Market Monitoring Unit

REPORT
TO
THE FEDERAL ENERGY REGULATORY COMMISSION

ANCILLARY SERVICES MARKETS

Market Monitoring Unit
PJM Interconnection, L.L.C.

April 1, 2000

Introduction

On November 25, 1997, the Commission approved the comprehensive restructuring of the PJM marketplace, establishing PJM as an Independent System Operator ("ISO").[1] The Commission further authorized PJM to administer the PJM Power Exchange ("PJM PX"), which has become one of the most active spot energy markets in North America.

In its order, the Commission found that the restructuring of PJM "will significantly alter the operation of the electric power market within PJM" and that, as a result, "it is important to monitor its implementation to assess undue discrimination and market operation" and to evaluate "how the pool and non-pool markets and transmission pricing arrangements are working."[2] The Commission directed PJM to submit a proposed market monitoring plan that would allow PJM to monitor and report to the Commission on the potential to exercise market power within PJM.[3] The Commission stated that the plan should evaluate the operation of both pool and bilateral markets to detect either design flaws or structural problems.[4]

On June 29, 1998, PJM filed a Market Monitoring Plan ("Plan") in compliance with the Commission's Order. The Plan was filed as an amendment to the PJM Tariff in order to ensure the PJM Board's independence in administering and revising the Plan.[5] By order issued March 10, 1999 the Commission accepted the Plan filed by PJM as part of the

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1 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997) ("November 25 Order").
2 81 FERC at 62,282.
3 Id.
4 Id.

PJM Tariff to be effective April 1, 1999.[6] The Commission found that the ability of the Market Monitoring Unit ("MMU") to effectively and broadly monitor and investigate the PJM Market to be essential in view of its contemporaneous decision to approve market-based pricing authority on offers to sell energy into the PJM-PX.[7]

The March 10 Order requires the MMU to report to the Commission by April 1, 2000 on: (1) the issue of enforcing requests for data and other information made during the course of its investigations and monitoring operations under the Plan;[8] (2) the efficiency of PJM's ancillary service markets, the pricing in these markets, and potential exercises of market power; and (3) its monitoring of bilateral transactions.[9] By order issued September 21, 1999, the Commission denied requests for rehearing, reiterating that its approval of the Plan "established a broad range of monitoring responsibilities."[10] By notice issued March 17, 2000 in Docket No. EL00-42-000, the Commission granted an extension of time for the MMU's report on bilateral transactions "to and including 90 days from the issuance of a Commission order" on PJM's petition in that docket.

This Report is filed pursuant to item (2) above in the Commission's March 10 Order.

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5 The Plan appears in the PJM Tariff at Original Sheet No. 184 through First Revised Sheet No. 190. Section references herein are to Sections of the Plan.

6 See PJM Interconnection, L.L.C., 86 FERC ¶ 61,247 (1999) ("March 10 Order").

7 Id. at 61,887 n.4 (citing Atlantic City Elec. Co., 86 FERC ¶ 61,248 (1999)).

8 In requiring this report, the Commission noted that while PJM was not being given authority to self-enforce such requests under the Plan, the Commission might revisit the issue if PJM or other parties believe that enforcement of such requests is ineffective. 86 FERC at 61,891.

9 86 FERC at 61,891.

10 88 FERC at 61,853.

Within PJM, the procurement of ancillary services is currently based, depending on the specific ancillary service, on both market based and cost based prices. The Commission designated six ancillary services in Order No. 888. They are: (1) scheduling, system control and dispatch service; (2) reactive supply and voltage control from generation sources service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve - spinning reserve service; and (6) operating reserve – supplemental reserve service.[11] Scheduling, system control and dispatch services are the administrative services provided by PJM, which are not suitable for provision via a market. Energy imbalance service is the balancing of loads and generation which occurs through the provision of PJM dispatch and interchange and is implemented via the free flowing ties which are fundamental to PJM. Energy imbalance service is provided via the PJM spot market. The remaining four ancillary services might be provided via properly designed competitive markets and efforts are underway to design those markets.

The PJM Open Access Transmission Tariff states, at Section I.3:

> "Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following

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[11] Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities, Order No. 888, 1991-96 FERC Stats. & Regs., Regs. Preambles ¶ 31,036, at 31,703 (1996), order on reh'g, Order No. 888-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,048, at 30,226 (1997).

> Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.
>
> The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. Subject to the provisions of Schedules 1 through 6, the Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider."

PJM will introduce a new market in regulation service on June 1, 2000.[12] PJM Members have met in a working group over the past year in an effort to develop a market structure for spinning reserves. PJM recently introduced a market oriented modification in the procurement of reactive service. As a result, this report to the Commission focuses on current ancillary service procurement structures and the potential for the evolution of markets in these three ancillary services.

Regulation

Introduction

The provision of the Regulation ancillary service is coordinated by PJM. NERC requires that the PJM Control Area maintain regulating capability in order to match short-term deviations in system load. Regulation refers to the PJM control action that is performed to correct for load changes that may cause the power system to operate above or below 60 Hz.[13] The Capacity Resources assigned to meet the PJM Regulation requirement must be capable of responding to the AR (Area Regulation) signal within five minutes and must increase or decrease their outputs at the Ramping Capability rates that are specified in the Offer Data that is submitted to PJM.[14] The Regulation service supplied by individual generating units is: "The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal."[15]

Not all generating units are equipped to provide Regulation service and the amount of Regulation that a properly equipped generating unit can supply is generally much less than the amount of energy or capacity that it can supply. Of the 516 generating units in

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12 See PJM's February 15, 2000 filing in Docket No. ER00-1630-000 reflecting amendments to PJM's Tariff and a restated Operating Agreement providing for market-based pricing of Regulation service.

13 PJM Manual for Pre-Scheduling Operations, Manual M-10, page 4-1.

14 PJM Manual for Pre-Scheduling Operations, Manual M-10, page 4-3.

15 PJM Manual for Scheduling Operations, Manual M-11, page A-30.

the PJM area[16], there are 107 generating units that are qualified to provide Regulation.[17] In the PJM area there are more than 56,000 MW of generating capacity while there are approximately 2,400 MW of Regulation capability.[18]

The PJM control area establishes separate control area wide Regulation requirements for both the off-peak hours (hours ended 0100-0500 hours) and on-peak hours (hours ended 0600-0000).[19] The peak Regulation requirement is equal to 1.1 percent of the forecast peak load for the forecast period while the off-peak requirement is equal to 1.1 percent of the lowest forecast demand for the forecast period.[20] [21] This requirement for the PJM control area ranges from approximately 220 MW of Regulation capability during off-peak hours in the spring and fall to approximately 575 MW of Regulation capability during on-peak hours in the summer. Within PJM, the Regulation capability of a qualifying individual generating unit is the difference between its current operating level and the level to which it could ramp, either up or down, within five minutes.

Responsibility for the control area's hourly Regulation requirement is assigned to all Load Serving Entities ("LSEs") within the PJM control area based upon each LSE's share of the control area's hourly load.[22] The LSE's Regulation obligation can be met by

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16 Mid Atlantic Area Council, Regional Reliability Council EIA-411 Report, April 1, 1999.

17 These are the units which are qualified to provide Regulation and which have actually provided Regulation during a recent time period.

18 This Regulation capability is net of forced outages based on average forced outage rates.

19 The definition of Regulation on-peak and off-peak hours differs from the standard PJM on-peak and off-peak periods. The Regulation periods are based on a PJM study of the PJM system demand for Regulation.

20 PJM Manual for Scheduling Operations, Manual M-11, page 3-4.

21 PJM's Regulation requirements are derived from NERC's Control Performance Standards CPS1 and CPS2.

22 PJM Open Access Transmission Tariff, Attachment K--Appendix, Section 3.2.2(a).

self-scheduling of its own generators, bilateral purchases, or purchases of Regulation through PJM.[23] Only the Regulation requirements that are not met via bilateral contracts or via self-scheduled resources are obtained via the PJM Regulation market.

Current market design

The current system for obtaining Regulation service is a cost-based market. Each quarter PJM determines the operating cost of regulating units based on three cost classifications. Units are placed in Class I, II, or III depending on the unit's incremental energy offer. The classes are used to represent base, marginal, and peaking units. The cost ranges for the classes are calculated each quarter by plotting the average operating cost of each unit certified to regulate in ascending order. From the curve, natural "breakpoints" for unit energy costs are derived by PJM. These breakpoints allow units to be placed into one of the three classes based on the unit's average incremental cost. After units are assigned to a class, an average operating cost for each class is calculated by first determining the cost for each unit in that class by multiplying the amount of certified regulation capability (MW) by the average energy offer ($/MWh) of the unit. The costs for all units in the class are then summed and divided by the total regulating MW in that class in order to determine the MW-weighted average cost for that class.

PJM obtains regulation from those LSEs, or other qualified suppliers of regulation, which offer regulation to PJM, in order to meet the pool regulation requirement after netting out the level of regulation supplied via bilateral contracts or self scheduling. PJM obtains

[23] PJM Open Access Transmission Tariff, Attachment K--Appendix, Section 1.11.4(a).

regulation on a least cost basis from either self scheduled or pool scheduled energy resources.

In the after-the-fact accounting, regulation credits and payments for each hour are determined based on the resources scheduled to regulate and the control area's obligation. For LSEs that had excess regulation in a given class scheduled by PJM, a credit is given hourly based on the absolute value of the difference between the actual market clearing price and the Regulation Class Average Cost, plus a 10% adder multiplied by the excess MW. This value is then multiplied by a value derived by PJM as an incentive for supplying regulation. The multiplier is determined by PJM based on the success PJM has had in meeting the NERC Standards for Control Area performance and published in advance. The current multiplier is 2. The equation is: Credit = Excess Regulation (MW) * [Absolute Value (LMP-Class Regulation Rate) + Adder] * Multiplier. The total credits calculated are divided by the total excess MW of regulation supplied to determine an average hourly cost of regulation. All LSEs deficient in regulation are charged for their deficiency at the average hourly cost of regulation.

The current market has, at times, produced less than the target amount of required Regulation especially during some shoulder hours.[24] For example, assigned regulation was more than 15 MW below the target level in 39% of the hours of 1999. However, the shortfalls were concentrated in hours ended 600, 700, 2300 and 2400. During the peak hour ended 1900, there were only 35 days on which assigned regulation was more than

15 MW below the target level. The graphs below show the average regulation levels for the year, by hour of the day, compared to the regulation target. The shortfalls could well have resulted from the fact that the current payments for Regulation are based on the difference between the current hourly LMP and a fixed, class average Regulation cost that is based on an historical average energy cost calculation. The result, during some hours, is that there may be little incentive to provide Regulation, especially for low cost units (less than the class average cost).

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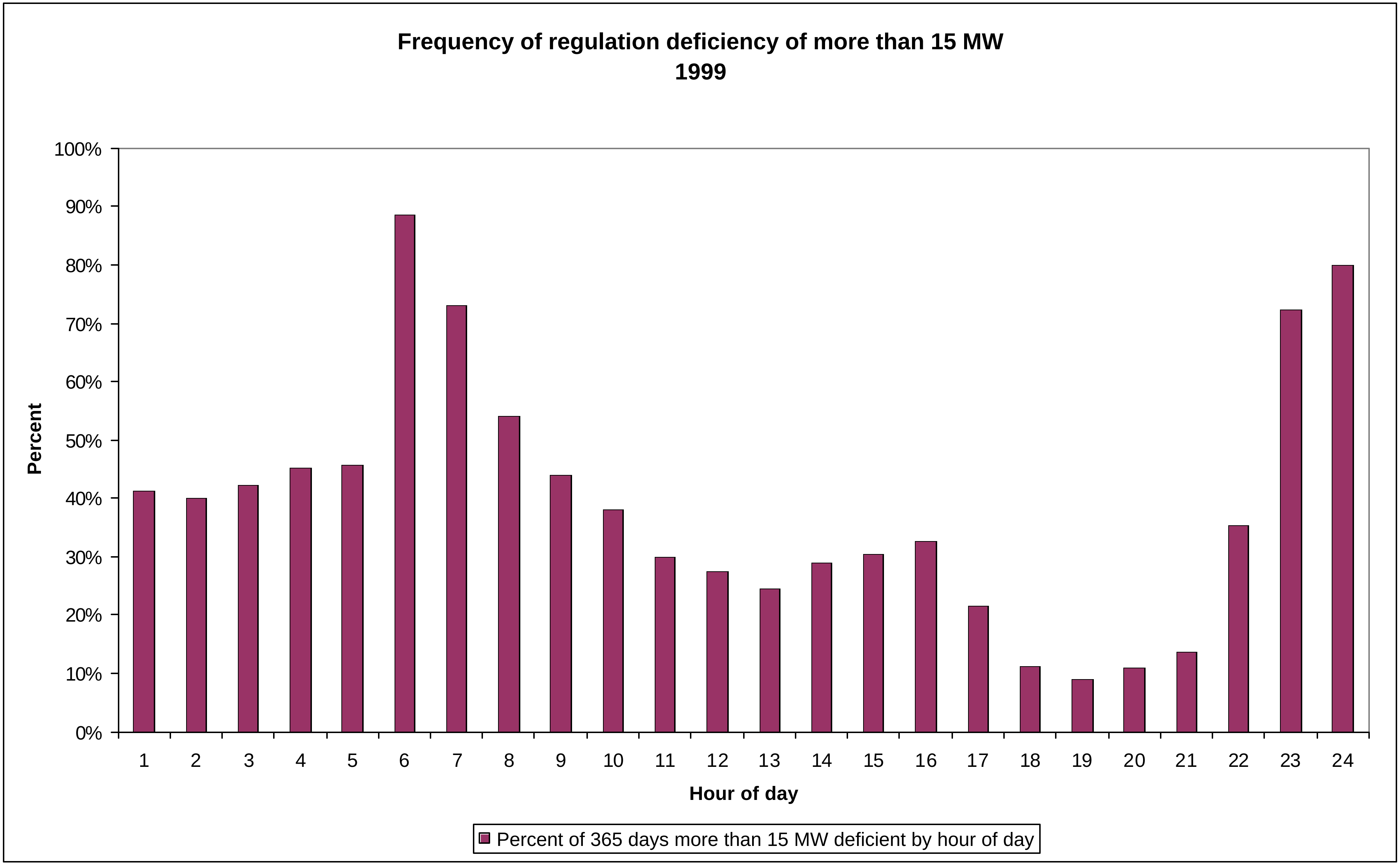
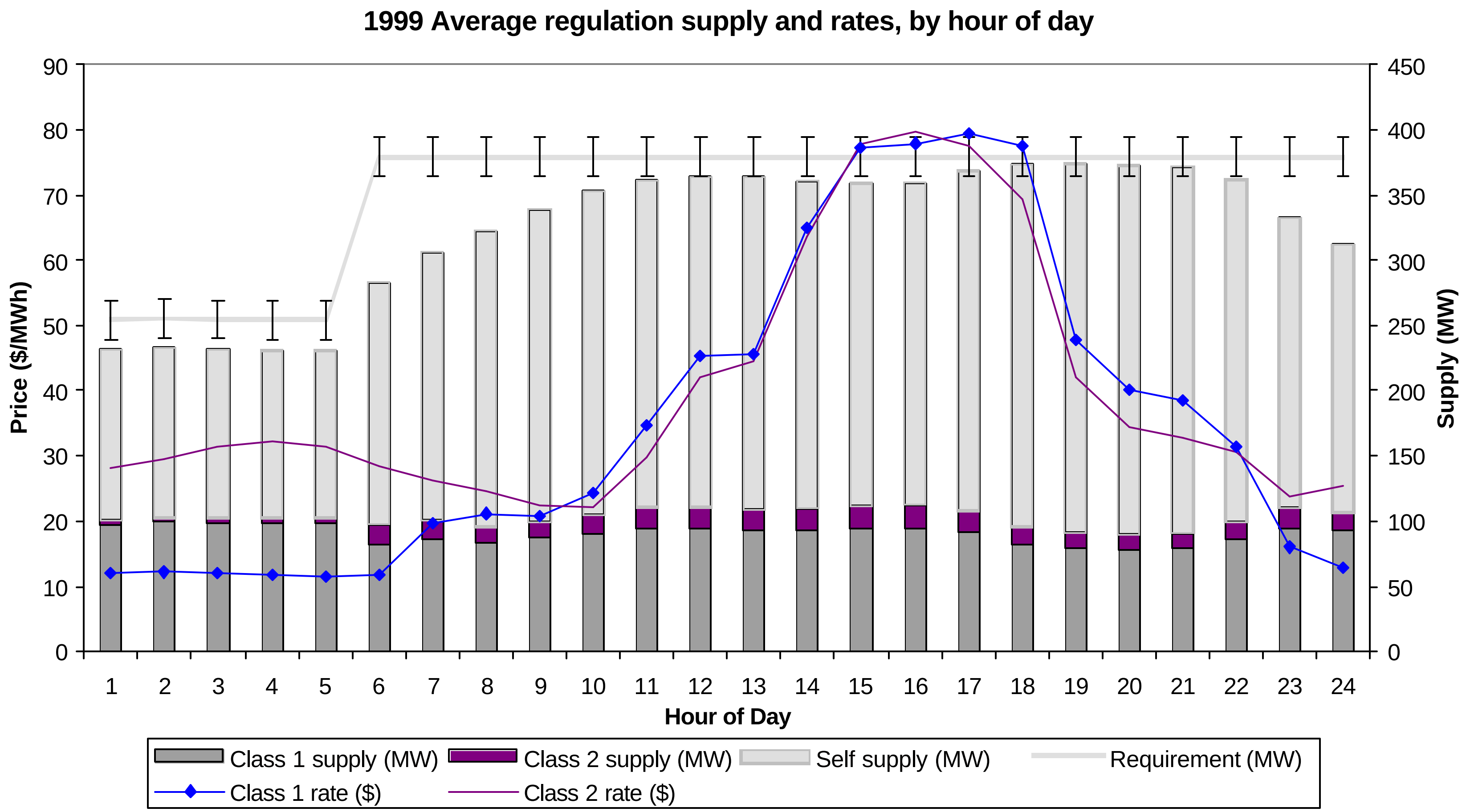
[24] PJM was in compliance with NERC Control Performance Standards CSP1 and CPS2 in 1999. When there is a shortfall in Regulation, PJM must rely on the dispatch of economic generation in order to meet these standards.


Frequency of regulation deficiency of more than 15 MW
1999
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent
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 of day
Percent of 365 days more than 15 MW deficient by hour of day



All items are averages for the hour across the 365 days of 1999. **The lines represent the average hourly regulation rate** paid to Class 1 and 2 units for supplying to the pool. Hourly regulation rates equal the absolute value of the difference between the hourly PJM weighted average energy price and the quarterly class cost, plus an adder, times two. The adder ranged from $1.30 to $5.60 in 1999. The quarterly class cost for Class 1 units was approximately $15/MWh in each quarter and for Class 2 units ranged from $22/MWh in the 2nd quarter to $32/MWh in the 4th quarter. **The columns represent average MW supplied to the pool** by class 1 and 2 units and self-supplied by companies to meet their obligations. Supply by class 3 units is not displayed because it did not exceed an average of 0.1 MW for any hour. The top line represents the average pool requirement with a 15 MW deadband.

Proposed market design

On February 15, 2000, in Docket No. ER00-1630-000, PJM submitted to the Commission for filing amendments to the PJM Open Access Transmission Tariff ("PJM Tariff") and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), unanimously approved by the PJM Members Committee at its August 26, 1999 meeting, providing for market-based pricing of Regulation service. In the February 15 filing, PJM proposed market based pricing for the sales of Regulation that will occur through the PJM Regulation market (i.e. those sales that are net of bilateral sales and self scheduled regulation).

Under the proposed new tariff provisions, market participants will be paid for providing Regulation at a market clearing price determined on the basis of (i) market-based offers of Regulation service and (ii) the opportunity costs of a resource providing Regulation instead of participating in the energy market.[25] On a day-ahead basis, market participants will submit Regulation offers, not to exceed $100 per megawatt-hour. PJM will evaluate the submitted offers and select Regulation units on a least-cost basis considering the Regulation offer price, estimated opportunity costs for the units that propose to provide Regulation, and PJM's obligation to minimize the total costs of energy, operating reserves, Regulation, and other ancillary services. A Regulation market-clearing price will be established for each hour and that price will be equal to the highest sum (from among the selected units) of a resource's Regulation

[25] Although a generator providing Regulation service will receive its locational marginal price for all energy output, in order to provide Regulation the generator often will have to set its output above or below its economic dispatch level so that it is capable of increasing or decreasing output in response to the regulating

offer and estimated opportunity costs. PJM's Regulation on-peak requirements will continue to be equal to 1.1 percent of the forecast peak load for the forecast period while the off-peak requirement is equal to 1.1 percent of the lowest forecast demand for the forecast period.

In real-time operations, with one exception, PJM will pay the market-clearing price to all units providing Regulation. However, if a unit's actual opportunity costs in the hour when added to the unit's Regulation offer exceed the market-clearing price, which is based on an estimated, day ahead, opportunity cost, then the exception will apply and the unit will receive this higher sum of its unit-specific offer and actual, real time, opportunity costs. The exception ensures that a generator will not suffer economically by being selected to provide Regulation rather than being able to participate in the energy market. Without this assurance, generators would be discouraged from offering Regulation service because, in some circumstances, it may be difficult to predict the next day's opportunity costs. With this provision, generators are assured that they will not suffer economically by offering generation for Regulation service if actual energy market prices vary from day-ahead predictions.[26]

Market participants purchasing Regulation service from the market will pay the market-clearing price for Regulation service. They also will share proportionally any amounts above the market-clearing price that are paid to individual generators, as described above.[27]

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control signal. The difference in energy revenues (or costs) resulting from this change in output level constitutes the generator's opportunity costs.

26 Providing this type of assurance is consistent with Order No. 2000. See Order No. 2000 at 31,216 ("if more than one product is being sold in the same temporal market, efficiency is maximized when arbitrage opportunities reflected in the bids are exhausted (i.e., after the RTO's markets have cleared, no technically qualified market participant would have preferred to be in another of the RTO's markets)").

It is reasonable to expect that the development of a more efficient market in Regulation will enhance the supply of Regulation, especially during the off-peak and shoulder periods. The close connection between the Regulation market and the energy market creates a concern that, in the absence of a Regulation market, there would not be adequate incentives to provide Regulation at certain times. The Regulation market design which has been submitted to the Commission would provide appropriate incentives to owners based on current, unit-specific opportunity costs in addition to the Regulation offer price.

The regulation market analysis performed by the MMU[28] concluded that it is appropriate to introduce a bid-based market in Regulation. The available supply of Regulation together with the market design features provide reasonable confidence that the market will be competitive. The regulation market analysis also concluded that there are concerns regarding: the potential competitiveness of the regulation market due to demand conditions; the relationship between the Regulation market and the energy market; the functioning of the market during off-peak periods and during periods of congestion; and the market shares held by certain generators. However, the MMU concluded that the results of the structural analysis, the supply/demand balance in the market, the potential for entry into the market and the new regulation market design suggest potential benefits associated with the introduction of a market which outweigh those concerns. In addition, the MMU will closely monitor the regulation market as it is introduced.

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27 The details of the operation of the Regulation market are set forth in revised sections 1.10.1(f), 1.11.3(b), and 3.2.2 of the Appendix to Attachment K of the PJM Tariff, submitted with the February 15 filing.

28 See February 15 filing, Affidavit of Joseph E. Bowring on behalf of PJM Interconnection, L.L.C., February 11, 2000.

Spinning Reserves

Introduction

Operating Reserve for the PJM control area is based on the concept of allowing reserves to be shared among all LSEs. To accomplish this, the participants integrate their operations under a central system operator. PJM's approach to integrated operations and free flowing ties allows the participants to gain a significant advantage in shared reserves. It also dictates that the control area operator, and not the participants, manages, maintains and deploys the reserves. PJM participants gain further economic benefits by a centrally coordinated unit commitment and central dispatch that provides both energy and reserves on a least-cost basis.

Operating Reserve in PJM is the reserve capability that can be converted fully into energy within 30 minutes of the request of the PJM dispatcher. Reserve capability is defined as generating capability and/or equivalent generating capability scheduled to operate in excess of the forecasted hourly integrated PJM Control Area load.

Operating Reserve is comprised of Primary and Secondary Reserve. Primary Reserve is reserve capability that can be converted fully into energy within 10 minutes of the request from the PJM dispatcher, while Secondary Reserve capability can be converted into energy within 30 minutes of the request. Primary Reserve consists of Spinning Reserve and Quick-Start Reserve. Spinning Reserve is provided by generation which is synchronized to the system and capable of producing energy within 10 minutes of a request from the PJM dispatcher. Spinning can also be provided by load which is capable of being interrupted within 10 minutes of a request from the PJM dispatcher. Quick-Start Reserve is provided by generation which does not have to be synchronized to the system but which is capable of producing output within 10 minutes of a request from the PJM dispatcher. Secondary Reserve can be provided by generation which does not have to be electrically synchronized to the system and which is capable of producing output within a 10-to-30 minute interval following the request of the PJM dispatcher.

Reserve objectives for the control area are determined and set by PJM. Spinning Reserve is the most reliable and therefore qualifies as Quick Start and Secondary Reserve. Quick Start also qualifies as Secondary Reserve. The individual reserve limits are set periodically by PJM based on a probabilistic analysis of the expected operations of the systems which includes such factors as generator mix, expected load, season, day of the week, time of day, historical load forecasting error, historical unit outage rates and time of exposure. Reserve objectives are calculated seasonally and published in the PJM Manuals.

PJM operates a voluntary central unit commitment and dispatch that includes both energy and reserves. Units that elect to participate in the scheduling and dispatch processes base their bids on both the energy and capacity of the units. Based on the bids submitted for all units, PJM schedules the required equipment to serve the expected load and reserves on a least-cost basis. Energy and reserves costs are not optimized separately but rather on the least production cost for the system. Units that bid into the market provide not only the energy as bid but also the overall capability of the unit to provide reserves within the required interval.

On a day ahead basis, PJM schedules enough generation to cover the forecasted load and the overall 30-minute operating reserve objective. Units that participate in the dispatch are expected to respond to system conditions as specified in their bids. Steam units are dispatched based on incremental energy costs and provide reserves based on their unloaded capacity after the energy requirements are met and the ability of the unit to respond to a request to increase output.

A unit started and operated by PJM is guaranteed to recover all of the costs of running that unit (as defined in its offer), whether for reserves or energy.[29] Units scheduled and dispatched by PJM are checked to determine if each recovered its operating costs, based on its bid, through the payments which it receives in the energy market over the entire operating day. The energy revenue to the unit, for the operating day, is then compared to the offer of the unit for the day including start-up cost, no-load cost, and incremental energy bid. If the offer is greater than revenues, the unit is paid the difference via an operating reserve credit. No explicit payment is made for reserves or the opportunity costs associated with scheduled units. PJM retains the rights to all reserves provided by PJM Capacity Resources and by scheduled units which remain under PJM dispatch for the operating day. Any unit providing reserves which is requested to load the energy from the reserves is paid for that energy through the energy market.

In actual operations, reserves are periodically verified through an Instantaneous Reserve Check (IRC). An IRC is a request to individual generation owners to provide data on the amount of available operating reserve, including spinning reserve, that is available from units that are operating per the dispatch signal but that are not at maximum output (incidental spinning), plus spinning from other sources. Each generation owner indicates the amount of spinning available in total. Thus, an IRC provides the operator with an indication of actual reserves on the system at any given instant. The total level of required spinning reserves is determined by the largest single contingency, e.g. the loss of a nuclear unit, which is typically between 1100 and 1200 MW.[30]

If the IRC indicates that economic dispatch provides the required reserves through resources that are economically loaded, no action is required and no additional costs for reserves are incurred. If the IRC indicates reserve objectives are not met, the system operator will take the necessary steps to increase the reserves. If the available spinning is less than the required spinning, the operator manages available resources to provide additional spinning reserves. Under normal operating conditions, PJM will meet the requirements for spinning reserve, regardless of the associated cost. Thus, while PJM attempts to obtain needed spinning reserve for the least cost, PJM's demand for spinning reserve is price inelastic.

Market issues

The market definition for the spinning reserve market includes all potential sources of spinning reserve: incidental spinning, hydro, synchronous condensing CTs, CTs at minimum generation, pre-scheduled steam, and interruptible load.

As an indicator of the size of the spinning reserve market, from January to September, 1999, the maximum total system spinning requirement has ranged from 1162 MW to as high as 2230 MW, due to special circumstances.[31] The total maximum available spinning resources have ranged

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29 The costs as defined in the offer can be actual costs or market-based bids.

30 PJM's spinning reserve requirement is derived from NERC's Disturbance Control Standard (DCS).

31 The normal spinning requirement is determined by the largest single contingency, which under normal circumstances is a nuclear unit. On some days during 1999, the largest single contingency was two nuclear units, due to conditions at the power plant. This is an unusual occurrence.

from 1867 MW to 2336 MW.[32] Instantaneous Reserve Checks showed a need for additional spinning reserve a total of 153 times, a minimum of 6 times per month and a maximum of 23 times per month, with a maximum additional spinning requirement equal to 930 MW. From 10% to 40% of IRCs during a month show a shortfall in spinning reserve, with the monthly average equal to 28% of IRCs which show a need for additional spinning reserve. From another perspective, 60% to 90% of IRCs show that the spinning reserve requirement is met by incidental spinning, with a monthly average of 72% of IRCs showing that the spinning reserve requirement is met by incidental spinning.

The cost of providing spinning reserve can best be characterized as a step function. The market for spinning reserve is characterized by supply segments with distinctly different costs to provide spinning reserve. The costs of these heterogeneous sources of spinning varies systematically from source to source. The lowest cost source of spinning is normally incidental spinning, followed by hydro, synchronous condensing CTs, CTs at minimum, and pre-scheduled steam. The important point is not that spinning can be supplied from various technologies, but that the market consists of segments characterized by different costs.

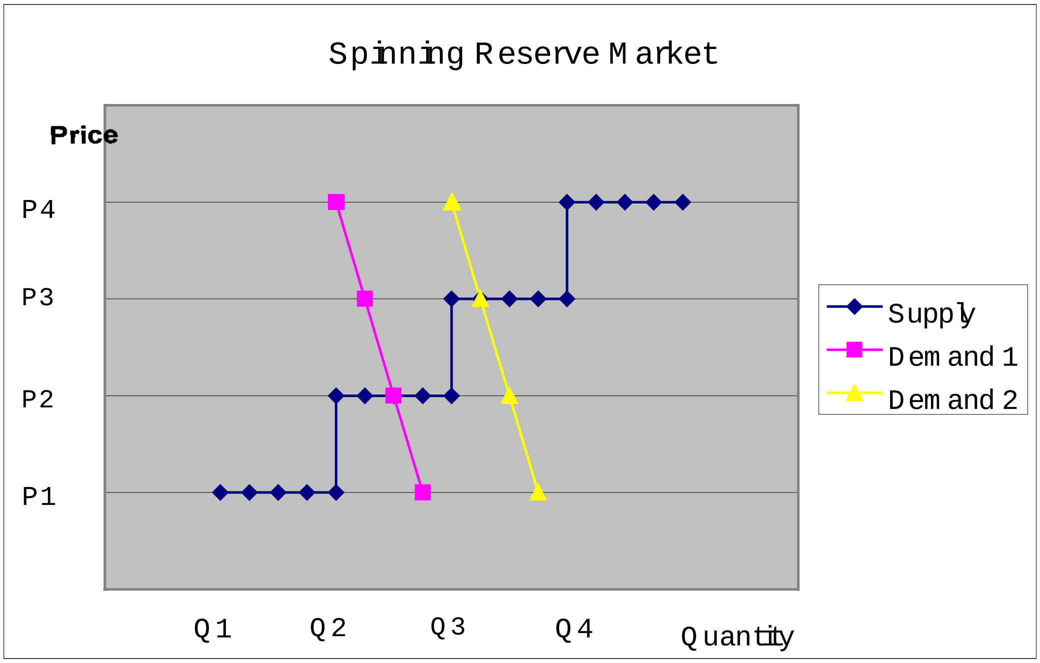
In a competitive market for spinning reserve, owners would be expected to bid to provide spinning reserve based on the marginal costs of providing spinning. In a competitive market, therefore, a supply curve would be expected to follow the underlying step function shape of the cost to provide spinning. (See Spinning Reserve Market graph below.) The market price of spinning at any time would depend on the relationship between the demand for spinning and the supply of spinning. If the demand were Demand 1 in the graph below, the price would be

[32] Per Instantaneous Reserve Check data.

expected to equal the cost of providing spinning from the suppliers on that portion of the supply curve, e.g. P2 in the graph. If the demand increased, to Demand 2, such that the entire quantity demanded could not be met by suppliers on the P2 portion of the supply curve, the price would be expected to equal the higher cost of providing spinning from the next highest cost source of spinning, e.g. P3 in the graph below. In a competitive market, all sources of spinning would receive that market clearing price.

In a market with a step function supply curve of the type illustrated in the graph, market power may, potentially, be exercised by owners of resources which are the low cost option, under certain market conditions. If the demand were Demand 1 in the graph and the competitive price were P2, it would be profitable for the suppliers at P2 to attempt to increase the price to just less than P3 by offering spinning at a price slightly less than P3. At price P3, supply from additional competitors would be economic, but there would be no supply response between P2 and P3.

In this market, the potential for the exercise of market power is inversely related to the number of suppliers which can produce at a given step of the supply curve. In this market, the potential for the exercise of market power also increases with the probability that PJM will require spinning resources from all the suppliers which can produce at a cost of P2.



There are periods, which recur regularly, during which the system operators determine that the available supply of incidental spinning from scheduled resources is not adequate to meet PJM's spinning reserve obligation. In such periods, the demand for spinning is inelastic, as it is a function of reliability standards. While there are multiple potential sources of spinning which are part of the market, during such periods the most economic source of spinning reserves available to the system dispatchers in real time operations is synchronous condensing CTs. As a result, it is synchronous condensing CTs which provide virtually all of PJM's spinning supply during such periods. The available synchronous condensing CTs are currently owned by only two companies.

The market for spinning is characterized by supply segments with distinctly different costs to provide spinning reserve, by inelastic demand at certain times and by a small number of suppliers in a key, low cost, segment of the market. As a result, there is the clear potential that the ability to exercise market power may exist at certain times in the market for spinning reserves.

In a bid-based market, the owners of synchronous condensing CTs could have the potential ability to profitably raise the price which they receive for providing spinning reserves to the system, to the cost of the next source of spinning, with the result being a financial detriment to those that pay these charges. To the extent that owners of synchronous condensing CTs have the ability to increase their offers to PJM, these owners may now have the ability to profitably raise the price to the system.

To date, spinning reserves have been provided based on the availability of incidental spinning and the management of additional specific resources offered to PJM. PJM has a Members working group which is attempting to develop a new market structure for the provision of spinning reserve. There are significant issues which must be addressed regarding the definition of costs and the potential for market power before a market for spinning reserves can be successfully introduced.

Joskow/Frame analysis of spinning market

The Joskow/Frame analysis of market power, submitted in Docket No. ER97-3729-000 on behalf of the Supporting Companies in support of market based pricing,[33] includes a discussion of the market for ancillary services including spinning reserves. (Page 114 et seq.) In the view of the MMU, the Joskow/Frame (J/F) analysis of spinning reserves omits a key segment of the spinning reserve market. The J/F analysis asserts (page 117) that "spinning reserves are provided from the unloaded capability of generating units currently on-line, i.e. synchronized to the system." This incidental spinning is the only source of spinning considered by J/F; the analysis omits any mention of synchronous condensing CTs. The result is that J/F omit a significant part of the market for spinning. J/F state (page 118): "None of these three reserve services (spinning, 10 minute/quick start, 30 minute) will be procured explicitly from generators in the PJM Interchange Energy Market being proposed, nor will they be priced as a separate service to customers." J/F state (page 120) that: "The Operating Agreement does not incorporate procedures that explicitly compensate generators that provide these types of operating reliability services (spinning, quick start and 30 minute reserves). Generators that are used by the ISO to provide spinning reserves receive no additional compensation for doing so, explicit or otherwise, if their energy value exceeds the sum of their start-up, no load and energy bids." J/F also state (page 119) that the total cost of Operating Reserves is the credits to generators which result when the energy payments to the generators fall short of covering start up, no load, and energy costs.

J/F miss the fact that synchronous condensing CTs can make offers separately, that synchronous condensing CTs can be compensated separately for the provision of spinning reserves, and that such compensation will be recovered via Operating Reserves. It is this oversight which permits J/F to conclude (page 120) that:

> "The above process suggests to us that it will be very difficult for generators to exercise market power in the provision of spinning reserves. The only way that generators can get paid for providing this service, as indicated, is via the residual

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[33] See Atlantic City Elec. Co., 86 FERC ¶ 61,248, at 61,895.

> credit amounts which flow through the Operating Agreement's Operating Reserves payment process when start-up and no load costs are not covered by energy profits. To exercise market power the owner of a generator would have to bid very high start up and no load costs or withhold spinning capability. However, because spinning reserves is not a service that will be procured and priced separately, either of these approaches inevitably would be accompanied by the sacrifice of profits on energy production. This is because a generator that bids high no load and startup cost is less likely to be scheduled and dispatched under the Operating Agreement's scheduling and dispatch procedure to supply energy to the market."

FERC's Market-Based Pricing Authority Order (Docket No. ER97-3729-000) bases its approval of market based rates for Operating Reserves, including spinning reserves, on the J/F analysis.

In the MMU's view, the Supporting Companies' application for market based pricing authority for spinning reserves was based on the inaccurate premise that compensation for the provision of spinning reserves is based entirely on the energy market bids of the units. The asserted absence of market power is based entirely on that assumption. It is true that spinning reserve is provided during a majority of hours from incidental spinning derived from the operation of units consistent with their energy market bids. However, synchronous condensing CTs do submit separate bids to provide spinning reserves which are evaluated independently of the energy market bids of such units. This portion of the spinning reserve market is important, has a significant impact on operating reserve payments, and needs to be considered explicitly when analyzing the market for spinning reserve.

Market behavior

During 1999, the MMU determined that certain of the offers from the suppliers of spinning reserves from synchronous condensing CTs exceeded the cost caps which had been specified in the PJM Cost Development Guideline Manual for cost-based offers. The MMU recovered the excess charges from one participant and is engaged in discussions with another participant regarding the recovery of excess charges.

One of the two suppliers of spinning reserves from synchronous condensing CTs has switched to market based offers for the combustion turbines which it uses to provide spinning. To date, the data reviewed by the MMU have not raised any concerns with the market based offers of this supplier, which have been below the relevant cost caps. Given that the suppliers do have the potential ability to exercise market power, it is questionable whether they should be permitted to make market based offers for spinning reserve from synchronous condensing CTs. The MMU is continuing to monitor the offers of this supplier.

Conclusion

For spinning reserve, the long-term goal should be the establishment of a market which would be based on the acceptance of competitive bids to provide spinning reserve. In order for a competitive market in spinning to be viable, the market for spinning reserves needs to be broadened. Potential sources of supply in the spinning market include, among others, hydro resources, retrofitting of existing combustion turbines to add condensing capability, investment in condensing capability by new entrants into the PJM generation market and interruptible load capable of meeting PJM criteria for spinning. The creation of such a broader market might reduce or eliminate the current potential ability to exercise market power held by the owners of synchronous condensing CTs. The market power issue is also made less tractable by the inelasticity of demand for spinning reserves. It may be necessary, in the short run, to modify the current rules for the procurement of spinning reserve with the goal of inducing entry into the market as a step towards the introduction of a fully competitive market in spinning. It may also be necessary to reconsider the way in which PJM schedules reserves. PJM has taken steps to publish data on historical spinning offers and historical spinning purchase prices and quantities in an effort to provide information which might encourage economic entry. If additional modifications to the market structure for spinning can create opportunities for new entrants into this market, this will help to alleviate the concerns about market power and contribute to the conditions required for the establishment of a competitive market for the provision of spinning reserve.

Reactive Service

Introduction

The sources of reactive power are of two basic types, active and passive. Active sources have control systems that respond to system conditions and automatically adjust their reactive power output over a range. Only active sources can supply reactive power on demand. Generators are the primary active source, with synchronous condensers and static var compensators (SVCs) providing only a small fraction of system reactive power requirements. Passive sources include capacitors and transmission lines. Passive sources supply a relatively constant amount of reactive power that is proportional to local voltage levels. Although capacitors are static devices, their reactive power contribution can be varied by partially or fully switching them in and out of service which usually requires operator action. Capacitors are also used on local distribution systems to reduce the need to transfer reactive power to load.

Power flowing across a transmission system produces active and reactive power losses. Capacitors and the inherent capacitance of the transmission system have the ability to supply a significant portion of the reactive power losses of the transmission system. When transfers exceed a certain level, additional reactive power must be supplied by generators and other active sources which are operating. Control systems on these active sources will automatically increase their reactive power outputs to supply the reactive power necessary to maintain transmission system voltages. At some transfer level, depending on the available resources, operating reactive power resources will not be able to keep up with the reactive power losses of the transmission system and voltage will begin to decay. If this occurs, loading additional, strategically located units can improve the reactive situation either by reducing the total amount of power transfers and/or by providing additional reactive power. In general, reactive power cannot be readily transferred long distances without adverse effects on system voltage. The requirement for additional reactive power can, under many conditions, only be met by local generation resources. In other words, under many conditions, the reactive market can consist of very small and distinct local areas.

Reactive Definitions

Typically, all generators possess the capability to produce both real and reactive power. Generators are usually rated in terms of the maximum active and reactive power load that they can produce continuously. A typical generator capability curve is shown in Figure 1.[34] The graph shows the generator's reactive power (Q) capability along the vertical or y axis and the generator's active power (P) output along the horizontal or x axis. The generator capability curve shows the relationship between the capability of a generating unit to produce active and reactive power. For a given active power operating point, e.g. *Rated* on Figure 1, reactive power can be produced without significant additional cost, up to the limit defined by the generator capability curve, or 50 MVAR in Figure 1.

However, when the unit is producing MW and MVAR at levels consistent with the generator capability curve, there is an inverse relationship between the level of active power output and the level of reactive power which can be generated. When the unit is operating on the generator capability curve, if the unit produces more reactive power, it must produce less active power. A generator operating at rated output, *Rated* on Figure 1, would produce 95 MW of active power and have the capability to produce +50 MVAR of reactive power. If the generator reduced its active power output to operating point *Reduced* on Figure 1 it would provide less active power, 85 MW, but would have an increased reactive power capability of +75 MVAR.

34 This is a theoretical curve and there may in fact be a family of curves which result from technical constraints on the ability of a generating unit to produce reactive power.

Thus, the cost incurred by the generator to produce additional reactive power is the opportunity cost associated with producing less active power, i.e. the lost revenues associated with selling less active power.

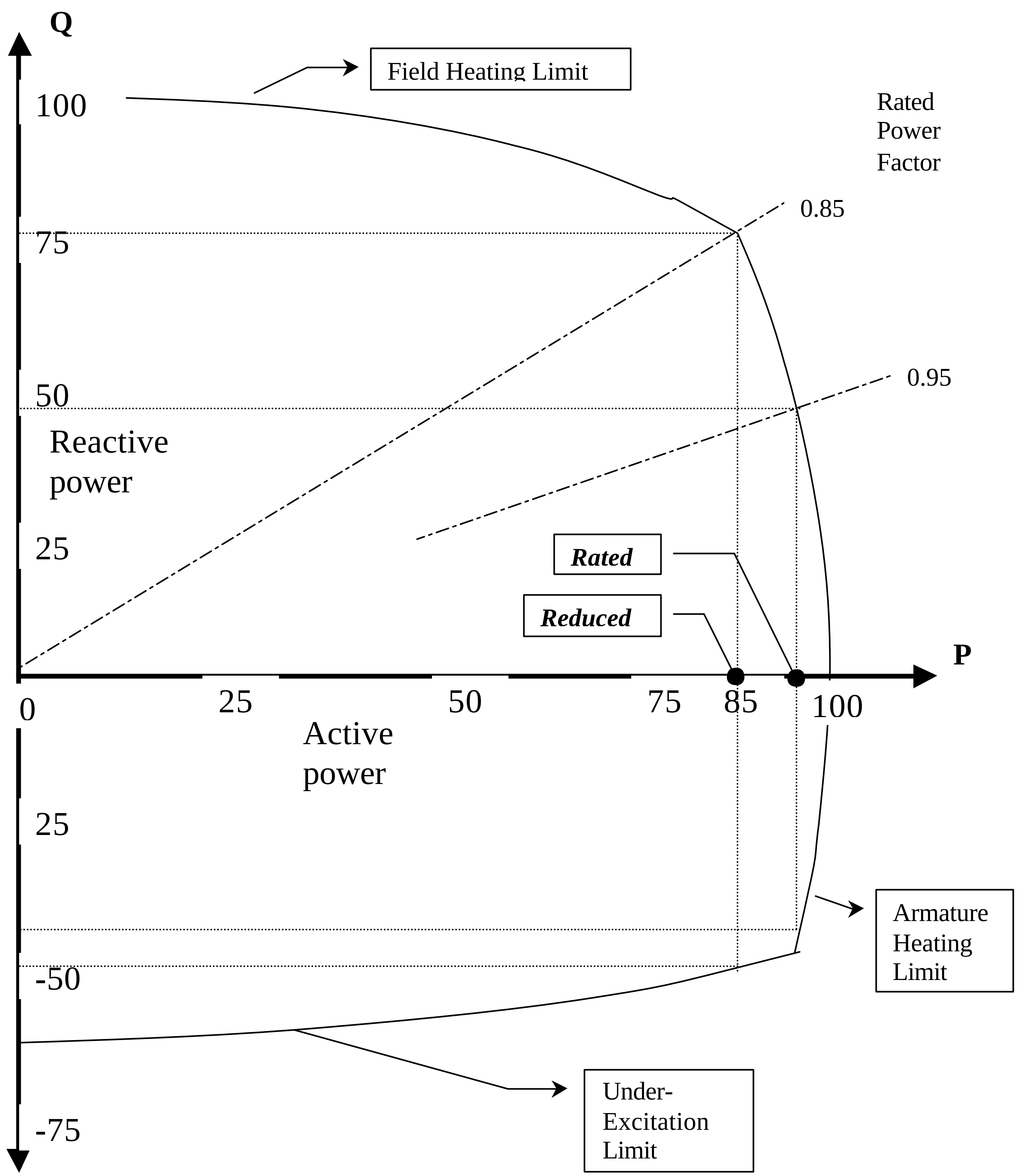
Rates for Reactive Power

Tariff

There are two distinct generator reactive power products in the PJM market: reactive power capability at rated generator output and reactive power provided at reduced generator output. Reactive power capability at rated generator output is the component that is incorporated into and compensated through the PJM Tariff. Control systems on generators react automatically to changing system conditions and increase or decrease generator reactive power output as needed to maintain local voltages within a bandwidth.

Reactive power charges are collected through Schedule 2 of the PJM Tariff, Reactive Supply and Voltage Control from Generation Sources Service. The PJM Tariff states that reactive supply and voltage control is to be supplied directly by the transmission provider. The FERC approved rates in the PJM Tariff provide for charges which are paid to transmission owners. These companies have defined, with FERC approval, the revenue requirement associated with the portion of their generation plant which is related to the production of reactive power for system voltage control. As a result, a relatively small proportion of the transmission owners' generation plant revenue requirement is collected via the reactive supply schedule of the PJM Tariff. FERC has approved zonal rates for PJM transmission owners for reactive power

Figure 1. Generator Capability Curve



production capability sufficient to cover that portion of their generation plant related revenue requirement. The rate is different for each company and currently averages $105/MW-month or $.3030/MWh on-peak on a pool-wide basis.

The current method of cost collection is based on a system in which integrated utilities both own generation resources and provide transmission service. However, as the result of the growing separation of ownership of generation and transmission, there are generators which do not own transmission and which therefore have no provision to receive payments for maintaining reactive power capability. Conversely, there are transmission owners which have divested their generation assets that are still collecting for reactive power through the transmission tariff although they no longer maintain reactive power capability.

As a result, the PJM Members Energy Market Committee ("EMC") commissioned a working group to develop a new reactive power rate structure. A proposal was presented to the EMC on November 11, 1999 and several revised proposals have been presented. The proposal is being finalized and has been submitted to the Tariff Advisory Committee for review. Under the revised proposal, all owners of PJM Capacity Resources would have the option to file with FERC to recover the costs associated with providing Reactive Supply and Voltage Control Service. Upon FERC approval of such revenue requirements, PJM would file the corresponding revisions to Schedule 2 of the PJM Tariff. The new reactive power rate structure would permit all owners of capacity resources to file for and to receive a share of Schedule 2 zonal revenues from PJM. When the proposal is finalized, a revised Schedule 2 filing will be submitted to the Commission.

Operating Agreement

MAAC Reliability Principles and Standards define a reliability obligation to provide adequate reactive power resources necessary to maintain system voltages within specified criteria. Schedule 2 of the PJM Tariff states: "In order to maintain transmission voltage on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider."

The defined level of required reactive power capability resources is based on planning criteria and is not an operational definition. Transmission owners (ultimately generation owners) recover revenues via reactive charges which cover the embedded costs associated with their obligation to provide reactive power capability as a provision of transmission service consistent with the PJM planning criteria.

In addition to the reactive power capability which is compensated via the PJM Tariff, additional reactive power may also be provided by reducing generator output. As described above, there is a tradeoff between real output and reactive output when the generator is on the capability curve. Thus, in order to produce an increased level of reactive power, a generator must produce less real power. Section 1.7.20(b) of the PJM Operating Agreement states that market sellers operating within the PJM control area shall respond to the Office of Interconnection's directives to "change reactive output levels." Under the PJM energy market design in place during the summer of 1999, generators were compensated for real power output via the energy market. PJM did not have a method to pay generators to reduce real power output and increase reactive power output.

A proposal to permit PJM to pay generators which reduce output at PJM's request to improve system control or for reliability was made at the November 11, 1998 EMC meeting. The proposal was developed and modified by a working group and was ultimately approved by the Members Committee at its August 26, 1999 meeting. Effective September 3, 1999 the Operating Reserves Section 3.2.3(c) of the PJM Operating Agreement was modified to permit, among other things, the payment to generators, including non-transmission owning generators, for the opportunity costs incurred as the result of increasing the production of reactive power by reducing generator output.[35] This opportunity cost payment is made directly to generators that are directed to reduce their active power output to allow for more reactive power output for system control or reliability purposes and that thus incur an opportunity cost equal to the LMP less their bid costs for each MW which they back down.

Conclusion

PJM has taken specific steps to make the provision of reactive power more consistent with the underlying economics of reactive power and to introduce market based solutions when possible. PJM is in the process of modifying the payment structure under the PJM Tariff to ensure that all owners of capacity resources can receive payment for the provision of reactive power capability when such generation provides reactive power capability. In addition, PJM has implemented a method which permits generators to be paid their market based opportunity costs when PJM requests that they reduce the output of real power in order to increase the output of reactive power in order to help maintain reliability within the PJM system. PJM will continue to examine the development of a market in reactive service, although the local nature of reactive requirements under some system conditions will make the development of markets more difficult than for the other ancillary services.

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[35] See Letter Order, issued October 27, 1999 in Docket No. ER99-4371.