MARKET SURVEILLANCE COMMITTEE

Congestion Rent Allocation

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Topics

- Goals
- Examples
- Observations
- Alternatives

Goals

An ideal congestion allocation design would have several properties. Compromises may be necessary to balance achieving the goals, but these goals should be understood.

- Be consistent with resource participation in the day-ahead and real-time dispatch, rather than incenting self-scheduling, and without distorting bidding incentives. This applies to resources that could be dispatched either up or down to manage transmission congestion.
- Enable the provision of congestion hedges that are reasonably consistent with the transfer capability of the transmission grid or are supported by the out of merit dispatch of the transmission seller’s generation.
- Enable balancing areas to preserve the rough overall benefit of the bargain for the parties to existing transmission contracts.
- Avoid undue cost shifts among market participants.

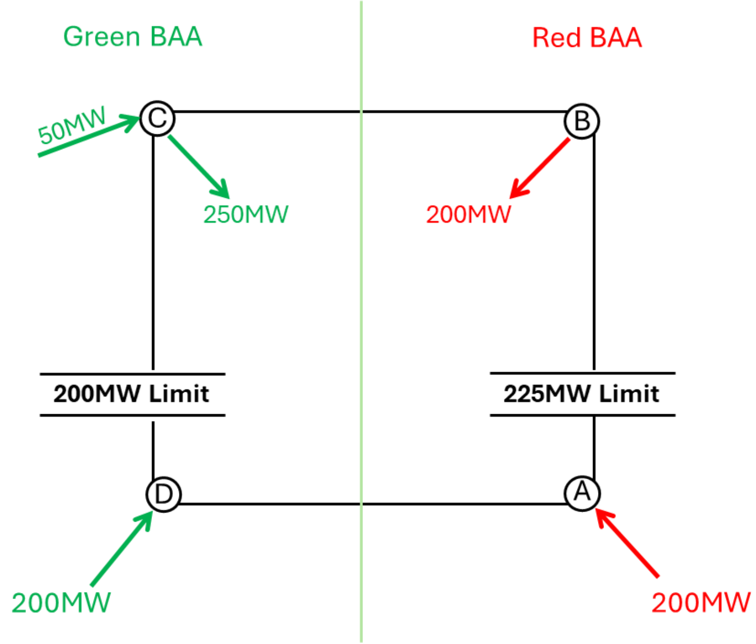
Example 1 – Least Cost Dispatch

Some simple examples have been prepared to illustrate significant features of alternative designs and the impact of parallel flows..

The first example has 4 buses, 4 lines, and all lines have equal reactance and zero resistance to made the flows easy to visualize and understand as the sum of the flows around the grid will sum to zero.

Green BAA has load at C and generation at C and D.

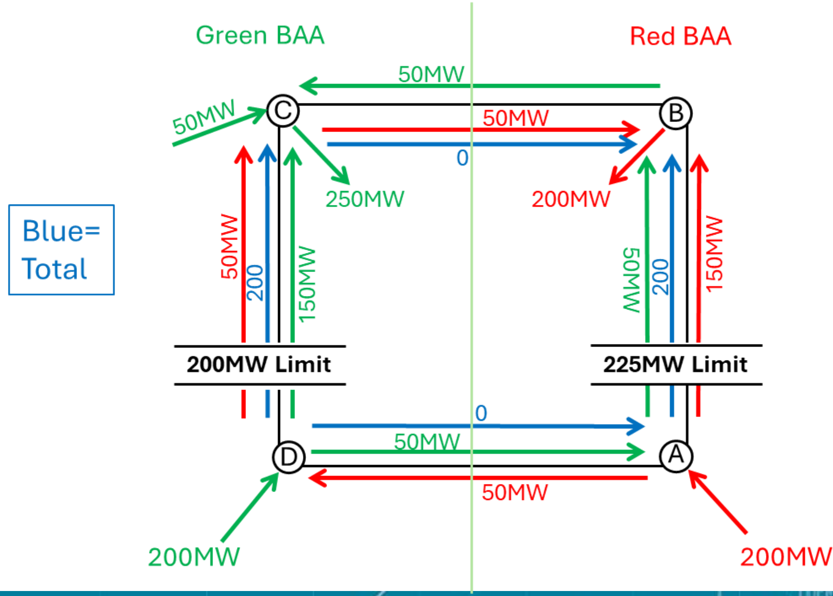
Red BAA has load at B and generation at A



Example 1 Least Cost Dispatch

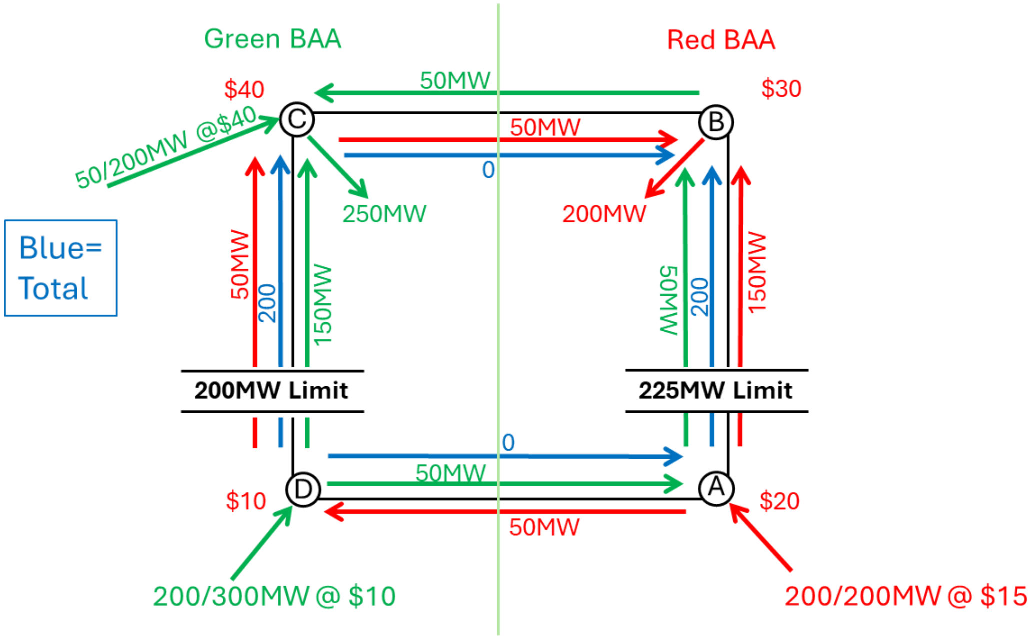
We assume that 300MW generation is offered at D at a price of $10, 200MW at A at a price of $20 and 200MW at C at a price of $40.

- The graphic below shows the least cost security constrained economic dispatch, with a binding constraint on the line D-C.
- 150MW injected at A flows over the line A-B and 50MW flows around on the parallel path.
- 150MW injected at D flows over the line D-C and 50MW flows around on the parallel path. 50MW of power is injected at C and reduces net load at C by 50MW



Example 1 Least Cost Dispatch

The LMP prices are $ 40/MWh at C, $30/MWh at B, $20/MWh at A and $10/MWh at D. The shadow price of the constraint is $40.



1. Raising the limit by 1MW would reduce the cost of meeting load by $40. 1.333 MW could be dispatched up at D and down at C. 1.333MW*$30 cost savings = $40 shadow price.

Example 1 Least Cost Dispatch

There are total congestion rents of $8,000. The total congestion rents can be calculated four ways, all yielding the same result.

Table 1 A Total Congestion Rents
Calculated from Load and Generation settlements

		Net Withdraw	charges
Node A	$20	-200	($4,000)
Node B	$30	200	$6,000
Node C	$40	200	$8,000
Node D	$10	-200	($2,000)
			$8,000

Table 1 B Total Congestion Rents
Calcualted Based on Transactions

path	MW	P diff	charge
D to C	200	30	6000
A to B	200	10	2000
			8000

Table 1 CTotal Congestion Rents
Calculated from Congestion Components

		Net Withdraw	charges
Node A	($20)	-200	$4,000
Node B	($10)	200	($2,000)
Node C	$0	200	$0
Node D	($30)	-200	$6,000
			$8,000

Table 1 DTotal Congestion Rents
Calculated based on flows and shadow price

Flows	SP	payment
200	40	8000

When the four methods do not yield the same result, something is wrong with the math in the example.

Example 1 Least Cost Dispatch

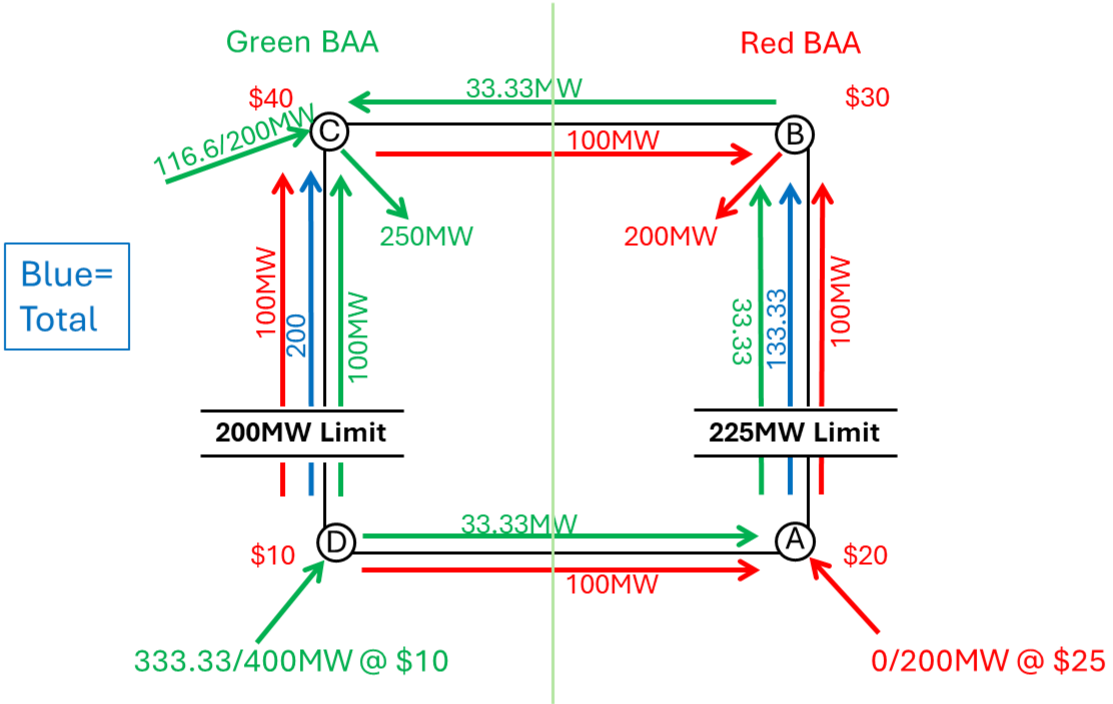
In an LMP market, the total cost of meeting load for Red BAA is the $4000 generation cost at A plus a transmission congestion charge of $10 on 200 MW from A to B for a total cost of $6000.

The total cost of meeting load for Green would be $4000 generation cost at C and D, plus a $30/MW congestion charge on 200MW from D to C for a total cost of $10,000.

The total charges to balancing area loads would be $16,000, but there would be $8000 of congestion rents that could be allocated to reduce the overall cost of meeting load to the production cost of $8000.

Example 2 Self-Scheduling Incentives

Suppose that the cost of generation at A was $25/MWH, rather than $20 as in Example 1. The least cost dispatch would be to dispatch up generation at C to 333.333 MW, generation at D to 111.667, and to dispatch generation at A down to zero.



Example 2 Self-Scheduling Incentives

The price of power at B would still be $30/MWh, so Red BAA would pay $6000 to buy 200MW of power. If Red BAA received $2000 of congestion rent rebates for the congestion charges it would pay on the constraint in Green BAA, its net cost of meeting load would be $4000.

- However, if receipt of the $2000 of congestion rents was contingent on the 200MW of generation at A being dispatched as in the DFP, then Red BAA would not receive any congestion rents when generation at A was not dispatched.
- Red BAA's cost of meeting load would then be $6000.

Example 2 Self-Scheduling Incentives

Hence, Red BAA could meet its load at lower cost if it self-scheduled its generation at A with a cost of $25/MWh, even though the generation was valued at only $20 in the market. This is because self-scheduling would entitle Red BAA to a share of the congestion rents.

- Buying in market at B, no congestion rent rebate = 200 *$30 = $6000
- Self-scheduling generation costing $25/MWh, paying $2000 congestion = $5000 + $2000= $7000 but Red BAA would receive $2000 of congestion rent rebates for a net cost of $5000.

There is no offsetting benefit from generation at A participating in the market dispatch. It is lower cost to self-schedule, participating in the economic dispatch based on actual costs raises the cost of meeting load.

Example 3 Self-Scheduling Incentives part 2

Example 3 assumes Red BAA has a load of 300MW rather than 200MW at B and meets 100MW of this load with generation having a cost of $27/MWh. The cost of generation at A is $25/MWH and is self-scheduled as in Example 2.

- The dispatch would be the same as in Example 2 with the additional 100MW of load at B being met with the 100MW of generation at B.
- The cost of meeting load would be $7700, $5000 as in example 2 for the generation at A and an additional $2700 for the generation at B.

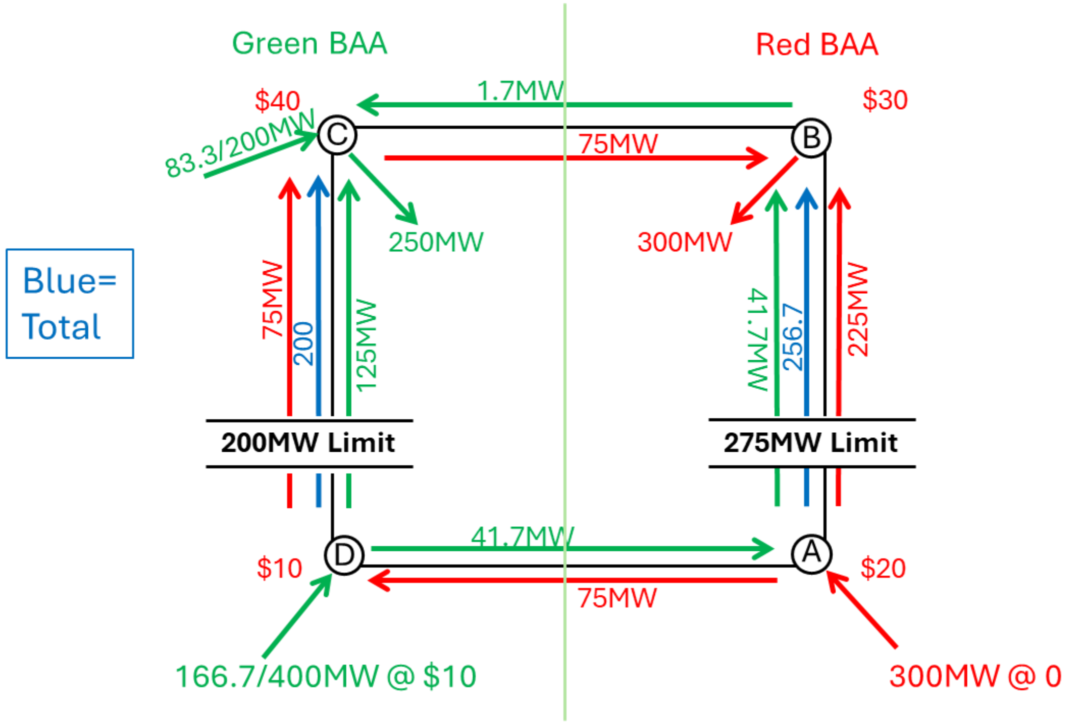
Example 3 Self-Scheduling Incentives part 2

Suppose, however, that dispatching generation at A using either Network Service or point to point rights entitles Red BAA to congestion rents on the flows over D-C.

- It would then be more economic for Red BAA to self-schedule the generation at A to operate at 300MW to meet its entire load at A, than to dispatch its generation at B.
- Increased output at A with a cost of $25 would displace the $27/MW generation at B, so it would be economic for Red BAA if it did not bear any congestion charges.

Example 3 Self-Scheduling Incentives part 2

The higher dispatch of generation at A would increase Red BAA flows over the constrained D to C line, displacing $10MW Green BAA generation at D and replacing it with $40/MWh generation at C. The least cost dispatch would be:



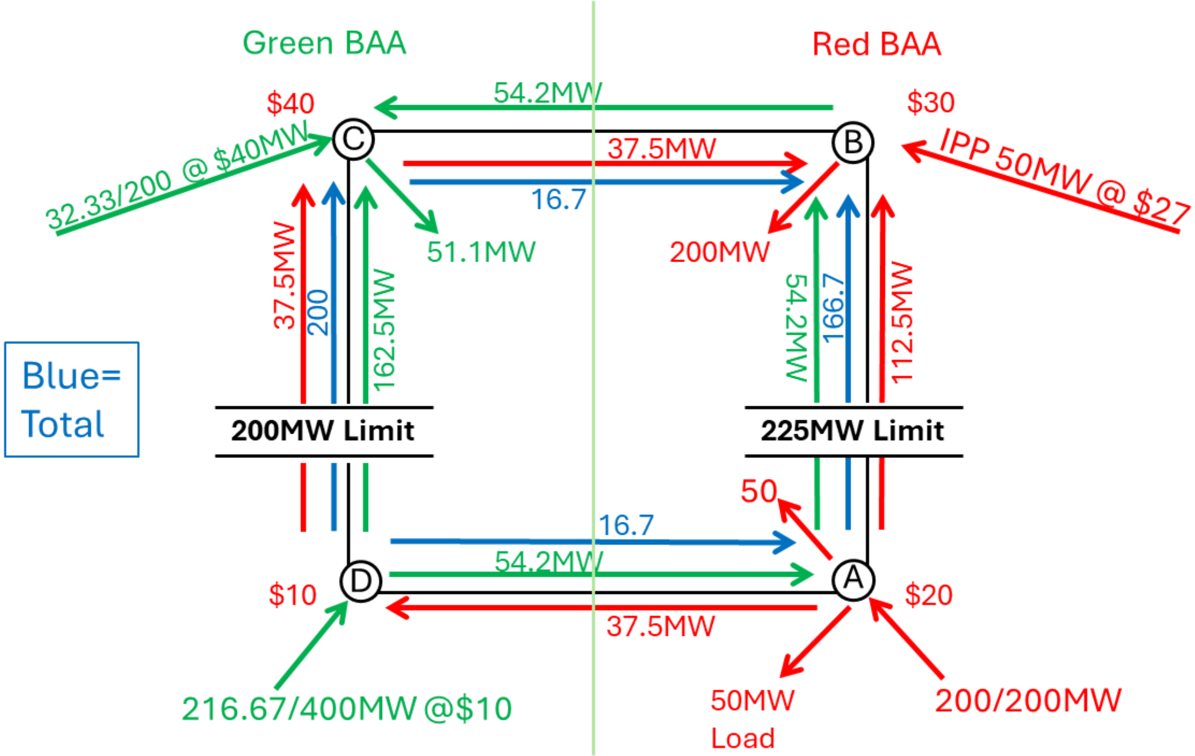
Example 3 Self-Scheduling Incentives part 2

The overall cost of meeting load would rise from $11,700 if the $27/MWh generation at B is dispatched, to $12,500 if the generation at A is self-scheduled at 300MW.

- With the congestion cost impact of the increased dispatch of generation at A borne by Green BAA, the cost of meeting Red BAA load would fall from $7700 (2000*$25 + 100*$27) to $7500 (300*$25).
- The cost of meeting Green BAA load would rise by $1000.

Example 4 Counter Flow

Example 4 assumes there is an IPP located at B which has bought firm transmission to serve a 50MW load at A that was previously served with its own generation at A.



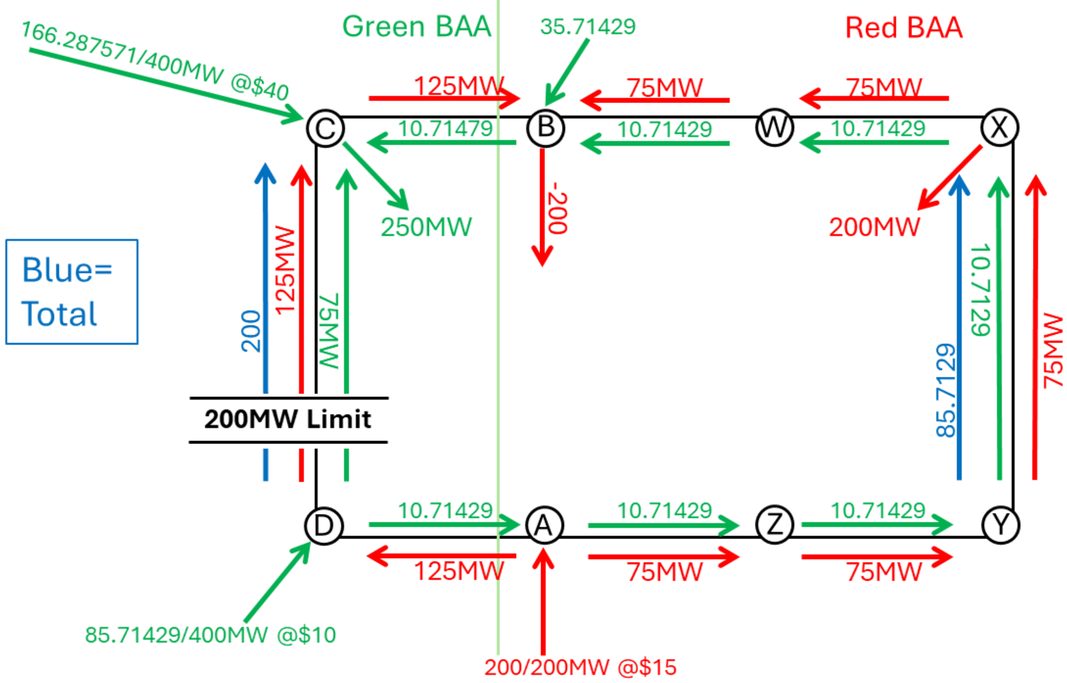
Example 4 Counter Flow

This transaction results in 150MW of net withdrawals at B and 150MW of net injections at A.

- These injections and withdrawals reduce Red BAA's flow over the constraint in BAA Green by 12.5MW, allowing Green BAA to dispatch up low cost generation at D, and reduce the dispatch of higher cost generation at C, reducing its cost of meeting load by $50 (12.5MW * $40 shadow price).
- This $50 benefit is equal to the payment of 50 * ($30-$20) for the B to A counterflow transaction.

Example 5 Weak Contract Path

Examples 1, 2, 3 and 4 assumed the same grid with symmetric flows over lines A to B and D to C. Suppose, however, the contract path from A to B was a very weak high impedance path as shown below. In this case, 62.5% of the power injected at A to meet load at B would flow over the line C-D.



Example 5 Weak Contract Path

Hence, 125 MW of the 200 MW injected at A would flow over line C-D requiring that Green BAA dispatch its low cost generation at C down to 85.71429MW. Hence Green BAA would be able to flow only 75MW over its line C-D, with 10.71429MW flowing on the parallel path.

- In instances with such large parallel flows in the east, the A to B transaction would almost certainly have been curtailed by Green BAA calling a TLR.

Cost and Benefit Shifts

In WEIM, Red BAA's transactions would generally be included in its base schedules.

- No congestion charges would be paid for base schedule flow impacts on the constraint in Green BAA. Congestion charges would be paid for flow impacts of resources dispatched above their base schedule, such as if Generation at B or C were dispatched up in the examples.
- No counter flow payments would be received for counterflow provided by base schedules. Payments would be received for generation dispatched above its base schedule that relieved congestion.

Cost and Benefit Shifts

It is possible that there is some strategic scheduling in WEIM base schedules of high cost resources whose operation at the base schedule output would create congestion, but which could be dispatched down in the FMM and RTD.

- The magnitude of this strategic base scheduling would be constrained by the need to pass the resource sufficiency test.
- However, BAAs would be able to assign base energy schedules to resources that would be dispatched down, designating resources able to meet load while providing counterflow as additional capacity to provide uncertainty reserves or economic dispatch.
- This strategic scheduling would increase the congestion benefits to the EIM entity from the WEIM base schedule and enable the WEIM entity to be paid for counterflow. We have no assessment of the extent to which this might be occurring in WEIM.

Cost and Benefit Shifts

The current EDAM tariff is different from WEIM, it would charge for all parallel flow congestion and would pay for counterflow in the day-ahead market.

- There would be no inefficient self-scheduling incentives under the current EDAM tariff and BAAs would be incented to offer resources able to provide counterflow in the market.
- However, the current EDAM tariff does not provide any hedge for congestion charges on parallel flows attributable to firm transmission schedules.
- The current EDAM tariff would be less favorable than WEIM to firm transmission customers whose transactions contribute to congestion and more favorable to firm transmission customers whose transactions provide counterflow.

Cost and Benefit Shifts

The DFP proposal would not charge for parallel flow congestion associated with the use of firm transmission rights.

- Our understanding is that there would be no MW cap on the level of unpriced parallel flows due to firm transmission schedules.
- Our understanding is that the DFP proposal would pay the LMP price for all counterflow in the day-ahead market whether associated with firm transmission schedules or not. By this it is meant that the counterflow transaction would be charged Price at sink – Price at source for the transaction, which would be a negative number for a counterflow transaction.
  - There have been comments about assigning the cost of counterflow that enables the scheduling of firm transmission to the BAA with the impacted constraint.
  - It is not clear that any special settlement is needed, the counterflow would simply be priced in the market. In the counterflow would enable more flows over the constraint with Green BAA collecting the congestion rents.

Cost and Benefit Shifts

In example 4 we saw that the counterflow would enable more flows over the constraint with Green BAA collecting the congestion rents.

- These additional flows would pay for the counterflow with their congestion charges.
- These additional flows were created by the dispatch of additional generation at D in the example. However, on the EDAM grid they could be created by the market dispatch as well.

There is no need for special cost allocation rules, the only change is to set the negative congestion credit for the firm transmission providing counterflow to zero.

Self-Scheduling

Overall, a congestion rebate design based on schedules, such as the DFP, would incent Red BAA to uneconomically self-schedule generation at A (examples 2 and 3).

- The DFP would also pay for counterflow that relieves the congestion (example 4).
- In example 4, the transmission schedule from B to A was paid the difference in prices in the market settlements, while the transmission schedule from A to B was not charged.

Self-Scheduling

Our understanding is that with the DFP congestion rebate design, the flow impact on the constraint in Green BAA would be calculated for overall Red BAA firm transmission flows which would include all firm point to point flows and flows using firm network service.

- In that case, if the counterflow and prevailing transactions in example 4 were both Red BAA transactions, there would be no payment for the counterflow.
- Red BAA would only be rebated the congestion charge on 150MW of net flows on the constraint.
- If the generation at B were owned by Red BAA, it would be incented to offer that generation at much higher price to cover the loss of congestion payments if it were dispatched.

Self-Scheduling

If the generation at B was not owned by Rec BAA, it would be offered and dispatched economically.

- In that case, with it dispatced Red BAA would collect congestion charges for the net 150MW of flows over the constraint on line D-C, which would not be enough to pay the congestion charges of the firm transmission customers.
- These incentives arising from the aggregation of BAA prevailing flows and counterflow appear problematic and hard to address in the DFP design.

Self-Scheduling

In example 4, Green's congestion rent collections were reduced by the Red BAA prevailing flows over the line D-C.

- Green's congestion rent collections would be increased by the counterflow schedule in Example 4 to the extent that the counterflow enabled Green BAA to dispatch more of its low cost generation at D to meet load at C.
- If the firm transmission schedules that do not pay congestion are self-scheduled, the impact of counterflow will always be to increase market flows on the constraint. The market flows would pay congestion charges.

Self-Scheduling

The DFP congestion settlement design will incent self-scheduling of resources in EDAM. This could result in EDAM schedules that are not the least cost dispatch.

- We illustrated in examples 2 and 3 how it could be economic for Red BAA to self-schedule generation in EDAM at A to meet its load at B under a design that assigned congestion rents based on firm transmission scheduled flows, even though Red BAA's load could be met at lower overall cost by purchasing power in the EDAM market.
- Another feature of the DFP design is that there is no cap on the level of unpriced parallel flows which could be increased by transmission outages or changes in sources and sinks.

Self-Scheduling

The current EDAM design would not require that resources self-scheduled in EDAM also be self-scheduled in real-time.

- Hence, resources that were uneconomically scheduled in EDAM, could be bid into the real-time dispatch at their actual cost and dispatched down in real-time.
- In the example, if Red BAA self-scheduled its high cost generation at A in the EDAM market, it could offer that generation into the real-time dispatch at its actual cost $25, enabling the resource to be dispatched down in real-time. However, resources that would be uneconomic in meeting Red BAA's load could also be offered with the expectation that they would be dispatched down in real time, such as generation at A with a cost of $35.
- This real-time dispatch flexibility would maintain the efficiency and reliability of the real-time market.

Self-Scheduling

However, the DFP design could incent scheduling of phantom generation (such as overstated intermittent output) in order to realize the congestion rebate value of firm transmission rights.

- The adverse reliability impacts of such phantom schedules might be limited by rules elating to the EDAM resource sufficiency evaluation, but the incentives are not good.
- It appears that these incentives would be avoided if real-time imbalances for firm transmission output that did not pay for congestion in EDAM, and does not flow In real-time, were settled at price at the sink of the firm transmission service, rather than at the source.

Self-Scheduling

Even if the DFP design does not incent scheduling of phantom generation in EDAM, if BAAs self-schedule uneconomic resources in the EDAM in order to receive congestion rebates, the EDAM unit commitment will likely not be least cost.

- In the example, for instance, generation at D needed to enable the generation at A to be dispatched down might not be committed in EDAM.
- If this generation had notification and gas scheduling time lines or minimum run times longer than the RTPD look-ahead, it might not be available in real-time and the higher cost generation at A would need to be dispatched in real-time.

Self-Scheduling

This would not be worse than the outcomes under WEIM. WEIM market participants have a similar incentive to include high cost resources whose base schedule creates flows on lines expected to be congested in their base schedules because the WEIM entity would not pay congestion created by its base schedules and the resources could be dispatched down in the WEIM FMM and RTD.

- However, part of the EDAM benefits analysis likely includes a more efficient unit commitment across EDAM than occurs in WEIM today.
- Those benefits might not be realized under the DFP congestion allocation design.

Self-Scheduling

We understand that the CAISO is considering a rule that would require that generation self-scheduled in EDAM to be self-scheduled in real-time.

- While such a restriction might reduce the benefits from self-scheduling high cost resources, it could lock in the dispatch of the high cost resource in real-time and adversely impact real-time dispatch flexibility and reliability.

- PJM during the summer of 1997 is an example of a situation in which rampant self-scheduling incented by congestion pricing required that PJM resort to command and control to maintain reliability.

DFP design

The DFP design as we currently understand it, has a number of troubling incentives relating to:

- Self-scheduling incented by use-it-or-lose-it settlements of parallel flow congestion charges;
- Potential incentive to schedule phantom generation or uneconomic generation in order to create flows on binding constraints in adjacent balancing areas in EDAM and receive rebates;
- Netting of counterflow and prevailing flows on parallel flow constraints across a BAA, combined with use-it-or-lose-it settlements.

Alternatives

The EDAM congestion rent design could avoid creating self-scheduling incentives while providing a degree of congestion hedge with a number of alternatives including:

- CRR obligations
- CRR options
- Financial flow entitlements

Alternatives

Financial flow entitlements could be similar to the firm flow entitlements defined between PJM and MISO.

- They would need to be defined as financial entitlements to avoid use-it-or-lose-it incentives if they were assigned to particular market participants.
- MISO and PJM firm flow entitlements benefit the overall market congestion rent charges, all transactions pay the congestion charge on market to market constraints, so there are no use-it-or-lose-it incentives.
- MW amounts of financial flow entitlements could be assigned to BAAs on specific constraints and reassigned by the BAA to particular transmission customers. They would be defined as a financial entitlement to the congestion charge on the constraint times a fixed MW amount
- Such a design would avoid use-it-or-lose-it incentives and cap the unpriced flows as the flow entitlement would not increase with outages and it could be reduced in settlements if the transmission element was derated.

Appendices

The first appendix provides more detail on the issues with self-scheduling in PJM during the summer of 1997.

The remaining appendix tables show that the equivalence among ways of calculating congestion rents shown for example 1 also exists for examples 2, 3, 4, and 5.

PJM 1997

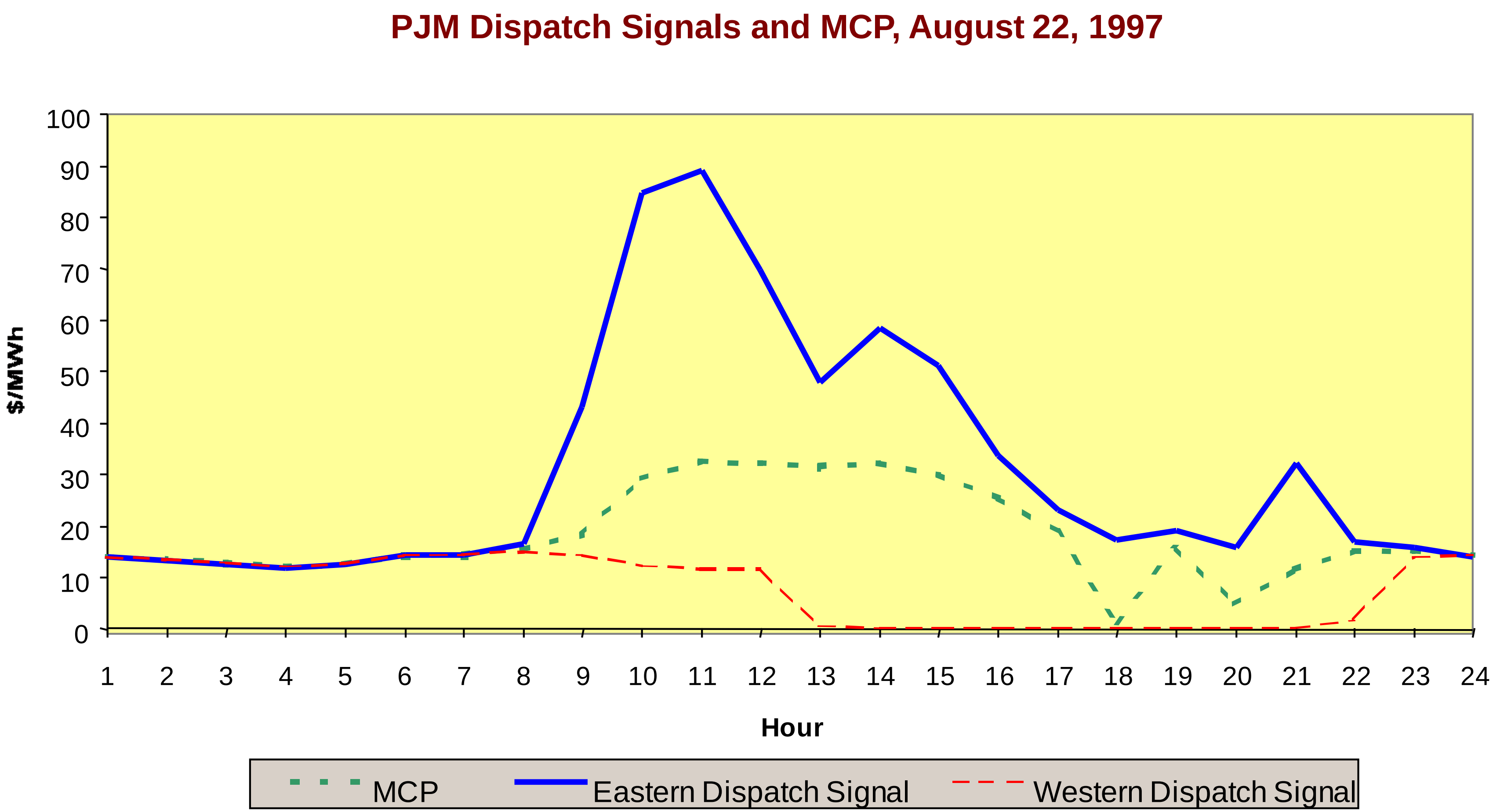
The use-it-or-lose-it incentives created by physical transmission rights gradually undermined the incentive of utilities to participate in the pool wide economic dispatch of the New York Power Pool and PJM during the 1990's.

- The inconsistency between economic dispatch and use-it-or-lose-it physical rights contributed to the breakdown of Enron's MCP pricing system in PJM during the summer of 1997.
- PJM initially addressed self-scheduling using non-firm transmission with its filing in ER97-3463-000, June 27, 1997. This filing, made at 4;59 pm on Friday, gave FERC until 4:59 pm on Saturday June 28, 1997 to say no.

PJM 1997

The June 28, 1997 tariff charges provided only a temporary respite for PJM.

- The PJM Western dispatch signal fell to zero on August 22 because LSEs had learned to use secondary service to bypass the dispatch when transmission congestion existed.
- Network transmission service was in effect “use-it- or-lose-it” and market participants could realize its value only if they ignored the dispatch signal and self-scheduled.
- Once all market participants had learned how to operate under the new system, it broke down and required that PJM use non-price criteria to ration grid use, completely abandoning economic dispatch and preventing market-based trading.


PJM Dispatch Signals and MCP, August 22, 1997
$/MWh
100
90
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
MCP
Eastern Dispatch Signal
Western Dispatch Signal

PJM 1997

PJM's MCP pricing system and physical rights required that PJM declare a minimum generation emergency during the daily peak on August 22, 1997.

Approximately 11:00 PJM had dispatched all units in Central and Western PJM down to their economic minimum cost. No further units remained in the central or west to control the transfer limit. Additional generation in the East was still required. No generation in the central or west had been scheduled by PJM. All generation operating in these areas was self-scheduled by the owning company.

At 11:21 PJM issues a minimum generation declaration for western and central PJM.

At 11:21-11:30 PJM pooled all companies effected by the minimum generation declaration to determine if any generation changes were anticipated. No generation changes were reported.

At 11:30 PJM started curtailing spot market transactions from the west that were bid in at a price of zero. Approximately 1200 MW of energy was bid in at zero. Curtailments were made based on the timestamp of when the bids were received. The initial curtailment was for 574 MW to start at 11:45.

-- System Operations Overview, August 22, 1997

Appendices

Example 2

Table 2A Total Congestion Rents			
Calculated from Load and Generation settlements			
		Net Withdraw	charges
Node A	$20	0	$0
Node B	$30	200	$6,000
Node C	$40	133.33	$5,333
Node D	$10	-333.333	($3,333)
			$8,000

Table 2B Total Congestion Rents			
Calcualted Based on Transactions			
path	MW	P diff	charge
D to C	133.333	30	3999.99
C to B	200	20	4000
			7999.99

Table 2C Total Congestion Rents			
Calculated from Congestion Components			
		Net Withdraw	charges
Node A	($20)	0	$0
Node B	($10)	200	($2,000)
Node C	$0	133.33	$0
Node D	($30)	-333.333	$10,000
			$8,000

table 2D Total Congestion Rents		
Calculated based on flows and shadow price		
Flows	SP	payment
200	40	8000

Appendices

Example 3

Table 3 A Total Congestion Rents			
Calculated from Load and Generation settlements			
		Net Withdraw	charges
Node A	$20	-300	($6,000)
Node B	$30	300	$9,000
Node C	$40	166.66	$6,666
Node D	$10	-166.666	($1,667)
			$8,000

Table 3 B Total Congestion Rents			
Calculalted Based on Transactions			
path	MW	P diff	charge
D to C	166.6666	30	5000.00
A to B	300	10	3000.00
			8000.00

Table 3 CTotal Congestion Rents			
Calculated from Congestion Components			
		Net Withdraw	charges
Node A	($20)	-300	$6,000
Node B	($10)	300	($3,000)
Node C	$0	166.66	$0
Node D	($30)	-166.666	$5,000
			$8,000

Table 3 DTotal Congestion Rents		
Calculated based on flows and shadow pric		
Flows	SP	payment
200	40	8000

Appendices

Example 4

Total Congestion Rents
Calculated from Load and Generation settlements

		Net Withdraw	charges
Node A	$20	-150	($3,000)
Node B	$30	150	$4,500
Node C	$10	-216.667	($2,167)
Node D	$40	216.6666	$8,667
			$8,000

Total Congestion Rents
Calcualted Based on Transactions

path	MW	P diff	charge
C to D	216.6666	30	6499.998
A to B	150	10	1500
			8000.00

Total Congestion Rents
Calculated from Congestion Components

		Net Withdraw	charges
Node A	($20)	-150	$3,000
Node B	($10)	150	($1,500)
Node C	($30)	-216.667	$6,500
Node D	$0	216.6666	$0
			$8,000

Total Congestion Rents
Calculated based on flows and shadow price

Flows	SP	payment
200	40	8000