Appendix 3:

Congestion Management: LMP/Financial Rights Model

Southeast RTO Mediation Process

EXECUTIVE SUMMARY

The congestion management model outlined in this paper is based largely but not wholly on the locational marginal pricing/financial congestion hedge (LMP/FCH) model that emerged from the SPP stakeholder process. A stakeholder process in this region is needed to develop the details of the model further.

KEY FEATURES OF LMP/FINANCIAL RIGHTS MODEL

- The RTO will operate a regional real-time and day-ahead energy market.[1] Through the use of voluntary bids into this market, the RTO will minimize the cost of balancing energy across the region and will make maximum use of the grid (*i.e.* congestion management) while keeping flows within all security limits.

- Prices in these markets will be visible to all. They will be based on the locational marginal price of energy at each location and reflect the impacts of congestion. LMPs will be used for energy market transactions and for congestion charges applicable to transmission schedules.

- Prices used in energy market settlement will be nodal for generation and zonal for loads. Nodal pricing for loads will be available also.

- The RTO will issue a set of financial rights, referred to as financial congestion hedges (FCHs), to allow transmission customers to hedge against congestion charges. To the extent practicable the FCHs will be offered in a choice of configurations to meet the needs of market participants.

- The FCHs will be allocated to firm customers, at least initially. Additional FCHs will be auctioned by the RTO. The RTO will also conduct monthly auctions to facilitate a secondary market in FCHs. There should be provisions for mandatory, non-discriminatory release of FCHs in retail access jurisdictions.

- There will be an installed capacity requirement applicable to all load-serving entities. The requirement should be designed to promote the efficiency of generation supply and should recognize differences in performance among supply sources.

- As a part of the capacity requirement, loads will be required to make capacity resources available to the RTO day-ahead, either through bilateral scheduling and/or through bidding, matching the level of their forecasted needs for the next day. This is called a "balanced resource" requirement. Apart from this requirement, bidding by generators into the market will be voluntary. No generation owner will be required to make resources available to the RTO beyond what it has obligated itself to do via

[1] The day-ahead market will be put in place as soon as practicable.

contracting with load to supply capacity resources.[2] Customers will be free to self-schedule resources.

- The RTO will coordinate a day ahead scheduling process that ensures sufficient capacity and reserves are committed or available to meet the projected load for the next day. The cost of day-ahead capacity commitments will be allocated where possible to the cost-causative customers (meaning those who have not submitted bilateral schedules or purchased spot energy day-ahead sufficient to cover their actual loads.)[3]

- The RTO will ultimately operate markets for operating reserves and regulation that are integrated with the real-time energy market.

ADVANTAGES OF THE LMP/FINANCIAL RIGHTS MODEL

- **Efficiency:** The model allows for maximum commercial use of the transmission grid consistent with the requirement to maintain a reliable electricity system. It manages congestion efficiently and results in a least-cost dispatch of generating resources. To the fullest extent possible the model assigns congestion costs to the cost-causative customer.

- **Reliability:** The installed capacity obligation for LSEs and a balanced resource requirement in the day ahead market are intended to ensure that reliability is maintained.

- **Transparency**: Congestion is managed through a market-based process rather than an administrative process, using visible spot market prices. Actions taken by the RTO with respect to dispatch and congestion management will be transparent and auditable.

- **Flexibility**: The model provides flexibility for market participants by allowing equally for bilateral and spot purchases of energy as well as self-scheduling of generation. The financial rights issued by the RTO will give customers great flexibility to hedge congestion charges and manage their delivery price risk.

- **Feasibility:** The model can be implemented across multiple control areas. The core of this model, LMP and financial rights, is a proven design that has been in operation for several years in other locations. Software to implement key parts of this market design is commercially available today.

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[2] There may be separate requirements to supply ancillary services that are contained in generation interconnection agreements.
[3] A provision will be developed to address gaming activity such as chronic underforecasting or otherwise leaning on the market.

- **<u>Consistency with Emerging Standard Market Design:</u>** A financial rights model is used by PJM and a financial rights model has been endorsed by SPP and MISO stakeholder groups. Use of a consistent market design across neighboring regions will facilitate seams agreements and inter-regional transactions, to the benefit of SPG (Southeast Power Grid RTO) customers.

REPORT ON LMP/FCH MODEL

1. INTRODUCTION

This appendix provides an overview of the LMP/FCH market design, then describes some important technical details of the model . The organization of this appendix is as follows:

2. OVERVIEW OF MARKET DESIGN

The LMP/FCH market design is based on an RTO-wide energy market. Initially there will be a real-time market and a day-ahead market will be implemented as soon as practicable. In these markets, voluntary bids are used by the RTO to provide least-cost balancing energy and to manage congestion across the system. The resulting dispatch yields a set of market-clearing prices for energy market transactions and for transmission congestion charges. The market-clearing prices are calculated on a locational basis; during periods of congestion the prices will reflect the differences in the value of energy at different points on the grid.[4]

Parties that buy and sell in these LMP energy markets will "see" the impact of congestion in the locational prices in that market. Parties that schedule bilaterally, rather than buy and sell in the energy market, will be charged separately for congestion, and the congestion charges will reflect the impact of their transactions on the grid. Conversely, parties that implement schedules that provides "counter-flow," and thus lower the marginal cost of redispatch, will be compensated for the value of that counter-flow by receiving a congestion credit rather than a congestion charge.

The RTO-coordinated market is voluntary. Parties that do not wish to be subject to the RTO's dispatch can schedule their own generation (and they can also submit bids that indicate the price at which they would prefer that generation to be dispatched up or down). On the other hand, self scheduling in not required, although there is a balanced resource requirement for all load-serving entities (described further below.) Parties are free to buy and sell as much as they choose in the

[4] To implement a model like this in an area such as the Southeast, with many control areas, requires a transition from local control area dispatch authority to a regional dispatch that is controlled by the RTO. A hierarchical approach in which the RTO coordinates the dispatch through existing local control areas is described in Part 4 of this paper.

RTO's day-ahead energy market, with generators voluntarily offering their day-ahead energy market, with generators uncontracted output into the market, and loads and retailers meeting their non-self-scheduled demand through energy market purchases.

Thus the Thus the mix between bilateral schedules and energy market transactions is left up to the market. Charges to customers are settled using the same set of market prices, regardless of whether the customer submitted a bilateral schedule or transacted in the energy market. The model is financially neutral between bilateral and energy market transactions. The mix between short-term and long-term contracts is also left up to the market. However, the existence of the short-term energy market facilitates long-term contracting, by providing visible spot prices that parties can use as reference prices for forward contracts. The visible prices can also serve as a basis for calculating liquidated damages when either party to a contract fails to perform as expected.

There are several features which ensure that the RTO has sufficient resources to support the energy market. First, there is a capacity requirement on all load-serving entities, which translates into a day-ahead "balanced resource" requirement, in that load serving entities are required to make resources available to the RTO day-ahead sufficient to meet their forecast load obligation, even if they do not self-schedule energy from them. They may also offer additional resources to the RTO on a voluntary basis. In turn, the RTO will perform a day-ahead security assessment to ensure sufficient resources are actually committed or available on short notice to meet forecasted requirements for energy and reserves. These features are discussed in more detail in the next section of this paper.

A final feature of this model involves financial rights and so-called "excess congestion rents." The term "excess" is potentially misleading. If there is congestion, the economic value of power varies across the grid. This is an economic fact of life. An LMP model will reflect those value differentials. And this will result, during periods of congestion, in the RTO collecting more revenues from customers than is paid to generators. In other words, if loads are charged the value of power at their location, and generators are paid the value at their locations, the RTO will collect more than it pays out. This "congestion rent" is by design; it is not an unintended consequence of the model.

In economic terms, the differential between what is collected from load and what is paid to generators is the value of transmission during that period. Under the LMP/FCH model, this money is paid to the holders of financial rights. There is no "overcollection problem" under an LMP/FCH model; the model is precisely designed to send different price signals to load and generation and to pay the difference to holders of financial rights. The total amount collected from customers and paid to generators and rightsholders will net to zero, so long as there are no transmission outages. (Part 6 of this paper discusses policy choices regarding treatment of financial rights in the event of transmission outages.)

By holding financial rights, customers can hedge congestion charges. That is why they are called FCHs (financial congestion hedges.) The FCHs benefit customers by allowing participants to manage the price uncertainty arising from a locational pricing model. Because the rights are "financial," they do not affect the RTO's dispatch activities. The financial nature of the FCHs can be expressed in different ways:

- The rights entitle the holder to a monetary credit in the RTO settlements; they do not guarantee physical access to the grid.
- Parties are not required to acquire or hold FCHs as a condition for scheduling or gaining grid access.
- Parties are not required to match their FCHs to their schedule, or to match their schedules to their FCHs.
- Parties can use FCHs to hedge their exposure to congestion arising from transactions in the RTO's real-time energy market.
- Parties are free to bid or not into the RTO's energy markets, whether or not they hold FCHs, and the dispatch selected by the RTO will not be affected by the FCHs they hold.
- In the RTO settlements, parties receive the market value of the FCHs they hold, whether or not they implement a matching schedule.
- FCHs allow a party to offset the impact of congestion on prices at any location.

Thus, by nature, FCHs provide great flexibility for customers and allow the RTO to find the most efficient balancing and congestion management solutions without respect to who holds what right. There are many issues associated with FCH design and distribution; these are discussed in Part 6 below.

3. DAY AHEAD SCHEDULING AND ENERGY MARKET

The competitive wholesale electricity market in the Southeast Region operates on many different time frames. Buyers and sellers develop a portfolio of bilateral contracts to manage their risk over periods ranging from hours to years. As real time nears, these entities need a process to schedule their resources to meet their load and contractual obligations. Likewise, the RTO needs an orderly process that allows all transmission customers to submit their resource schedules and allows the RTO to evaluate the overall security of the entire system. This section describes the day ahead scheduling process to accommodate the needs of both the users of the transmission system and the RTO.[5]

[5] Many of the RTO system operation functions discussed in this paper will be administered by the Independent Market Administrator, which is part of the RTO construct.

DAY-AHEAD SCHEDULING

The day ahead scheduling process consists of the following major activities:

- Participants submit their plans for the next operating day. These plans include their generation self-schedules, load forecasts, scheduled transactions between control areas, and voluntary offer prices. [6] Participants also identify the resources they have self-scheduled to meet their ancillary service obligations.

- Participants submit offer prices for their resources. Offers must be submitted for cCapacity rResources (resources identified by load-serving participants for the purpose of meeting their capacity obligation) in sufficient quantity to to satisfy the load's balanced resource requirement. Additional offers may be submitted, but are not required. Offers for units that are not otherwise committed can be in the form of multi-part bids (start-up costs, minimum load generation costs, incremental energy bid).

- The RTO performs a reliability and security assessment to ensure sufficient capacity is available to meet both the load forecast and operating reserve requirements. As part of this process, the RTO also schedules any additional capacity required for ancillary services in its role as provider of last resort, after taking into account the ancillary services self-scheduled by participants.

While time has not permitted all the necessary details to be worked out, the day-ahead assessment and supplemental unit commitment can be summarized as follows.

- The RTO will compare the capacity scheduled by the market participants to the region's capacity requirements, namely the load forecast and reserve requirements. There may be circumstances where the RTO identifies a potential capacity shortfall day-ahead.

- If the RTO identifies a potential capacity shortfall, the RTO may schedule additional capacity to meet the projected shortfall. In doing so, the RTO will use the bid information submitted by participants to find the lowest cost resources (which could be generation willing to be committed, or load willing to decrease its consumption), in the proper locations, to eliminate the potential deficiency. The cost of day-ahead capacity commitments will be allocated where possible to the cost-causative customers (meaning those who have not submitted bilateral schedules or purchased spot energy day-ahead sufficient to cover their actual loads.) Provisions to prevent gaming will be developed, to be triggered in the event that this cost allocation mechanism proves insufficient to deter loads from underforecasting or otherwise leaning unfairly on the market.

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[6] Schedules must indicate a source and sink. However, the sink may be a node, a zone (eg control area) or a hub. It does not have to be a specified load sink.

- The RTO will ensure that resources committed by the RTO will recover at least their bid-in costs over the course of the day.

There are a number of detailed rules required to implement this procedure and ensure the costs associated with scheduling this capacity are allocated fairly. Such details must be worked out through a stakeholder process. At a minimum, however, the process should ensure that the RTO has access to sufficient capacity to meet its projected load and reserve requirements the following day.

4. OPERATIONS OF REAL-TIME BALANCING MARKET

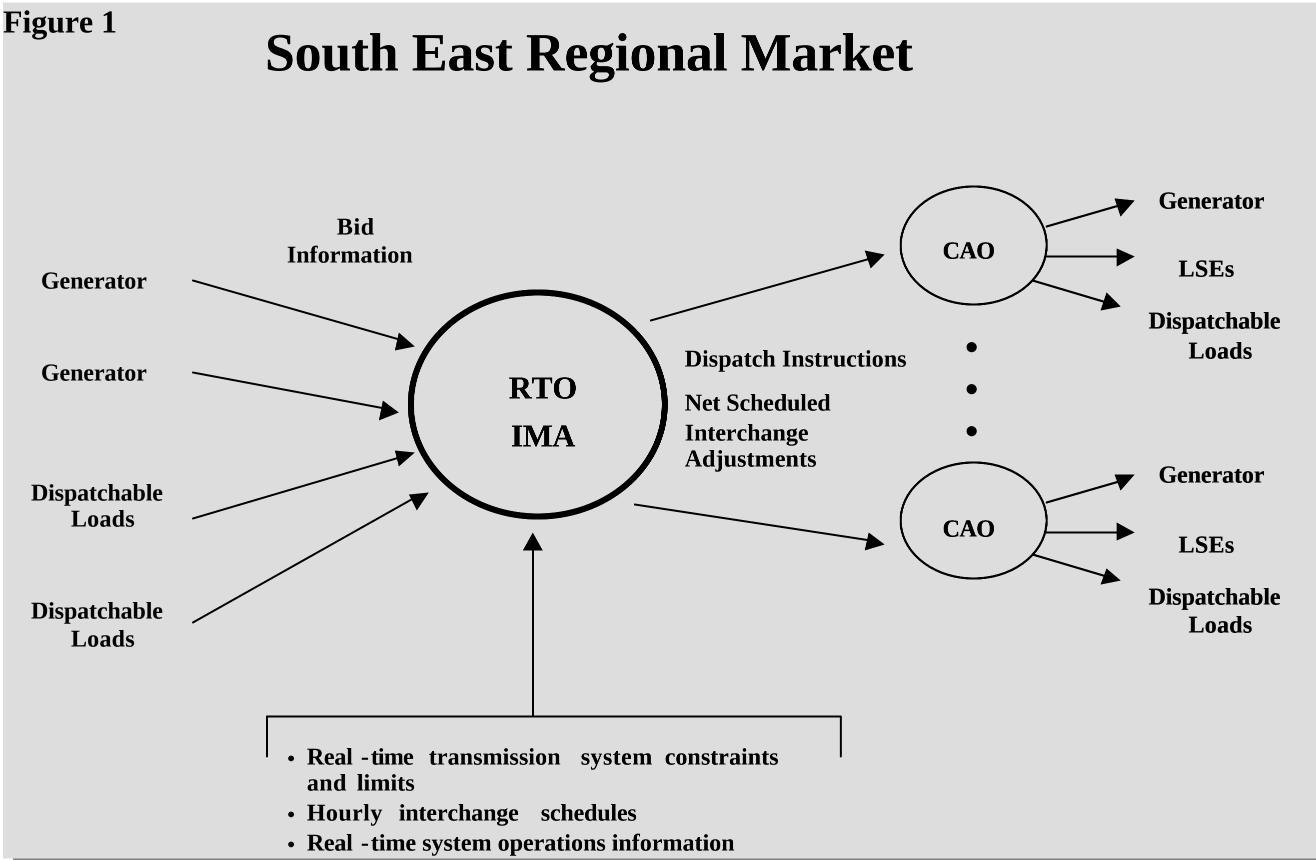
Once the day-ahead process is complete, the RTO must coordinate the real-time balancing market. The RTO will implement a common real-time balancing market across the entire region, which encompasses all control areas within the region. Figure 1 provides a simplified illustration of this process.

The major features of this market are as follows:

- There is a common set of market rules that govern the balancing market operations across the entire region.
- The RTO operates the regional balancing market through a hierarchical dispatch mechanism as depicted in Figure 1.
- The inputs to the RTO include bids from generators and loads that can provide balancing or ancillary services, real-time system information, interchange schedules, and the transmission system security limits. Communication may be directly between the RTO and the generators, or through existing control area operators (CAOs), depending on communications capability.[7]

[7] Regardless of the communication method, the RTO will supply control area operators with all the information they need in order to perform their control area functions reliably. This is discussed further in the Operating Protocol.

Figure 1



- The RTO will run a Security Constrained Economic Dispatch (SCED) computer program to manage both balancing and congestion management throughout the region. This algorithm combines the features of both an economic dispatch and security analysis tool. The SCED program will have least cost dispatch as its objective function and will minimize the incremental cost at each node based upon the units participating in the RTO dispatch.

- The output of the SCED process is a set of desired dispatch points (called "recommended setpoints") for all generators available to the RTO for real time dispatch. These dispatch points are communicated to the CAOs and ultimately to the generation and dispatchable loads participating in the real time market.

- The RTO will recalculate the net scheduled interchange between the Control Areas in the region every (X) minutes[8] for use in managing the Area Control Error. The net interchange schedule will be based upon the dispatch signals generated by the SCED program and hourly interchange schedules submitted by market participants. These adjustments, which are taking place within an hour, will be used in situations where generators in one control area can be increased or decreased to meet the balancing or congestion management needs in other control areas within the region.

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[8] It is We aanticipated that this will be on the order of every 5-10 minutes depending on technical implementation requirements.

- The individual control areas will continue to manage the Area Control Error and be subject to NERC control performance and disturbance standards. Accordingly, each control area will be responsible for managing regulation service and sending out control signals for regulation to units on Automatic Generation Control (AGC). At some point it is expected that the RTO willdevelop a market for regulation services, which will supercede this protocol.

5. LOCATIONAL MARGINAL PRICES

CHARACTERISTICS OF LOCATIONAL PRICES

The calculation of locational prices, whether day-ahead or real-time, will be based on the results of the actual dispatch process. The following points describe some of the main characteristics of these prices:

- The LMP at a node is the incremental cost to the system to serve one increment of load at that node. The LMP at a given location incorporates the bid price of the marginal generator and the impact on congestion across the system of serving the increment of load from the marginal generator. [9]

- The LMP at a location is not necessarily equal to the offer of any single generator. Nor is it the offer of the last generator dispatched in a "zone."

- The LMP can differ between two buses even if a line between them is not at a limit.

- A generator's offer will generally set the LMP at its location when the generator's capacity segment is only partially dispatched (unless it is at its minimum, or being held down to provide regulation, spinning reserves, or to serve must run requirements).

- If a generator capacity segment is fully dispatched by the RTO, the LMP that it is paid will be determined by the bids of other generators and will be greater than or equal to the generator's energy bid for that capacity segment.

- If a generator capacity segment is not dispatched, the LMP at its bus will be less than its energy offer. In other words, there is a cheaper way to serve load at the generator's bus than accepting its energy offer.

[9] LMPs will not include marginal losses at this time. Currently, marginal losses are included in LMP calculations in NY but not in PJM.

- Generators will be settled at their respective nodal LMPs, while loads will have the option of nodal or zonal pricing. The RTO will charge bilateral schedules for any congestion between the points of injection and withdrawal.

- The LMP program will calculate the nodal prices for all locations, regardless of whether there is actual load at that location. Hub and zonal prices will also be calculated and posted on the RTO website. Hub and zonal prices will be based on load-weighted nodal prices.

STANDARD TOOLS USED TO CALCULATION LOCATIONAL PRICES

There are a number of standard industry tools that the RTO will use to calculate the locational prices. The tools needed to accomplish this process are depicted in Figure 2 and are listed below:

- State Estimator
- LMP Preprocessor
- LMP Contingency Processor
- LMP Processor

Locational Marginal Pricing Model

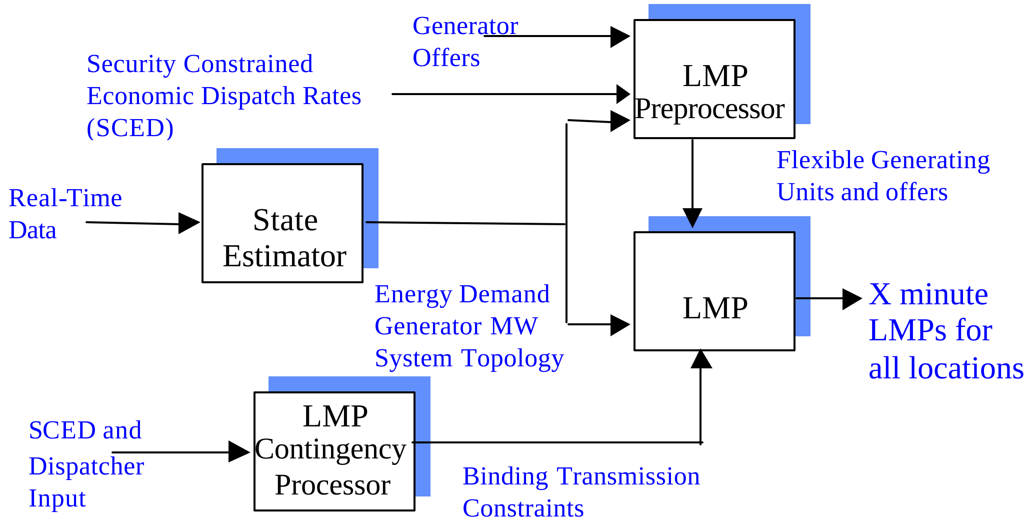

Figure 2: Locational Marginal Pricing Model

USE OF STATE ESTIMATOR

The State Estimator is a standard power systems operations tool that is designed to provide a model of the conditions that currently exist on a power system based upon metered input and an underlying mathematical model. State Estimator programs are widely used in the industry to provide a complete and consistent view of conditions on both the observable and unobservable portions of the electrical network. In LMP models, the output of the State Estimator is used in both the SCED program as well as in the computation of LMPs.

State Estimator programs are useful in filling in the blanks where complete nodal metering is not available. Meters are not required at every node in order to implement an LMP system. The use of a State Estimator allows LMPs to be calculated for points on the system where meters do not currently exist.[10] The State Estimator can correct bad data and calculate missing data in the model. However, the RTO will need to ensure the current number of observable points on the system are sufficient for the State Estimator program to provide the accuracy needed in developing nodal pricing as well as load-weights for zonal pricing.

[10] To illustrate this point, PJM does not have metering at every location for which it calculates a locational price.

HOW LOCATIONAL MARGINAL PRICES ARE CALCULATED IN THE REAL TIME MARKET

Locational prices are calculated twice in the real-time market under this proposal. First, "advisory LMPs" are calculated during the dispatch process as a means to communicate the desired dispatch point to generators participating in the real time market. The RTO uses the bids it received and its knowledge of system conditions to calculate advisory LMPs and give generators a recommended setpoint based on the advisory LMP price at their location. These calculations come from the SCED program described earlier.

The locational prices used in the settlements process are calculated after-the-fact based on the actual of generators. Market rules define which generators are eligible, or qualified, to set the market clearing price. Typically, these rules would be along the following lines:

- Generators who choose to run close to their recommended setpoint are said to be "qualified" to set the actual, ex-post LMP. This means their offer prices will be factored into the calculation of the actual LMP at their location. They receive the nodal price at their location, which may be set by their offer price or a higher price if the actual LMP at their location is set by another unit.

- Units with output greater than the recommended setpoint (plus some yet to be determined percentage) are paid the actual LMP at their node for all their output, but their bids are not factored into that LMP determination. In other words, they are not eligible to set the clearing price and are effectively price takers. The same is true of units operating under must-run contracts with the RTO and units committed by the RTO to provide regulation or operating reserves; they will not have their energy bids factored into the actual LMP calculation.[11]

- Units with output less than the recommended setpoint are not subject to explicit penalties, nor are they disqualified from setting the LMP at their node. These units are paid the LMP for their (reduced) output. For transmission customers with units on bilaterals schedules, their scheduled level is considered their setpoint and they will be charged for spot energy to fulfill bilateral contracts should they generate less than their scheduled level.

These calculations are done automatically through a program referred to as the Locational Marginal Pricing Preprocessor (LMPP). The LMPP compares the recommended setpoint of each unit against its actual output, and determines which units are qualified to have their bids set the actual LMPs. Using bids from "qualified" generators, information about transmission constraints and system topology, and the actual output of the units, the 5 minute actual LMPs are then calculated and used for settlements with loads and generators.

[11] Such units may receive supplemental payments for energy under separate contractual arrangements with the RTO.

INCLUSION OF MARGINAL LOSSES AND ANCILLARY SERVICES IN NODAL PRICES

The locational marginal prices will not initially include marginal losses or reflect the cost of ancillary services. The methodology for allocating and settlement of losses will be determined through the stakeholder advisory process.

6. FINANCIAL CONGESTION HEDGES

DESCRIPTION OF FCHS

A critical component of any market based congestion management system is the definition of transmission rights. Under this model, the RTO will offer such rights in the form of financial congestion hedges. As explained earlier, FCHs are financial rights, meaning that no such right is needed in order to schedule, and priority of use of the system is not linked to whether or not a transmission customer holds such a right. Holders of FCHs will be paid the applicable "congestion rents" associated with the right, regardless of whether they schedule transmission service or not.

To date, transmission pricing models using financial rights have denoted the rights as point-to-point instruments that are "obligations" rather than "options." These point-to-point financial rights are called firm transmission rights (FTRs) in PJM, transmission congestion contracts (TCCs) in New York and financial congestion rights (FCRs) in New England.[12] In its market development process the SPP stakeholder group explicitly recognized that financial rights in other configurations, such as rights denoted as options, or financial rights that hedge for congestion on a flowgate rather than congestion between a point of injection and a point of withdrawal, would be of value to market participants. Thus, the SPP group adopted the term FCH or financial congestion hedge, meaning a broad variety of financial transmission rights.

While the feasibility of a model using only point-to-point rights is well-established, no model is currently in operation that uses a variety of configurations of financial rights – in particular, that uses both options and obligations. There is additional technical complexity associated with having the RTO issue flowgate-based financial rights[13], especially if they are to be issued simultaneously with point-to-point rights, and if they are to be denoted as options, not obligations. These issues should be worked through with the stakeholders as quickly as possible

[12] Point-to-point financial rights are also referred to as nodal FCHs.

[13] To clarify, an FCH model with "flowgate-based financial rights" is NOT the same as a so-called "flowgate rights model." That term refers to a physical rights model. Nor is it the same as a model using "flowgates in the forward market; LMP in real time". That also refers to a model that uses physical rights, not financial rights. The LMP/FCH model does not involve physical rights in any form.

in order to establish a schedule for implementing the FCH model, in whole or in part in a timely fashion.

Key features of FCHs are as follows:

- Ownership of an FCH entitles the holder to be paid the difference between the locational prices at the points of injection and withdrawal or across a specific flowgate. FCHs will specify a megawatt quantity and a term during which the FCH is in effect. FCHs will be unidirectional.

- FCH holders will be entitled to payments based upon the difference in the congestion components of the locational prices when those differences are positive. To the extent the FCHs are defined as obligations, the holders will be obligated to make payments when the locational differences are negative.

- All transmission customers will be responsible for full congestion charges associated with their transactions. In this way, the proposed design treats all transactions, spot market and bilateral transactions, exactly the same. Transmission customers that hold FCHs, whether the FCHs are point-to-point or flowgate based, will receive a credit against the congestion charges assessed to their transactions.

- Point-to-point FCHs may be specified to be either node to node, node to market hub, market hub to node, or hub, node or load zone to load zone. Such FCHs will be settled based on the locational price differences of the appropriate node, load zone, or hub prices at the destination and origin locations specified in the FCH.

SIMULTANEOUS FEASIBILITY

All FCHs outstanding at a given time must be simultaneously feasible. In other words, the transmission system under security constrained conditions must be able to accommodate all the potential energy flows represented by an outstanding set of FCHs. The system constraints used in the modeling process for feasibility will be consistent with the model used in the spot energy market. Simultaneous feasibility will be determined initially in the distribution process and reconfirmed in subsequent distributions, whether through auction or allocation.

FCH SETTLEMENTS AND REVENUE ADEQUACY

FCHs will generally be settled monthly for all the hours in the month. Because of the simultaneous feasibility condition, the congestion revenue fund should ordinarily receive more than enough revenues to make all required FCH payments. To the extent that excess payments are received (because not all feasible FCHs are sold or because system conditions permit greater flows than those modeled) a reserve will be established within the fund.

However, physical conditions on the system (such as loss of transmission line) may mean that energy flows (and resulting revenues) are less than the expected feasible flows. If revenues in a month plus the available cash reserves are sufficient to make all FCH payments, they will all be made. If revenues plus the available reserve are insufficient, the RTO faces a policy choice. In PJM, in this situation payments to FCH holders are reduced pro rata. In New York, FCHs are "fully funded" and revenue deficiencies are made up through uplift charges on all load. This policy choice needs further stakeholder discussion.

INITIAL ALLOCATION OF TRANSMISSION RIGHTS

The initial distribution of transmission rights is one of the most highly debated issues in the context of moving to a market-based congestion management system. Transmission customers want to know how their existing transmission service arrangements will be converted to the new world of financial transmission rights. What rights will they get? Will they be exposed to any more costs than they are under their existing arrangements today? These questions must be answered in any RTO market design model.

Two mechanisms for accommodating existing transmission service arrangements under the financial rights model have been discussed. Under one method, transmission customers would be issued FCHs, the financial instruments themselves, reflecting their current transmission reservations and contractual arrangements. Under this mechanism, transmission customers are not required to purchase their FCHs in an auction.The second method is to allocate the rights to the auction revenues generated from the sale of FCHs, rather than the FCHs themselves. Under this mechanism, the transmission customer would receive some portion of auction revenues from the sale of FCHs, and must participate in the auction with all other possible bidders if it wishes to obtain FCHs.

This model adopts the first method, direct allocation. In order to effect a fair conversion from today's tariffs to an RTO tariff, existing long-term load commitments must be taken into account. In many cases the only way to avoid imposing new costs on existing arrangements is to allocate FCHs consistent with current firm service. This is true for IOUs and for public power and other load serving entities.

Advocates of the auction approach argue that the concerns of those with fixed price obligations are adequately addressed by crediting FCH auction revenues back to customers. But markets are not perfect, especially immature ones. An auction approach may cause undue uncertainty and risks. Imposing risks of this nature on regulated providers would likely be unacceptable to state regulators, at least until parties have had sufficient time to experience LMP in operation and learn the potential value of FCHs.

However, to encourage maximum liquidity in the market, an open stakeholder process should be used to obtain full market input on the design of allocation rules, the process for auctioning of excess FCHs, and rules for non-discriminatory release in the event of retail access.

7. SETTLEMENTS EXAMPLES

The following examples illustrate the financial settlement of energy, congestion charges and FCHs between a transmission customer and the RTO. These examples are based on point-to-point FCHs. The same calculations would apply for the settlements involving locational prices for nodes, zones or hubs. And similar calculations could be done for FCHs denoted as flowgates, using the congestion value of the flowgate as a financial credit.

These examples illustrate the settlement for one hour. While the examples are based on a one-hour settlement interval, the basic concept applies to other settlement intervals as well (i.e. 10-minute settlement)

There are four basic steps to the settlement process (as noted, this process applies whether nodal FCHs or flowgate FCHs are held):

1) Generation Credit. Calculate the credit paid for generation by multiplying the amount of actual generation by the LMP at the generator node. This is done for each generator that the transmission customer either schedules or bids as a resource.
2) Load Charge. Calculate the charges for load by multiplying the amount of actual load by the LMP at the load node or zone. This is done for each of the locations where the transmission customer has responsibility for load.
3) FCH Credit. Calculate the credit value of FCHs held by multiplying the FCH price by the MW level specified by the FCH. This is done for each FCH held.
4) Net Bill. Net the Generation Credit, Load Charge and FCH Credit calculated above.

This calculation results in a net bill from the RTO that includes any energy imbalance charges (for transmission customers that have more load than generation), energy imbalance credits (for transmission customers that have more generation than load), congestion charges for bilateral schedules, and credit for any FCHs held.

Example 1:

In this example, the transmission customer (TC) has load at two nodes and generation at one node. Load and generation for this TC are in balance (supply = demand). The settlement is for one hour. For the eight-bus example, this TC has:

Generation Node	Actual Generation	LMP
F	150 MW	$15.00
Load Node	**Actual Load**	**LMP**
B	100 MW	$38.51
E	50 MW	$23.28

1) Generation Credit:
Since the TC has only one generator, the credit for generation supplied is equal to the amount of generation supplied times the LMP at the generator node:

Generation Credit = (Generation Supplied at Node F) * (LMP at Node F)
= (150 MW) * ($15)
= $2,250

2) Load Charge:
This TC has load responsibility at two different nodes, Node B and Node E. The charge for these loads is simply the MW level of the load times the LMP at the load node. This is calculated for each load node separately.

Charge for Load at B = (Load at Node B) * (LMP at Node B)
= (100 MW) * ($38.51)
= $3,851

Charge for Load at E = (Load at Node E) * (LMP at Node E)
= (50 MW) * ($23.28)
= $1,164

Total Load Charge = Load Charge at B + Load Charge at E
= $3,851 + $1,164
= $ 5,015

3) FCH Credit:
In this example, the TC holds two different nodal FCHs to hedge the cost of congestion:
- 100 MW of Nodal FCHs from Node F to Node B
- 50 MW of Nodal FCHs from Node F to Node E

The financial value of a nodal FCH is determined by the difference in LMPs between the POI and POW specified by the FCH.

FCH_{FB} Credit = (LMP at Node B – LMP at Node F) * (FCH_{FB} MW)
= ($38.51 - $15.00) * (100 MW)
= $ 2,351

FCH_{FE} Credit = (LMP at Node E – LMP at Node F) * (FCH_{FE} MW)

= ($23.28 - $15.00) * (50 MW)
= $ 414

Total FCH Credit = FCH_{FB} Credit + FCH_{FE} Credit
= $ 2,351 + $ 414
= $ 2,765

4) Net Bill:
The Net Bill from the RTO is then calculated as the sum of the Net Energy and Congestion Charges and the FCH Credit.

Net Bill = Net Energy and Congestion Charges + FCH Credit
= (Generation Credit - Load Charge) + FCH Credit
= ($2,250 - $5,015) + $2,765
= $ -2,765 + $2,765
= $ 0

In this example, the FCH Credit exactly offsets Net Energy and Congestion Charges. Since the nodal FCHs held exactly matched the TC's transactions, the TC is fully hedged against congestion charges. The Net Bill from the RTO would be $0 with any combination of LMPs.[14]

Example 2:

In this example, the transmission customer (TC) has load at three nodes and generation at two nodes. Load and generation for this TC are in balance (supply = demand). The settlement is for one hour. This example represents network service, where multiple resources serve loads at multiple delivery points. The nodal FCHs are configured as obligations. For the eight-bus example, this TC has:

Generation Node	**Actual Generation**	**LMP**
D	90 MW	$44.09
E	88 MW	$23.28
Load Node	**Actual Load**	**LMP**
B	50 MW	$38.51
D	96 MW	$44.09
E	32 MW	$23.28

[14] Since the generation supplied by the TC exactly balanced the load requirement, the net of the Generation Credit and Load Charge from the LMP ($ -2,765) reflects only congestion charges. However, when there are imbalances (under-supply or over-supply of generation), the TC would either be credited for excess generation or charged for extra load. These credits or charges would be the incremental dollars associated with multiplying the MW at each node by the corresponding LMPs.

1) Generation Credit:
Since the TC has generation at Nodes D and E, a credit for generation supplied is calculated for each resource:

Generation Credit at Node D = (Generation Supplied at Node D) * (LMP at Node D)
= (90 MW) * ($44.09)
= $3,968

Generation Credit at Node E = (Generation Supplied at Node E) * (LMP at Node E)
= (88 MW) * ($23.28)
= $ 2,049

Total Generation Credit = Credit at Node D + Credit at Node E
= $3,968 + $2,049
= $ 6,017

2) Load Charge:
This TC has load responsibility at three different nodes, Node B, D and E. The charge for these loads is simply the MW level of the load times the LMP at the load node. This is calculated for each load node separately.

Charge for Load at B = (Load at Node B) * (LMP at Node B)
= (50 MW) * ($38.51)
= $ 1,926

Charge for Load at D = (Load at Node D) * (LMP at Node D)
= (96 MW) * ($44.09)
= $ 4,233

Charge for Load at E = (Load at Node E) * (LMP at Node E)
= (32 MW) * ($23.28)
= $ 745

Total Load Charge = Load Charge at B + Load Charge at D + Load Charge at E
= $1,926 + $4,233 + $745
= $ 6,903

3) FCH Credit:
In this example, the TC holds three different nodal FCHs to hedge the cost of congestion:
- 6 MW of Nodal FCHDB
- 44 MW of Nodal FCHEB
- 12 MW of Nodal FCHED

The financial value of a nodal FCH is determined by the difference in LMPs between the POI and POW specified by the FCH.

FCH_{DB} Credit = (LMP at Node B – LMP at Node D) * (FCH_{DB} MW)
= ($38.51 - $44.09) * (6 MW)
= $ -33.48

FCH_{EB} Credit = (LMP at Node B – LMP at Node E) * (FCH_{EB} MW)
= ($38.51 - $23.28) * (44 MW)
= $ 670.12

FCH_{ED} Credit = (LMP at Node D – LMP at Node E) * (FCH_{ED} MW)
= ($44.09 - $23.28) * (12 MW)
= $ 249.72

Total FCH Credit = FCH_{DB} Credit + FCH_{EB} Credit + FCH_{ED} Credit
= $ -33.48 + $670.12 +$249.72
= $ 886

Note that since the LMP at the POI is higher than the LMP at the POW for FCH_{DB} the TC is charged for owning these FCHs. This charge is offset later in the settlement since the TC is credited for generation at the higher POI and charged for load at the lower POW (the TC is essentially credited for creating a flow counter to the direction of congestion).

4) Net Bill:
The Net Bill from the RTO is then calculated as the sum of the Net Energy and Congestion Charges and the FCH Credit.

Net Bill = Net Energy and Congestion Charges + FCH Credit
= (Generation Credit - Load Charge) + FCH Credit
= ($6,017 - $6,903) + $886
= $ -886 + $ 886
= $ 0

In this example, the FCH Credit exactly offsets Net Energy and Congestion Charges. Since the Nodal FCHs held exactly matched the TC's transactions, the TC is fully hedged against congestion charges. The Net Bill from the RTO would be $0 with any combination of LMPs.

8. INFORMATION PROVIDED TO THE MARKET

The RTO website will have an Operational Data page to provide the current five- or ten-minute, hourly integrated and day-ahead LMP values for selected points and to provide other market information. Historic information will also be provided.

LMP values posted will include:

- Nodal prices
- Load-weighted zonal average LMPs
- Trading Hub LMPs
- Aggregate LMPs
- Interface LMPs

9. SUMMARY

In Order 2000, FERC required RTOs to adopt market designs that promote efficient grid operations. The LMP/FCH model meets this objective and provides maximum flexibility for market participants and for the RTO.