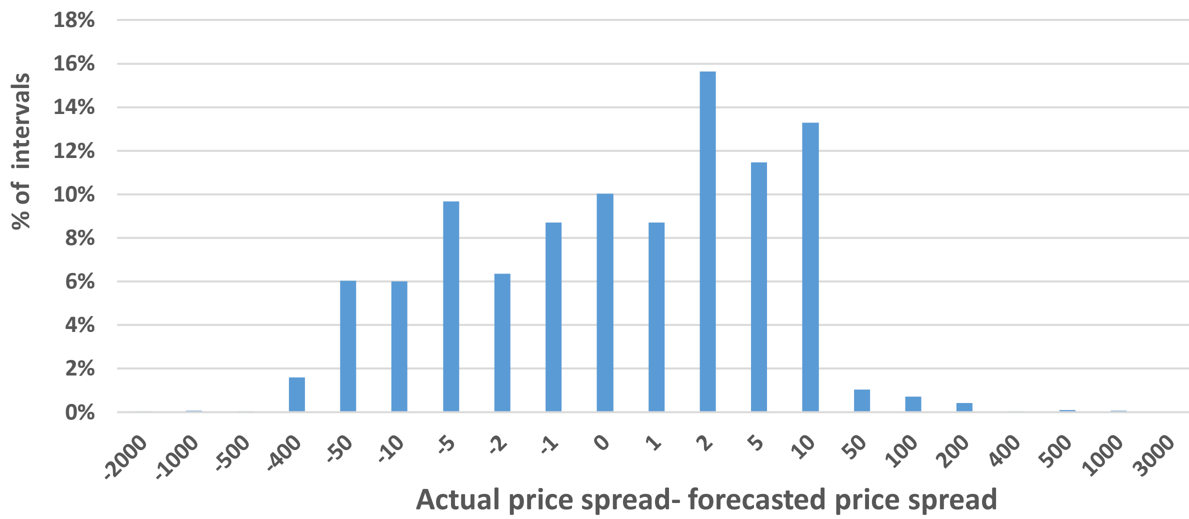
[7] The 2018 SPP Annual State of the Market report provides examples of spin prices during spin shortages: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf, page 83, Figure-17.

[8] The 2019 SPP Annual State of the Market report has not be finalized, but can be viewed in the draft form in the SPP Board of Directors/Member Committee Meeting materials for April, 28 2020 ("Draft State of the Market Report"). https://www.spp.org/documents/62043/bod-mc%20materials%2020200428_pgd.pdf, page 13.

Approximately 65 percent of the intervals in our study period had a MISO price higher than SPP's price. This compares reasonably well with our forecasted prices, which had 57 percent of intervals with a MISO price higher than SPP's price. However, the forecasted price spreads did not accurately align with actual price spreads.

Figure 2–2 displays the differences between the forecasted price spread in each interval from the actual price spread.

Figure 2–2 Histogram of forecast errors between MISO and SPP[9]



Ten percent of the intervals of our study had forecasted price spreads within a dollar of the actual price spreads and 49 percent of the time, they were within $5/MWh. However, price forecasts struggled with predicting the outlying price spreads, reducing the likelihood of strong trading in those intervals. During price spreads over $100/MWh, the average error was

[9] The absolute average forecast errors for MISO and SPP were $5.55/MWh and $11.13/MWh, respectively. It should be noted that the forecasts for SPP were specific to each 5-minute interval. However, the MISO forecasts where for 15-minute blocks increasing their error rate, as each interval in the 15-minute block was applied the same forecasted price. These forecast errors align with the price volatility in each market.

$161/MWh. The absolute average price-spread change was $9.26/MWh between intervals and the median change between intervals was nearly $1.75/MWh.

In addition to forecasting prices, the MMU attempted to estimate participants' offer behaviors. This was done by using the offer structures submitted at the New York ISO and ISO New England seam and adjusting them slightly for differences seen in the SPP and MISO markets.[10] In particular, the SPP market typically has a higher percentage of its energy obligation met by variable energy resources and as a result has higher volumes of price volatility. Although price spikes greater than $1,000/MWh happened infrequently during the study, the analysis showed that the SPP forecasted prices rarely predicted the severity of these events. In these intervals, the actual energy prices can become very high as they are often being priced by scarcity demand curves. In fact, in one interval, the forecasted price spread was -$70.66/MWh but the actual price spread was $3,426.71/MWh, due to a MISO contingency reserve event. Based on the forecasted price spreads and the estimated offer curves 500 MW would have cleared from MISO to SPP. These megawatts would have resulted in market inefficiency and cost the CTS participants $3,497.84/MWh, which was the actual price spread between the markets at that time.

Figure 2–3 displays the offer curves used for estimating CTS transaction volumes. These offers presume that no exporting will transpire if forecasted price spreads are less than $5/MWh and no imports will transpire if less than $4/MWh.[11] The percentages represent the percentage of total capacity cleared under each price spread scenario.

Figure 2–4 shows the percentage of intervals in which the CTS offers cleared under our analysis using these assumptions and actual price spreads.

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[10] The 2018 State of the Market Report for New York ISO Markets; https://www.potomaceconomics.com/wp-content/uploads/2019/05/NYISO-2018-SOM-Report__Full-Report__5-8-2019_Final.pdf; page 47, figure 11.

[11] Other markets showed some levels of trading below these lowest offer points, including negative offers. These are most likely serving power-purchase agreements and were not considered in this analysis.

Figure 2–3 Estimated CTS offer curves

SPP to MISO offer	
$0	0%
$5	10%
$5.25	25%
$6	30%
$10	40%
$11	50%
$17	65%
$21	100%

MISO to SPP offer	
$0	0%
$4	10%
$4.25	25%
$5	30%
$9	40%
$10	50%
$15	65%
$20	100%

Figure 2–4 CTS analysis percentages of cleared capacity

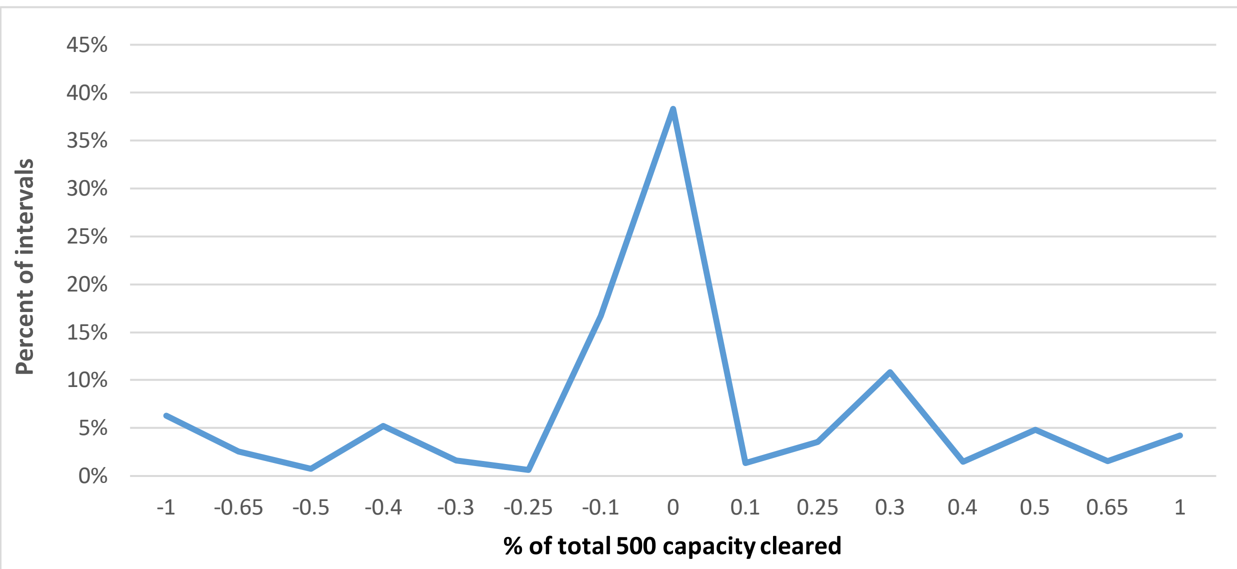


Figure 2-4 shows that roughly 40 percent of the intervals in our study did not clear any CTS transactions using the assumed offer curves from Figure 2-3. The largest clearing point was at 30 percent of the capacity from SPP into MISO. This means that during roughly 11 percent of the intervals 30 percent of the total 500 MW capacity available was flowing from SPP to MISO. Five percent of the time, 40 percent of the 500 MW capacity available was flowing from MISO to

SPP. Just under 10 percent of the intervals cleared at the maximum available capacity of 500 MW, using these assumptions.

2.5 ESTIMATED BENEFITS TO THE MARKET FROM CTS TRADING

The MMU applied three methods in estimating the benefits that a CTS product can bring to the SPP and MISO markets.

2.5.1 Production rerun analysis

The first method applied predicted transaction volumes that would clear based off actual price spreads and the offer curves described in Section 2.4. SPP and MISO both performed market reruns with the applicable exports and imports predicted. This method is highly accurate in predicting market changes, including congestion changes, from imports and exports; however, it is limited in scope.

Due to the time-consuming nature of performing market reruns, only six intervals were reran. These intervals included the following cases:

1) MISO incurring a large price spike (contingency reserve event);

2) SPP incurring a large price spike (ramp scarcity event);

3) MISO incurring negative prices;

4) SPP incurring negative prices;

5) Normal prices, but MISO price > SPP price; and

6) Normal prices, but SPP price > than MISO price.

While this method is limited in scope, it helps to show the full benefits and harms that a CTS product can bring to the markets under different scenarios, assuming these scenarios are accurately forecasted. Market re-runs also provide insight into the congestion impacts on CTS trading around the seams and the redispatch needs applied to meet the cleared CTS megawatts.

Figure 2-5 shows the outcomes of the market reruns.

Figure 2–5 Production rerun summary

			Changes in Congestion		Changes in LMP		Production cost changes		CTS profit+/loss-
Interval GMT	Price Spreads	CTS FLOW (MW Hours) Positive denotes SPP to MISO Negative denotes MISO to SPP	MISO	SPP	MISO	SPP	MISO	SPP	Assumes no fees
8/2/18 7:05 PM	$ 14.55	105	$ (0.04)	$ 0.67	$ (2.88)	$ 7.79	$ (289)	$ 313	$ 405
9/14/18 9:55 PM	$ 3,466.42	500	$(12.86)	$ 7.80	$ (2,999.40)	$ 226.83	$ (5,883)	$ 3,458	$ 120,095
9/28/18 4:40 AM	$ 46.20	500	$ -	$ (1.35)	$ (0.50)	$ 40.80	$ (886)	$ 84	$ 2,451
12/11/18 6:30 PM	$ (59.50)	(500)	$ 1.88	$ (0.14)	$ 10.16	$ (51.28)	$ 1,055	$ (494)	$ (969)
5/10/19 1:10 AM	$ (2,565.77)	(500)	$ 0.31	$ -	$ 3,435.51	$ (2,079.45)	$ 2,574	$ (744)	$ (1,474,597)
5/15/19 10:00 PM	$ (24.36)	(121)	$ 0.01	$ 0.02	$ 0.40	$ (0.53)	$ 92	$ (976)	$ 2,835

The market rerun outcomes showed that the CTS transactions had a relatively minimal impact on congestion prices, even during the extreme intervals with maximum volumes transacting. The average change in the congestion prices on the MISO interchange was $1.78/MWh, with most of this coming from the interval on September 14, 2018. The average change in congestion prices on the SPP interchange was $1.17/MWh. However, the changes in prices were substantial. At 21:55 GMT on September 14, 2018, SPP prices were $3,466/MWh lower than MISO prices, because of a contingency reserve event in MISO. Presuming that the event was forecast accurately and 500 MW would have gone from SPP to MISO, the rerun shows that prices converged to $240/MWh. This increased flow raised SPP's production cost by $3,458 and lowered MISO's by $5,883 for a net market benefit of $2,425 for the interval.

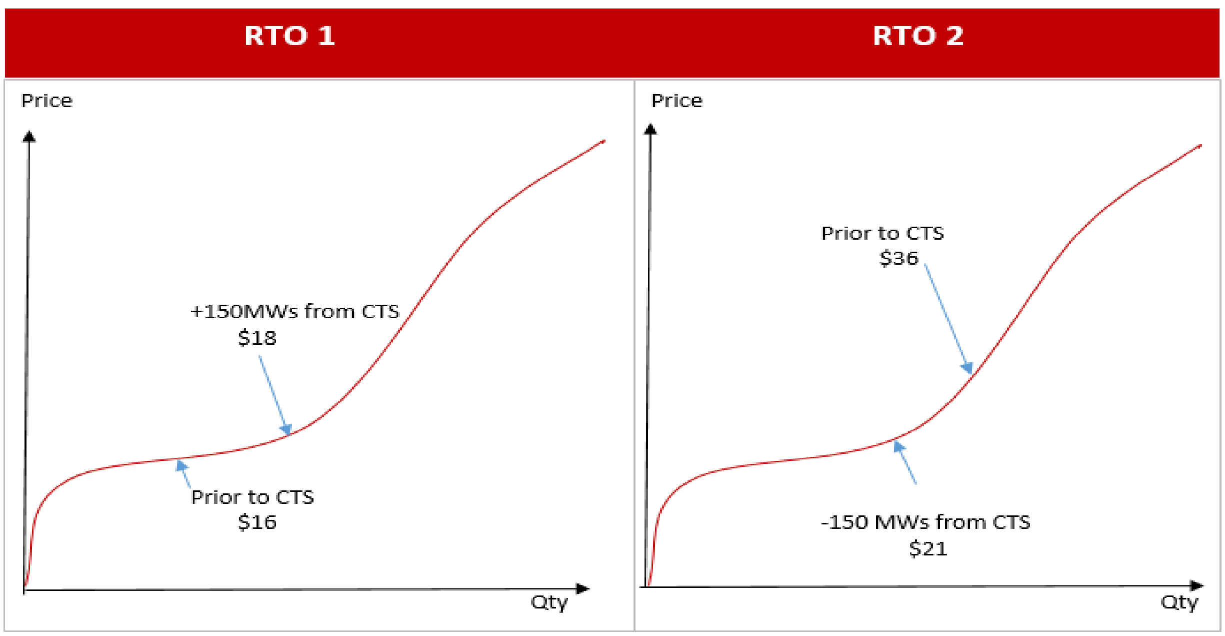
On May 10, 2019, SPP had scarcity pricing, diverging the SPP and MISO price by $2,567/MWh. Our analysis presumed that all 500 MW of CTS would have gone from MISO to SPP. This caused the MISO price to increase by $3,436/MWh and the SPP price to come down by $2,080/MWh, a $5,515/MWh swing in market prices. This diverged prices in the opposite direction by $2,949/MWh, which would have cost the CTS participants a total of $61,000 (500* $2949/2)/12. This was due to MISO not having the available ramp to meet the CTS requirement. The next section discusses how this over clearing could be managed with the use of sharing each RTO's aggregate supply curves.

2.5.2 Supply curve analysis

The next method applied uses the marginal movement along supply curves caused by a shift in demand curves as a proxy for production costs. It also reveals the impacts a CTS product can have on consumer and producer surplus. One way to estimate the changes that a CTS product could bring to the market is to look at how the CTS transactions move each market up or down their product supply curves.

Figure 2–6 is a hypothetical example of two RTOs' supply curves. The illustration shows how a CTS product could help converge energy prices between the RTOs by moving each RTO's total generation output up and down its supply curve.

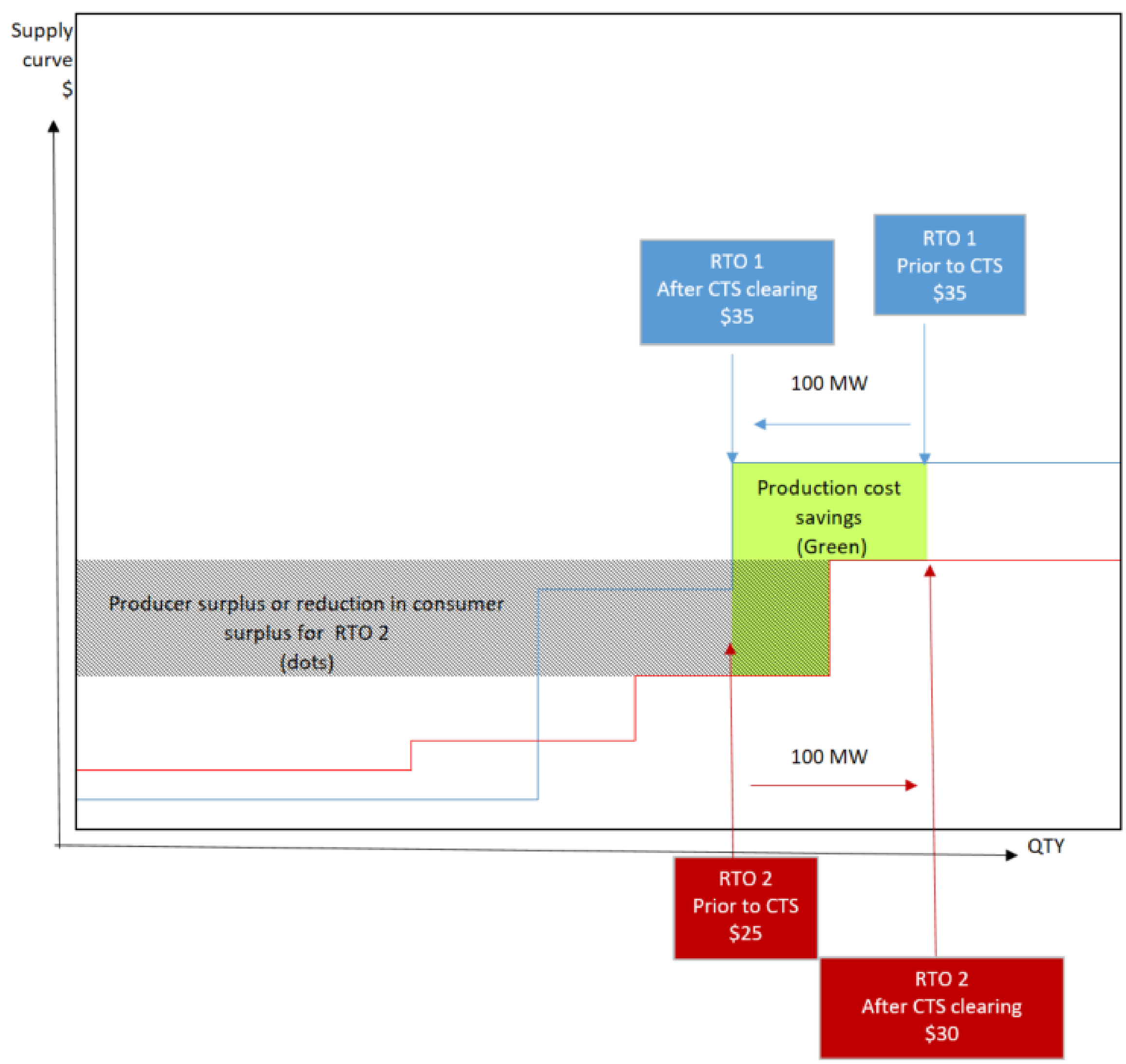
Figure 2–6 Supply curve changes from CTS transactions



The red lines represent the aggregated supply curves in two different markets. In this example, 150 MW of CTS exports cleared to move from RTO 1 to RTO 2. To meet this requirement, RTO 1 will need to generate 150 MW more and RTO 2 will reduce its output by 150 MW. Because RTO 1 moved mostly up the flat part of its supply curve, the cost increases were relatively low compared to the cost decreases that RTO 2 incurred from moving down the steep part of their supply curve. In this simple example, 150 MW of exporting would cause RTO 1's marginal energy cost to increase $2/MWh, from $16 to $18/MWh. However, the 150 MW of importing into RTO 2 reduced the energy cost $15/MWh, from $36 to $21/MWh. In this scenario, efficiencies were gained because cheaper resources are now producing the 150 MW. In addition, the exporting side had a $2/MWh increase in producer surplus and $2/MWh decrease in consumer surplus. The importing side had a $15/MWh increase in consumer surplus and $15/MWh decrease in producer surplus.

Figure 2–7 is an example of the consumer and producer surpluses change between two markets.

Figure 2–7 Supply curve movements across markets

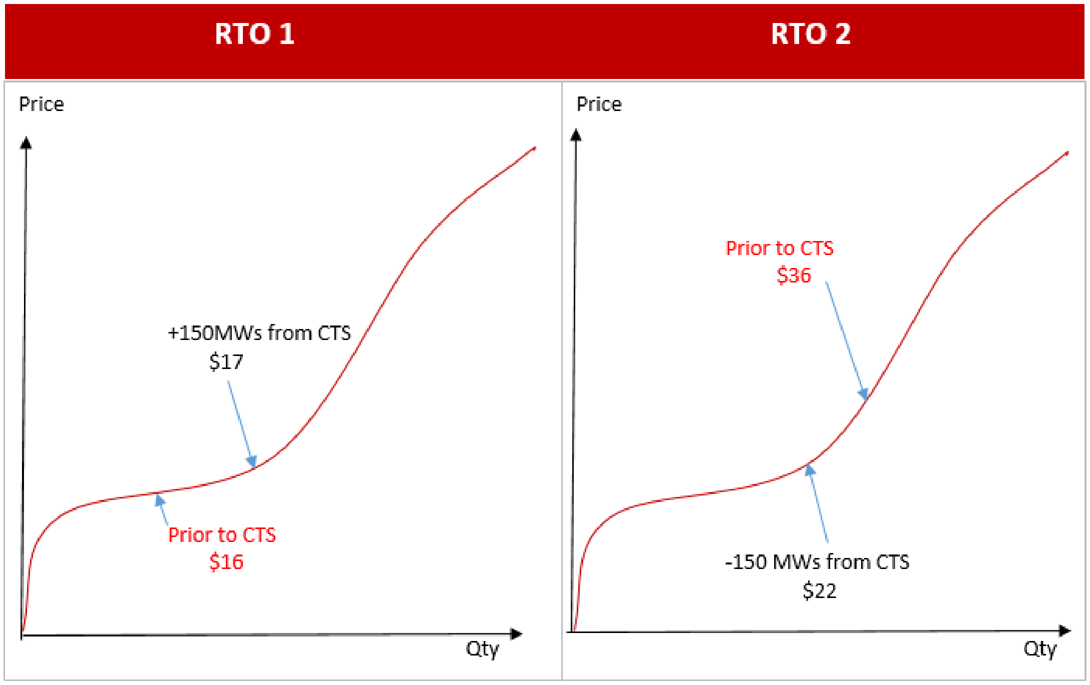


In this example, RTO 2 (red-line) has lower energy cost than RTO 1 (blue-line), so 100 MW of CTS clears between the two markets flowing from RTO 2 to RTO 1. RTO 1 will move down the supply curve and RTO 2 will move up their supply curve. The green area is the total benefits across both markets. It represents the area-under the curve for the difference in cost between the two markets to produce the 100 MW. When we look at the producer and consumer surpluses in this example, we see that RTO 2 had an increase in producer surplus and a decrease in consumer surplus. Consumers in RTO 2 will now pay $5/MWh more for energy than before CTS transacted. Producers will now be paid $5/MWh more. The grey shaded area represents the changes to consumers and producers in RTO 2. RTO 1 did not see a change in price so there was no realized change to the consumers or producers.

Using the estimated CTS megawatts cleared from Section 2.2, each market monitor calculated their RTO's movement along the supply curve. The analysis used these movements along the supply curves as a way to define the benefits to producers and consumers in each market. The analysis showed that when SPP was exporting to MISO the average price increase to SPP was about $0.13/MWh and the average MISO price decrease was about $0.28/MWh. When MISO was exporting to SPP the average price decrease to SPP was about $0.26/MWh and the average price increase to MISO was about $0.31/MWh. The price changes show us that MISO appears to have a more elastic supply curve than SPP.

Ideally, the RTO's will share offer curves prior to clearing to help prevent over clearing of a product. In this example, without sharing aggregated generation supply curves between the markets, a $20/MWh offer to export from RTO 1 to RTO 2 will clear. However, because the shifts that the CTS megawatts had on each RTOs' supply curves, the price difference would only be $3/MWh (ignoring congestion and loss prices) after applying the CTS megawatts. Figure 2–8 is an example of how supply curves can be shared to reduce the effect of over clearing CTS products.

Figure 2–8 Supply curve sharing example



Offers

MWS offered	Required Price Spreads
0	$0
50	$4
100	$5
100	$6
100	$10

Eligible to clear

NOT Eligible to clear

In this example the forecasted price differences is $20/MWh ($36-$16), so without supply curve analysis all 350 MW would clear. However, if all 350 MW cleared it would push the supply curves past equilbrium, which would represent an inefficiency in the markets and would cause a loss to the CTS participants in this scenario. To combat this the supply curves are shared at the time of clearing. In this example, clearing 150 MW the gap between the markets prices closed to $5/MWh, so the $6/MWh offers and above did not clear. Sharing forecasted supply curves helps to ensure that the CTS cleared megawatts do not diverge the prices in the opposite directions. This is a practice that is shared by New England and New York ISOs. It will be imperative that the supply curves account for as much information as possible such as ramp and transmission constraints on resources.

2.5.3 Evaluating production cost benefits

The final method used to calculate CTS benefits is an approach that is similar to what was used by Potomac Economics to evaluate other seams in the markets they evaluate. This approach requires running econometric regressive models on historical trading differences by hour to obtain the price spread changes by hour, while controlling for variables such a fuel cost, load changes, supply curve slopes, and congestion between each seam's interchange location. This in conjuntion with the market rerun analysis provided coefficents for predicting the typical CTS megawatt volumes needed to converge prices at the SPP/MISO seam. Because regression analysis and price reruns showed large price spreads needed a lower rate of CTS megawatts to converge prices, graduated coefficents were used for increasing price spreads. For instance, at price spreads less than $5/MWh a coefficent of 0.015 was used as it took much more trading for the markets to reach equilbrium. However, during large price spreads the analysis showed that the markets moved much quicker along their supply curves or in some cases where moved off scarcity demand curves. For this reason, the coefficents above a $600/MWh price spread were 1 for imports into MISO and 2 to exports from SPP. The coefficents for price spreads above $1,500/MWh were 2.65 for imports into SPP and 4.27 for imports from MISO.

The calculated coefficients were used to predict the CTS megawatts needed to converge prices. For instance, if the price spread is $1.50/MWh it would take 1,000 MW to converge the price with a coefficent of 0.015. However, if the price spread was $3,500 the coefficent was 4.27. This means that it would take roughly 820 MW of CTS trading to converge a $3,500 price spread (e.g. $3,500/4.27). However, CTS products are constrained to a 500 MW limit so full convergence will not happen, as only 500 MW of the 820 MW will clear. Using these calculated volumes, production cost savings were calculated using the absolute value for the following equation: estimated (CTS volume * (MISO-SPP price spread) / 2)/12. This is similar to the green section illustrated in Figure 2-6 above, except the equation assumes linear supply curves and no changes in slopes along the supply curve. This method netted a total gain between $9.4 million and $11.2 million, per the one year study.[12] It shows the full benefits that a CTS product could bring to a market. However, there are many key issues that will never allow this full potential to be reached. These limitations include, but are not limited to:

1) participants will most likely not participate in the high volumes needed to close small price spreads less than $5/MWh, which account for roughly 58 percent of all intervals in the study and $876,000 of the benefits;

2) when ramp constraints allow, it assumes perfect forecasting and does not evaluate the markets' abilities to forecast prices;

3) it assumes perfect price convergece, however, CTS particpants will not be willing to participate with perfect price convergence, as price seperation is required for CTS participants to profit from the product;

4) it assumes no fees are applied;

5) both markets have similar supply curves and supply curves are linear; and

6) it assumes both markets have available ramp.

To account for the 30-minute forecast errors, CTS clearing was assumed to have occurred in accordance with Figure 2-3. For instance, if the 30-minute forecasted price spread going from SPP to MISO was $5/MWh then 50 MW were assumed to have cleared. If the price spread was greater than $21/MWh then 500 MW were estimated to clear. This assumes that the full 500 MW capacity is available and not being reduced by other interchange transactions.

The cleared megawatts were multipled by the actual price spread then divided by two. In each interval of the study, this forecasted production cost savings was netted against the total possible savings, presented above in the amounts of $9.4 million to $11.2 million. For instance, if the actual price spread was $10/MWh with flows going from SPP to MISO and the forecasted price spread was for $20/MWh then 200 MW would be expected to clear based on forecasted

[12] The spreads account for varying assumptions on the stratification of graduating coefficients.

prices. Per the coefficents analysis described above, a $10/MWh price spread from SPP to MISO takes roughly 167 MW to converge the price spread. Because 200 MW cleared, 33 MW were considered harmful to the market and 167 MW benefited the market, for a net benefit of 134 MW. This means that the benefit applied is (134 MW * $10/MWh (Actual price spread)/2)/12 = $55.83. It is important to note that this would be harmful to CTS transactions as they would incur charges from the price spread shifts.

If the megawatts cleared were less than the 167 MW needed to converge the price spread. Then only the megawatts cleared would be applied. For example, if 100 MW cleared then the net benefit would be $41.67 ((100 MW * $10/MWh/2))/12. Lastly, if the amount was forecast in the wrong direction, then the whole amount cleared would be considered a harm. For example, 100 MW was importing due to forecasted price spreads, but real time price spreads suggested exporting, then the net harm to the markets would be $41.67.

After applying the 30-minute forecast adjusments to the in total annual benefits of $9.4 million and $11.2 million we found that the market benefits were reduced to an estimated range between a $1.5 million benefit and negative $647,000.[13] The same analysis was performed using 5 minute lagging price spreads, which resulted in estimated net benefits between $3.3 million and $2.9 million. In addition, CTS studies were performed where MISO's price was lagged 5-minutes but SPP's was current. This resulted in estimated net benefits between $3.4 million and $2.5 million. Lastly, when SPP's price was spread was lagged 5 minutes and MISO's was current, the estimated net benefits ranged between $4 million and $3.2 million. Each method assumes no fees are applied to the CTS transactions. Additionally, the 5-minute models assume that market clearing would never excede the amounts needed to converge the forecasted price spreads.

The 30-minute forecast numbers indicate that the current forecast methods stuggle in predicting the rapidly changing price spreads. However, if the clearing can happen near real-

[13] The spreads account for varying assumptions on the stratification of graduating coefficients, as well as assumptions around the clearing of products under varying price spreads. The high end assumes that the markets will never clear more CTS megawatts than are needed to converge prices. The negative outcome included clearing in excess of what is needed to converge prices.

time, forecast errors can be reduced and increased benefits can be obtained. SPP plans to implement a ramp product and possibly a price uncertainty product. These two products should help to reduce the price variances and better help with addressing forecast errors. The numbers used for the SPP forecast come from pre-real-time market studies and are not currently used for forecasting. These numbers may be improved if relied on in the future. In addition, the net losses shown on the bottom end of these estimates from forecast error would likely never materialize as trading volumes would subside when trading became unprofitable. The losses and benefits projected above do not account for the $6 to $10 million initial outlay needed to implement the ramp product.[14]

[14] ISO New England's Market Monitor stated that ISONE spent approximately $4.5 million to implement their CTS process and assumed that NYISO shouldered an approximately equal cost. Cost savings could be gained from MISO already having some of the necessary components needed to implement a CTS product. However, cost overruns could occur. Given these factors, implementation costs ranging from $6 million to $10 million appear reasonable. These costs do not include any costs incurred by the individual participants for system updates.

3 CONCLUSION

The analysis finds that a well designed CTS product can capture benefits from the $9.4 million to $11.2 million in unrealized value on the SPP/MISO seam annually. However, there are issues that currently impede the markets from achieving these benefits. In fact, current price forecasting and fees would impede the CTS product from being cost effective at this time. The MMU found that only about 17 percent of intervals during the study period would have any significant volume of CTS transactions with a hurdle rate equal to the current fees. Therefore, fee removal is important for the CTS product to capture potential benefits.

In addition, fluctuations in the price spread of the two markets were difficult for either market to forecast. The absolute average fluctuation of price spreads between intervals was $9.26/MWh, and the median fluctuation was $1.75/MWh. The average 30-minute forecast error was over $14/MWh, and the median error was around $3.60/MWh. These errors in forecast frequently caused harm to CTS transactions. This happened in cases where too many megawatts were cleared, diverging the prices in the opposite direction, or when price spreads were forecast in the wrong direction. The analysis showed that when 30-minute forecast errors were accounted for, a CTS product resulted in estimated benefits between $1.4 million and losses of $647,000, annually. However, the analysis also showed that a CTS product that cleared near real-time could have increased benefits. The most benefit came when assuming that the clearing happened when using real-time MISO prices and a 5-minute lagging SPP price. This method produced a total estimated benefit between $4 million and $3.2 million, annually.

Implementating a CTS product with the current fee struture and using forecasted prices would likely result in CTS volumes being relatively small. However, our analysis finds that CTS benefits can be unlocked if fees are removed, supply curves are shared between MISO and SPP, actual ramp as opposed to estimated ramp is used, and more accurate forecasted prices are developed or clearing can happen near real-time. If these additional steps are taken, there can be efficiency benefits along the SPP/MISO seam.

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