STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

THREE EMPIRE STATE PLAZA, ALBANY, NY 12223-1350

Internet Address: http://www.dps.state.ny.us

PUBLIC SERVICE COMMISSION

MAUREEN O. HELMER
Chairman
THOMAS J. DUNLEAVY
JAMES D. BENNETT
LEONARD A. WEISS
NEAL N. GALVIN

LAWRENCE G. MALONE
General Counsel

JANET HAND DEIXLER
Secretary

December 3, 2002

Honorable Magalie R. Salas,
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1-A209
Washington, D.C. 20426

Re: Docket No. RM01-12-000 - Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electric Market Design

Dear Secretary Salas:

For filing, please find my comments as a speaker at the October 2, 2002 Staff Conference on Market Monitoring in the above-entitled proceeding. Should you have any questions, please feel free to contact me at (518) 474-8267.

Very truly yours,

Mark Reeder
Chief of Regulatory Economics

Attachments

RECOMMENDATIONS ON MARKET MONITORING

STANDARD MARKET DESIGN CONFERENCE
ON MARKET MONITORING

FERC Technical Conference
Docket No. RM01-12-000
Wednesday, October 2, 2002
Written Comments Submitted on December 3, 2002

by: Mark Reeder[1]
Chief of Regulatory Economics
NYS Department of Public Service
e-mail: mark_reeder@dps.state.ny.us
518-474-8267

[1] The views expressed in this paper are those of the author and do not necessarily represent the views of the Department of Public Service or the New York Public Service Commission.

RECOMMENDATIONS ON MARKET MONITORING

STANDARD MARKET DESIGN CONFERENCE
ON MARKET MONITORING

FERC Technical Conference
Docket No. RM01-12-000
Wednesday, October 2, 2002

by: Mark Reeder

Introduction

Thank you very much for inviting me to come here today to share my views on market monitoring and mitigation. FERC serves the industry and itself well by holding technical conferences of this type and inviting so many qualified speakers to appear and share their views. Processes like these contribute substantially to improved understanding and better decision making.

We at the New York Public Service Commission (NYPSC) believe that we have a perspective that is valuable to share with the FERC in helping you to do as good a job as possible in your own monitoring efforts. Our staff has access to the confidential data at the New York Independent System Operator (NYISO). We evaluate bids and other data to gauge the competitiveness of the markets and to look for anomalous behavior that may be indicative of market power. Thus, we have hands-on experience in the data issues that are at the heart of this conference.

We are regulators, like FERC, and we are pursuing a policy in which we believe markets—specifically, competitive markets—best serve consumers. Like FERC, however, we acknowledge the current imperfections in the markets and the need for market monitoring units (MMUs) to vigorously monitor them, and even to intervene where it is thought that intervention serves consumers better than not doing so. We think that our perspective, as regulators, is valuable to FERC.

My overall observations, before I turn to some specific areas, are that the FERC Notice of Proposed Rulemaking (NOPR) and the staff paper distributed in preparation for this conference have done an excellent job of identifying needed data analyses. Most of the key analyses that I would recommend have been described in these documents. Furthermore, I applaud FERC's goal of bringing consistency in the types of a data analysis that is done across independent transmission providers. Such consistency will be a great benefit to entities of all kinds that desire to understand the competitiveness of markets in any one particular place or across the nation as a whole.

Look at Bids and Look at Bills

One question posed to me is to describe the most valuable kinds of data analysis that the NYPSC does. My advice to the FERC is to do two things. First, look at the bids, and look at them often. Set up algorithms that can compare bids to

your own estimates of marginal costs and identify situations in which bids deviate dramatically from marginal costs. When unusually high bids occur, ask a lot of questions of the ISO. Keep them on their toes; implore them to explain why the bids are reasonable, and if they are not reasonable, why they should or should not be subject to mitigation. Second, look at the bills of generating companies and individual generators. By looking at bills, one can spot an unusually large payment or a pattern of unusually large payments that can be indicative of a market power problem (but not necessarily so). Simply looking at bids does not tell one whether or not the bids were accepted and resulted in unreasonable prices. But, looking at bills gives one an indication of situations in which unusually high bids have been accepted. Such situations trigger the need to look further.

While there are many other analyses that one can do with the confidential data, these two are the most important ones, and tend to the be most revealing. For example, while one can look at a wide variety of data analyses, there is nothing like seeing extraordinarily high bids occurring over and over again. Such an observation hits one square in the face and immediately focuses one’s inquiry on the player submitting the unusually high bids in an attempt to determine the cause, and whether or not there is a market power problem. Keep in mind

that high bids sometimes manifest themselves in uplift payments, such as the uplift payments for out-of-merit generation, and therefore fail to produce price spikes that attract the attention of analysts.

Competitive Reference Bids (Reference Levels)

The Importance of Valid Competitive Reference Bids

The FERC NOPR uses the concept of Competitive Reference Bids. A Competitive Reference Bid is an estimate of a reasonable bid, a.k.a. a bid that an entity facing full competition would submit. The FERC NOPR also refers to them as "bid caps." In New York State, they are called "reference levels" or sometimes "reference prices." The effective detection of market power and mitigation of market power absolutely requires valid and up-to-date estimates of Competitive Reference Bids. If a MMU is not using good quality Competitive Reference Bids, then it will have difficulty properly detecting market power and, when mitigating, will mitigate to the wrong bid level. As such, nothing could be more important to the effective implementation of a monitoring and mitigation effort.

One approach to developing Competitive Reference Bids is to use the average of accepted bids from a generator, given that the accepted bids occurred during times (e.g., hours, months) of effective competition. However, as I will discuss

more fully a little later, there are often instances in which accepted bids cannot be used either because there are not enough of them, or they do exist but do not come from a competitive environment. In such a situation, and these situations occur often and are important, an alternative methodology is needed to estimate Competitive Reference Bids.

FERC Guidance on Generic Estimation Methodologies is Needed

The basic task in developing a Competitive Reference Bid is to estimate the short-run marginal cost of production of a generator. This is hard to do. It is not straightforward. It involves lots of issues and lots of judgment. At the NYPSC, we know that this is a difficult exercise because we've tackled it for 25 years' worth of marginal cost studies and, in the last 3 years, as part of our efforts on ISO mitigation matters.

A generic methodology to guide the estimation of Competitive Reference Bids, issued by FERC, is needed: 1) to ensure the reasonableness of the Competitive Reference Bids, so that both buyers and sellers can be assured that the mitigation is being done properly by a given ITP; and 2) to ensure the consistency in the estimation of Competitive Reference Bids across ITPs. In order for the FERC to be confident that the mitigation policies are producing just and reasonable rates, it is critical that the Competitive Reference Bids, which are the single most critical component in mitigation, are being

estimated reasonably. Consumers will be assured of adequate protection from uncompetitive markets that contain market power problems only if FERC is explicit in setting forth policies that guide ITPs in estimating Competitive Reference Bids. Furthermore, many generators have significant questions about the processes used by ISOs in estimating Competitive Reference Bids, and these generators face uncertainty about prospective mitigation activities; this uncertainty can be lessened by methodological guidance on marginal cost estimation by the FERC.

Finally, for many of the data analyses that have been discussed and recommended at this conference, the comparison of the results across ITPs is valuable only to the extent that the estimates of marginal costs, a.k.a. Competitive Reference Bids, are reasonably consistent across ITPs. For example, if price is $70 in two different regions, but one ITP estimates marginal cost to be $65, whereas the other estimates it to be $40, the estimates of Lerner Indexes (which key off of the difference between price and marginal cost) will differ dramatically from the one region to the other, tempting the policymaker to conclude that there is a big difference in the competitiveness between the two regions when the real difference is just in how each ITP estimates marginal costs.

The Unbalanced Process for Establishing Competitive Reference Bids

Consider the process by which an ITP estimates a given generator's marginal cost for use as its Competitive Reference Bid. Due to confidentiality concerns, no market parties other than the individual generation owner whose marginal costs are being estimated are allowed to be part of the process. Where the only two entities involved in estimation of Competitive Reference Bids are the generation owner and the ITP, the process is unbalanced. The ISO is the adjudicator that decides what the Competitive Reference Bid should be and it hears pleadings from the generator, presumably arguments for the ISO to adjust its initial estimate upward. An obvious weakness of this process is that there is no counterpart at the table to make a case for downward adjustments that may be warranted. One would expect a generator that observes an overstated marginal cost estimate to stay silent and allow it to remain in place, whereas any components of the marginal cost estimates that appear to be understated will surely be highlighted by the generator. Unless the ITP does a perfect job, with imperfect information, such a process would, on average, lead to overstated Competitive Reference Bids.

Not only is the process unbalanced, the results of the process—the Competitive Reference Bid itself—is considered

confidential and remains completely out of the view of all of the market parties, other than the generator. As such, consumers and consumer advocates have no idea what the Competitive Reference Bids that their ITP is using actually are. They do not know enough to complain about overstated Competitive Reference Bids because they have no way of knowing whether they are overstated.

I suggest two ways of addressing this unbalanced, confidential process. First, ITPs should be required to publish aggregate information on Competitive Reference Bids. Consistent with retaining confidentiality, subaggregations should be published, such as average Competitive Reference Bids by types of generators (e.g., peakers, baseload) and the average levels of the various components of a Competitive Reference Bid (for example, fuel costs, variable O&M costs, environmental compliance costs, etc.). Second, the FERC should establish a review process, one in which confidential data continues to be protected, by which the FERC would screen Competitive Reference Bids and cull out just a few for review each year. Certain generating units will stand out as critical ones from a market power mitigation perspective, and can be reviewed more often than other units. For example, the bids of peakers tend to be more important in setting competitive market clearing prices during times of high load than the bids of other units, since

the profitable exercise of market power by a generation firm that owns a fleet of units is easier done via the economic withholding of its peaking units than its baseload units. Furthermore, generators located in transmission-constrained areas would be high priority candidates for review. Some review process of this type is needed, since the buying side of the market has no way of requesting review of specific values that they cannot see.

Pitfalls of the Accepted Bid Method

The SMD notes that the Commission has approved a method of setting Competitive Reference Bids in which they are set equal to the average of the previously accepted in-merit bids of a generator (paragraph 420). The use of accepted bids to establish Competitive Reference Bids can work quite well for some generating units, such as baseload units, but can work poorly for other types of units, especially peaking units. It is important to understand the pitfalls of using accepted bids as the basis for Competitive Reference Bids for peaking units, and therefore to appreciate the importance of estimating the marginal costs of such units, since marginal cost estimation is what will, in many cases, need to be used to establish the Competitive Reference Bids for peaking units.

Consider a generating firm that has a fleet that consists of 2,000 megawatts of baseload units and 500 megawatts

of highly inefficient, older vintage, peakers. This firm's peakers will hardly ever run, since they are among the most expensive units in the system. Another way of looking at it is to note that the firm's peaking units are located on the steep part of the supply curve, or, at best, at the very end of the non-steep part of the curve, just before the curve goes vertical. A generation firm with this kind of portfolio could well find it profitable to have a policy of submitting bids for the peakers that are $100 above their marginal costs for every hour of the year. The reason it is profitable is that the peakers, if bid competitively, would act as a brake that helps prevent prices from rising to extremely high levels during high load situations. By economically withholding the peakers, through the use of excessively high bids, the generation firm can force the system to slide up the steep part of the supply curve in any hour in which the peakers would otherwise have been found economic. This drives the price up dramatically any time the peakers would otherwise have been needed, but does not cause the firm to forego much in terms of profits from the peaking units themselves, since they virtually never run at any other times other than the high load periods in which market power is profitable.

Thus, a profitable strategy is to bid the peakers at $200, for example, every hour of the year. The peaker's $200

bids will inevitably be accepted during the heat waves, or perhaps on extremely cold days, but not at other times. As far as establishing Competitive Reference Bids, these units will produce a pattern of $200 accepted bids which would yield a Competitive Reference Bid of $200. The obvious problem here is that the accepted $200 bids should not be considered useful data because they do not come out of a competitive bidding strategy.

Any relatively high-cost peaking unit is susceptible to a bidding strategy like the one described above. Such a strategy makes the accepted bid methodology for establishing Competitive Reference Bids invalid for the peaking units that use this strategy. It is, therefore, important for all MMUs to examine the results that are obtained from an accepted bid methodology by comparing the average of the accepted bids to estimates of marginal costs. Where there is a substantial difference, one must check carefully to determine whether the marginal cost estimate actually forms a better basis for the Competitive Reference Bid than does the average of accepted bids. In practice, it might make sense to use marginal cost estimates rather than accepted bids for the bulk of the peaking units in any given electric system. This is especially so for peaking units that are in load pockets, since such units tend to operate in situations that are not competitive.

Lerner Indices

There are three types of Lerner Indices that would appear to be valuable in examining the competitiveness of wholesale electricity markets. First is the standard Lerner Index, which is a comparison of the market price of electricity to the market's marginal cost of providing it. Second is a comparison of the annual revenue stream that the market's actual prices would yield for a new entrant to the marginal cost of entry, i.e., to the full total cost (annualized) of a new entrant. Third is a variation of the Lerner Index in which one measures, on a generator-by-generator basis, the difference between the energy bids of each generating unit and its marginal costs, and then aggregates this difference over all of the units in the system to get an overall system average differential between bids and marginal costs. This last version of a Lerner Index is the one that I would like to focus your attention on and recommend be used in addition to the other two more commonly discussed versions. But first, let me describe the other two.

Lerner Index 1 – Market Price vs. Market Marginal Cost

In its most pure form, the Lerner Index involves a comparison of the market's price to the market's marginal cost of providing the marginal unit of output. The easy part of this calculation is to measure the market's prices, which can be separately stated for every hour of the year; averaged over the

year; or stated in terms of averages during high load periods, medium load periods, etc. The hard part of the calculation is estimating the market's marginal cost. What makes this so difficult is not necessarily measuring the marginal cost of each individual unit, although as I have described above in my Competitive Reference Bid comments, this itself is a difficult task. Rather, the hard part is to model the electric system under the hypothetical scenario in which each generator's bids equal its marginal costs, and then to simulate the system's flow of power, etc., to produce an estimate of what the market's marginal cost is. Stated another way, this modeling exercise produces an estimate of what the market price would have been if, hypothetically, all generating units had bid their marginal costs.

A substantial amount of work has been done on the modeling complexities, and the approach is reasonably well understood.[2] It is a good approach and should be used. Its downside, however, is the substantial room for error in the modeling of the system. Thus, when comparing from one region to another, there will invariably be modeling infirmities, and/or differences in modeling methods, that are the cause of some of the apparent differences in competitiveness across regions, no

[2] Severin Borenstein, James Bushnell, and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale

matter how hard one tries to get the modeling as good as it can be. This does not make the method useless; it just makes it something to use with caution.

Lerner Index 2 – Profitability of New Entry

A second variation of the Lerner Index is to look at the revenues and costs of a hypothetical new entrant. Like the above form of the Lerner Index, this involves a comparison of actual prices produced by the market in a given year to an estimate of cost, in this case, an estimate of the full annualized costs incurred by a hypothetical new generation entrant. One hypothesizes a new entrant, such as a combined cycle gas turbine, and estimates how often it would have run in the most recent year and what prices it would have received under the prevailing actual market clearing prices. This generates an annual revenue estimate for the new entrant. This is then compared to an estimate of the annualized costs of the new entrant, including a normal rate of return. The annual revenue estimate is the "price" in the Lerner Index, and the estimate of the annual cost of the new entrant is the "cost" in the Lerner Index. In long-run equilibrium, a market that is effectively competitive will yield annual revenues for a new entrant that do not very significantly from its annualized cost.

Electricity Market," American Economic Review, 92(5), December 2002 (forthcoming).

The new entry version of the Lerner Index is easier to calculate than the more pure version of a Lerner Index described above, but one must be careful in interpreting the results. The results are most easily interpreted if the electric system is in a part of its long-run cycle in which it is characterized by neither excess capacity nor tightness. In such a year, the annual revenue stream the Lerner Index would produce should be about equal to the cost of a new entrant if the market is competitive. An annual revenue level that exceeds annual cost would indicate the lack of effective competition and the opposite relationship would indicate a problem of the market producing prices that are too low. For a market with excess capacity, one would expect the revenue stream for a new entrant to be less than the cost of the new entrant. If that is the result that is observed, the market may be working fine. Conversely, during a year in which an inadequate amount of installed generation exists, one would expect the market-based revenue stream to lie above the cost of new entry. While interpreting the results of a Lerner Index based on the revenues and cost of a new entrant requires care, the exercise is useful enough to be worth doing, especially since it is easier to calculate than the more complicated hour-by-hour, pure Lerner Index 1.

The analysis would probably need to be done for several types of units, including, at the minimum, a baseload unit and a peaking unit. This is because an electric system may have a sufficient amount of one type of unit but be in need of another type, or vice versa. The new entrant version of the Lerner Index is a long-run measure, which looks at whether or not the system, over time, produces prices that equilibrate around the cost of new entry. A system that does so can be considered workably competitive. A system that consistently produces prices that lie above the cost of new entry is one that has a persistent market power problem. As with the first form of the Lerner Index, the controversial and most difficult part of the analysis is the estimation of the cost of new entry. If the FERC were to mandate that this analysis be done by all ITPs, it should direct the ITPs to work toward consistent approaches and assumptions, where possible, in the methodologies used across the ITPs to estimate the cost of new entry.

Lerner Index 3 - Bids versus Marginal Costs

A third kind of Lerner Index is to simply compare the bids of generating units to their marginal costs. While this is commonly done by a MMU in looking for individual instances of improper behavior on the part of a generator, it can also be used, in aggregate, as a measure of the overall competitiveness of the market. In theory, a generating unit facing effective

competition will submit bids that equal its marginal cost. If the average of the bids of all generators was observed to be quite close to the average of those generators' marginal costs, the market would be demonstrating much more competitive behavior than if the average of the bids was well above the average of the marginal costs.

This version of a Lerner Index is the easiest of the three to calculate, although only the ITPs can calculate it because it requires access to confidential bid data. One simply needs to have estimates of the marginal costs of all of the generating units in the system. Fortunately, such estimates should be readily available because Competitive Reference Bids are used in the detection and mitigation of market power as part of the SMD. Having valid methods of estimating Competitive Reference Bids is paramount; a reasonable measure of a bid-based Lerner Index requires that they be valid. Furthermore, for comparison purposes, it is important that the marginal cost estimation methods used across different ITPs be reasonably consistent.

The aggregations used in calculating aggregate measures of the differences between bids and marginal costs would need to be carefully considered, due to the possible unusual bidding pattern of certain types of units, and the need to eliminate some of the bidding data from the analysis. For

example, many baseload units bid zero, negative, or some other value well below their running cost for the minimum-load portion of the unit. This is done because the operators of the units do not want to have to stop and start such units often. One way of dealing with this data issue is to limit the analysis, as regards baseload units, to the portion of the units that lies beyond their minimum loadings. Similarly, the bids of hydro units may need to be either excluded or treated in a special way because marginal cost estimates are hard to come by and depend primarily on the marginal opportunity costs of generating at one time of the day versus another. Despite these limitations, valuable aggregate measures of the differences between bids and marginal costs can be had for fossil units, at a minimum, and can be reported separately for aggregates of baseload units, peaking units, or other groupings. Comparisons of such a Lerner Index for a single system through time, or across different systems, would yield valuable insights into the effectiveness of competition. Because of the ease with which this method can be estimated, and because it produces publicly available aggregate information about confidential bids that otherwise remain hidden to interested parties, I recommend that it be included in the core set of analyses that the FERC mandates.

Estimation of Supply Elasticities and Demand Elasticities

Market power is most easily exercised at times when the price elasticity of supply is very low, i.e., when the market is clearing on the steep portion of the supply curve. The technical way of measuring the steepness of the supply curve is to measure the price elasticity of supply. It will vary along the curve, being generally large on the flat portion of the supply curve and low in the steeper ranges. A MMU should be aware of the place on the supply curve at which the price elasticity of supply becomes so small that the exercise of market power by the system's largest firms becomes profitable. Hopefully, other than in transmission-constrained load pockets, this will occur for only a very few hours of the year in which the system is at its highest load levels.

Similarly, the price elasticity of demand should be measured by the MMU. Based on the demand response programs that are operable in the system, including any real-time pricing that is occurring, the MMU should have estimates of the short-run price elasticity of demand that would come into play to moderate the increase in price that might result from an attempt at market power. The sum of the supply and demand elasticities yields an overall measure of the extent to which prices will rise in response to the withholding of supply.

With data in hand on both the price elasticity of supply and the price elasticity of demand at various price

levels, the MMU will be armed with a solid awareness of the times in which the system is vulnerable to market power and in which it must be prepared to mitigate in the event that an attempt at market power occurs. Hopefully, demand response programs will continue to expand, and will do so to the point at which the sum of the price elasticities of supply and demand will be large enough to frustrate virtually any attempt at market power (avoiding large market shares is also very important), and thereby allow the FERC to relax its market monitoring efforts. By monitoring these elasticities over time, the MMU can keep track of the extent to which the system is making progress toward such a goal, and can report on that progress.

Econometric Modeling of Market Prices

In recent years, attempts to casually observe prices from year to year and draw conclusions about whether those prices indicate increased competitiveness or reduced competitiveness of electric wholesale markets, have been difficult because of the large year-to-year variations in, among other things, fuel prices. Other factors that have a significant impact on prices in any given year are the weather (or more directly the load levels) and the outages of generators. Changes from year to year in the outages of nuclear plants, in gas prices, and in the intensity of heat

waves can have such large impacts on the average level of prices that it becomes difficult to sort out these effects in one's mind in making comparisons of prices from one year to another. In effect, these dominant variables camouflage one's ability to see the effect of changes in the competitiveness of the market on prices over time.

One way to address this problem is to build econometric models that use fuel prices, load levels, and generation availability as explanatory variables in regression equations that attempt to explain movements in the wholesale price. An econometric model built for this purpose, if successful, can be used to "normalize" the effects of weather, fuel prices, and generator outages, and allow one to see what is happening to prices over time in the absence of changes in these variables. For example, once an econometric model has produced parameters for the above variables, "normal" values can be assumed for them and the model can produce values for the actual prices, adjusted to reflect normal levels of these key explanatory variables. These normalized prices can then be more easily evaluated in an attempt to identify movements in the market price over time that might reflect changes in competitiveness; the impacts of policy changes, such as mitigation; or other factors.

While this is a difficult exercise, it is well worth doing and, given that most of the data is publicly available, MMUs and the FERC could encourage the academic community to take the lead in developing this kind of analysis. In New York, we have begun work on econometric models to explain these factors, and have met with some limited success, while still having models that are in the preliminary stages and that need further work.

MMUs Should Publicize Their Mitigation Activities

The FERC should require that all MMUs that have mitigation measures promptly post on their websites all mitigation activity that takes place. Preferably, the ITP should maintain a place on its website in which all mitigation activities are documented and a history of mitigation activities is maintained and regularly updated. It is important for interested parties to be aware of the mitigation activities of a MMU. For example, policymakers like to know how often mitigation is taking place so that, for example, judgments can be made about the natural competitiveness of the marketplace based on how often the MMU must intervene in the marketplace in the form of mitigation activity. Market participants, in their attempts to understand what drives prices in the marketplace, need to know when a mitigation event has occurred that may have caused a sudden drop in prices. Otherwise, market participants

are left attempting to explain the drop in prices with other market phenomenon and obtain a confused and incorrect understanding of the workings of the marketplace. As such, in order for market participants to understand their own marketplace as much as possible, they need to be provided with complete and timely information about mitigation activities. I think this is an example where more public information is a good thing and I can see no downside to it.

Conclusion

I embrace the strong emphasis that FERC's SMD has placed on market power mitigation and monitoring. The detailed effort to explore best practices on data analysis is to be commended, and the proposal to establish a core set of questions and analytical techniques that all ITPs must use is a good one. Any questions on any of the comments made above are welcomed.

Respectfully submitted,

Mark Reeder
Chief of Regulatory Economics

New York State Department of
Public Service
3 Empire State Plaza
Albany, NY 12223-1305
(518) 474-8267

Dated: December 3, 2002
Albany, New York

CERTIFICATE OF SERVICE

I, Naomi Tague, do hereby certify that I will serve on December 3, 2002, the foregoing Comments of Mark Reeder, Chief of Regulatory Economics of the New York State Department of Public Service by depositing a copy thereof, first class postage prepaid, in the United States mail, properly addressed to each of the parties of record, indicated on the official service list compiled by the Secretary in this proceeding.

Date: December 3, 2002
Albany, New York

Naomi Tague