Chapter 2

"Whether or not a viable wholesale electricity market exists in a region which includes Nebraska."

1.0 Introduction

1.1 Groups' Purpose and Membership

The purpose of the second “condition-certain” issue group was to determine "whether or not a viable wholesale electricity market exists in a region which includes Nebraska." The Technical Group #2 that worked on this issue was combined with the Technical Group #4 because of the common backgrounds required and the similarities of the issue and included the following individuals:

Clint Johannes (Chair)	-	Nebraska Electric Generation & Transmission Cooperative, Inc. (NEG&T)
Deeno Boosalis	-	Omaha Public Power District (OPPD)
Jim Fehr	-	Nebraska Public Power District (NPPD)
Dennis Florom	-	Lincoln Electric System (LES)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
Burhl Gilpin	-	Grand Island Utilities
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
David Ried	-	OPPD
Jon Sunneberg	-	NPPD

One critical "condition-certain" factor is whether there is a viable wholesale market in place. The LR455 Phase II report (released in December 1999) stated, "that a viable wholesale market requires an operational regional 'market hub' through which transactions may take place. It requires sufficient buyers and sellers to make an active market. It requires clear and equitable trading rules. While judgment of what level of these requirements is sufficient may be considered subjective, viability should be reflected in stable or predictable pricing patterns."

Before moving toward retail competition, wholesale markets must be viable. The primary lesson from the California experience with deregulation is, if the wholesale market is dysfunctional, the retail market will be as well. The portion of a retail customer's bill that will be open to competition is the electric commodity (wholesale) portion. The transmission and distribution wires will be utilized much the same with any electric commodity supplier – only one set of electric wires can be financially or operationally supported. It is, therefore, important that the wholesale electric market be adequately established and be viable. This chapter addresses that viability for Nebraska.

1.2 Approach

To accomplish the purpose described, the Group first defined the meaning of the term “viable” and the alternative methodologies for testing the viability of a market. This definition and the evolution of standard tests for market viability are outlined in Section 2. Next the regional markets that include Nebraska were defined. Nebraska is somewhat unique in that it transcends two major transmissions grids in the U.S., the Eastern Interconnection and the Western Interconnection. Therefore Nebraska has two separate and distinct regional electricity markets. Both of these markets are defined in Section 3. The general approach for completing this year’s report is different than previous years. This is because the Federal Energy Regulatory Commission’s (FERC) thinking has evolved significantly since the initial LB901 report. Experience that FERC has gained in regulating emerging wholesale markets has provided valuable lessons learned which they have applied by trying new tests and techniques. Technical Group #2 has endeavored to follow these changes and modify our approach to reflect the FERC’s latest thinking. In the past, Technical Group #2 conducted FERC’s standard test of market viability using data obtained by the group. Two factors have changed this approach. First, the data used for conducting this analysis is no longer available to the group. Second, FERC has proposed that Regional Transmission Organizations (RTO) assume the responsibility of testing for market viability in the regions they serve. Conducting annual market viability tests is one of these responsibilities. The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes the Eastern Interconnection of Nebraska. In May 2003 they published their first *State of the Market Report.* The analysis includes all the current and prospective utility members of MISO. Therefore the major transmission owning utilities in Nebraska are included. Since the MISO report is the definitive analysis for “whether or not a viable electricity market exists for the region which includes Nebraska”, it is the primary source for this report.

2.0 Viable Wholesale Market Definition

2.1 Economic Logic

According to the Merriam-Webster Collegiate Dictionary Tenth Edition, the term “Viable” means:

> **1 :** capable of living; *especially* **:** capable of surviving outside the mother's womb without artificial support <the normal human fetus is usually *viable* by the end of the seventh month>
> **2 :** capable of growing or developing <*viable* seeds> <*viable* eggs>
> **3 a :** capable of working, functioning, or developing adequately <*viable* alternatives> **b :** capable of existence and development as an independent unit <the colony is now a *viable* state> **c** (1) **:** having a reasonable chance of succeeding <a *viable* candidate> (2) **:** financially sustainable <a *viable* enterprise>

For the purpose of this report, the definition shall be deemed as “having a reasonable chance of succeeding” financially.

2.2 Evolution of FERC Definition and Tests for Market Power

A “viable market” must be one in which no single utility, or group of utilities, is able to exercise “market power.” The standard test for market power is called the “Hub and Spoke” test. It was first used by FERC to assess the impacts of electric utility mergers on market concentration as set out in FERC Order 592, Merger Policy Assessment. This has been considered the “official” test of market power since FERC started using it in 1996. It has been the basis of this report since the inception of LB901. This test is described and presented in Section 2.3. The appropriate size of the region used in the conduct of this test is defined in Section 3.

As wholesale electric markets matured and market power became a prevalent issue, FERC acknowledged that the Hub and Spoke test alone was not sufficient to detect all market power. Notably, FERC has recognized the effect of transmission constraints on the exercise of market power. Initially, FERC began using variations to the traditional hub and spoke analysis that compensated for transmission constraints. This culminated in a FERC order issued on November 20, 2001 entitled “ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). This order proposed a new standard test called “Supply Margin Assessment.“ A moratorium on this test was initiated soon after it was released because of political opposition. A complete review of the new FERC tests and the specific reasons for using them are discussed in Section 4.

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket nos. ER96-2495-016 et. al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001 but suspended shortly thereafter. The new order was released after several rounds of comments and a technical conference examining the issues surrounding the SMA. The new interim generation market power order is presented in Section 4.1.1.4.

The “Standard Market Design” Notice of Proposed Rulemaking (Docket RM01-12-000) was issued July 31, 2002. This rulemaking along with a FERC Whitepaper clarifying certain issues introduced in the rulemaking (Issued April 28, 2003) is known by the abbreviation “SMD.” The SMD is a very far-reaching and prescriptive outline of how Regional Transmission Organizations (RTO) should be organized and how they should operate. SMD proposes that RTO’s assume the function of *Market Monitoring and Market Power Mitigation.* This includes the responsibility to constantly watch for the abuse of market power and also grants authority to implement defined corrective actions when market power is detected. As it is anticipated by FERC that all utilities will eventually belong to an RTO, every utility in the country will be subject to this oversight. A review of the *Market Monitoring and Market Power Mitigation* responsibilities as outlined in the SMD is shown in Section 5. The proposed rules will set out prescribed tests for market power but also gives considerable leeway to each RTO in devising new tests they believe are appropriate for their region. The RTO will be required to periodically report on the status of market power in their region. The assumption is that RTO’s are uniquely qualified to assess market power in the region they serve. RTO’s are independent. They will run the regional spot market and operate the transmission system, therefore they will have all the operational data required to run the appropriate tests. RTO’s will also have the transmission and market models, the budget and the expertise to conduct market power analyses. As of this writing the SMD rulemaking has not been implemented because of controversy over the far-reaching powers afforded to FERC through the RTO's. The voluntary RTO's that have been established, however, have generally followed the guidelines set out in the SMD proposed rulemaking and whitepaper.

2.3 Basic Elements of Traditional FERC "Hub and Spoke" Market Power Analysis

The Federal Energy Regulatory Commission (FERC) established procedures for determining whether a proposed merger or settlement will impact certain regions or individual utilities, and enhance the ability of certain utilities to control prices or exclude competition. This is known in the regulatory community as "market power." FERC provides the following definition: Market power exists if there are concerns with market concentration.

In its merger guidelines, FERC defines "market concentration" in Order No. 592, Merger Policy Statement. In Order No. 592, FERC defines two relevant products for this assessment: economic capacity and available economic capacity. Economic capacity includes all generation in a given area that can be delivered at a price not exceeding 105% of the market price. Available economic capacity is similar to economic capacity, except it does not include capacity required to serve native load. For purposes of determining how viable the wholesale market is, available economic capacity is of greater relevance. Resources committed to serving existing native load would not provide suitable competition to create a "viable market," as that term is defined in this report.

In determining the market concentration for available economic capacity, FERC looks at suppliers that can supply the product (wholesale capacity and energy) at a cost no greater than 5% above the competitive price. The concentration of suppliers that have available economic capacity and energy that can be supplied is less than the FERC-defined threshold for an "unconcentrated" market. FERC defines this using the Herfindahl-Hierschman Index (HHI), which is calculated by summing the squares of the market share of all competitors that can supply power at a price no greater than 5% above the competitive price. An HHI of less than 1,000 indicates an unconcentrated market while an HHI of over 1,800 indicates a concentrated market.

In general arithmetic terms, to achieve an unconcentrated market, there would need to be roughly 10 suppliers each with roughly 10% of the market. No single supplier should have more than 20% of the market and there should be at least 10-15 other competitive suppliers. Each of these suppliers must be capable of providing capacity and energy at prices competitive with the prevailing market price.

For every year that this report has been completed, Technical Group #2 has conducted the Hub and Spoke test by calculating the HHI index using public domain data. This year the complete set of data was not publicly available. Fortunately, MISO calculated the HHI as part of their *State of the Market Report.* This analysis was conducted for the entire MISO region as well as sub-regions of MISO corresponding to the reliability areas that are represented in MISO. This is shown in Exhibit II-1. The results of the 2004 HHI analysis are shown in Exhibit II-2. It shows that the MAPP region has and HHI of 938, indicating that it is free from market power. It is lower than last years index of 1,128. It should be noted that last year's index included Iowa, which has been broken out separately this year. The HHI statistic calculated for the entire MISO region as shown in Exhibit II-2 sheds some light on the deficiencies of the hub and spoke test. The very low index number of 261, as compared to 408 last year, suggests the entire MISO area is a very unconcentrated market. This is because the larger the area, the more suppliers, the smaller the HHI. This is misleading because the entire MISO area does not behave as one big market; rather it is divided into sub markets because of transmission constraints. The WUMS (Wisconsin –Upper Michigan) area has a high HHI of 2,656. This suggests a concentrated market with high potential for market power. In fact, the WUMS area is a known load pocket created by transmission constraints that isolate local generators.

Exhibit II-1

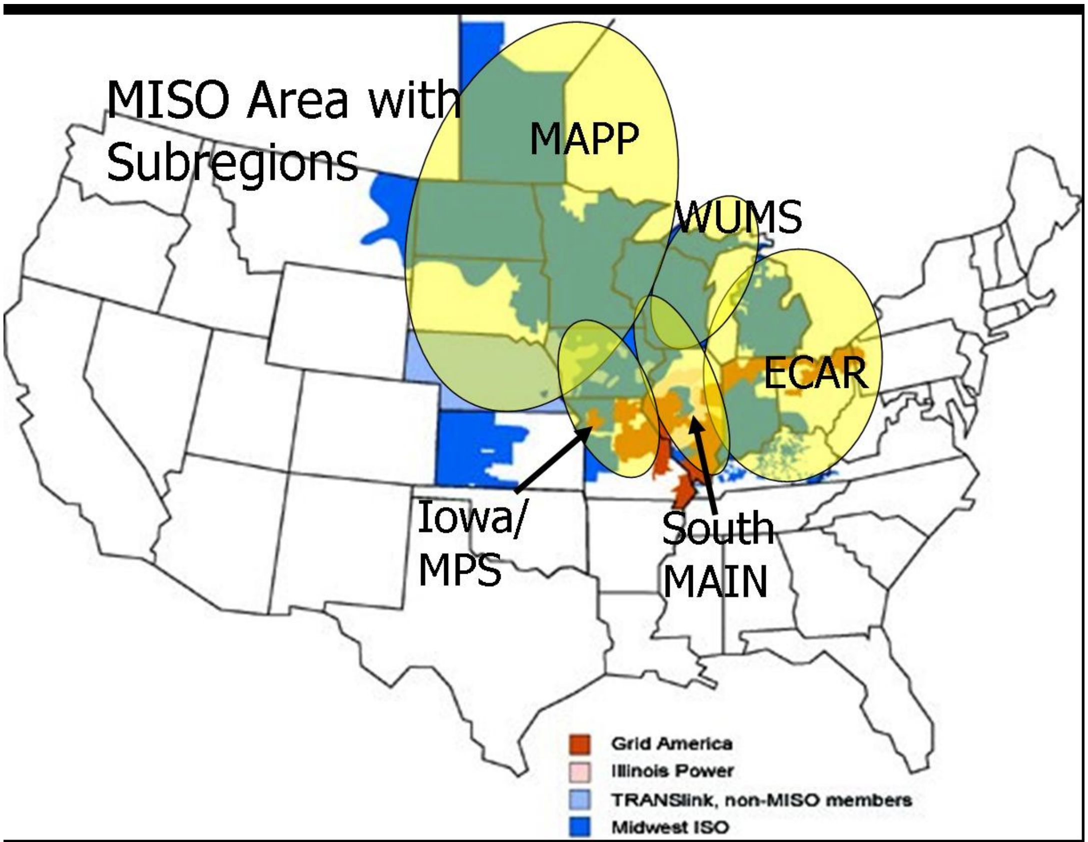


Exhibit II-2

MISO Subregion	HHI
ECAR	563
North MAPP	938
South MAIN	1,736
Iowa/MPS	1,343
WUMS	2,656
MISO	**261**

Last Years Results

- MAPP (including Iowa) – 1,128
- MISO – 408

3.0 Region Defined

3.1 East/West Interconnection Description

The Eastern and Western Interconnections are separated by seven alternating current/direct current/alternating current (AC/DC/AC) tie converter stations, which are located throughout various states in the U.S. and provinces in Canada. These include ties such as the Miles City Tie in Montana, the Rapid City Tie in Western South Dakota, the McNeill Tie in Western Saskatchewan, Canada, the Blackwater Tie and the Artesia Tie, both in Eastern New Mexico. Two of those ties are located in the State of Nebraska: (1) the Stegall converter station located just southwest of Scottsbluff, Nebraska, which is a 110 MW facility that is owned and controlled by Basin Electric Power Cooperative from North Dakota; and, (2) the Virginia Smith converter station (also known as the Sidney tie), which is located just north of Sidney, Nebraska, is a 200 MW converter station that was installed by Western Area Power Administration (WAPA), and controlled by the WAPA-Rocky Mountain Regional office in Loveland, Colorado. In essence, the potential market that interconnects to the West to/from Nebraska has an impact of 310 MW; however, most of that capacity is committed for the long term by utilities and marketers outside Nebraska.

3.2 Nebraska's Portion of Each Interconnect

The converter station owned and controlled by Basin (Stegall) is used at the discretion of Basin operational staff. The Sidney tie is placed under WAPA's Open Access Tariff that is being applied on a uniform tariff basis by WAPA. Therefore, it uses FERC approved Open Access Same Time Information System (OASIS) and all the other tariff provisions that are required including on-line reservations and ancillary charges that are Internet subscription based. There are a few Nebraska based utilities that have rights to deliver WAPA allocations over the Sidney Tie from the Loveland Area Office to utilities located in western Nebraska. Other utilities, specifically NPPD and MEAN, have contracted paths for deliveries from the West system to the East system. There are also long-term rights that are held by some Nebraska utilities to serve loads via the Sidney Tie. Concerning the Stegall Tie, there is no contractual commitment by any Nebraska utilities to transmit power through this facility.

3.3 Eastern Interconnection Defined

The Eastern Interconnection is defined as any generation and load that is synchronously connected to the grid that includes the entire eastern, southern and central United States and eastern Canada. Generally, this includes the states and provinces of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, a small portion of Texas and all states to the east as well as Saskatchewan and provinces to the east. However, there are a few locations including the far western edge of South Dakota (divided at Rapid City) and everything located west of Sidney, Nebraska, that are not on the Eastern Interconnection. This includes most all of NERC reliability regions such as MAPP, MAIN, SPP, ECAR, NECC, FRCC, MAAC and SERC as defined in the glossary. The regions that specifically impact Nebraska include the MAPP region, the MAIN region and the SPP region because some Nebraska utilities have contracted to receive or deliver power to those locations. (See Exhibit II-3)

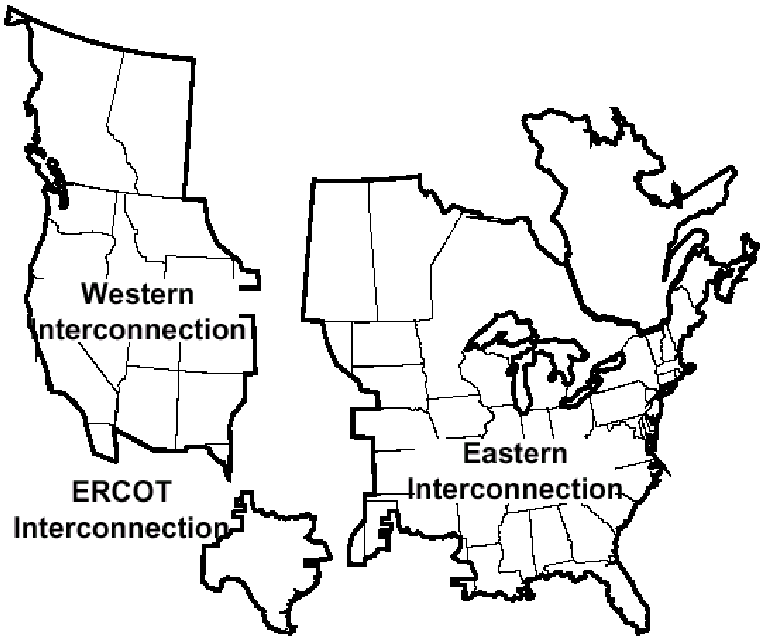
3.4 ERCOT Interconnection

The Electric Reliability Council of Texas (ERCOT) operates its own interconnect, separated from the rest of the Eastern Interconnection by two AC/DC/AC ties. The amount of transfer capability between ERCOT and the Eastern Interconnection is 800 MW.

3.5 Western Interconnection Defined

The Western Interconnection is defined as all load and resources that are synchronously connected with the reliability region of the Western Systems Coordinating Council (WSCC). States and provinces in this region include most of Montana, with the exception of a small part of eastern Montana that is located on the Eastern Interconnect (basically, everything west of Miles City, Montana); Wyoming; Colorado (with the exception of a small portion in the northwest corner that is connected on the Eastern Interconnect); New Mexico; Nevada; Idaho; Washington; Oregon, California; Alberta, and British Columbia.

Exhibit II-3



3.6 Comparison of Region to that in Technical Group #1

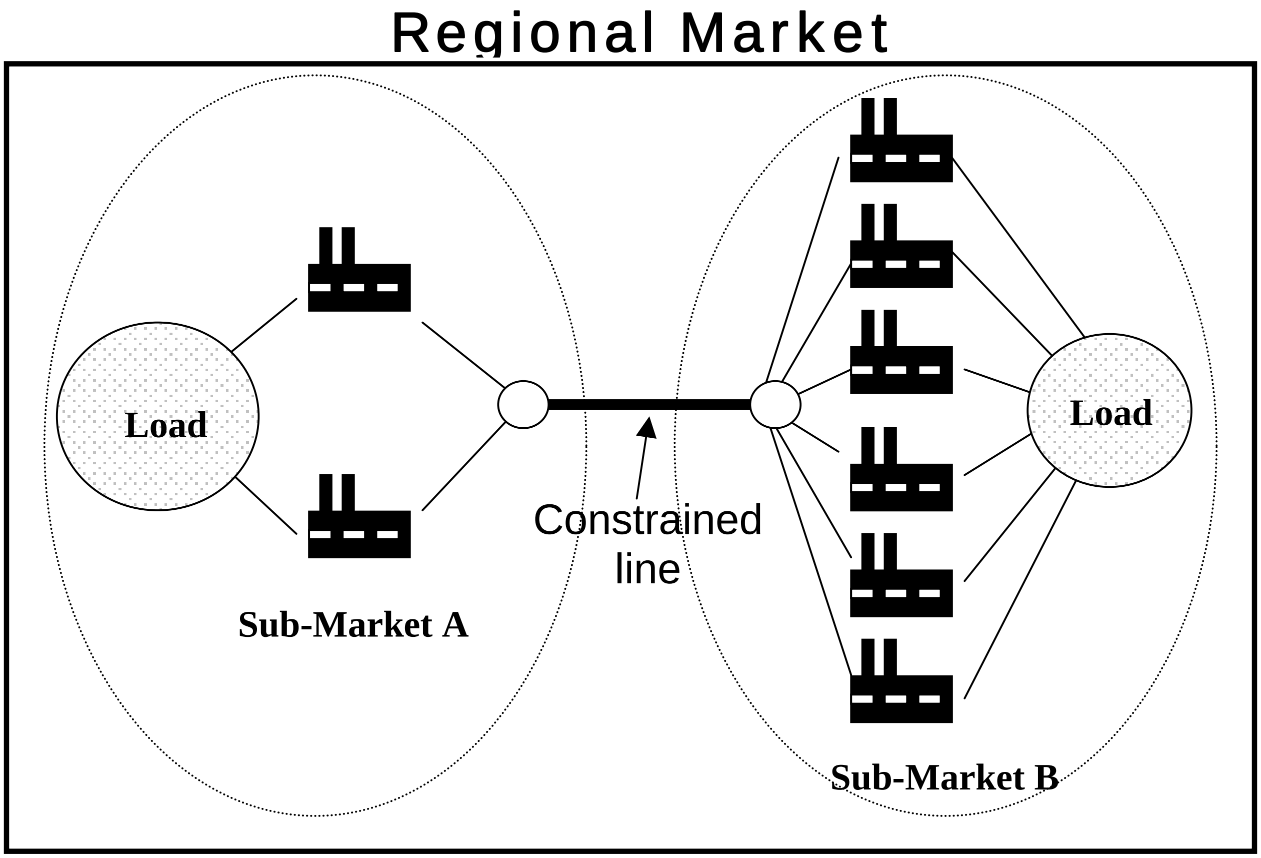
Technical Group #1 was assigned to review the viability of the transmission in the region including Nebraska. The regional definition of Technical Group #1 is essentially the same as the definition used in this report.

4.0 New FERC Methods for Assessing Market Power

4.1 Reasons for Instituting New Methods

FERC began to consider alternatives to the hub and spoke method because of concerns that transmission constraints can create pockets of market power. This was brought to the attention of FERC by many parties who intervened in FERC dockets attesting to market power created by constraints. The traditional hub and spoke analysis does not consider the effects of limited transmission when defining market share. According to FERC, "Hub and spoke worked reasonably well for almost a decade when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market. Since that time, markets have changed and expanded. Because markets are fundamentally different from years ago, the hub and spoke may no longer be a sufficient test for granting market-base rates". An implicit assumption in the hub and spoke analysis is that market power derived from transmission will not be an issue if the utility in question has filed an open access tariff. Transmission constraints have been shown to cause market power for generators by subdividing a large market area into two or more sub-markets during times of high transmission usage. For example Exhibit II-4 shows a simplified, hypothetical market with eight generators serving total customer load (represented by the shaded circles). Assuming none of the eight generators has more than 20% market share, this would be a viable market. However, a constraint on a major transmission line will split the market into two sub-regions, A and B. The two generators left serving the lion's share of load in Sub-Market A can exercise market power by withholding generation. Experience from California and other areas have provided strong evidence that this can indeed happen. Even though the constraints may last for a limited period time, they generally coincide with periods of high wholesale prices. Therefore the effect of these short periods of market power can be dramatic.

Exhibit II-4



4.1.1 New Tests of Market Power

4.1.1.1 Modified "Hub and Spoke" Test

One test FERC has used to assess market power caused by transmission constraints is a variation of the traditional hub and spoke test. This test is similar to the analysis shown in Exhibit II-1 except that it calculates utility market shares for non-requirement wholesale power during peak periods as opposed to the entire year. During peak periods some utilities may not be able to sell wholesale power because of transmission constraints raising the market shares for the utilities unaffected by transmission constraints. Therefore a traditional hub and spoke test may show a relatively unconcentrated market whereas the same test during peak periods may show a concentrated market. Conducting this analysis requires data that may not be publicly available, notably the wholesale sales and available capacity for each utility during the peak time period.

4.1.1.2 Electricity Market Models

FERC has started to employ electricity market simulations to assess market power in electric markets. This is especially true for merger analysis. These simulations attempt to model both the price determination (bid-auction) of wholesale and the electricity flows in the regional market. The advantage of using such a simulation is that it captures some of the nuances and gaming that can occur in electric markets. For example, a simulation may demonstrate that a company can run one generating plant at a loss but create a transmission constraint that will create market power for another generating plant that will more than compensate for the loss. The disadvantages of such models are that they are time-consuming and costly to run, and they are somewhat subjective in the sense the test does not deliver a "number" like the HHI index. The Technical Group considered employing such a model for both Issue #2 and Issue #4. It was decided that the cost was prohibitive.

4.1.1.3 Supply Margin Assessment

On November 20, 2001 FERC issued a new order entitled "ORDER ON TRIENNIAL MARKET POWER UPDATES AND ANNOUNCING NEW, INTERIM GENERATION MARKET POWER SCREEN AND MITIGATION POLICY (Docket No. ER96-2495-015, et al). The order introduced a new test for market power called the “Supply Margin Assessment”, laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order. The Supply Margin Assessment is designed to test for market power within a utility control area. A control area is defined as the area transcribed by an individual utility’s transmission system in which the utility has responsibility of balancing supply and demand of electricity and maintaining the stability of the system. FERC has stated that a utility has market power if the utility’s generation capacity in the control area is greater than the Supply Margin in the control area. The Supply Margin is defined as the total generation in excess of the peak load (reserve margin) in the area plus the total transmission capacity interconnected to the area. If a utility fails this test, FERC will judge the utility as having market power unless the utility joins a Regional Transmission Organization (RTO). If the utility joins an RTO they are absolved of having market power by FERC. Ostensibly, this is because an RTO will have market monitoring capabilities and transmission congestion management protocols that will mitigate market power within the RTO. If a utility refuses to join an RTO, FERC has set out a number of onerous mitigation measures including revoking the utilities ability to charge market-based rates for wholesale market transactions as well as requiring that an independent third party operates the utility’s open access, real-time information system. With this order FERC has migrated from the hub and spoke method where it was relatively difficult to demonstrate market power to the Supply Margin Assessment where virtually every vertically integrated utility in the country will fail the test unless they join an RTO. In this regard, the order seemed designed to “encourage” all utilities to join RTO’s. In a dissent to the order, FERC commissioner Linda K. Breathitt stated, “If forming RTO’s is the goal here, then we should be straightforward about that and do a rulemaking to mandate them, going through the front door and not the back door”. This FERC ruling has interesting consequences for the Conditions Certain of LB901. If one applies the FERC logic, then Issue #1, “Nebraska being part of an RTO” and Issue #2 “Whether or not a viable wholesale market exists in a region which includes Nebraska” merges into one. In other words if Condition #1 is satisfied, Condition #2, by definition, will also be satisfied. The Supply Margin Assessment Order generated so much controversy that FERC suspended implementation. In the two and a half years following the suspension, FERC solicited many rounds of comments, held a two day technical conference and issued a whitepaper to gather feedback on various options and proposals.

4.1.1.4 Interim Generation Market Screen and Mitigation Policy

On April 14, 2004 FERC released the ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY (Docket nos. ER96-2495-016 et. al.). This order adopts two new screens to assess generation market power and proposed new measures for mitigating market power in the future. The new screens were intended to replace the Supply Margin Assessment (SMA) generation market power analysis proposed in November of 2001, but suspended shortly thereafter. The two new screens are called the “Pivotal Supplier Analysis” and the “Market Share Analysis”. Both tests attempt to take into account some of the objections to the SMA such as adjusting for native load and contract obligations when assessing market power.

If a utility fails to pass either screen there is a “rebuttable presumption of market power”. This means that the utility can request to submit additional analyses to FERC demonstrating an absence of market power or waive that right and accept the mitigation measures outlined in the order. The additional analysis would include, among others, the “Delivered Price Test”.

AEP, Southern Company and Entergy, (the original utilities involved in the SMA controversy) were ordered to file the results of the new tests by June 13, 2004. All other jurisdictional utilities currently possessing market-based rate authority would have to file test results according to schedule published by FERC.

4.1.1.4.1 Relevant Market Area for Interim Generation Market Screens

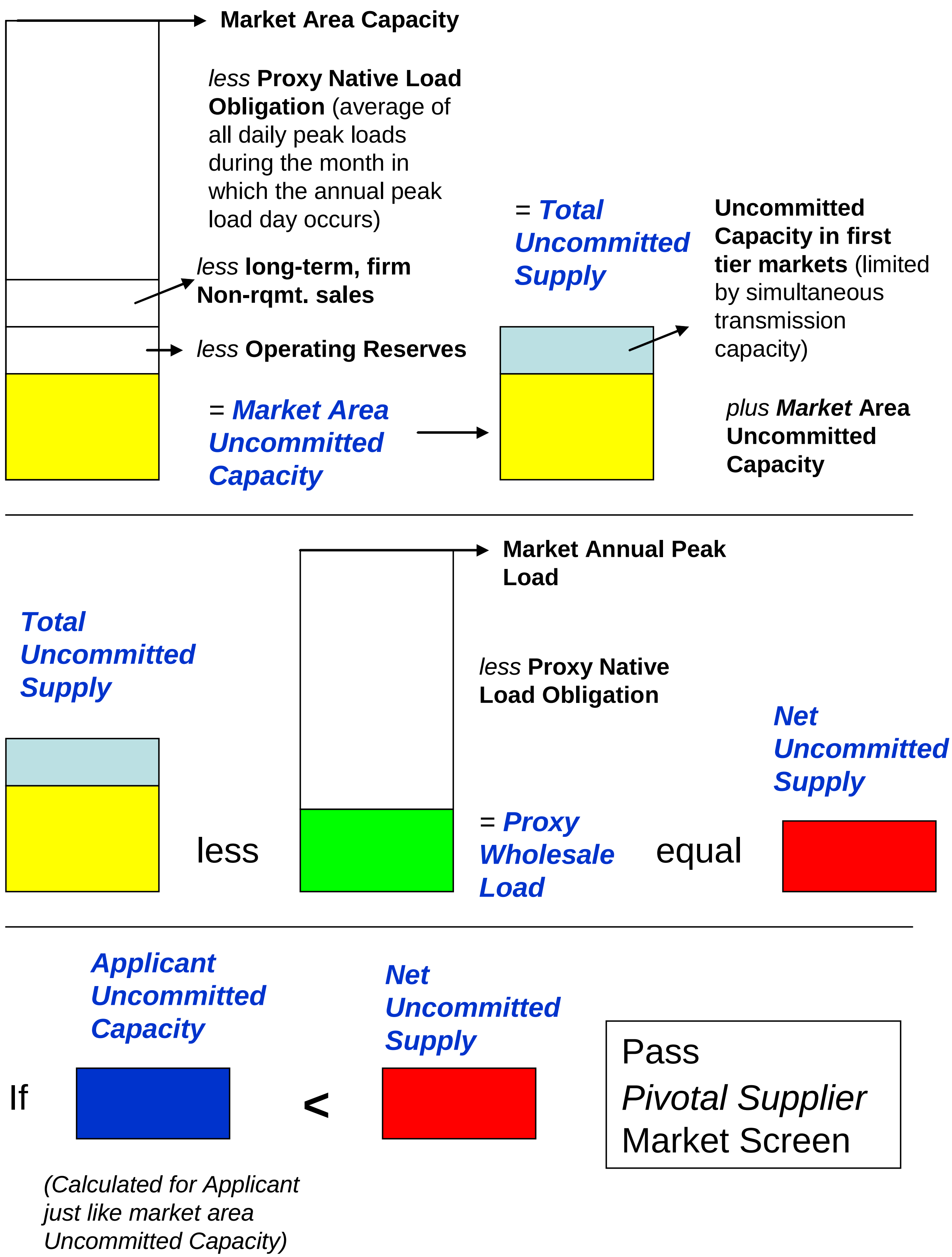
The relevant market area used when conducting the two market screens has a profound effect on the results of the test. The greater the size of the relevant market area the less likely the applicant will be found to possess market power. For utilities belonging to an RTO, the entire geographic region under the RTO will be considered the relevant market area, provided the RTO has a sufficient market structure and a single energy market. The rehearing order stated that this would include PJM, ISO-NE, NYISO and CAISO, but would not include MISO or SPP because neither performs single central commitment and dispatch at this time. For all utilities that do not belong to a qualified RTO, the control area in which they operate would be the relevant market area.

4.1.1.4.2 “Pivotal Supplier” Market Screen

The Pivotal Suppler Analysis seeks to determine if the applicant utility has the ability to manipulate market prices by unilaterally withholding generation from the market during peak period conditions. If the applicant’s generation is absolutely essential to meeting peak wholesale market demands of the relevant market area (control area), the applicant will fail the screen. Exhibit II-5, shows how the Pivotal Supplier screen is calculated.

Exhibit II-5

Pivotal Supplier Market Screen



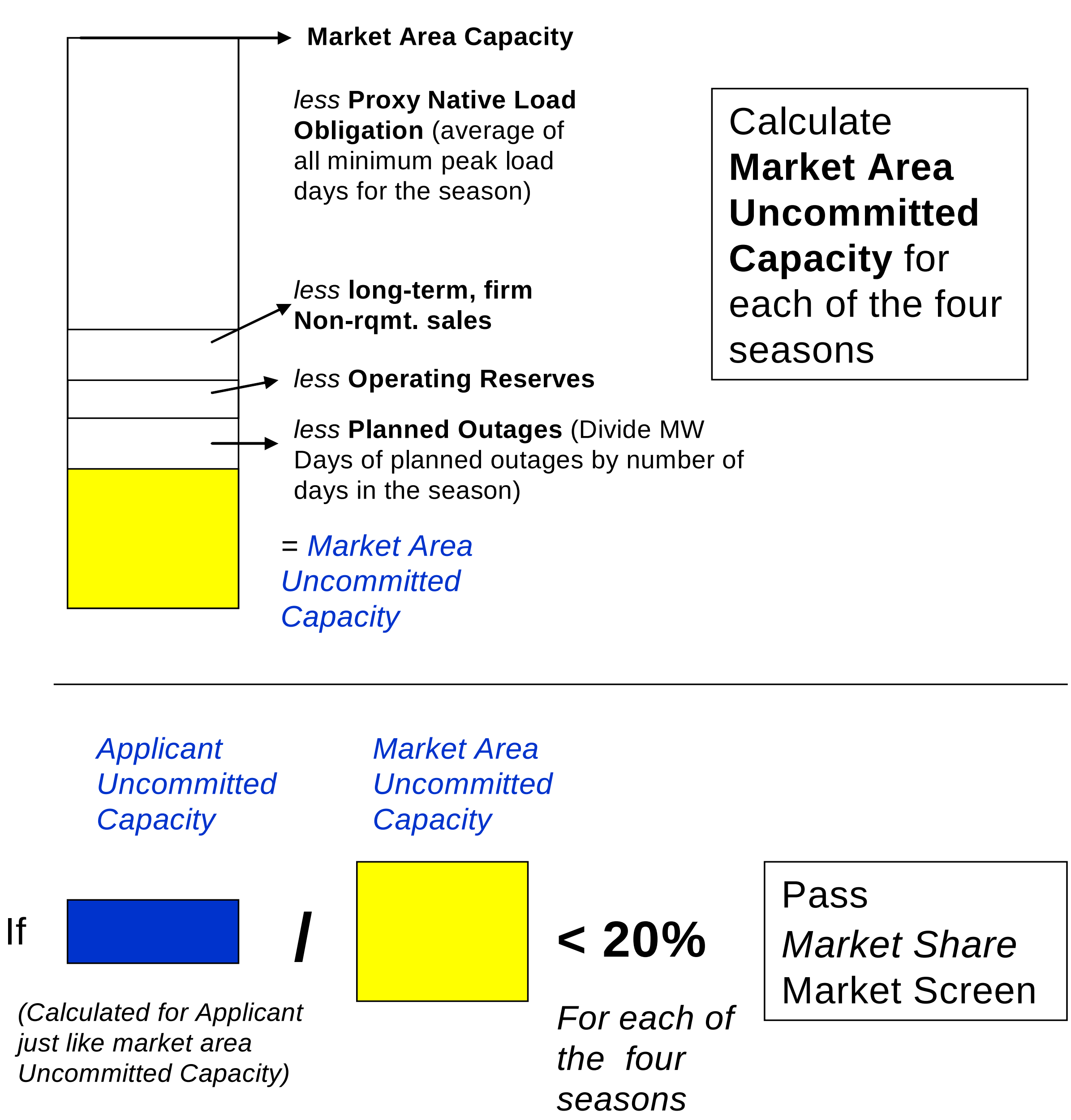
As shown in Exhibit II-5, if the applicant's uncommitted capacity is less than the uncommitted capacity offered by all other competitors than it will not be required (or pivotal) in satisfying all of the wholesale market demands in the area. On the other hand if the applicant's uncommitted capacity is more than that of all other suppliers to the area, the applicant's uncommitted capacity would be essential in meeting the wholesale demands. In that case the applicant could effectively withhold generation and unilaterally raise prices for electricity.

4.1.1.4.3 "Market Share" Market Screen

The Market Share Analysis considers the percentage of total uncommitted generation that is owned or controlled by the applicant during each of the four seasons of the year. If the applicant has more than 20% of the total market it is considered to have market power. Where the pivotal supplier analysis tests for market power under specific peak conditions, the market share analysis is a general test of market power attributed to sheer size.

Exhibit II-6

Market Share Analysis



The calculation for the "Market Share" test is shown in Exhibit II-6. Note that the definition of Uncommitted Capacity changes under this test. The native load obligation used to calculate the Uncommitted Capacity is defined as the minimum peak load day for the season. This focuses the test on the off-peak market. The Uncommitted Capacity is also adjusted for planned generation outages that generally occur during non-peaking times.

4.1.1.4.4 "Delivered Price" Market Screen

The Delivered Price Analysis can be submitted (along with other specialized tests) if the applicant fails the first two market screens. The delivered price test is similar to the first two tests, except that the price at which the capacity can be delivered is taken into consideration.. For example, an applicant may have a high market share of uncommitted capacity relative to total uncommitted capacity. However, if the applicant can prove that the capacity cannot be delivered at competitive prices (i.e. it is high cost) they would be incapable of realizing market share. This capacity can be effectively eliminated from the market power calculations.

4.1.1.4.5 Mitigation Measures

If an applicant fails the first two market screens and fails to prove a lack of market power with subsequent analysis or chooses not to submit such analysis, they will be required to implement measures to mitigate their market power. An applicant may propose mitigation measures tailored to their particular circumstance. If FERC finds these remedies inadequate, it will rescind the applicants market-based rate authority and order cost-based rates. The cost-based rates for mitigation are shown in Exhibit II-7.

Exhibit II-7

Term of Sale	Cost-based Rate allowed
Short-term - ≤ 1 week	**Marginal cost + 10%**
Mid – term - > 1 week and < 1 year	**Embedded costs "up to" unit providing service**
Long-term - ≥ 1 year	**System embedded costs**

4.1.1.4.6 Implications for Public Power

As non-jurisdictional utilities, Public Power is not directly impacted by this order. The Large Public Power Council in an opinion paper stated "…members are not generally required to perform the tests and make filings with FERC. However, they could be asked to provide proprietary information to be used in the preparation of the market power analysis for neighboring jurisdictional utilities. They could also be 'dragged into' the mitigation phase where a jurisdictional utility argues that mitigating their market power would place them at a disadvantage relative to neighboring non-jurisdictional utilities (this argument has already been made in a rehearing requests) or that non jurisdictional participation in an RTO is an essential part of the required mitigation."

Indirectly, Public Power could see some near-term impacts. If a number of jurisdictional utilities fail the market screens and are required to sell at cost-based prices, this may dampen wholesale electric prices, notably during peak periods when excess demand would normally drive prices above marginal costs. This is especially true for the MISO area, where most jurisdictional utilities are more likely to not pass the screens because they are vertically integrated and because MISO does not yet qualify as a single market RTO. This would be positive for net buyers and the market and negative for net sellers.

The longer-term consequences may be more profound. It would difficult for any vertically integrated utility with control area responsibilities to pass both market screens without being a member of an RTO. This rehearing order is clearly intended as a strong incentive for jurisdictional utilities to join RTO's expeditiously. Non-jurisdictional utilities are probably on the radar screen. As more jurisdictional utilities join RTO's, public power will become more isolated. RTO's may began to implement reciprocity conditions for sale into the RTO market. Eventually, Public Power may have to join an RTO or sell into the wholesale market at cost-based rates.

5.0 RTO Market Monitoring and Market Power Mitigation

5.1 Market Monitoring

As stated in Section 2, the Standard Market Design (SMD) proposes that RTO's are given the responsibility for monitoring market power and implementing mitigation measures when it is found to exist. Monitoring will include close daily monitoring of the day ahead and real-time markets as well as tracking of transmission transactions. The Final Rule would specify how often reports must be prepared. At least annual reports on the status of market power in the region will be prepared for FERC, the regional state committee and other appropriate state regulatory authorities.

5.2 Market Power Rules and Mitigation

The SMD Whitepaper states: "The Final Rule would require that each RTO or ISO have an independent market monitor either for the individual RTO or ISO or for a larger region. The RTO or ISO tariff must contain appropriate market power mitigation measures to address market power problems in the spot markets. These mitigation measures must work together with measures on resource adequacy to ensure that the measure do not suppress prices below the level necessary to attract needed investment in infrastructure in the region."

Furthermore the RTO will be empowered to take action if market power abuse is found. This will include: enforcement of Reliability Must Run agreements for generation units with localized market power; enforcement of price caps; and the potential to adjust a generator's bid downward automatically if it is out of line with its historical bidding behavior.

6.0 Midwest Independent Operator (MISO) State of the Market Report 2003

6.1 Report Overview

The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes Nebraska. In May 2004 they published their second *State of the Market Report* assessing market power in the Midwest. The analysis includes all the current and prospective utility members of MISO. Therefore the major transmission-owning utilities in Nebraska are included. The report includes a number of market power tests for the region. These tests are described and presented in Sections 6.2 – 6.6 below. They range from simple to complex. Many of them require detailed transmission and market price data that only MISO has. At the same time, they require sophisticated loadflow and market models. Taken together they offer a complete picture of market power in the wholesale electric market that includes Nebraska.

6.2 MISO Subregions used in Market Power Tests

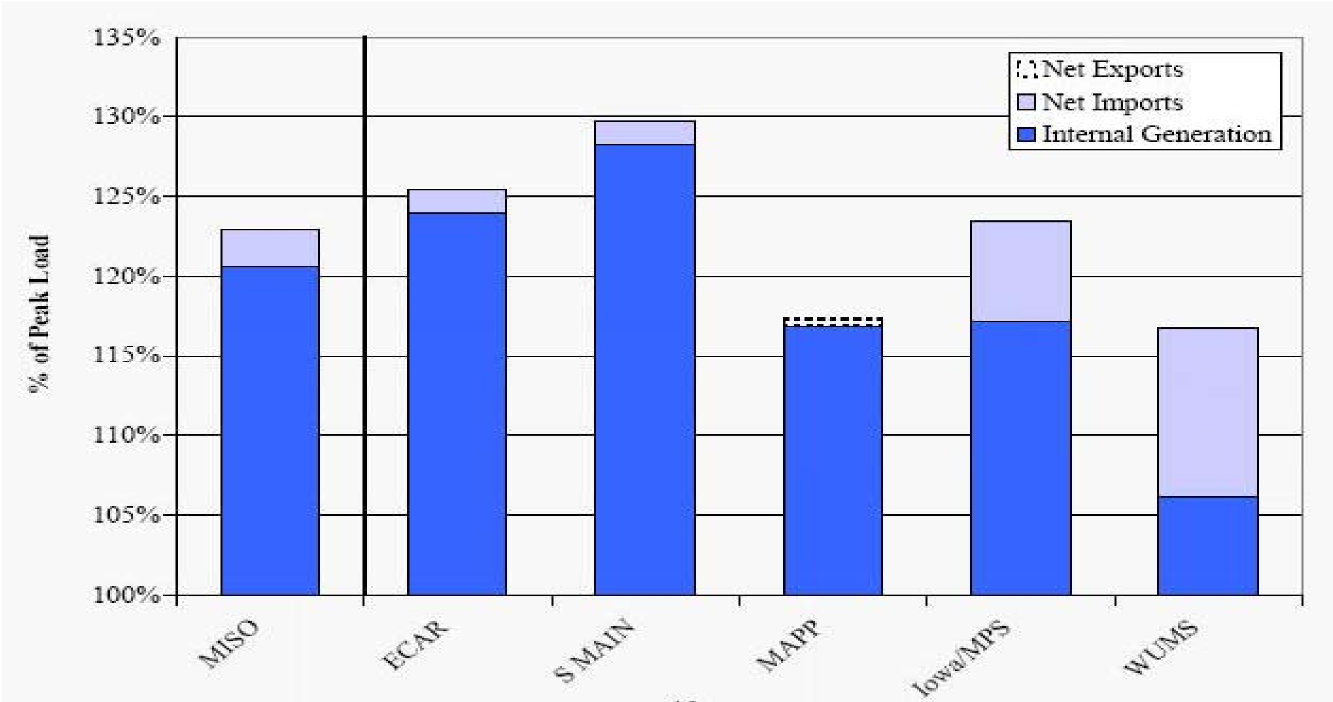
Many of the tests use MISO subregions to provide geographic detail. These subregions are generally defined as MISO areas that fall into different NERC reliability regions. Some special regions are also defined. The regions are shown below:

MAPP………..	Current or prospective MISO members in Nebraska, North Dakota, most of Minnesota, most of South Dakota, Western Iowa and Eastern Montana
South MAIN…	Illinois, Southeastern Minnesota, eastern Iowa and eastern Missouri
WUMS……….	This is not a reliability region. It is separated out because lack to transmission makes it a particularly troublesome area as far as market power. It includes North MAIN, Specifically Eastern Wisconsin and the Upper Michigan peninsula
ECAR………..	Lower Michigan, Indiana, Ohio, Kentucky and Western Pennsylvania
Iowa/MPS……	Mid-American Energy, Alliant West (including Muscatine) and Missouri Public Service

6.3 Reserve Margin Analysis

This is a very simple but effective test. For each region in MISO it shows the total generation as a percentage of peak load as shown in Exhibit II-8. This is called reserve margin. It is the amount of excess generation in a region. Overall, MISO has a reserve margin of 22.9%. Regions with low reserve margins (like WUMS) are susceptible to market power. Generators can increase prices by unilaterally withholding generation from the market. In tight supply situations this will raise the price of electricity. In regions with high reserve margins,, if a utility tried to withhold power, it would simply be compensated for by others with excess generation.

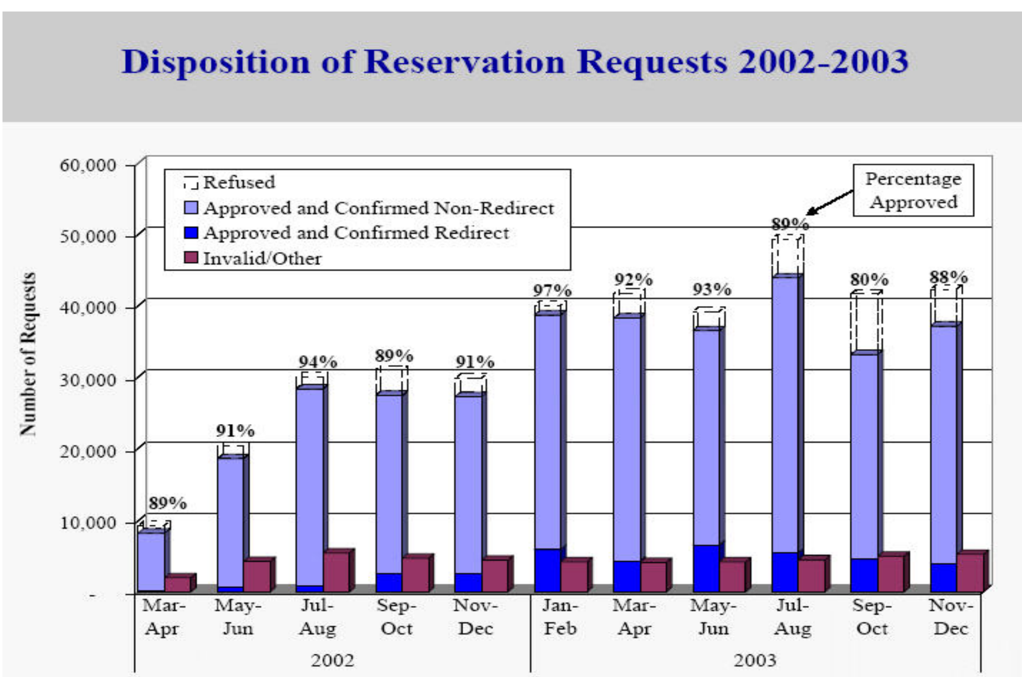
Exhibit II-8



6.4 Transmission Request Analysis

This is a simple test that seeks to determine if the transmission system is being used to prevent competitive suppliers from getting to the market. The report finds that both the requests and approvals of transmission service have risen substantially from 2002 to 2003. As Exhibit II-9 shows, approvals ranged from a low of 80% to 97% with most months showing approval rates in the mid 90's. At the same time approved firm requests increased by 73% from 2002 to 2003. This <u>suggests</u> that parties who want to move power generally can get the transmission they need. This test may make the situation appear better than it is, however, because often transmission users will not even make a request if they know it will be denied. The OASIS Scenario Analyzer system facilitates this by providing an indication of transmission availability even before the request is made. Based upon the experience of Nebraska utilities on Technical Group #2, this is a fairly common occurrence. An exact measure of this self-declination is unknown, but it is thought to be significant.

Exhibit II-9



6.5 Transmission Curtailment Analysis

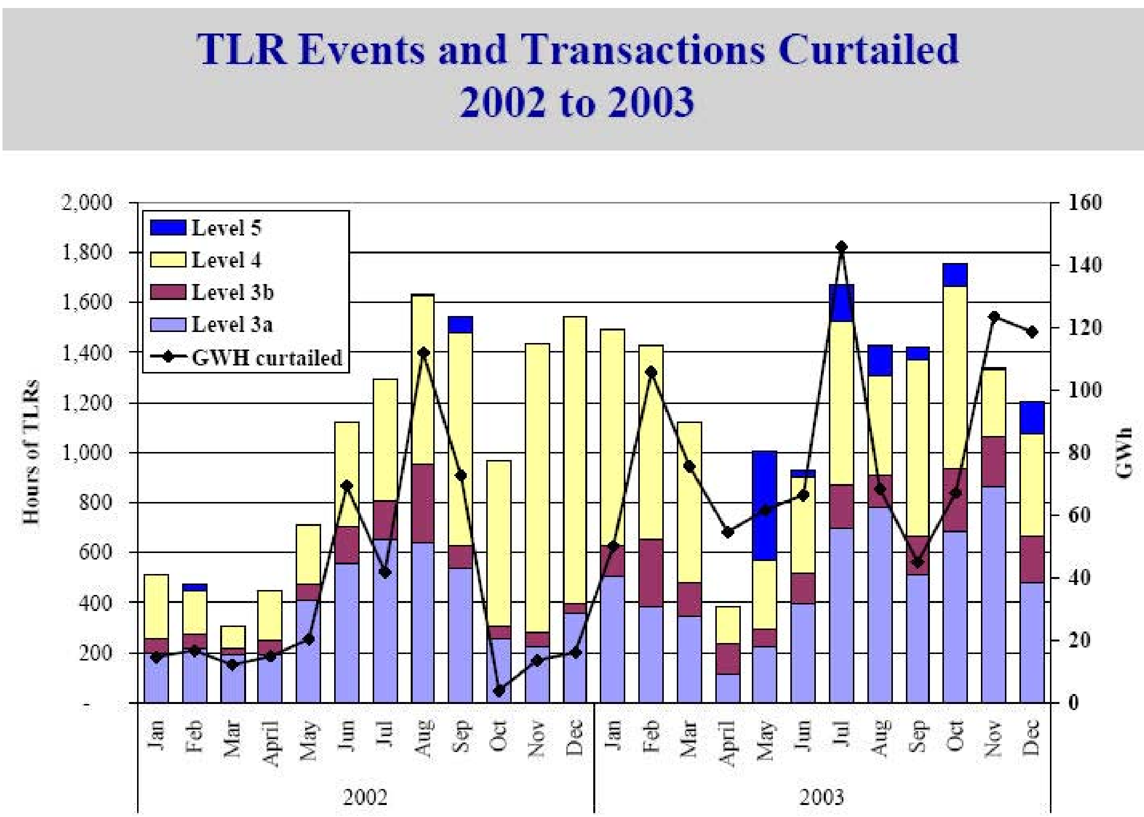
6.5.1 Number and GWH Amount of MISO Electricity Transactions Curtailed

Whenever a transmission line becomes loaded to the point it is operating near its total capacity, the reliability of the system is threatened. In these situations, a TLR or Transmission Loading Relief can be called. If a TLR is invoked several actions may be taken depending on the severity of the situation. The first step, called TLR level 3a, is to curtail non-firm electricity transactions for the next hour. TLR level 3b is the next step, curtailing non-firm transactions for the current hour. If this is not enough, a TLR level 4 is invoked whereby the system is redispatched by asking generators to increase or decrease their power output. Next a TLR level 5 is called where firm transactions are curtailed. Finally, TLR level 6 requires emergency actions to protect the integrity of the system.

Whenever a TLR is called, there is an opportunity to exercise market power on the downstream side of the constrained line. The curtailment can create a load pocket where an isolated generator can manipulate the price.. Therefore the number of TLR's called and the GWH amounts involved in the curtailments are an indicator of the potential for market power. Exhibit II-10 shows the number of TLR's and GWH curtailed in MISO have both risen significantly in 2003 when compared to 2002. This was more TLR's than any other RTO, representing 62% of the TLR's in the Eastern Interconnect. This indicates at least the potential that isolated submarkets may exist that give generators the opportunity to exercise market power.

One mitigating factor is that a large percentage of the MISO TLR's called were in the WUMS area. It is a known load pocket where mitigation measures can be implemented. A number of TLR's also occurred in Iowa. This was due to relatively light hydro conditions for Manitoba Hydro, which significantly affected the schedules and flows through the regions.

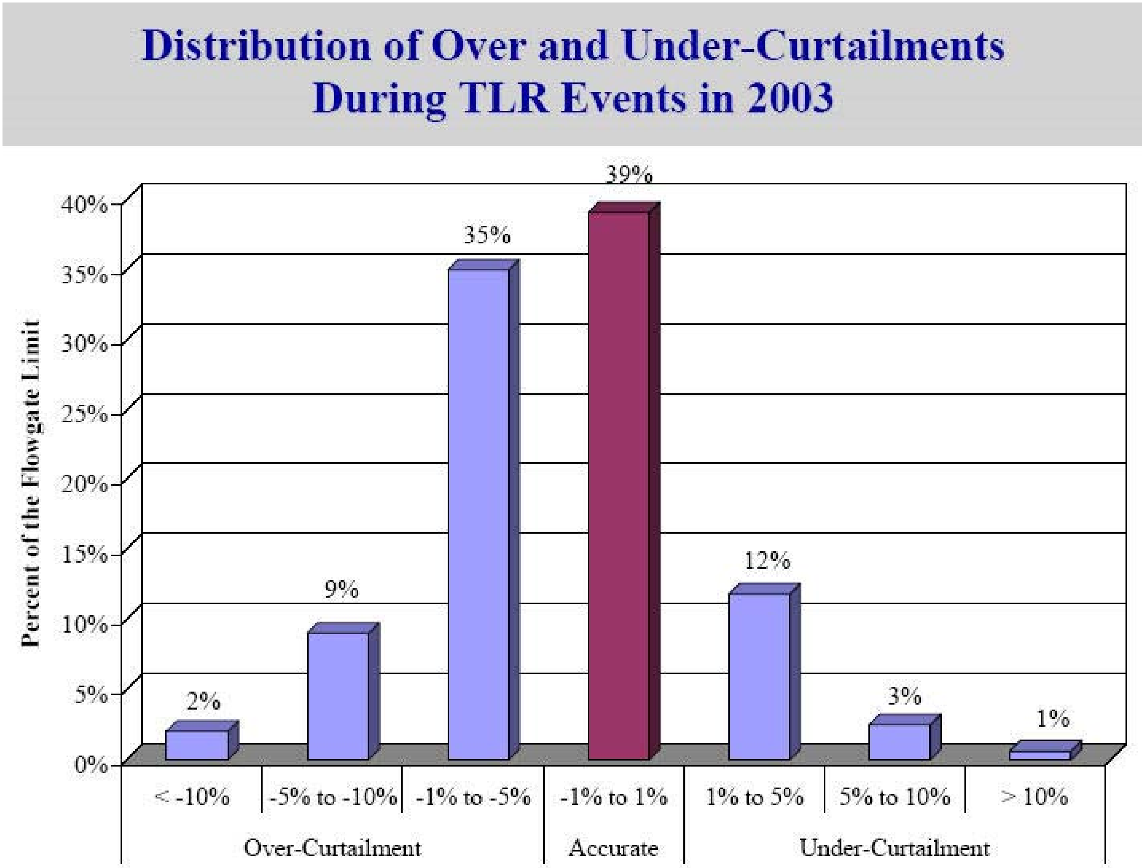
Exhibit II-10



6.5.2 Justification of MISO TLR's

Another question is whether the MISO TLR events were justified. If TLR's are called when the conditions are not warranted, it may indicate use of the process to support the exercise of market power. A way to test this is to conduct studies that compare the real-time electricity flows relative to transmission capacity at the time that TLR's were called. Exhibit II-11 shows of all the TLR's that were called in MISO, 39% brought the actual electric flows over the flowgate to within +/-1% if the actual flowgate capacity. 86% of the TLR's were accurate to within 5. This demonstrates that TLR's were justified for reliability purposes and not to exercise market power.

Exhibit II-11



6.5.3 TLR Price Effects Analysis

The most important question about TLR's is whether they actually result in the exercise of market power. When constraints are binding, and additional power is prevented from flowing into the constrained area, the price in the constrained area ("downstream price") should rise relative to the price outside of the constrained area ("upstream price"). The analysis was conducted on major transmission lines or "flowgates" within the MISO area. There are about 600 flowgates that MISO routinely monitors. A sample of flowgates with a history of many TLR's was selected for the analysis. For each of the flowgates selected, the upstream-downstream wholesale price differential was calculated for times when the flowgate did not have a TLR called and for times when there was a TLR invoked. The price differential is simply the wholesale market price on the upstream side of the constraint minus the price on the downstream side. By statistically comparing the non-TLR differentials with the TLR differentials it can be determined if the TLR had an effect on the market price in the constrained region. This year the analysis demonstrated that there were not significant differences in upstream prices and downstream prices during a TLR event. Very few flowgates had differences that were statistically significant. The flowgates that were identified are in known localized load pockets where it is expected that market power would exist.

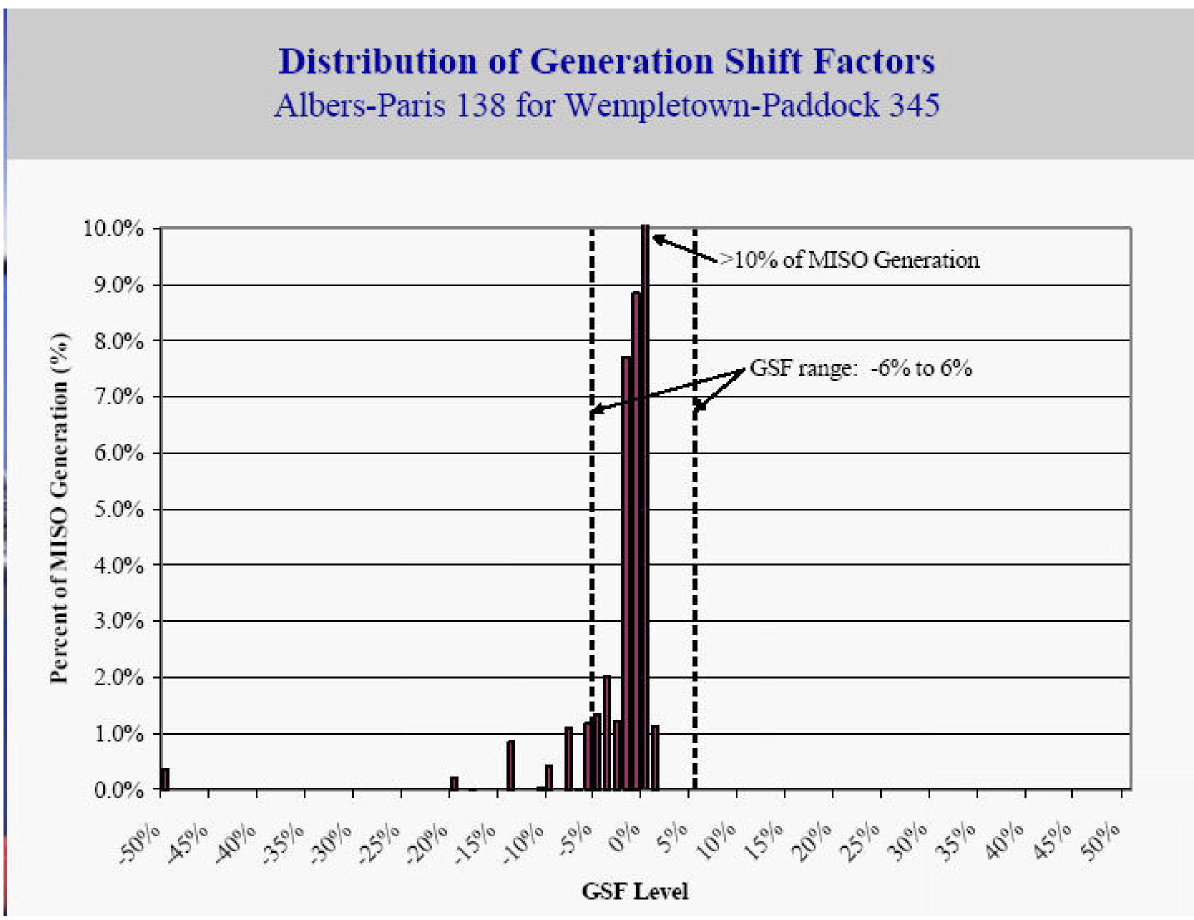
Even though there appear to be a significant number of TLR's in MISO, this analysis demonstrated that the TLR's do not generally result in the exercise of market power.

6.6 Pivotal Supplier Analysis

Every generator in a region will affect the loading on every transmission flowgate in a region. If one generator has a very significant impact on the loading of a flowgate and there are few other generators in the position to counteract that dominance, the generator is said to be a Pivotal Supplier. Pivotal Suppliers have the ability to create congestion on a line. This can induce transaction curtailments that may favor the Pivotal Supplier. In many cases it is economically more efficient to "redispatch" generators in order to relieve a transmission constraint as opposed to arbitrarily curtail firm transactions. The RTO redispatches by taking bids from generators who will either increase or decrease generation to relieve the constraint. Pivotal Suppliers would be in a position to bid up the price of redispatch because they lack competition. Both the ability to induce curtailments or create an advantage in redispatch bidding result in localized market power for the Pivotal Suppler.

Some generators that are very large and are in close proximity to the transmission line will have significant effects on the loading of the flowgate. Other generators that are small or are far away from the flowgate will have a negligible effect. The portion of each generator's output that will flow over a flowgate is called a Generation Shift Factor or GSF. A positive GSF indicates that additional production from the generator will increase the flow on the flowgate in the normal direction of the flow (i.e. it will increase the congestion). A negative GSF indicates that additional production from the generator creates flows in the opposite direction of normal flow. An increase in production from this unit would decrease congestion. Pivotal Suppliers can be identified by calculating all of the GSF's for every flowgate in the region. To identify potential Pivotal Suppliers, MISO calculated the GSF's for 121 of the most congested flowgates. The GSF values came from the results of the MISO Load Flow Case using the PowerWorld Transmission simulation Model. For example, Exhibit II-12 shows the GSF's of all generators in MISO over one Flowgate. In this example it is the Albers-Paris 138 for Wempletown-Paddock 345 Flowgate. As would be expected, this graph shows that almost all the generators in MISO have very little influence on the additional flows through the flowgate, i.e. the GSF's are between -5% and 5%. This means less than 5% of additional output from those units flow through the flowgate. .

Exhibit II-12



However, this flowgate has very few generators that can significantly affect the flowgate in this load flow case. This would give each of the generators a greater opportunity to cause congestion on the flowgate and to have an advantage in redispatch bidding. This flowgate is more likely to have a pivotal supplier.

For the Pivotal Supplier Test, MISO considered a supplier to be pivotal when it was able to cause a constraint to be binding on the MISO system that cannot be resolved by redispatching other supplier's generation. In the least conservative scenario used to identify Pivotal Suppliers, a total of 52 Pivotal Suppliers were identified. However, of all the flowgates that exhibit one or more pivotal suppliers, generally only flowgates into or within WUMS are frequently congested. This means of all the pivotal suppliers identified, only those in the WUMS area would be able to effectively use that position to exercise market power. To mitigate the market power of Pivotal Suppliers, MISO suggests that "reliability must run" agreements be signed with those generators. MISO has designated WUMS and North WUMS as narrow constrained area for purposes of the market mitigation measures filed in March 2004.

7.0 Conclusion

7.1 Status of Viable Midwest Wholesale Market in the Eastern Region

The new information gathered for this year's analysis is sending mixed and ambiguous signals regarding market power in the Midwest portion of the Eastern Interconnect (as shown in Exhibit II-1). On one hand, "traditional" tests of market power used by FERC suggest that this market has a large number of buyers and sellers and appears to be viable. A defined process for accessing wholesale transmission is available through MAPP, utilizing Schedule F for a period of up to 12 months, or by utilizing Midwest Independent System Operator (MISO) or individual transmission provider's tariff for durations ranging from hourly service to multi-year service. In short, the wholesale market appears to reasonably efficient and workable, supporting many useful trades each day. On the other hand, the Midwest wholesale market, at times, has limited access to reliable transmission for delivery, conditions that are conducive to the exercise of market power. The *MISO State of the Market Report* show that while this has not lead to widespread exercise of market power, the potential clearly exists. This is evidenced by the large number of TLR's in the area, the existence of pivotal suppliers and the anecdotal evidence that many transmission requests are not attempted because of the likelihood that they would be rejected. Furthermore, the newly approved FERC market power tests suggest most of the utilities in the region would be found to have market power, at least until all are members of an RTO that has centralized dispatch, a formal power market and established market power mitigation measures, a status not yet attained by MISO. The final conclusion is that a reasonable efficient and workable wholesale market does exist in the Midwest region, but it cannot be judged as being free from market power given the new FERC rules.

7.2 Status of Viable Midwest Wholesale Market in the Western Region

There have been disruptions in Western wholesale power markets in recent years. In spite of these disruptions, energy deliveries have been maintained to customers in Nebraska located on the Western Interconnection. These customers are primarily served by MEAN and Tri-State.

The viability of the wholesale market has been hampered in recent years by transmission constraints, adverse hydro conditions, and lack of a viable regional transmission organization. Unless these conditions are addressed, it is unlikely that a viable wholesale market will exist on the Western Interconnection in the foreseeable future.