National Energy Marketers Association

NEM Analysis of FERC's January 13 - 14, 2004, Supply Margin Assessment Technical Conference

FERC held a technical conference on **January 13 and 14, 2004**, to discuss modifications or alternatives to the "Supply Margin Assessment" (SMA) interim generation market power screen and its mitigation measures. The SMA screen was announced in 2001 in the SMA Order.[1]

Under the SMA screen, an applicant will pass if, "it or its affiliates own or control an amount of generation located in a control area which is less than the supply margin (generation in excess of load) in the control area." Applicants can sell at market-based rates into any control area where they pass the screen. The SMA Order required applicants that failed the SMA screen to offer uncommitted capacity for spot market sales in the relevant market.

On **December 20, 2001**, FERC deferred the date by which public utilities failing the screen must implement its mitigation measures. This conference is being held to re-evaluate the SMA screen in preparation for a generic ruling on this subject

SMA is just one part of the four-part test FERC uses in reviewing applications for market based rates. The four-prongs are: (1) generation (horizontal) market power; (2) transmission (vertical) market power; (3) other barriers to entry; and (4) affiliate abuse. The generic rulemaking will address all aspects of the market-based rate program.

FERC's two-day SMA conference was comprised of four panels. The first panel was on **"How to Define the Relevant Geographic Markets**," the second panel focused on the "**Appropriate Interim Generation Dominance Screen**," the third panel involved the "**Appropriate Mitigation Measure for Those That Fail the Screen**," and the fourth panel focused on "**Data Concerns**." All four commissioners attended the conference.

<u>Panel 1: Discussion on Defining the Relevant Geographic Markets, Including Transmission Considerations</u>

This session included a discussion of how transmission should be accounted for in the context of the interim generation dominance analysis. According to FERC's Supplemental Notice, transmission affects which generators are in the market, and how they should be accounted for in a screen. Specific topics discussed in this

[1] <u>AEP Power Marketing, Inc.,</u> <u>et</u> <u>al.</u>, 97 FERC & 61,219 at 61,969 (SMA Order).

session included the following: **1)** Should the relevant geographic market be defined as the control area?; **2)** Where can reliable data be found for markets that are not defined using control areas?; **3)** How should load pockets be accounted for inside and outside of RTOs/ISOs?; **4)** How should transmission limitations be accounted for; using Total Transmission Capability (TTC) or Available Transmission Capability (ATC); **5**) How should competing supplies be accounted for?; **6)** How much transmission capacity should be included in the analysis where transmission providers (whose control over transmission has not been transferred to an RTO/ISO) calculate the capacity and also participate in generation markets?**;** and **7)** Where transmission or other operating constraints exist within a control area (such that some generators are not able to run to their maximum rated capacity), what percent of these generators' capacity should be included as participating in the market?

Joe Pace, appearing for **AEP**, stated that native load and long-term contracts tied to the system should be excluded when calculating generation. **AEP** stated that it is important to recognize that the screen analysis has a three-year time frame, but the applicant could change is market position by way of contracting the next day after it files its screen analysis. **AEP** believes that entities should have to report significant changes in their position to FERC. **AEP** stated that the absence of significant transmission constraints means that the single control area should be treated as the relevant geographic market. **AEP** believes that the control area approach to defining geographic markets is a reasonable method. They also believe that evidence of transmission constraints could cause a control area to be divided into smaller geographic areas and that relevant geographic markets could be defined as encompassing more than one control area when there are not transmission constraints between those areas. **AEP** thinks that the most practical approach to measuring transmission limitations is with Total Transmission Capability (TTC). **AEP** believes that if the screen uses ATC, FERC would have to know all the scheduled uses for this to be an accurate measure. **AEP** stated that this information is very difficult to get. Additionally, **AEP** stated that ATC understates imports and does not reflect capacity available for use by competitors. **AEP** believes that a screen should only take into account the amount of total competition. **AEP** believes that to measure commercial reality where transmission or other operating constraints exist within a control area the screen should only include the amount of capacity that can actually enter the market due to these constraints. **AEP** stated that to address local market power in load pockets FERC could peg the prices in the load pocket area to the prices in part of the control area outside the load pocket or have must run contracts. **AEP** also believes that the market screen should take outages into account.

John Apperson, Director of Trading, **PacifiCorp** stated that the focus of the SMA and the Staff alternatives is misplaced in the West. **PacifiCorp** stated that the entire western interconnect should be used for the first tier screen and that load pockets should be the 2nd tier screen. **PacifiCorp** believes that TTC is a better estimate of transmission available in the market. Additionally, **PacifiCorp** stated that non-jurisdictional entities must be subject to the screen.

Jesse Tilton, CEO of ElectriCities of North Carolina, and representing **American Public Power Association** (**APPA**) stated that LSEs must plan and use the long-term market to meet the needs of their customers. **APPA** believes that there is a need for a bottoms-up approach to fully address the transmission crisis and that all stakeholders must be involved. **APPA** stated that TTC does not reflect the capacity available to consumers relying on the transmission system and that FERC must at least look at ATC. **APPA** believes that there must be independence of and consistency in transmission capacity calculations. Additionally, geographic market definitions must reflect the actual purchasing and selling practices in a market. **APPA** stated that FERC's examination and mitigation of hourly markets ignores LSEs' service obligations, leaving Transmission Dependent Utilities (TDUs) vulnerable to the exercise of market power in the long-term bilateral markets. **APPA** believes that rejecting or mitigating requests to sell at market-based rates is only a temporary solution. **APPA** stated that FERC needs to take affirmative steps to ensure that markets are structurally competitive to provide economic access to both short-term and long-term products. This would require: 1) transmission under the control of a truly independent ISO/RTO; 2) continued application of market power tests for market-based rate authorizations, even in areas with an ISO/RTO; and 3) a transmission infrastructure sufficient to support the competitive market funded through rolled-in rates.

Ricky Biddle, Vice President of Planning, Rates and Dispatching**, Arkansas Electric Cooperative** (**AEC**) stated that a load control area should not define a geographic market. **AEC** stated that transmission is the key in defining the geographic market, and the definition should address how buyers and sellers interact in the market. **AEC** believes that it is important for a screen to address how import capability is allocated in a geographic market. **AEC** stated that retail load should <u>be included</u> when calculating generation because a portfolio of generation can be used in many ways to serve wholesale and retail load. **AEC** believes that a possible solution is to limit the way generation is used once it is reported as part of the screen analysis. **AEC** stated that if a utility is going to make wholesale sales out of the generation assigned to retail load it may be appropriate to only allow them to do that at a cost-based rate. As far as RTO participation is considered, **AEC** does not think that they should be exempted without looking at how they are structured.

Ron McNamara, Vice President of Regulatory Affairs and Chief Economist, **MISO**, spoke about a future state where energy and transmission have been separated and energy is sold under financial contracts. At that point, he said that profit will come from risk management and there will be no reason to define capacity because generation will simply establish a long position and load will establish a short position. In that state, RTOs/ISOs will mange delivery risks and entities financial contracts will be used to cover risks. The **MISO representative**

stated that the screen must be well understood and that FERC should carefully investigate the potential for disincentives. The **MISO representative** stated that the spot and long-term markets are very different with regard to risk and this must be accounted for when designing screens. In discussing the appropriate measure for transmission limitations, **McNamara** stated that ATC is linked to the spot market and TTC is more closely related to the long-term market. **McNamara** stated that if an RTO has LMP and financial markets in place, the RTO member companies can be exempted from the screen.

Steven Corneli, Director of Regulatory Affairs, **NRG Energy, Inc**., stated that physical withholding is the primary exercise of market power. The SMA test and Staffs' modifications ignore discrimination in access to transmission by those in control of transmission. **NRG** stated that in defining the geographic market you should look at the effect of a price increase. **NRG** stated that there is a link between vertical and horizontal market power. In terms of accounting for transmission constraints, **NRG** agrees with AEP, that it is important to look at who has the rights to use the reserve transmission capacity. **NRG** also stated that a screen that counts all megawatts without regard for their ability to access transmission is not effective.

Panel 2: Discussion of the Appropriate Interim Generation Dominance Screen

This session included a discussion of Staff's proposed interim generation dominance screens and alternative proposals offered by others. Specific topics discussed in this session included the following: **1)** Which approach is preferable for the interim screen: pivotal supplier? market share? other?; **2**) Should the analysis be applied on a monthly or annual basis?; **3)** Whether and how to capture generators' ability to withhold on non-peak days or over a sustained period of time?; **4)** How to determine capacity (installed and/or uncommitted)?; **5)** How to determine "opportunity" demand under the Wholesale Market Share screen?; and **6)** Whether and under what circumstances to adopt an ISO/RTO exemption.

Bill Marshall, Vice President of Fleet Operations and Trading, **Southern Company**, stated that FERC must take into account firm obligations and focus only on uncommitted capacity in the design of the market screen. **Southern** stated that FERC should avoid screens that only measure relative size instead of market power. **Southern** next discussed the modified screens in the Staff Paper stating that the SMA test fails to recognize that much of a vertically integrated utilities' capacity is committed to wholesale and retail obligations. **Southern** stated that the Limited Competing Supplier Screen ignores the effect of retail and wholesale obligations and that the Wholesale Market Share Screen still only focuses on size rather than on the amount of load that is served. **Southern** wants a modified SMA test that focuses on wholesale load that is subject to competition and an applicant's uncommitted capacity. **Southern** agreed that if competing generation cannot get transmission capacity in the market that it wants, it should not be counted as a competitor in the calculations of the adopted screen.

Steve Henderson, Vice President, Charles River Associates, appearing on behalf of **Entergy,** stated that accounting for native load and long-term contracts in the wholesale market is the overall issue. **Entergy** believes that the focus of the screens should begin once a utility fulfills its native load commitment and enters the wholesale market and uses market power. **Entergy** stated that a starting point for analysis of market power should be the utilities uncommitted capacity, that which is above its native load and long-term contract obligations. **Entergy** agreed that if competitors do not have access to transmission they should not be counted in the SMA test. **Entergy** stated that long-term commitments come and go, and this is an issue. **Entergy** believes that regulated retail load can be excluded because it grows steadily. A Staff member stated that he has documents stating that a utility can dispatch its megawatts in ways to block competitors and asked how FERC should deal with this. **Entergy** stated that if competitors are blocked from the market they should not be counted, but questioned how this could be detected. **Entergy** supports using a screen that incorporates uncommitted capacity and supports a pivotal supplier screen. **Entergy** stated that SMA is too strict because it does not account for uncommitted capacity

Michael Wroblewski, Assistant General Counsel for Policy Studies, **Federal Trade Commission**, stated that if the geographic market is not defined properly the results of any screen will be meaningless. **FTC** stated that FERC should look at the unilateral exercise of market power as well as collusion with other suppliers by high concentration or entry impediments. **FTC** also stated that FERC may want to require applicants to pass multiple screens. The **panelist** stated that the problem with the SMA and Capacity Surplus Index models (pivotal supplier screens) is that they are both unilateral models. Additionally, **FTC** stated that these screens look at peak data and that when you look at peak data you are only looking at one hour of one day. **FTC** also believes that there is a conceptual problem with doing assessments only at peak demand periods because peak demand may occur simultaneously across an entire region and imports will not be able to come into other markets. **FTC** stated that the two market share screens are an improvement over the pivotal supplier screens because they take into account the possibility of collusion. The **panelist** stated that FERC should allow an applicant that fails a screen to provide confidential additional data to FERC on why it should be allowed to use market-based rates.

Mark Haskell, **Tractabel** Corporation, stated that if FERC approved an ISO/RTO’s market power mitigation mechanisms the members of the ISO/RTO should be exempted from the screen. **Tractabel** supports the pivotal supplier screen with modification. **Tractabel** believes that FERC should provide incentives for new market entrants bringing new generation as well as incentives for existing generation bringing in new capacity and that these entities should be eligible for market-based rates if they make a demonstration that they are not dominant players in the market. **Tractabel** stated that FERC can re-examine the position of these entities in the future. **Tractabel** believes that FERC should not only use uncommitted capacity, but should consider that installed capacity is a better indicator in markets undergoing transition to competitive markets. **Tractabel** thinks that native load should be counted in an installed capacity type of measure. **Tractabel** stated that native load obligations can be met from many sources. Additionally, **Tractabel** is concerned that the modified screens provide only for seasonal mitigation, which may not be effective in influencing forward market prices.

Gary Ackerman, Executive Director, **Western Power Trading Forum** believes that RTOs/ISOs should be exempt from the screen because they have market monitoring. The **panelist** stated that residual transmission market power is a very real problem. He stated that the market needs functional separation of generation and transmission. He stated that it is ill-advised to implement seasonal mitigation because market power is a long term-problem. In terms of price mitigation measures, he believes that cost-based rates are an administrative nightmare and recommended supporting a seller-specific bid cap adjusted for risk factors.

Denise Goulet, Senior Assistant Consumer Advocate, **Pennsylvania Office of the Consumer Advocate**, stated that any screen that FERC chooses must include analysis of the type of capacity owned by the applicant, where that capacity falls on the supply curve, and identification of regularly occurring load pockets. The **Consumer Advocate** believes that the Capacity Surplus Index best determines whether the applicant's capacity is needed to serve load. The **Consumer Advocate** stated that FERC should modify the Capacity Surplus Index screen to include analysis of the types of capacity the applicant owns and where the capacity falls on the supply curve. She also stated that FERC should fully analyze regularly occurring load pockets. The **Advocate** also stated that FERC should apply the screen to applicants that participate in RTO or ISO regions.

<u>Panel 3: Discussion of the Appropriate Mitigation Measures for Those That Fail the Applicable Screen</u>

This session included a discussion of Staff's Proposed Price Mitigation Measures (Cost-Based Rates and Single Market Clearing Price) as well as alternatives proposed by others. Specific topics discussed in this session included the following: **1)** Which approach is preferable (cost-based rate, single market clearing price, or other), and to what products should the price mitigation apply; **2)** Over what time period should price mitigation be applied (monthly, seasonally, daily); **3)** Posting of Incremental/Decremental costs; **4)** Other mitigation proposals; **5)** Revocation of market-based rate authority or use of formula rates; **6)** Whether utilities that fail the interim generation dominance screen should be allowed to propose their own remedy; **7)** The extent to which control of transmission may create opportunities for affiliate abuse or convey market power to those that own generation in the same market (and if so, should such entities be required to hand over control of transmission system to a third party); **8)** Is mitigation only needed in the short term, or should it also apply in the long term (e.g., long-term contract mitigation); and **9)** Adopting a formula that sets a generic area-wide rate cap (e.g., using a cost of capital set by the state commission(s)).

Bill Hieronymus, Vice President, Charles River Associates, representing **Exelon**, stated that he is concerned about the results of requiring applicants to pass multiple screens and about allowing market-based rate authority for just a portion of an entity's generation. He stated that the role of the screen and mitigation should be to preserve and protect the competitive market. He stated that market problems are caused by the characteristics of markets not the characteristics of individual participants in the market. He was concerned with the idea of using cost-based rates to price the uncommitted capacity offered into the spot market of applicants that fail the screen. The **panelist** also stated that using a single market clearing price approach has difficulties but is better than the cost-based approach. The **panelist** raised the following issue in regards to the proposed mitigation alternatives: **Who gets to buy at the mitigated price?** Most wholesale buyers are not in that control area – are they going to be allowed to buy at the mitigated price? The **Exelon** representative stated that the long-term solution is RTOs.

Bill Dudley, Assistant General Counsel of **Xcel Energy Services Inc**., suggested two alternative pricing mechanisms: 1) a regional price cap set sufficiently high to include capacity costs, or 2) a cost-based up-to rate that appropriately factors in capacity costs. **Xcel** had no objections to FERC's focus on the spot market to mitigate market power. **Xcel** believes that FERC must not encourage purchasers to free ride by over-relying on the spot market.

Pat Alexander, Energy Industry Advisor, **Dickstein Shapiro Morin & Oshinsky**, focused on how up-to rates and split-the-savings rates came to be designed. She stated that the value of resurrecting these rate designs is not apparent. She believes that cost-based rates work in the long-term product market when there is both a cap and a floor. She stated that using cost-based rates to mitigate market power seems to be a step in the wrong direction.

Don Sipe, Counsel with Preti Flaherty, on behalf of **Industrial Customers**, stated that it is reasonable to adopt a cost-based mitigation methodology when there is a market failure. He also stated that the split-the-savings methodology makes sense given the premise that we have market failure. He believes that scarcity pricing is going to be captured with the split-the-savings model. He stated that the interconnection requirement in the FERC SMA Order should be structured to allow a new unit to interconnect both when the utility fails or passes the market power screen. He stated that the interconnection requirement should be a condition for using market-based rates. The **Industrial Customers representative** stated that allowing competition through displacement is the key to mitigation and that native load will still be served. He stated that incumbent utilities should be looking for cheaper sources of generation and if those sources are available the utilities should buy at wholesale from the cheaper unit and then serve its same retail customers with these cheaper wholesale purchases. He believes that participant funding is less of an issue when the proper facilities for interconnection are considered. **Industrial Customers representative** believes that the key is to focus on what sort of facilities need to be built including those facilities necessary to reliably interconnect additional generators.

Robert O'Neil, General Counsel, **Golden Spread Electric Cooperative** (FERC jurisdiction cooperative), stated that the notion of a cost-based rate is being re-thought, however he supports the cost-based rate approach to mitigation. He suggested that people not look at cost-based rates as confiscatory rates.

Craig Roach, Partner, **Boston Pacific Company**, stated that an important policy goal of this proceeding is to use competitive forces to get the best deal for consumers. Market power measurement and mitigation are just two tools among many to achieve that goal. He stated that today, the central market power concern is with foreclosure of non-affiliates in longer-term power markets. **Boston Pacific** stated that if an applicant fails a screen and that applicant is in control of procurement for wholesale power to serve regulated retail customers, a recommended mitigation scheme is to compel the applicant to hold competitive solicitations. **Boston Pacific** stated the following as minimum standards for the solicitation: 1) use a collaborative process to design the solicitation; 2) use an independent third party monitor hired by the State Commission; 3) affiliate and non-affiliate bids must be evaluated with identical criteria; 4) all winning bidders must sign pay-for-performance sales contracts; and 5) any bidder must be allowed to request a timely estimate of what it would take to be a network resource. **Boston Pacific** also stated that FERC needs to implement mitigation in longer term markets as well as the spot market. The **panelist** also stated that FERC should continue to use total installed capacity as the measure in the SMA test because exempting capacity used to serve native load (shifting to uncommitted capacity) may create an incentive for a utility to always self-build instead of buying from the market. **Boston Pacific** believes that cost-based rates should not be used since they will not get to a price that the competitive market would produce. Instead, the split-the-savings method should line up closer to what the competitive market should be.