

## Changes To The FERC's Market-Based Rates Requirements

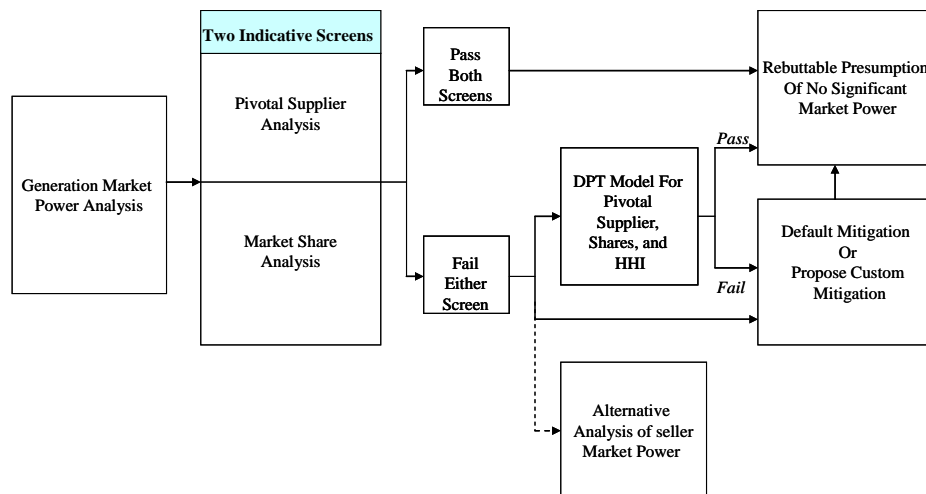
### I. INTRODUCTION

For the fourth time in its history, the Federal Energy Regulatory Commission (FERC) last week issued an order setting its procedures for granting market-based rate (MBR) authority to wholesale power sellers (Order 697 or the Order).<sup>1</sup> This time around, the Commission maintained the basic framework of the tests that qualify sellers for MBR authority originally set in its April, 2004 Order.<sup>2</sup> However, the Commission made several significant changes to the tests that will both help and hurt sellers seeking MBR approvals, including certain new provisions for default mitigation.

Overall, the Order increases the Commission's oversight of market-based rates by clarifying several aspects of its market power analyses, imposing greater on-going filing requirements as a condition of obtaining and retaining MBR authority, and requiring MBR tariffs to contain certain standard provisions. The FERC anticipates that these improvements will discharge its statutory duty and respond to criticisms that its past market power enforcement protocols were not adequate.<sup>3</sup>

### II. HORIZONTAL MARKET POWER

In Order 697, the Commission retained the core elements of the April 14, 2004 generation market power test, which contains a two-step procedure: (1) the two indicative screens [a pivotal supplier screen (PSS) and market share screen (MSS)] as an initial screen, and (2) the delivered price test (DPT)—the same test used for approving mergers and acquisitions—as a second test if a seller fails either one of the two indicative screens.<sup>4</sup> Figure 1 below, reproduced from our April, 2004 review, shows the pathways to MBR approval under the Commission's procedure.



**Figure 1**  
*FERC's Horizontal Market Power Analyses for Obtaining and Retaining MBR Authority*

While the basic architecture of the tests remains the same, certain components of the screens were modified and clarified by the Commission. In our view, the most significant modifications to the *horizontal* market power screens include the following:

### **1. Native Load Proxy for MSS**

To calculate uncommitted capacity for the MSS, the Commission replaced minimum daily peak load with average daily peak load within each season. This new native load proxy is an improvement for many sellers who are load-serving entities (LSEs) within franchise areas. Nevertheless, we caution that LSEs may not be guaranteed a lower market share by the new rules in every market, as other LSEs' uncommitted capacity may also be relatively lower and the market may become more concentrated overall.

### **2. POLR Load Deductible by IPPs**

The new change in this area is that the Commission may allow Independent Power Producers (IPPs) to deduct their short-term POLR contract obligations to LSE buyers -- though only if they can show that the power sold to franchised utilities was used to meet native load. The Commission continues to allow IPPs to deduct their retail contracts or provider of last resort (POLR) with a term of one year or more from their total capacity. This will call for some new certifications and determinations and may prove to be controversial in some instances.

### **3. Contractual Control Over Generation**

In performing the horizontal market power test, the Commission requires that a supplier's capacity must include its owned and controlled resources. Certain types of contracts may confer upon an entity rights of control over power plants essentially equivalent to ownership. Agreeing with our comments in the NOPR, the Commission did not make a generic finding on presumption of control, instead concluding that the determination of control should be made on a fact-specific basis in view of the totality of circumstances.

As we explained in our comments, nowadays many innovative types of agreements have been created, and thus there is no longer an absolute certainty that degree of control over the resources involved in a long-term purchase power contract is readily identifiable or assigned to a buyer or seller.

We provided examples of contracts that may convey different degree of control to buyers or sellers. We suggested that the details of each contract vary, depending upon parties and circumstances involved as well as on conditions in the market place, and it must be reviewed and evaluated with care. The Commission therefore requires sellers to submit their contracts and make an affirmative statement as to whether their contractual arrangements result in the transfer of control of any assets. Sellers must also provide a "letter of concurrence" from affected parties identifying the degree to which each party has control of generation facilities.

### **4. Relevant Geographic Markets**

There is no change in the Commission's *default relevant geographic market* definition, namely the control area (including an RTO/ISO).<sup>5</sup> However, again in agreement with our NOPR comments, the Commission allows for an exception if it makes a specific finding that there is a submarket within an RTO or other control area. In this case, sellers in an RTO/ISO must prepare the indicative screens or DPT based on the submarkets identified. For example, the Commission has found that PJM-East and Northern PSEG are markets within PJM; Southwestern Connecticut and Connecticut are separate markets within ISO-New England, and New York City and Long Island are separate markets within the NYISO. Alternative geographic markets will be considered by the Commission only if a seller shows how often transmission constraints are binding during peak periods using historical data.

### **5. Nameplate or Seasonal Capacity**

The Commission now allows the use of either nameplate or seasonal capacity in calculating a supplier's uncommitted capacity, whereas prior practice employed nameplate capacity only.

## **II. VERTICAL MARKET POWER**

For an assessment of vertical market power, the Commission continues to require that a seller (or its affiliate) who owns and controls transmission facilities file a Commission-approved open access transmission tariff (OATT). If the Commission finds a nexus

between the specific facts relating to an OATT violation and the seller's MBR authority, the Commission may revoke its MBR authority, disgorge its profit, or impose civil penalties. The Commission makes it clear in the Order that if a transmission provider loses its MBR authority in a particular market as a result of an OATT violation, there is a rebuttal presumption that all affiliates also lose their MBR authority in the same market as well.

In addition, under this new rule the Commission will review "other barriers to entry" as part of the vertical market power. A seller is required to address its ability to erect barriers to entry if the seller or its affiliate owns or controls *intrastate* natural gas transportation, storage or distribution facilities, sites for generation capacity development, and/or sources of coal supplies or transportation of coal supplies, such as barges and rail cars. The seller must provide a description of the assets and an affirmative statement that it has not erected, nor will it erect, barriers to entry into the relevant market. The Commission does not require the description or an affirmative statement from sellers with ownership or control of interstate natural gas transportation, oil supply, and oil transportation.

### III. MITIGATION

Mitigation is one of the most difficult issues in market power enforcement, and it has been especially difficult in the MBR setting in the absence of clear benchmarks from the FERC. In principle, the primary focus of a mitigation measure is to prevent suppliers from exercising market power, while maximizing opportunities for the use of cost-reducing competition. A well-designed mitigation measure should offer an effective solution, guarantee a mitigated seller's cost recovery within regulatory risk parameters, provide investment incentives for entrants, and be easy to administer.

With this Order, the FERC adopted a set of default mitigation price levels, initially issued in the 2004 MBR order, as shown in Table 1.

Products	FERC's Default Mitigations
One Week or Less	Incremental cost plus 10 percent adder
Greater than One Week but Less than One year	"Up to" cost based rate based on its expected capacity factor to meet the sales
Greater than One Year	Embedded cost-of-services

*Table 1: FERC's Default Mitigations*

For sales of one-week or less, the default mitigated price is set at incremental cost plus 10 percent. For sales of more than one week but less than a year, the Commission's default mitigation rate methodology is based on an "up to" cost-based rate, and for sales of one year or longer, the default mitigated rate is based on embedded cost-of-services.

Nevertheless, the Commission stated that these default mitigation rates are only deemed as a backstop measure in an event that a mitigated seller does not opt to propose its own mitigation. The Commission permits sellers to submit other methodologies as alternatives to default cost-based rates and will examine the proposed non-default mitigation measures on a case-by-case basis. For example, for sales of one-week or less, a seller may design an "up-to" rate as long as the proposed rate design eliminates its ability to exercise market power. The Commission's rate policy allows a seller to recover prudent incurred costs plus a reasonable return on investment.<sup>6</sup> For example, in Docket No. ER05-1082 the Commission approved Progress Energy's mitigated cost-based "up-to" capacity charge and a cost-based energy charge for power sales of less than one year, including sales of one week or less.<sup>7</sup>

The use of a price cap or "up to" rate is useful as it allows suppliers the flexibility to conduct their transactions at prices below the cap, as well as up to the cap when, for example, there are binding transmission constraints. A variation of approaches can be used to design the price cap.

For example, in our comments submitted to the MBR NOPR, we suggested setting the cap at a level that reflects the incremental cost of new entry in order to encourage new investment. A cost of new entry approach allows the price cap to be somewhat formulaic and generic, based on the estimated annualized total cost of building a new combustion turbine peaking facility, or some other technology choice likely to be built in a mitigated market. This will reduce subjectivity when determining units used as the foundation of a cost-based rate and attract new sources of supply.

Although the Commission believes that alternative methods of mitigation should be cost-based, the Commission is willing to consider “market-based” mitigation on a case-by-case basis. But sellers must show why and how an index-based price of one market is relevant to their markets and is just and reasonable.<sup>8</sup> Sellers wishing to use this approach will need significant data and analysis to prove their point.

With respect to the Commission’s question on whether a seller that is subject to mitigation in its home control area should be allowed to sell power at market-based rates outside its control area, the Commission declined to impose a must-offer requirement or a “right of first refusal” as a generic mitigation for sellers who fail the MBR screens in their home control areas.

A must-offer requirement is normally designed to mitigate physical withholding. We stated in our comments that this form of mitigation may work well in an organized power market where an independent operator ensures that the power is used to serve the local needs caused by reliability or local resource deficiency, rather than remarketing the power outside the control area. Without an independent operator, a must-offer requirement is more difficult to administer, but may be imposed on specific generating units under specific conditions, such as transmission outages or transmission constraints. The Commission concluded that it will consider a must-offer requirement on a case-by-case basis—a point emphasized by Commissioner Kelly in her concurrence.

Additionally, the Commission allows mitigated sellers to make MBR sales at metered boundaries between mitigated and non-mitigated balancing authority areas. However, mitigated sellers must maintain information related to the

sales for a period of five years in order to demonstrate that their sales are not intended to serve load in the sellers’ mitigated markets, and to ensure that no affiliate will ricochet the power back into the mitigated sellers’ mitigated market. This requirement is imposed directly upon mitigated sellers’ MBR tariff if they seek to make MBR sales at the metered boundary.

#### IV. CHANGES IN THE IMPLEMENTATION PROCESS

A few important changes that the Commission put forth to streamline the administration of its MBR program include the following:

##### ***1. Streamlined Reporting Format***

The Commission streamlined the reporting format for the two indicative screen analyses. A uniform formatting will increase consistency and aid the Commission in its decision making process.

##### ***2. Set Regional Schedules for Triennial Market Power Analyses***

The Commission set schedules that require sellers to update their market power analyses by region on a regular basis. MBR sellers in the Northeast region, which includes PJM, NYISO, and ISO-NE, are required to file their updated analyses between December 1, 2007 and December 30, 2007. Schedules for other sellers can be found in the reproduced regional schedule from Appendix D of the FERC Order 697.

##### ***3. Sellers with 500 MW or Less (Category 1) Need Not File Updated Market Power Analyses***

Sellers with generating capacity of 500 MW or less who are not affiliated with a public utility and do not own or control transmission facilities will not be required to file a regularly scheduled triennial review. However, these sellers must make their filings with the Commission at the time of their regional schedule for their triennial market power review, explaining why they meet Category 1 criteria. Once the Commission approves, the Category 1 sellers will not be required to file their updated market power analyses unless there are changes in their characteristics that trigger a change in status filing.

#### 4. Sellers with Greater Than 500 MW or More (Category 2) Need to File Updated Market Power Analyses

To enhance Commission oversight, Category 2 sellers must file updated market power analyses at the time of their regional schedule. They also must continue to file their change in status as required in the FERC Order 652 no later than 30 days after such change takes effect.<sup>9</sup>

#### 5. New Generation Commenced On or After July 9, 1996 No Longer Exempt from Submitting Market Power Analysis

To ensure that the seller does not have market power in generation, the Commission eliminates the exemption provided in § 35.27(a).

## V. CONCLUSION

The Commission found a workable middle ground in this latest MBR framework and clearly improved several nagging problems. While we continue to be concerned that the MSS screen produces too many false positives, the modifications to the screens are generally on target. The solution to the MBR boundary problem is an elegant way around a must-offer requirement; we will all have to see how well it works in practice. With new guidelines for mitigation and many other technical clarifications, we congratulate the Commission for an impressive, hard-won accomplishment.

## ENDNOTES

- 1 The authors spoke to the Commission in several technical conferences leading to this Order and submitted comments to the FERC in the rulemaking that led to this Order. The authors' comments can be found at [http://ferris.ferc.gov/idmws/File\\_list.asp?document\\_id=4428487](http://ferris.ferc.gov/idmws/File_list.asp?document_id=4428487).
- 2 Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 FERC ¶ 61,018 (2004) [hereafter 2004 MBR Order].
- 3 State of California, ex rel, Bill Lockyer v. FERC, 383 F.3d 1006, 9<sup>th</sup> Cir. 2004. The 9<sup>th</sup> circuit court found the FERC's MBR authority complies with the Federal Power Act, but criticized the Commission's particular monitoring and enforcement protocols. The U.S. Supreme Court upheld the decision of the 9<sup>th</sup> circuit court. Certiorari, Nos. 06-888 and 06-1100, June 18, 2007. Public Utility District No. 1 of Snohomish County, Washington v. FERC, 471 F.3d 1053, 9<sup>th</sup> Cir. 2006.
- 4 See Fox-Penner P., Broehm R., *Deregulated Electricity Pricing in the U.S. Dramatic New Rules from the FERC*, April 2004. <http://www.brattle.com/documents/Publications/ArticleReport2314.pdf>
- 5 Relevant markets are defined as a control area or now called a balancing authority area where a seller is physically located and the seller's first-tier balancing authority areas.
- 6 108 FERC ¶ 61,026 at P.140.
- 7 See Order 697 at P. 626. Carolina Power & Light, 113 FERC ¶ 61,130 (2005). Also Illinois Power Co. 57 FERC ¶ 61,213 (1999).
- 8 Members of Western Systems Power Pool (WSPP) suggested alternative mitigations that tied mitigated prices to the cost of a group of sellers as stated in the WSPP Agreement. Thus FERC, in a concurrent order, issued a Section 206 investigation into whether the WSPP ceiling rate is just and reasonable for a public utility seller in markets where the seller has been found to have market power, or is presumed to have market power.
- 9 The change in status includes the change in ownership or control of generation, transmission or inputs that results in net increases of 100 MW or more.

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