ANNUAL REPORT-2003
MONITORING OF LEGISLATIVE BILL 901
'CONDITION CERTAIN' ISSUES

OCTOBER 2003

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INTRODUCTION

In 1996, the Nebraska Legislature passed Legislative Resolution 455 (LR 455) which directed the Legislature's Natural Resource Committee to perform a two phase study to examine issues related to competition and restructuring of the electric utility industry and the possible effects on the state. Advisory groups and task forces were formed and utilized along with a consultant.

The first phase of the study examined the history and current status of Nebraska's electric industry. The report produced in Phase I provided a comprehensive overview of the structure, governance, operations, financing and comparative effectiveness of Nebraska's consumer-owned electricity industry. Phase I was completed in December 1997.

Phase II of LR 455 examined the transition of the electric utility industry nationwide and developments at the federal level and in other states related to possible impacts and options for Nebraska's electric industry. Based on these exa minations, the Phase II report provided a planning framework for Nebraska centered on a "condition certain" approach to retail competition. Several states that pursued a 'time certain' approach to retail competition encountered problems which probably could have been avoided had a "condition certain" approach been followed. The "condition certain" approach requires that specific preconditions in structure and market be in place when, and if, a transition to retail competition is to be made for Nebraska's electric industry. The Phase II report was completed at the end of 1999.

In early 2000, the elements of the "condition certain" approach as outlined in the LR 455 Phase II report were incorporated in legislation that was introduced in the Nebraska Legislature. Legislative Bill 901 (LB 901) was passed by the Legislature on April 11, 2000.

LB 901, the pertinent part of which is now codified at Neb. Rev. Stat. Chapter 70-1003 (5), (6) and (7) (Cum. Supp. 2000), directs the Nebraska Power Review Board (NPRB) to hold annual hearings concerning the benefits of retail competition in the electric industry in Nebraska and what steps, if any, should be taken to prepare for retail competition. LB 901 also directs the NPRB to submit an annual report to the Governor, with copies to the Clerk of the Legislature and the Natural Resources Committee, analyzing five items or conditions concerning the electric system in Nebraska and the region to help determine when and if retail competition should be initiated in Nebraska.

To carry out the mandate of LB 901, the NPRB formed Technical Groups comprised of experts from Nebraska's electric industry to conduct research and prepare the part of the study corresponding to each of the five conditions outlined in the legislation. The members of the Technical Groups that addressed the five issues are shown in the individual issue reports.

The NPRB also formed a Review Group to allow for participation in the process by a wide spectrum of interested parties. The Review Group includes representatives from government agencies, consumer groups, public power entities, investor-owned electric utilities, residential, agricultural, commercial and industrial consumers and other groups. The Review Group acts as a sounding board for the Technical Groups' information and findings, and offers suggestions for the final report. The members of the Review Group were as follows.

NAME	**REPRESENTING**
Jim Anest	Agricultural Customer
Jeff Baker	Industrial Customer
Doug Bantam	Lincoln Electric System
Chuck Barrett	Commercial Customer
Fred Bellum	American Association of Retired Persons
Anne Boyle	Nebraska Public Service Commission
Tim Burke	Omaha Public Power District
Richard Duxbury	NMPP Energy
Jon Empson	UtiliCorp United
Marvin Fishler	Irrigation Customer
Joe Francis	Nebraska Department of Environmental Quality
Jody Gittins	Natural Resources Committee
Gary Hedman	Southern Public Power District
Jay Holmquist	Nebraska Rural Electric Association
C. G. Holthus	Commercial Customer
Clint Johannes	Nebraska Electric Generation & Transmission
Don Kraus	Central Nebraska Public Power & Irrigation
Richard Kuiper	IBEW/NE State Utility Workers
Gary Mader	Grand Island Utilities
Derril Marshall	Fremont Utilities
John McClure	Nebraska Public Power District
Dave Mazour	Tri-State Generation & Transmission
Larry Pearce	Governor’s Policy Res./ Nebr. Energy Office
Bruce Pontow	Nebraska Electric Generation & Transmission
Mary Powers	Nebraska League of Women Voters
Frank Reida	Residential Customer
Rodney Schroeder	Commercial Customer
Marvin Schultes	Hastings Utilities
Adam Smith	Industrial Customer
Jennifer States	Community Action of Nebraska
Tim Texel	Nebraska Power Review Board
Alfred Thomsen	Residential Customer
Robert White	Loup River Public Power District

The NPRB retained PAPE CONSULTING SERVICES as the Coordinating Consultant. The Consultant is responsible for coordinating the activities and meetings of both the Technical and Review Groups, and for assembling the annual report. The first Annual Report was issued in October 2001.

Although Nebraska is unique in the United States in that it’s electric utilities are exclusively consumer-owned, Nebraska’s major public power utilities have historically participated in the initial development and growth of the region’s high voltage electric transmission system. It is critical that a reliable and adequate transmission system exists in Nebraska and in the region. Nebraska is not and cannot be an island. Nebraska is electrically interconnected to numerous investor-owned and consumer-owned utilities, and regularly trades wholesale electricity with these utilities as well as other energy service providers for reliability and economic purposes.

Nebraska needs to be aware of the successes and failures of customer choice programs in other states, and congressional and regulatory activities at the federal level. Although the “Condition Certain” approach to customer choice being followed in Nebraska is more conservative than the approach being taken in other states, it should enable Nebraska to move towards customer choice in a more orderly manner with reasonable assurance of success, when, and if, the State believes that Nebraska's electric consumers will benefit.

In order for customer choice to be effective in Nebraska, it would not be adequate to only have a viable regional transmission organization and adequate transmission in Nebraska or in a region that includes Nebraska, only a viable wholesale electricity market in a region that includes Nebraska, or only wholesale electricity prices in the region comparable to Nebraska prices. For an effective customer choice program, all three of these conditions must be favorable.

This report is the third report following up on the five "Condition Certain" issues identified in LB 901.

EXECUTIVE SUMMARY

The five 'Condition Certain' issues identified in LB 901 were assigned to five separate Technical Groups. The Executive Summary that follows includes the new findings and conclusions that are incorporated in the 2003 Update, as well as the findings and conclusions from the 2002 and 2001 Reports.

Issue #1 (Chapter 1)

2003 REPORT UPDATE-The August 14, 2003 blackout, the most wide-ranging in U. S. electric history, will cause a significant review of the nation's transmission infrastructure and the organizational entities controlling it. Congressional hearings have been scheduled and a joint U. S. and Canadian Task Force have been appointed to investigate the blackout. Many are calling for passage of the long debated federal energy legislation. How this will impact the continued development of Regional Transmission Organizations (RTOs) remains to be seen. The Midwest ISO has indicated that it will be reevaluating the timing for the start-up of its energy markets, and will make a recommendation to its Board of Directors in September. Progress on the development of TRANSLink has been slowed due to the lack of state regulatory commission approvals, and as a result the TRANSLink participants are reevaluating their options for continued development of TRANSLink. In light of the pending investigations of the blackout, and uncertainty about federal legislation which may be enacted, it seems prudent for Nebraska utilities to wait until such time as more is known so they can make an informed decision before proceeding to join a RTO. At this time there is not a RTO that has been shown to be economically, technically and operational viable. There is adequate transmission capacity in Nebraska to deliver the generation output of plants in Nebraska to the Nebraska customer load, but there is not sufficient capacity to support all of the wholesale power transactions that are requested in the region.

SUMMARY OF 2002 REPORT -There have been numerous filings at FERC proposing RTO's since Order 2000 was issued. While conditional approval has been granted to several proposals, FERC has only given full approval to the Midwest RTO (MISO). MISO was approved in December 2001 and the MISO tariff went into effect in February 2002. The geographic size of MISO continued to grow as new members have joined. The Southwest Power Pool (SPP) has agreed to merge with MISO and the SPP transmission system should be integrated into the MISO transmission tariff by late 2002. It can be said that MISO is viable from a legal, financial, and operational viewpoint, but it is still in the early stages of operation and has many issues to resolve before it can perform all of it's functions and duties satisfactorily. Other considerations in determining whether MISO is viable to participate in are dependent on the legal aspects of a participation agreement with MISO to recognize Nebraska state law restrictions, MISO's costs to participate, and the impact on the utilities' transmission revenue due to the MISO transmission tariff. The MAPP/MISO merger has been completed and some of the MAPP members have joined MISO. One of the conditions of the merger was that MISO would continue to provide transmission services for six years to MAPP members that do not join MISO. Certain transmission facilities in western Nebraska would need to participate in a RTO in the western interconnection because those facilities are not electrically connected to the rest of the state.

Since RTO's have not developed as envisioned in Order 2000, FERC took another step to further the development of competitive wholesale electric markets when it issued another Notice of Proposed Rulemaking on July 31, 2002, which is known as FERC's Standard Market Design (SMD). This Order proposes sweeping changes to the development of wholesale electric markets. The Order will not go into effect for many months, until FERC has considered comments submitted by all interested industry participants. Nebraska utilities will need to thoroughly evaluate the economic and legal impacts of this Order as many of the requirements will be implemented by the RTO. The reader is referred to page I-8 for a full listing of items proposed by FERC in the SMD rulemaking. The development of competitive wholesale electric markets continues to be a moving target. Just as utilities think they understand the rules FERC has set forth, FERC pushes the industry in a new direction. Until the FERC rules stabilize, it will be difficult to assess the economic impacts of RTO participation with any degree of certainty.

FERC issued an order in April 2002 accepting certain aspects of the TRANSLink filing and requiring changes to other parts. Since then a TRANSLink Development Company, LLC has been formed and it is expected additional FERC filings will be made in September 2002. In the TRANSLink ITC proposal NPPD and OPPD will no longer be control area operators. They will continue to balance generation and load within their area, but TRANSLink will operate one control area for the MAPP members facilities. NPPD and OPPD will retain operational control under certain emergency conditions. In the TRANSLink Order, FERC ruled that TRANSLink cannot have it's own transmission tariff, but can have it's own rate design under a MISO rate schedule.

In the last year a number of new generation resources have been announced by Nebraska utilities. In each case a transmission adequacy study must be completed and approved by MAPP. Thus far all new generation additions have been able to be accommodated without significant transmission additions. This reinforces the conclusion that adequate transmission exists in Nebraska to deliver the generation resources located in Nebraska-to-Nebraska customers. However, the ability to export generation located in Nebraska for off-system sales, or to purchase generation outside of Nebraska for delivery into Nebraska will be dependent on several factors. In general, it is fair to say that the adequacy of the regional transmission system to accommodate these types of transactions is limited.

SUMMARY OF 2001 REPORT-The issue addressed by this Technical Group was "whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska". The development of Regional Transmission Organizations (RTOs) has been underway since the Federal Energy Regulatory Commission (FERC) issued Order No. 2000 in December 1999. FERC stated that RTOs would promote competition in the wholesale electric market, enhance reliability, and remove any remaining opportunities for discriminatory practices by transmission owning utilities. In that Order FERC called for all transmission owning utilities to work towards the voluntary formation of RTOs in collaboration with state regulators, transmission dependent utilities, and other market participants.

However, in a series of orders issued on July 12, 2001 FERC reversed its course and now suggests that only four RTOs should be formed, one in the Northeast, Southeast, Midwest and West. This change in direction by FERC has caused considerable confusion in the industry. As a result, this Issue is in a state of flux. At this juncture the only organization that has the potential to become a viable RTO for Nebraska utilities to participate in is the Midwest ISO (MISO), assuming FERC decides that MISO is to become the Midwest RTO it envisions. This report will serve to identify key issues that could significantly affect the way the electric transmission system in Nebraska is planned, operated and priced.

The Nebraska transmission system is adequate to serve Nebraska customers when system conditions are normal. However, under abnormal system conditions, such as the loss of major transmission lines or a large generation plant, Nebraska customers depend on the interconnected utilities in surrounding states and the generation reserve sharing pool to maintain reliability. Nebraska utilities contribute to the reliability of the region in a reciprocal manner. The Nebraska system does experience significant usage due to the wholesale transactions occurring in the region. Reliability is maintained by setting limits on the constrained interfaces and curtailing transactions when system conditions approach those limits.

Because the wholesale market has become regional in nature, it requires regional solutions to fix the constrained interfaces. Additional high voltage transmission lines will need to be built that cross several utilities service areas in order to accommodate much more wholesale activity than what currently exists. Several transmission projects have been identified to relieve the transmission constraints, but until the projects can be funded and paid for by a regional transmission tariff, utilities will be unlikely to build new transmission.

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Issue #2 (Chapter 2)

2003 REPORT UPDATE-In the past, Technical Group #2 conducted FERC's standard test of market viability using public domain data. Two factors have changed that 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 those 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 MISO issued their first "State of the Market Report". This 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. The reader is referred to Chapter 2, Section 6.0 for a full discussion of the information included in the first MISO "State of the Market Report".

The standard test for market power is called the "Hub and Spoke" test. It has been the basis for this report for the last two years. The "Hub and Spoke" test conducted by MISO for the MAPP region in 2003 produced results that are very similar to the results produced by Technical Group #2 for a similar region in 2001 and 2002. The MISO analysis confirms the previous year's conclusions that the MAPP area of MISO has an unconcentrated market and is relatively free of market power.

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 recognized the effect of transmission constraints on the exercise of market power. The latest evolutionary cycle of market power testing and mitigation is defined in the "Standard Market Design" (SMD) Notice of Proposed Rulemaking. SMD proposes that RTO's assume the function of Market Monitoring and Market Power Mitigation. The RTO will be required to periodically report on the status of market power in their region. The assumption is that RTO's are unique 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, and therefore 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 analysis. The reader is referred to Chapter 2, Section 4.0 for a full discussion of the new FERC methods for assessing market power.

The Eastern Interconnect wholesale market appears to be viable in that it has a large number of buyers and sellers. However, at times, it has limited access to reliable transmission to either deliver into Nebraska or export from Nebraska generation, depending on system loading conditions. There have disruptions in the 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. The viability of the wholesale market in the Western Interconnect 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 Interconnect in the foreseeable future.

SUMMARY OF 2002 REPORT -FERC's methodology for assessing market power has been evolving. Notably, FERC has taken steps to recognize 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 evolution culminated in a new 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". The order introduced a new test for market power called the "Supply Margin Assessment" which laid out mitigation measures for companies failing the test and found a number of companies not in compliance with the order.

This Group used the same definition of a viable market that was used for the 2001 Report. The Group considered an alternative market region that was basically a footprint of the proposed Midwest Independent System Operator (MISO). However, it was decided to use the same market region that was used for the

2001 Report since MISO has not yet been completely formed, nor are all of the protocols and rules completely developed. As a result, Nebraska utilities and MISO do not currently function as a single market and may not do so for the foreseeable future.

It was concluded that the Eastern Interconnect appears to be a viable market in that it has a large number of buyers and sellers. However, at times it has limited access to reliable transmission to either deliver into Nebraska loads or export from Nebraska generation, depending on system loading conditions. The presumption that the region will be served by MISO, which will migrate to a standard transmission tariff, manage congestion and monitor the members for market power, suggests that this viability will be maintained in the future.

If one applies the FERC logic, Condition # 1, "Whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska", and Condition # 2, "Whether or not a viable wholesale electricity market exists in a region that includes Nebraska", merge into one. In other words, if Condition # 1 is satisfied, Condition # 2 by definition, will also be satisfied. If the TRANSLink ITC is accepted by FERC as part of the MISO, then the portion of Nebraska included in the Eastern Interconnect will be part of one RTO. By FERC's definition, this entire region, which includes the majority of Nebraska, will therefore be free of market power.

There continue to be significant capacity short falls and transmission interconnect problems that have caused a substantial lack of continuity to energy deliveries to loads in the Western Interconnect.

SUMMARY OF 2001 REPORT-This Technical Group dealt with the question "whether or not a viable wholesale electricity market exists in a region which includes Nebraska". The LR 455 Phase II report 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 portion of a retail customer's bill that will be open to competition is the electric commodity (wholesale) portion. It is, therefore, important that the wholesale electric market be adequately established and be viable. The Group defined the term 'viable' using several alternate methodologies. Next the size of the region was determined. Since the Nebraska electric system is in two portions of the United States interconnected systems, the region for each (Eastern and Western) was determined.

The Eastern Interconnect wholesale market appears to be viable in that it has an adequate number of buyers and sellers. However, at times it has limited access to reliable transmission facilities to either deliver electricity to Nebraska loads or export electricity generated in Nebraska to surrounding states, depending on the demands on the transmission system. Since Nebraska's electricity supply is cost-based and consumer owned, there is considerably less volatility than that of the regional indices, which are based on the hourly, daily and monthly wholesale spot market.

There are considerable capacity shortfalls and transmission interconnect problems that have caused significant lack of continuity to energy deliveries to loads in the Western Interconnect. There could be significant economic implications to Nebraska utilities if large coal-fired generation are unavailable, de-rated or off-line to Western Nebraska utility members, which includes primarily MEAN which serves most of the municipalities in western Nebraska, and Tri-State G&T in Westminster, Colorado which serves all of the rural electrics in the panhandle of Nebraska.

ISSUE # 3 (Chapter 3)
2003 REPORT UPDATE-There were no new developments in 2003 for Technical Group #3 to address.

SUMMARY OF 2002 REPORT -For this year's report, this Technical Group was requested to estimate the cost that would be incurred if retail electric bills were to be unbundled in Nebraska. The cost associated with moving to retail competition is hard to estimate because of the different issues and concerns to be addressed. Unbundling of retail bills is put one small part of the entire deregulation process and can be impacted by the unique requirements that each state imposes on the process. In the 2002 report, this Group presents information regarding the estimated costs for unbundling bills in Nebraska for informational purposes only. It is not intended to estimate the total cost of deregulation.

The consumer-owned utilities in Nebraska were contacted to obtain their estimated costs of unbundling based on guidelines provided by the Technical Group. In addition, using information obtained from other states, a component for consumer education was derived and applied uniformly on a per customer basis to all of the utilities. Information from the utilities was aggregated to obtain a total cost for the State of Nebraska.

The expenses were identified in three categories. The total one-time Set-Up Expenses are estimated to be approximately $7 million, the Annual On-Going Expenses are estimated to be approximately $1 million, and the State-Wide Consumer Education Expenses are estimated at approximately $1.2 million. These are preliminary estimates for informational purposes only and should not be relied on as the costs to unbundle retail electric bills in Nebraska if deregulation of the State's electric utility industry were to occur.

SUMMARY OF 2001 REPORT-This Technical Group was charged with determining "to what extent retail rates have been unbundled in Nebraska". To do this, the Group surveyed 162 municipal, rural electric cooperative, federal, state, and district electric utilities. The survey results showed that, except for one case, retail electric rates in Nebraska are not unbundled. The majority of electric utilities in Nebraska do not have unbundled cost of service studies, although half of all electric utilities surveyed believe they have enough information to unbundle their rates. The survey also disclosed that only half of the utilities' billing systems would handle unbundling. Seventy percent of the utilities stated they would not unbundle their electric rates unless mandated.

There are many issues that are involved in unbundling retail electric rates. These issues will require resolution by the utilities or the state legislature in order to implement unbundling. Issues such as upgrading of billing systems and educating customers will involve significant time and expense. Discussion of these issues is contained in this report. The results of the survey, sample bills from other out-of-state utilities, and a summary table of unbundling activity nation-wide are included in the appendixes.

Issue #4 (Chapter 4)

2003 REPORT UPDATE-Technical Group # 4 utilized the same fixed and variable cost allocation tool in 2003 that was used in the prior two reports. The results of this years comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 2000-2003 (three years actual and one year estimated) and weighted based on MWH. These results are slightly better than the 15% results for the prior period 1999-2002 due primarily to the upward trend of market prices driven by higher natural gas prices and stable generation. The price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers. The "median" market prices compare favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2001 shows that Nebraska's average retail rate of 5.39 cents/kWh is approximately 26 % below the national average of 7.32 cents/kWh.

The Nebraska power system product is based on a long-term “obligation to serve” that is not inherent in market-based electricity products. Typically, there is a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having “iron in the ground”, and limited dependence on the market. This translates to a long-term commitment to providing physical resources that meet or exceed Nebraska’s power systems “obligation to serve”. A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market-based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes. Four different analytical approaches were developed and modeled to establish the value of the long-term “obligation to serve”. The results of the four different analyses indicate that it appears reasonable that the value of the long-term obligation to serve is in the $3-$5/MWH range for a 5X16 peaking type product. This results are presented for subjective consideration only, and are not specifically accounted for in the 2000-2003 Nebraska production cost comparison to market pricing.

SUMMARY OF 2002 REPORT - Although there are other cost allocation issues that could be considered for equitable comparison purposes, the modeling tool that was initially developed last year was updated and enhanced in 2002 to include user options to incorporate transmission cost adders that reflect the additional cost of actually delivering a market product to the Nebraska system (both losses & tariffs). Although this flexibility is built into the modeling tool, this year’s overall comparison results are based on these values being set to zero so that an equitable comparison to last year’s results can be made and any market bias perception is eliminated. A model user option to include an “obligation to serve” value was also incorporated, but, again, this option was set to zero for the same reasons described above. Additional model flexibility and information detail was incorporated to allow users to determine the effect of allocating fixed costs when the market price would allow higher price signals, even in winter months. This is for informational purpose only, and strictly impacts the market price weighted results, so the MWH-weighted results, considered the bottom-line comparison values, are not affected. Also, in order to compare various generation resource types, (baseload, intermediate & peaking) the model is enhanced to provide informational detail and comparisons on multiple physical resources as opposed to only an intermediate-type unit.

The results of this years comparisons between the market price indices and the Nebraska production costs show that Nebraska production costs are approximately 15% lower than the equivalent wholesale “median” market price based on the period 1999-2002 (three years actual and one year estimated) and weighted based on MHW. The results for the 1999-2002 study period are slightly lower than the results for the previous period, 1998-2001, due mostly to the downward trend of market prices driven by lower natural gas prices and increased generation, as well as a slight increase in Nebraska production costs. However, the price volatility associated with Nebraska production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska’s ratepayers.

The “median” market prices compare favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2000 shows that Nebraska’s average retail rate of 5.31 cents/kWh is approximately 22% lower than the national average retail rate of 6.78 cents/kWh.

SUMMARY OF 2001 REPORT--The task assigned to this Technical Group was to make “a comparison of Nebraska’s wholesale electricity prices to the prices in the region”. There are no directly comparable electric price indices available for the electricity product currently provided to and expected by Nebraska customers. The Nebraska product is a firm, total requirements product, available 24 hours per day, seven days a week in quantities that usually vary hourly, weekly, monthly, seasonally and annually based on individual customer needs. This obligation to serve includes both existing and new customers. The typical index provides a price for a fixed hourly quantity of energy, possibly with a premium for financial firmness, but with no obligations on the part of the seller beyond the current month or in the case of daily indices, beyond that day. The forward market does not have a published product that goes beyond an 18 to 24 month period. To make a price comparison using these available market product indices required the conversion of Nebraska's electricity prices to the market product indices.

There are several methods of approaching a fair and equitable comparison. As outlined in the report, the development of a fixed and variable cost allocation tool was deemed to be the best approach for modeling Nebraska's costs to the price indices that are publicly available, independent and credible.

The results of the comparisons between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 1998-2001 (three years actual and one year estimated) and weighted based on MWH. The "median" market prices compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 1999 shows that Nebraska's average retail rate of 5.31 cents/kwh is approximately 20% lower than the national average retail rate of 6.61 cents/kwh.

Issue #5 (Chapter 5)

2003 REPORT UPDATE-Retail deregulation gained considerable popularity between the late 1990's and January 2001 with 25 state legislatures or regulatory agencies committing to various forms of retail customer choice. This trend reversed considerably by June 2003 when only 18 states and the District of Columbia were pursuing such action and some of these states have retail choice on only a very limited basis. Five other states have suspended or repealed retail choice, while retail choice is not being pursued in the remaining 27 states.

In 2003, Arkansas repealed retail choice with the caveat that their PUC would study the possibility of retail choice for the largest power users. New Mexico also repealed retail choice in 2003, while in Oregon, retail choice has commenced for non-residential customers only. In late 2002, Arizona eliminated a key provision of their deregulation plan that would have required two of the state's large investor-owned utilities to move their power plants into a separate subsidiary or sell them to another unrelated company.

By June 2003 new developments were emerging in California's efforts to restore stability to it's electricity markets. Pacific Gas & Electric reached a tentative settlement with the PUC on a plan to allow the company to emerge from bankruptcy. Also in June 2003, the California Legislature was working on a proposal to dismantle the state's retail choice law and return to traditional rate regulation. The Legislature is experiencing difficulty in writing the new law in the face of opposition from consumer, business and utility interests. The legal effort to recoup nearly $12 billion in energy costs under contracts signed during the height of the 2000-2001 wholesale power crisis was set back when FERC voted to uphold the contracts despite massive evidence of market manipulation during the time frame which they were entered into.

In Montana, the PUC approved guidelines for NorthWestern Energy to follow as the company procures electricity on behalf of its 290,000 mostly residential and small business customers who have not chosen an alternative supplier. In it's role as default supplier, NorthWestern must assemble a portfolio of supply contracts to provide electricity to these retail customers, and can recover its prudently incurred costs for that service.

Pennsylvania has seen deterioration in retail choice over the last three years as measured by the energy sold to all customers and industrial customers by competitive suppliers.

Some customer switching has occurred in New York, although the numbers are but a fraction of those that are eligible.

Although retail choice has technically been in effect in Connecticut since July 2000, the concept remains more theory than reality as most suppliers have shown little interest in the Connecticut market. In January

2003 Green Mountain Energy Co. pulled out of the Connecticut market after less than a year of doing business in the state.

In Maine there has been some progression of the percentage of load served by competitive suppliers but mostly to customers with attractive load profiles. There is virtually no competition in the residential or commercial markets.

In Massachusetts retail choice accounts for about 15% of all energy sold, with the majority being sold to the largest customers. There has been some minimal success in marketing to residential customers via a municipal aggregation program in the Cape Cod region of the state.

Some analysts of the New England electricity markets are now raising flags of caution on the regions increasing reliance on natural gas as the fuel choice for new generating facilities. The regions fuel diversity is now undergoing substantial revision due to environmental concerns and the cost of construction associated with coal and nuclear construction. According to a 2003 report of the Associated Industries of Massachusetts, "New England's reliance on natural gas to fuel all new plants has raised concerns that new plants may cause existing natural gas pipeline capacity to be approached or exceeded within a few years. In addition, up to 75% of the new power plants being built or currently in operation are located on just two of the regions five major pipelines. As a result, the security of the gas grid is becoming increasingly important to the reliability of the electric grid."

In a May 2003 report the Ohio PUC indicated that most of the success of retail choice in Ohio is a result of the customer aggregation provisions of the retail choice law.

In Illinois, there was a small increase in the number of customers participating in retail choice. However, of the 15 alternative energy suppliers certified by the state, none have requested certification to serve residential customers

In a January 2003 report, the Texas PUC detailed the status and progress of retail competition after one full year of implementation. The PUC estimates that retail customers have saved over $1.5 billion in electricity costs during the first year, and low-income customers have received almost $70 million in discounts through the System Benefit Fund through October 2002. In all areas open to competition, there are multiple retail electric providers, with as many as ten offering residential service in some areas. The PUC indicated that the competitive market is small but growing. There have been some problems in the Texas market. New Power was one of the more aggressive marketers in Texas. After signing up 78,000 customers, it filed for bankruptcy in June 2002. Technical problems have delayed bills and blocked some switching requests. A far more serious problem emerged in March 2003 when a surge in wholesale power prices indicated evidence of market manipulation, prompting a Texas PUC official to state that some regulation of the merchant energy business may be needed.

Arkansas has been thru a series of legislative actions dealing with retail choice since 1999, the latest of which was in early 2003 to repeal the retail choice in Arkansas.

Driven in large part by the electricity supply and reliability problems in the western United States, the issues of restructuring have now been expanded to include energy supply and infrastructure concerns. Transmission across the United States is frequently inadequate to support retail deregulation. Legislation addressing regional transmission entities, eminent domain, transmission reliability standards, and other issues has been the focus of both Congress and the FERC. Infrastructure/pipelines for natural gas supply have not kept up growing demand for natural gas which has become the most common fuel for generating facilities built in the last ten years.

SUMMARY OF 2002 REPORT -On March 21, 2002 the California PUC took the long anticipated step of suspending the direct access program effective back to September 20, 2001. The order announced a remarkable shift in philosophy on the part of the PUC that has long championed the merits of customer choice and market efficiency. In February 2002, the California PUC filed a complaint with the FERC against certain sellers of long-term power contracts to the state alleging that a significant number of wholesale power contracts entered into by the state were at prices some $21 billion in excess of what could be considered “just and reasonable” and that the state was forced to procure enormous amounts of electricity under conditions of extreme market power. Recent disclosures in the Enron bankruptcy matter have given new ammunition to California’s claim.

In Montana very few residential customers have selected a competitive supplier and no competitive suppliers are currently marketing to them. Montana Power Company faded into history when it’s electricity assets were purchased by NorthWestern Energy Company based in South Dakota.

Although Pennsylvania is often cited as the one state where retail competition exists in a meaningful way, there are fewer customers switched today than there were three years ago. Both the energy sold by competitive suppliers to all customers and the quantity of energy sold by competitive suppliers to industrial customers is considerably below that of three years ago.

In Illinois, residential customers were given the retail choice option as of May 1, 2002. The Illinois Commission continues to find signs of retail electric market growth in the service territories of the three largest utilities in the state, but customer switching is still negligible or non-existent in the service territories of the state’s smaller utilities. The Commission explained in it’s 2001 report that growth in the retail market is dependent on the competitiveness of the wholesale market, but there are indications that the wholesale market is not yet capable of supporting a competitive retail market.

In February 2002, Vermont halted it’s investigation into retail competition stating that significant changes and uncertainty in the wholesale market for electricity make conditions inappropriate for the implementation of retail choice for several years.

In November 2001, a Florida Study Commission issued a final report calling for the State of Florida to transition to a competitive wholesale market. However, the Commission recommended that the retail electric market remain regulated.

The Louisiana Public Service Commission issued an order in December 2001which reaffirmed their earlier conclusion that retail competition in Louisiana, which is a low cost state, would not be in the public interest for any class of retail customer.

In December 2001, the Arkansas PUC provided a report to the legislature recommending either a repeal of the Electric Consumer Choice Act of 1999, or a delay in the start of retail competition until 2012. The Commission estimated that retail competition could result in rate hikes of up to 13%. The legislature will consider this recommendation when it next meets in 2003.

The jury is still out on the State of Texas Electrical Deregulation. After a brief pilot program last summer to test the waters, nearly all the State of Texas was deregulated on January 1, 2002. Information on the number of customers that have switched is limited. In southeast Texas, deregulation of retail sales has been delayed to 2003 due to the lack of a regional transmission organization. Despite aggressive promotional campaigns, the average Texas consumer isn’t convinced there is much value in switching providers, and interest is not much higher among commercial and industrial customers. Startup delays, lag in switching customers to new suppliers and computer problems have contributed to customer reluctance to switch providers. Texas Utilities recently announced that as many as 150,000 customers have gone without power bills for several months and many municipalities report hundreds of thousands in lost savings because of billing problems. The aftermath of the California troubles and the bankruptcy of Enron have cast a shadow over deregulation. Recent disclosures of trading irregularities at Dynegy and Reliant have also created further doubts in consumer’s minds. Texas has plenty of power plants to supply power, and Texas incumbent utilities can raise rates twice a year when natural gas prices change, shielding them from bankruptcy when power prices skyrocket. Until the switching process is smoothed out, consumers will continue to resist deregulation as they see no positive value in changing providers.

At the Federal level, House Bill HR4 and Senate Bill S517 have both been passed and are now in conference. Whether compromise legislation can be agreed to should be known by October 2002.

Depending on its final form, this legislation could dramatically impact the electric industry throughout the nation.

SUMMARY OF 2001 REPORT-This Technical Group was asked to assemble "any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska's citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation activities".

Retail deregulation gained considerable popularity between the late 1990's and 2001 with 25 state legislatures or regulatory agencies committing to various forms of customer choice. However, developments during the summer of 2000 in California, Washington, Montana, New York and certain other states have created significant questions about the benefits of retail choice and have resulted in delays or repeals of retail choice in six states.

This section contains a brief summary of the status and implementation of retail competition in a variety of states. Some of these states have attempted a retail competition regime for a number of years while others are just now beginning to implement retail competition legislation. No state was found that had a vibrant competitive retail electricity market. The crisis in California affected all 11 states in the western grid. Volatile wholesale markets resulting, in part, from poorly implemented retail deregulation can have tremendous impacts in states that have formally rejected retail choice.

On the federal level, two national energy policy bills have been introduced in the Senate, but neither has been passed. In the House, national energy policy legislation (H.R. 4) was introduced on July 27, 2001 and was passed on August 2, 2001. The Bush Administration has released its recommendations for a national energy policy, but no action has taken place to date. FERC recently extended wholesale price controls over California's spot market as well as spot market sales in the entire 11 state Western System Coordinating Council area.

In July 2001, the FERC issued orders, the purpose of which is to create four regional transmission organizations. FERC's orders mandate action designed to create Southeast and Northeast RTO's. The orders do not require immediate action for the Midwest or West RTO's. FERC's ability to make that happen and how Nebraska's public power, cooperative and federal transmission facilities might be voluntarily integrated in the process remain as open questions.

Chapter 1

"Whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska."

1.0 Purpose

Technical Group #1 dealt with the question "whether or not a viable regional transmission organization and adequate transmission exist in Nebraska or in a region that includes Nebraska".

2.0 Team Members

Paul Malone	Nebraska Public Power District
Dan Witt	Omaha Public Power District
Bill Leung	NMPP Energy
Bruce Merrill	Lincoln Electric System
Lloyd Linke	Western Area Power Administration

3.0 Summary

The August 14, 2003 blackout, the most wide-ranging in U.S. electric utility history, will cause a significant review of the nation's transmission infrastructure and the organizational entities controlling it. Already, congressional hearings have been scheduled and a joint U.S. and Canadian Task Force have been appointed to investigate the blackout. Many are calling for passage of the long debated federal energy legislation. How this will impact the continued development of Regional Transmission Organizations (RTOs) remains to be seen.

The Midwest ISO has indicated it will be reevaluating the timing for the start-up of its energy markets, and will make a recommendation to its Board of Directors in September.

Progress on the development of TRANSLink has been slowed due to the lack of state regulatory commission approvals, and as a result, the TRANSLink participants are re-evaluating their options for continued development of TRANSLink.

In light of the pending investigations of the blackout, and uncertainty about federal legislation which may be enacted, it seems prudent for Nebraska utilities to wait until such time as more is known so they can make an informed decision before proceeding to join a RTO. Nebraska utilities are members of MAPP, and MAPP will continue to provide regional transmission service, generation reserve sharing and reliability functions until the membership acts to discontinue those functions.

At this time there is not a RTO that has been shown to be economically, technically and operationally viable. There is adequate transmission capacity in Nebraska to deliver the generation output of plants in Nebraska to the Nebraska customer load, but there is not sufficient transmission capacity to support all of the wholesale power transactions that are requested in the region.

4.0 August 14, 2003 Blackout

On August 14, 2003 starting about 4:11 pm. EDT, the worst blackout in electric utility history occurred. Approximately 61,800 MW of customer load was lost in an area that covers 50 million people in the Northeast, parts of the Midwest and Canada. The areas most affected include Michigan, Ohio, New York, Ontario, Quebec, northern New Jersey, Massachusetts and Connecticut. Not until August 16 at 10:00 EDT was power restored to nearly all customers.

At the date this report is being written the initial investigation of the causes of the blackout are just beginning. Data from thousands of recording devices on the electric system is being gathered to establish the exact sequence of events, which will be analyzed to determine how the blackout occurred. Preliminary information indicates that the blackout occurred over a time frame of approximately nine seconds when the electric system became unstable and automatic protection devices tripped out hundreds of generating plants and transmission lines. However, during the two hours preceding the blackout, numerous transmission lines tripped off line in the Ohio area and power swings were noted in Canada and the eastern United States.

The electric system is designed with automatic protective devices, which are intended to isolate areas that are experiencing severe electrical disturbances, and prevent the cascading effect that occurred. Certainly one of the many questions to be answered in the investigation is why the systems did not operate properly to isolate the disturbance to a much smaller area.

Electric service to customers in Nebraska, and nearly all of the MAPP region, was unaffected by the blackout. Nevertheless, because most of Nebraska is electrically interconnected with the rest of the Eastern United States and Canada, in what is known as the Eastern Interconnection, control room operators at electric utilities in Nebraska did observe a momentary frequency excursion.

The blackout and the ensuing investigation will likely have significant repercussions for electric utilities throughout the U.S and Canada. Already congressional hearings have been scheduled for September to hear from government and utility leaders about the causes of the blackout and what needs to be done to prevent it from occurring again. In addition, a joint U.S. and Canadian Task Force has been established to investigate the blackout.

Along with the technical aspects of how the system failed to operate to isolate the blackout and what steps could have been taken by the electric utilities, RTOs, ISOs and NERC Security Coordinators to prevent the blackout, the congressional investigations and the Task Force will likely address the condition of the transmission infrastructure and the institutions which govern electric utility system operations. It has been reported by the media that the nation's transmission infrastructure is "antiquated". This is not an accurate representation. What is accurate is that wholesale electric competition has caused a significant increase in the loading of the transmission system due to transactions which transfer power over multi-state areas. The transmission system has only limited capability for such transfers and very little interstate transmission has been built to accommodate the new wholesale markets. In Nebraska, there is adequate transmission to deliver the output of utilities' generators to customer load, but the Nebraska transmission system is being loaded with wholesale transactions that pass though the system. Nebraska utilities and customers need to be concerned with any mandates which could result from the blackout investigation, such as the requirement to build additional transmission in Nebraska, and who will pay for it.

5.0 Current Status of Regional Transmission Entities

5.1 Mid-Continent Area Power Pool (MAPP)

As part of the unbundling process in MAPP, the Power and Energy Market Committee (PEM) has been spun off into a separate organization called the Midwest Energy Marketing Association (MEMA). The organization was officially formed in May 2003. It is no longer part of MAPP, although all members of PEM are now members of MEMA. It has a new Board of Directors, and the members will continue to use MAPP Service Schedule F to facilitate energy transactions.

Another new entity formed in 2003 is the Midwest Reliability Organization (MRO). Currently, over 20 MAPP Reliability Committee members have joined the new MRO. The MRO would adopt, implement and enforce NERC and regional reliability standards, governed by a balanced stakeholders' board. An organizational meeting of the MRO is expected to be held in the fall of 2003. Since generation reserve sharing is not part of the function of the MRO, this function will remain as a MAPP function.

The MAPP RTC has gone through significant changes since 2002. With a number of members joining the Midwest ISO and the continued development of TRANSLink and Crescent Moon independent transmission companies, it appeared that the end to MAPP Service Schedule F was near. In March 2003, the Regional Transmission Committee (RTC) created a Transition Task Force to develop and recommend a plan of actions in anticipation of the termination of Service Schedule F transmission service. The task force will review the organizational transition of the RTC, its subcommittees and the MAPP Restated Agreement. The task force will also review and make recommendation on a number of technical issues associated with termination of Service Schedule F transmission service.

The task force presented a preliminary progress report of its findings and recommendations to the RTC at their June 2003 meeting. A final report is expected to be presented later in 2003.
A recent development in MAPP is that a meeting will be held this fall to discuss whether the membership desires to have a cost benefit study performed so the members can determine the cost impact to their customers before they decide whether or not to join the Midwest ISO, or whether other options are available.

The RTC passed a resolution in October 2001 that established a membership threshold. When a specific number of MAPP members had joined the Midwest ISO and removed their transmission facilities from Schedule F, Schedule F would terminate. It appears that due to concerns about the direction the Midwest ISO is headed with the implementation of energy markets, the costs associated with those markets, and the delays with TRANSLink, it is unlikely that the Schedule F threshold will be passed anytime soon.

5.2 Midwest ISO

The Midwest ISO is proceeding to develop their Day 2 operations, scheduled to be operational March 31, 2004. Midwest ISO Day 2 will be significantly different from their current Day 1 operations and will also be significantly different from the operations that utilities in this region are accustomed to. Midwest ISO Day 2 will include a spot energy market for generation and a transmission congestion management system, neither of which Midwest ISO is currently doing. These two new markets will be combined by utilizing a bid based Locational Marginal Price (LMP) system. The congestion management system will utilize a Financial Transmission Rights (FTRs) market to enable customers to hedge against the cost of congestion.

Locational Marginal Price (LMP) is the wholesale electric price at a particular location on the transmission system that reflects the cost to meet the next unit of demand at that location. Without any congestion, or losses, the LMP at all locations would be the same. This is true because the next increment of load in any portion of the system could be met by the same generator in the least cost dispatch order of the generators in the region. With congestion the LMP at all points on the system will be different.

Congestion on the transmission system is created when the least cost dispatched resource in the dispatch order causes a facility to be overloaded or could become overloaded under a system contingency. To keep the facilities from overloading the generation resources in the market are redispatched to the minimum extent possible that relieves the overload(s). This is referred to as a security constraint least cost dispatch. The per-unit cost of congestion between two points on the system is the difference in LMP between those two points. A Financial Transmission Right (FTR) entitles the holder of that financial instrument (FTR) the right to receive a payment, or perhaps make a payment in some cases, equal to the per-unit cost of congestion between the points multiplied by the megawatts of the rights held.

Midwest ISO believes that by establishing these markets the most cost effective dispatch of resources will be obtained for the generation and the transmission that is available to the market at any given time. Also, if properly implemented, they believe that FTRs would provide an adequate hedge against the cost of congestion. For example, if a load serving entity holds FTRs of the same magnitude as its schedule on the same path, they would pay for congestion to Midwest ISO, but by being the FTR holder, they would be paid back that value from Midwest ISO. This load serving entity however would not have to continue to hold these FTRs. They could be sold in an auction or to another party if that is believed to be economical by the holder. Once sold, the new holder would receive the payment for the FTR, and the load serving entity would still have to pay congestion but has been paid by the FTR purchaser an amount to offset that cost.

Midwest ISO is currently in the process of determining the initial allocation of FTRs. In this process they are utilizing a Simultaneous Feasibility Test (SFT) to ensure that at any time all the FTRs that are sold can be funded by the congestion revenues collected. In order to not violate this SFT, Midwest ISO is finding that they will only be able to convert about 90% of the existing transmission rights to FTR's. This percentage may actually be higher or lower by the time Midwest ISO gets to their final allocation early in 2004, but to the extent that they are not 100% means that not all existing transactions will be fully hedged against congestion.

In addition to the FTR market, Midwest ISO is setting up a day ahead market and a real time LMP markets. The day ahead market will allow participants to make financially binding commitments for every hour of the coming day. The real time market will be based on the transmission and generation system in place, the bi-lateral transactions that are being scheduled between two parties, the best load estimates at the time, and the dispatch of units in the security constrained least cost dispatch on five minute intervals. So every five minutes Midwest ISO will send signals to adjust market participating generation to meet the least cost security constrained dispatch considering all the current conditions.

In order for Midwest ISO to meet their operational date of March 31, 2004, other milestones also have to be met. By the end of October of this year they have to complete the Market Registration of participants, they have to completely test their software systems from beginning to end and all the control areas need to be certified with Midwest ISO. Then in November the market trials would begin and run for 4 months to fully test and debug the systems.

Although Midwest ISO has been developing this Day 2 proposal for over two years, there is still much to be completed in each of these markets. There are multiple procedural steps: market protocols have to finalized, tariff language approved by FERC, FTR allocations developed by Midwest ISO and approved by FERC, the software needed to implement the Day 2 features has to be completed, and all the data bases and interfaces need to be finalized. In addition, these markets need to be coordinated, all the supporting areas need to be finalized, all of the processes need to be tested, and the participants need to be trained. Some supporting areas would be settlements, billing, and customer relations. Throughout the process the stakeholders in Midwest ISO have been providing comments to Midwest ISO on input parameters. So while much progress has been made there still remain substantial milestones that need to be completed before the Midwest ISO Day 2 markets are fully operational.

With any new system there are many uncertainties but for Midwest ISO Day 2 the changes are so significant and the potential costs so high that the uncertainties are much larger.

5.3 TRANSLink

The TRANSLink utility participants are re-evaluating their options for proceeding with continued development. While TRANSLink has received favorable "conditional" approvals from FERC, state regulatory approvals in Iowa and Minnesota were not granted. TRANSLink has determined it will withdraw any pending state regulatory proceedings and work with the state regulatory commissions to address their concerns. The Iowa and Minnesota regulatory commissions expressed a concern about the uncertainty of the impacts of FERC's Standard Market Design on their regulatory authority. The blackout will undoubtedly raise additional concerns by the states that will need to be addressed.

NPPD and OPPD are continuing their involvement with TRANSLink as a potential option for participation in a regional transmission entity.

5.4 Crescent Moon

Western Area Power Administration (Upper Great Plains Region), Basin Electric Power Cooperative, Sunflower Electric Power, and others have been working to develop an alternative contractual arrangement, called a Coordination Agreement with the Midwest ISO. To this point they have not been successful in working out differences in the Coordination Agreement. These utilities are interconnected to the Nebraska transmission system, and power deliveries and interchanges are made between these utilities and Nebraska utilities, so it will be important to ensure that procedures are developed to accommodate the interactions, should these utilities and Nebraska utilities join different regional transmission entities.

5.5 Southwest Power Pool (SPP)

The merger of SPP and the Midwest ISO has been cancelled due to an insufficient number of SPP members joining the Midwest ISO. SPP members have determined that they will proceed to re-organize as an Independent System Operator. To date, SPP has not filed any documents at FERC to request approval as an Independent System Operator.

6.0 FERC Rulemakings

6.1 FERC's White Paper on Wholesale Power Market Platform

Last year's LB901 report discussed the Notice of Proposed Rulemaking FERC issued on July 31, 2002 on Standard Market Design (SMD). That proposal elicited broad-based opposition, particularly from congressional representatives, states utility regulators, the Northwest and Southeastern parts of the U.S. and others. In response to the strong opposition FERC backed off its proscriptive approach, and on April 28, 2003 FERC issued a White Paper, entitled Wholesale Power Market Platform. In addition, FERC has been holding a series of technical conferences around the country to gather input from the state regulators and others on the white paper proposal. FERC has indicated it plans to issue a final rulemaking later in 2003. Any rulemaking FERC may issue later this year will be directly influenced by the results of the blackout investigation and any federal legislation that may be enacted.

7.0 Organization of Midwest ISO States (OMS)

One of the concepts that FERC offered in the White Paper in response to the concerns of the state regulators was to invite the states to form Regional State Committees to provide input on a number of the RTO design issues, such as what level of generation supply adequacy is appropriate, what form of transmission pricing should be implemented, and how to allocate Financial Transmission Rights.

An organization of state regulatory commissions representing states that have utilities in the Midwest ISO region held its initial organizational meeting in Omaha on June 11, 2003. The Organization of Midwest ISO States (OMS) approved its Bylaws and elected officers. The Nebraska Power Review Board will have a representative on the OMS.

8.0 Transmission Planning & Adequacy

8.1 MAPP Subregional & Regional Transmission Plan Update

After reviewing the MAPP Transmission Planning Subcommittee's (TPSC) 2002 MAPP Regional Plan the following was summarized. The MAPP TPSC performed power flow analysis to determine the import/export capability between MAPP and its neighboring regions, namely MAIN and SPP. The impact on this simultaneous export/import capability, and the impact upon key MAPP flowgates, was quantified for a futuristic Vision Concept. The Vision Concept includes over 1,900 miles of new 500 kV line at an estimated cost of about $1.3 billion. The TPSC did not make any specific recommendations for constructing the facilities in the Vision Concept. If the transmission system is to accommodate a range of options for new generation and support a competitive power supply market, the TPSC believes that the need for some type of Vision Concept is imminent. Further analysis among the impacted regions and adjacent regional stakeholders would be needed to better develop the details and assess the benefits and cost of such a project. To this end, the formulation of the TPSC Vision Concept, as well as the recommended SPG plans are being incorporated into the Midwest ISO planning process.

Another issue that warrants some consideration in the planning process is the recent presence of "non-traditional" flows across much of the MAPP region. Flows across the MAPP region have historically been North-to-South and West-to-East. Recently there have been heavy flows in opposite directions, South-to-North and East-to-West, sometimes even forcing TLR to be used to mitigate such flows. For example, Cooper South has been operating predominately South-to-North for the better part of the last 18 months, sometimes as high as 600-700 MW. These "non-traditional" flows are generally related to wholesale market price conditions that cause the transmission system to be used in ways not normally expected.

8.2 Midwest ISO Transmission Expansion Plan

On April 19, 2003 the Midwest ISO approved their first long-range transmission expansion plan. This initial plan, MTEP-03, covers the period from 2002 through 2007 and was developed as part of Midwest ISO's responsibility as a FERC approved RTO. The information is provided for use by state authorities and market participants for guidance and determining expansions needed for reliability purposes and additional transmission expansion that may provide commercial benefit.

There are two major components of the plan, a reliability review and exploratory plans.

Reliability Review

The reliability review was conducted for the proposed transmission plans of the transmission owners within the Midwest ISO system, including facilities to be in service in the 2002 through 2007 time frame. The cost of the new facilities to be added is expected to be $1.8 billion. This will include about 3,500 miles of transmission lines being constructed or rebuilt within the Midwest ISO footprint. For reference there are approximately 112,000 miles of existing transmission lines. The plan itemizes all the additions in tabular form in appendices and more detailed explanations of projects exceeding $15 million are in the body of the report.

One of the major transmission issues is how much business is lost due to constraints. The current method of handling constraints and congestion on the transmission system is through the NERC Transmission Loading Relief (TLR) procedures. Midwest ISO reviewed how often TLRs are called on the system and for what constraints. Then they compared the transmission additions that are being proposed to identify which constraints are being addressed. The analysis found that there were 19 Midwest ISO flowgates accounting for 80% of the TLRs. Of these 19, 12 are addressed by the planned transmission projects within the 5-year planning horizon. Nine of these are addressed by projects to be in service by 2004. Midwest ISO continues to evaluate the remaining flowgates with the highest incident of TLRs to determine the value in relieving these constraints. None of these top 19 flowgates are in Nebraska.

Exploratory Plans

The second part of the MTEP-03 is the most controversial. Midwest ISO has investigated system improvements that would, in their view, provide a commercial benefit to the customers of the transmission system.

The original motivation for doing this may have come from the MAPP Vision Concept that was developed in conjunction with the last MAPP transmission plan. The MAPP vision was an overlay of 500Kv transmission additions in the MAPP region that was believed to eliminate limits on most of the flowgates in the MAPP region. That concept was given to the Midwest ISO to investigate further. Midwest ISO expanded the original concept with some conceptual facilities in SPP and investigated it as part of their exploratory plans. Their findings for this particular plan were that this was probably too expensive for the benefits derived.

In order to determine the economic benefits of the exploratory plans Midwest ISO prepared a 2007 model of the system that includes both the transmission system and the generating system expected to be in place at that time. Utilizing a software package (GE MAPS), Midwest ISO developed projections of locational marginal prices (LMP) that would occur given the transmission system, the generators, and utilizing a transmission system security constrained dispatch of the generators in the model. Midwest ISO evaluated a full year of estimated bi-hourly loads (they did not look at 8760 hours for the year, but they did look at half of that amount). This was a significant effort to pull together all the associated data and assumptions for this type of analysis. There are literally thousands of assumptions that have to be made. The result of this portion of their analysis gives them a base line LMP and system to compare other generation scenarios to or other transmission plans against.

Midwest ISO then looked at four different generation scenarios: the base set of generators that would be in place by 2007; a case where more generators utilizing natural gas are installed; a case where there is more of a balance between the coal and the natural gas units installed; and finally, a case for a high wind generation scenario which includes 10,000 megawatts of wind. Midwest ISO investigated the impacts of these generation scenarios on the estimated LMP within the region and also exploratory transmission additions.

The exploratory transmission plans added selected transmission facilities within the region, calculated the LMP including the use of additions, and then compared those results back to the base case to calculate the benefits of the additions for the test year. They looked at 11 different exploratory transmission additions. It is important to note that even Midwest ISO stated that these are very preliminary indications of potential effective transmission expansions. There are many additional economic and reliability studies needed before definitive plans are developed.

One of these exploratory plans, however, did connect Western Nebraska to Western Kansas and further expanded portions of the 345 kV system in Kansas and Oklahoma. This plan had about 620 miles of 345kV line additions of which between 100 to 120 miles would be in Nebraska. It was one of the more cost-effective exploratory plans identified by Midwest ISO. Midwest ISO estimated the cost of the additions to be $503 million and the annual reduction in marginal wholesale energy cost to be between $259 million and $517 million depending on the cost of natural gas. Although both MAPP and SPP facilities are involved, the benefits mostly accrue to SPP where the cost of generation is higher than in Nebraska and the rest of MAPP. For this plan MAPP actually had higher marginal wholesale energy cost by between $99 million and $144 million, while SPP has lower costs by between $314 million and $516 million. Thus, as always is the case on regional facilities, the major question will be who pays and who benefits. None of those details are developed at this point. But since this MTEP-03 is a plan that will be widely disseminated, review of that system will be required by the transmission owners in the area. In Nebraska that would require that NPPD particularly be involved in further analysis of that system.

Midwest ISO plans to revise their MTEP at least bi-annually with updates occurring in any years between the MTEP's. Also during the intervening periods, analysis of any of these exploratory transmission configurations will undoubtedly be reviewed by affected utilities. Presumably feedback from transmission owner analysis would also be included in the next Midwest ISO transmission expansion plan.

9.0 Conclusions

Due to the recent blackout, and potential ramifications for federal legislation, as well as the uncertainties over any final rulemaking FERC may issue on Wholesale Power Market Platform, uncertainties about the economic impacts associated with the start-up of the Midwest ISO markets, the lack of success with achieving state regulatory approvals for TRANSLink, and the potential for MAPP members to re-evaluate their options, at the timing of this report, it is impossible to predict what will transpire in the months ahead. At best, the report will serve to identify key issues that could significantly affect the way the electric transmission system in Nebraska is planned, operated and priced.

At this juncture the only organization that is a "viable" RTO for Nebraska utilities to participate in is the Midwest ISO. The context of "viable" is limited to the fact that the Midwest ISO has received FERC approval as a RTO; the Midwest ISO is operational and has an approved transmission tariff for wholesale transactions. However, because the Midwest ISO is proceeding to implement energy markets, and due to the uncertainties associated with how those markets will impact Nebraska customers, it cannot be said that at this time that participation in the Midwest ISO is “viable” from an economic impact standpoint.

For transmission facilities in Nebraska that are part of the Western Interconnected System, there is no “viable” Western RTO at this time.

The Nebraska transmission system is adequate to serve Nebraska customers when system conditions are normal and even many abnormal conditions. However, under severe abnormal system conditions, such as the loss of major transmission lines or a large generation plant, Nebraska customers depend on the interconnected utilities in surrounding states and the generation reserve sharing pool to maintain reliability. Nebraska utilities contribute to the reliability of the region in a reciprocal manner.

The transmission system in Nebraska does experience significant usage due to the wholesale transactions occurring in the region. Reliability is maintained by setting capacity limits on the constrained interfaces, and curtailing transactions when system conditions approach those limits.

Because the wholesale market has become regional in nature, it requires regional solutions to fix the constrained interfaces. In other words, additional high voltage transmission lines will need to be built that cross several utilities’ service areas in order to accommodate much more wholesale activity than what currently exists. The transmission planners have identified several transmission projects to relieve the transmission constraints, but until the projects can be funded and paid for by a regional transmission tariff, utilities will be unlikely to build new transmission.

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)
Barry Campbell	-	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.

The latest evolutionary cycle of market power testing and mitigation is defined in the "Standard Market Design" Notice of Proposed Rulemaking (Docket RM01-12-000, 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.

The Standard Market Design, if implemented, will have a profound effect on market power and market power mitigation. The U.S. Congress asked the U.S. Department of Energy to assess the impact of SMD on, among other things, the exercise of market power and regional prices. The DOE report entitled *Report to Congress: Impacts of the Federal Energy Commission's Proposal for Standard Market Design* is summarized in Section 7.

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.

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 is shown in Exhibit II-1 shown on the next page. Note that the HHI is calculated for the entire MISO region as well as sub-regions of MISO corresponding to the reliability areas that are represented in MISO. Also presented are the results of the Hub and Spoke test as calculated by Technical Group #2 in 2001 and 2002. Note the similarity between the MISO calculation for the MAPP region and the previous year's HHI calculated for MAPP region plus one transmission wheel. This analysis confirms the previous year's conclusions that the MAPP area of MISO has an unconcentrated market and is relatively free of market power. The HHI 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 408, 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 2,752. 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

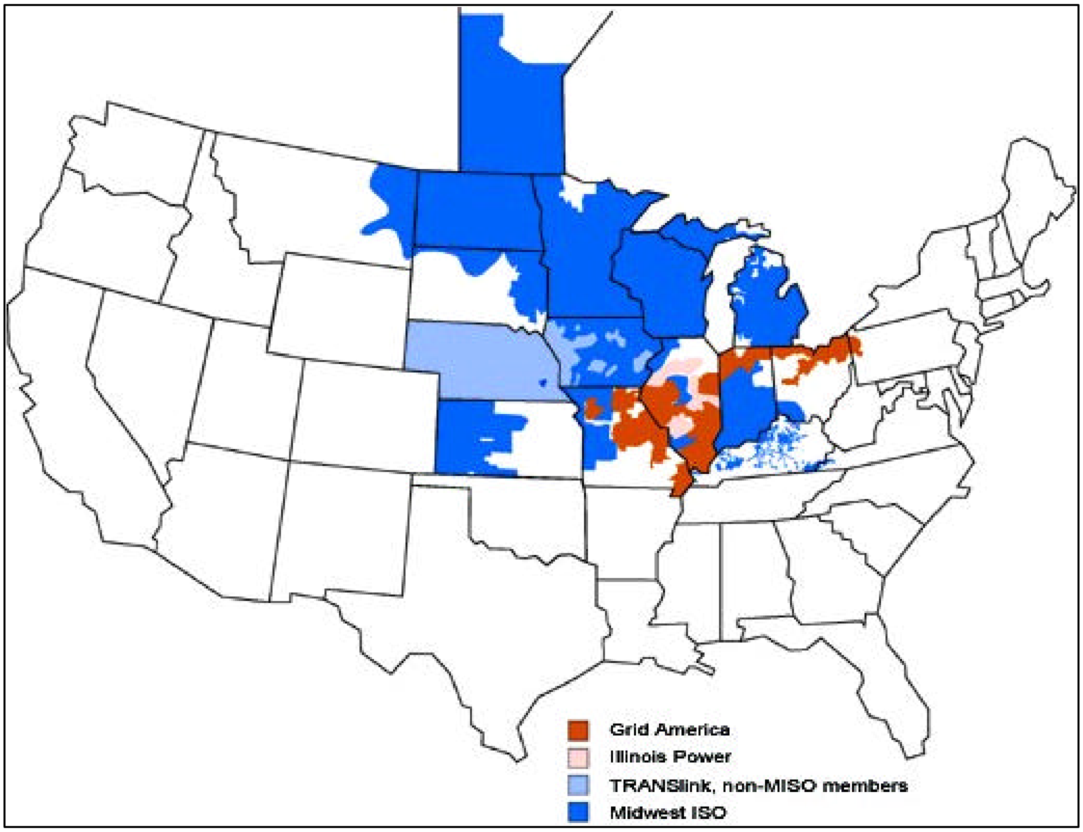
Hub and Spoke Test

MISO Sub- Region	HHI
ECAR	1,087
MAPP	1,128
S. MAIN	1,669
WUMS	2,752
MISO-Wide	408

Very close to similar analysis completed by Tech Group #2 last two years

- 2001 Study – 1,178
- 2002 Study – 943

Exhibit II-2



3.0Region Defined

3.1 East/West Interconnection Description

The Eastern and Western Interconnections are separated by six 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 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)

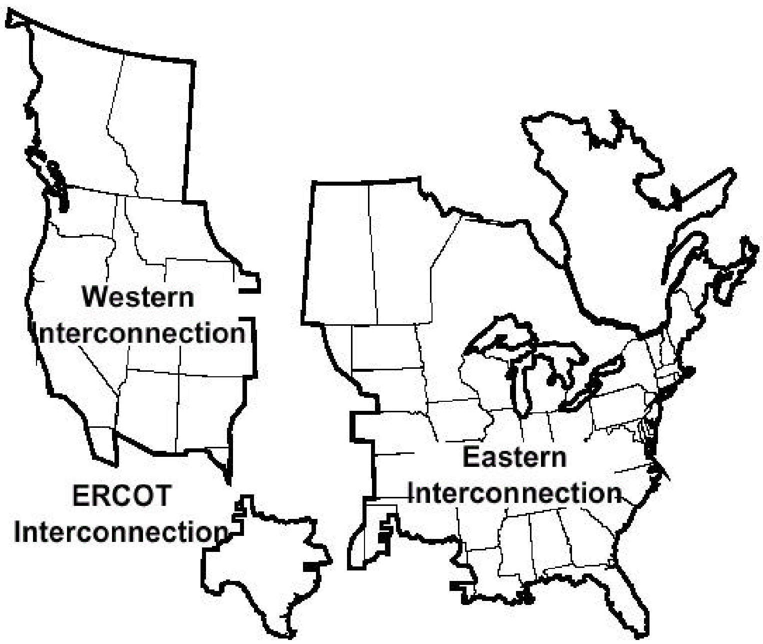
3.4 ERCOT Interconnection

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.

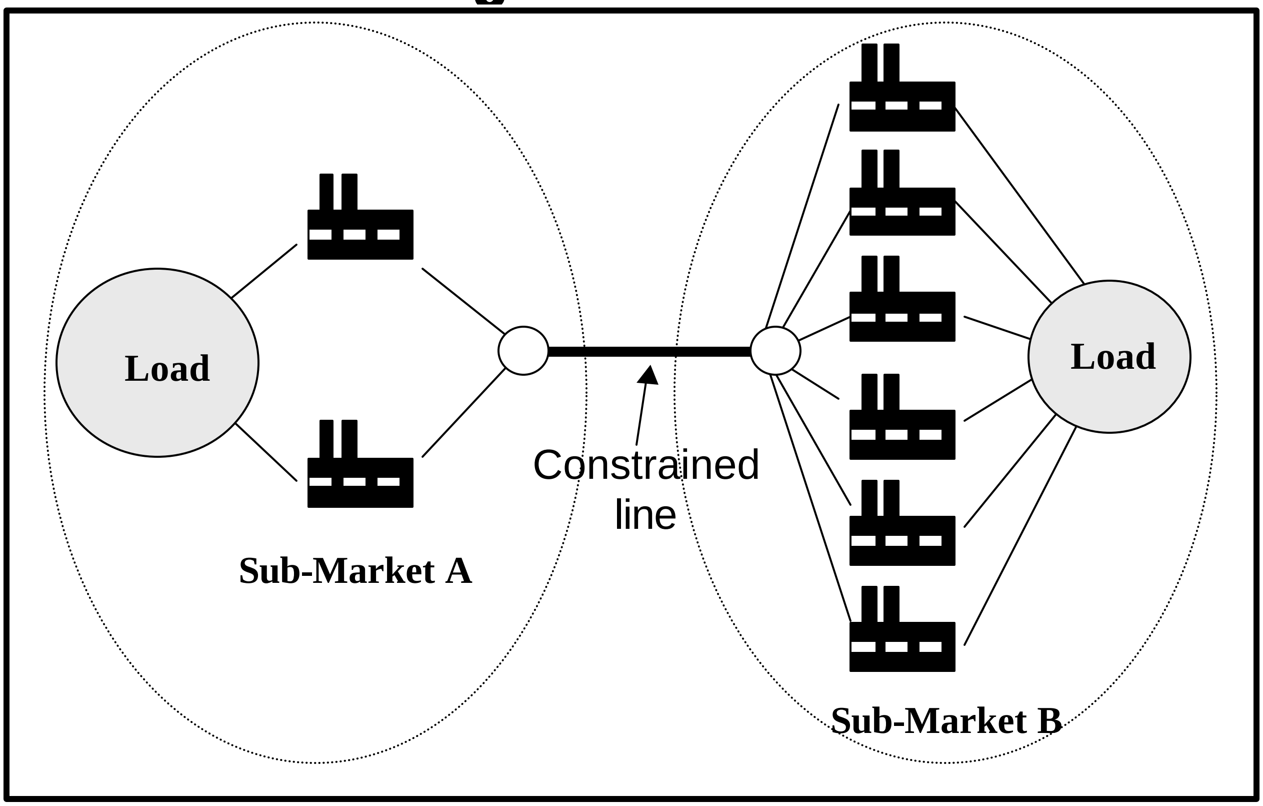
4.0 New FERC Methods for Assessing Market Power

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

Regional Market



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 than 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. If the TRANSLink ITC is accepted as part of the Midwest Independent System Operator (MISO), then the entire Eastern Region of Nebraska will be part of one RTO. By FERC's definition, this entire region, which includes Nebraska, will therefore be free from market power.

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 2002

6.1 Report Overview

The Midwest Independent System Operator (MISO) is the approved RTO for the Midwest region that includes Nebraska. In May 2003 they published their first *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

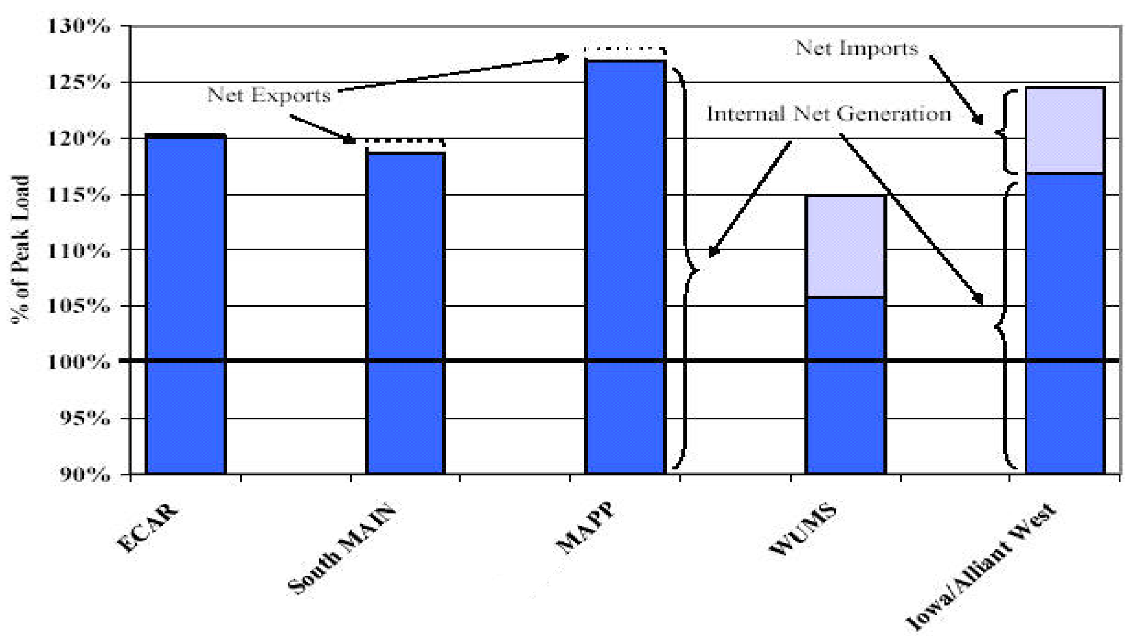
Many of the tests use MISO subregions to provide geographic detail. These subregions are generally defined as MISO areas that fall into different NERC reliability regions. Some special regions are also defined. The regions are shown below:

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………….	Occasionally Iowa, including MidAmerican Energy and Aliant are broken out of MAPP.

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-5. This is called reserve margin. It is the amount of excess generation in a region. Regions with low reserve margins (like WUMS) that are susceptible to market powe r. 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 like MAPP, if a utility tried to withhold power, it would simply be compensated for by others with excess generation.

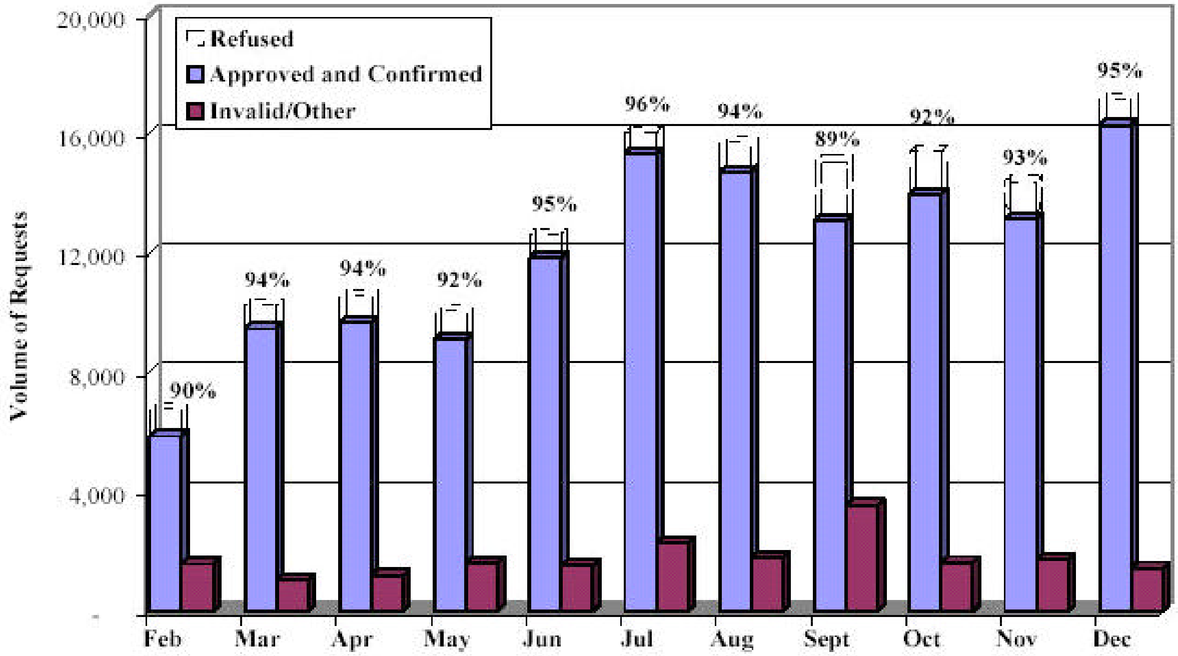
Exhibit II-5



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. It shows the percent of firm and non-firm transmission requests that are being approved. The relatively high rates of approved requests ranging from 89-96% suggests 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 sometimes transmission users will not even make a request if they know it will be denied. The OASIS transmission scheduling system facilitates this by providing an indication of transmission availability even before the request is made. The magnitude of this self declination is unknown, but may be significant.

Exhibit II-6



6.5 Transmission Curtailment Analysis

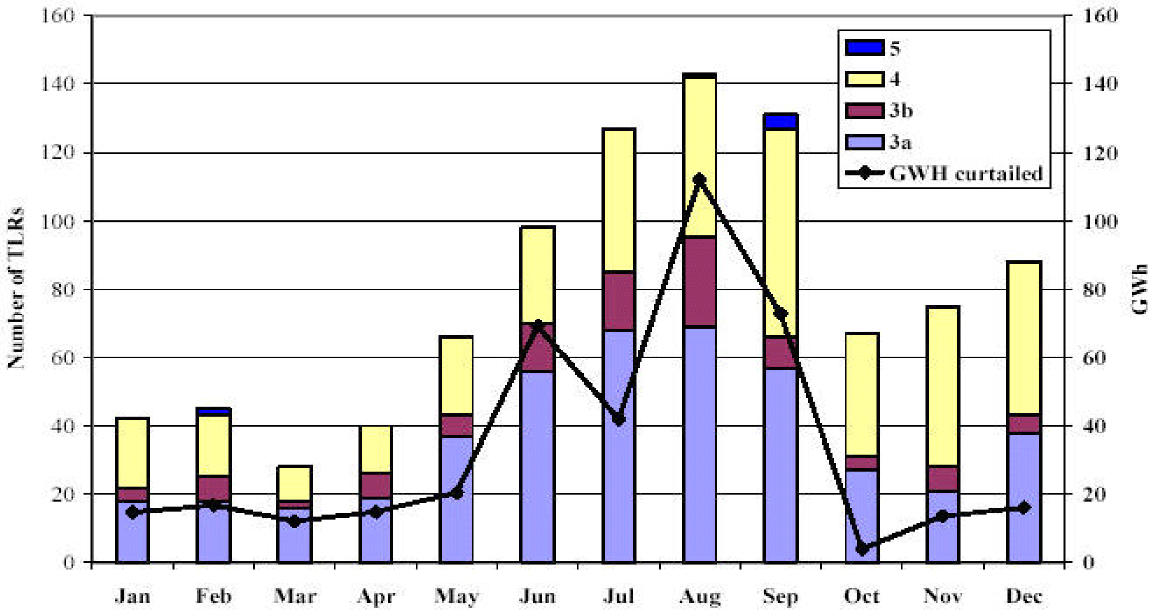
6.5.1 Number and GWH Amount of MISO Electricity Transactions Curtailed

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 as described in Section 4.1 and shown in Exhibit II-4 above. 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-7 on the following page shows the number and GWH curtailment of the TLR's called in MISO for 2002. This shows a large number of curtailments and GWH curtailed. In August of 2002 over 140 TLR's were called involving nearly 115 GWH of electricity. This was more TLR's than any other RTO, representing over 65% 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 nearly 50% of the MISO TLR's called were in the WUMS area. It is a known load pocket where mitigation measures can be implemented.

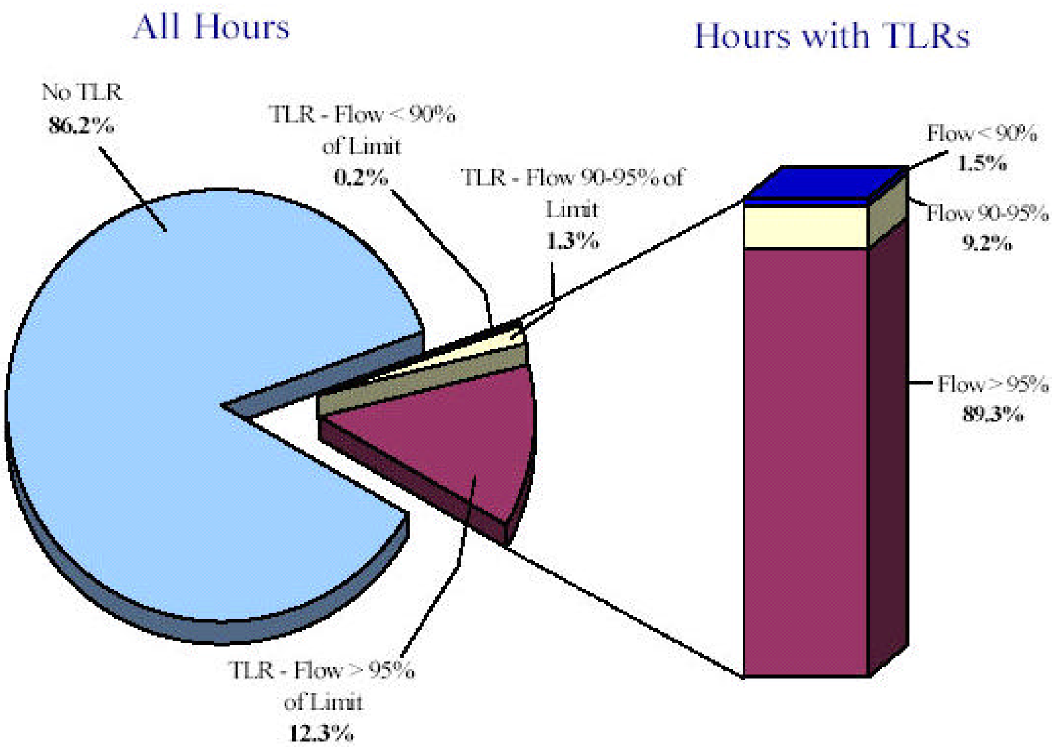
Exhibit II-7



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 compare the realtime electricity flows relative to transmission capacity at the time that TLR's were called. Exhibit II-8 shows that in 86.2% of all 2002 hours no TLR's were called in MISO. In the remaining 13.8%, where TLR's were called, only .2% were invoked when the line loading was less than 90%. This demonstrates that TLR's were justified for reliability.

Exhibit II-8



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 <u>and</u> 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. Exhibit II-9 shows the results of this analysis. In this analysis "N" is the number of sample points used to calculate the average or mean price differential. This differential is in units of $/MWH. For example on the EauClaire-Arpin 345 line, 299 price-differentials were used to calculate the mean price differential when there were no TLR's. This differential was $0.41/MWH. In times when TLR's were invoked the upstream-downstream price differential was -$0.85/MWH. The negative number means that the downstream prices were higher than upstream prices during a TLR. This supports the theory that downstream prices should be higher when the flowgate is constrained. Only two flowgates show a statistically significant difference in prices. These flowgates (shown in bold on Exhibit II-9) have a "p-value" of .05 or less. This means we are 95% confident that the TLR mean price and the non-TLR mean price are indeed different. The flowgates that were identified are in known localized load pockets where it is expected that market power would exist. The Eau Claire-Arpin line is a flowgate between MAPP and WUMS. WUMS has been identified as a problem area.

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.

Exhibit II-9

	Without TLR		With TLR		Difference	
Flowgate Name	N	Mean	N	Mean	of Means	P-Value
Eau Claire-Arpin 345 Kv	**299**	**$0.41**	**29**	**-$0.85**	**$1.27**	**0.052***
Paddock Xfmr 1 + Paddock-Rockdale	311	-$0.66	19	-$0.45	-$0.21	0.769
Albers-Paris138 For Wemp-Padock 345	317	-$0.65	13	-$0.67	$0.03	0.978
Kewaunee Xfmr+Kewaunee-N Appleton	295	-$0.72	35	$0.00	-$0.72	0.169
Lor5-Trk Riv5 161kv/Wempl-Paddock 345	**307**	**$0.81**	**23**	**-$1.56**	**$2.37**	**0.002***
Poweshiek-Reasnor 161 For Montezuma-Bondurant	300	-$0.72	7	-$1.06	$0.34	0.79
MHEX_N	319	$0.27	9	$1.45	-$1.19	0.291
MHEX_S	322	-$0.28	6	-$1.28	$0.99	0.599
MWSI	308	$0.38	20	-$0.89	$1.27	0.073

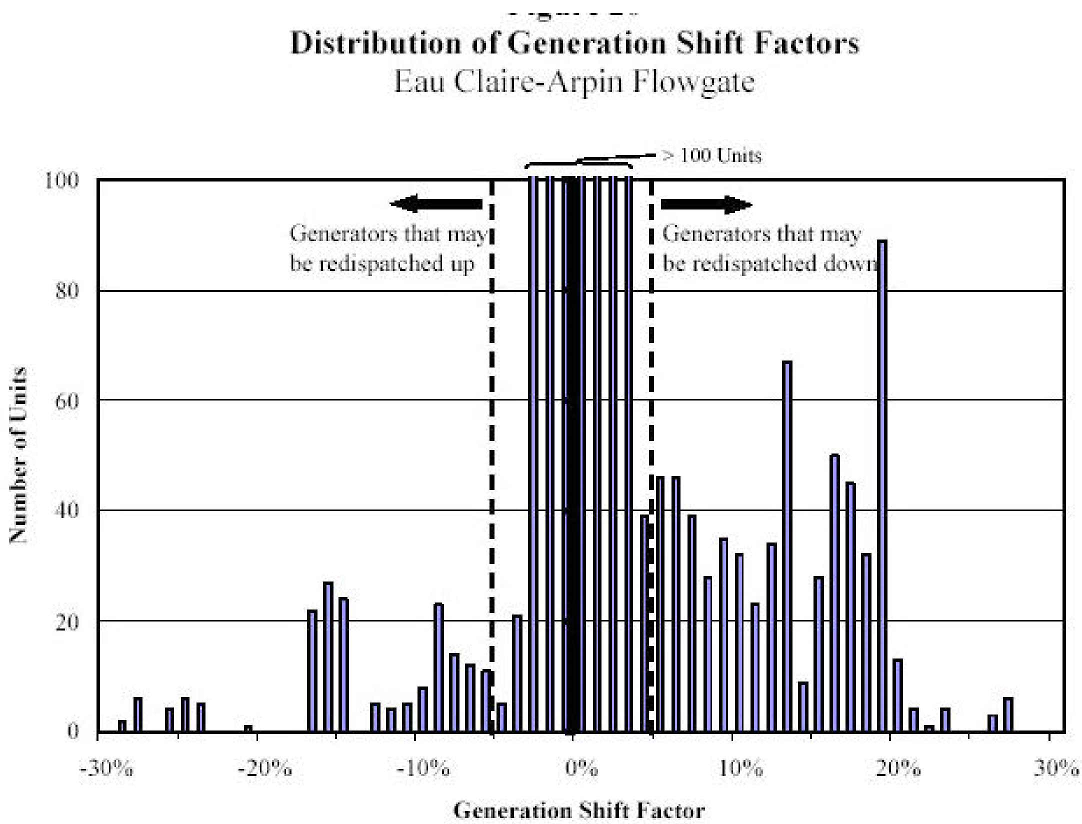
* Statistically significant at 95% level or better

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 41 of the most congested flowgates. The GSF values came from the results of the MISO Load Flow Case for July 2002 using the PowerWorld Transmission simulation Model. For example, Exhibit II-10 shows the GSF's of all generators in MISO over one Flowgate. In this example it is the Eau Claire-Arpin 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. It also shows that there are a number of generators that have high GSF's. The fact that there are so many generators with high GSF's means that any one of them would have a hard time manipulating the market. Because many of these generators have similar costs and are owned by a number of different suppliers, the Eau Claire-Arpin flowgate is less likely to have a Pivotal Supplier.

Exhibit II-10

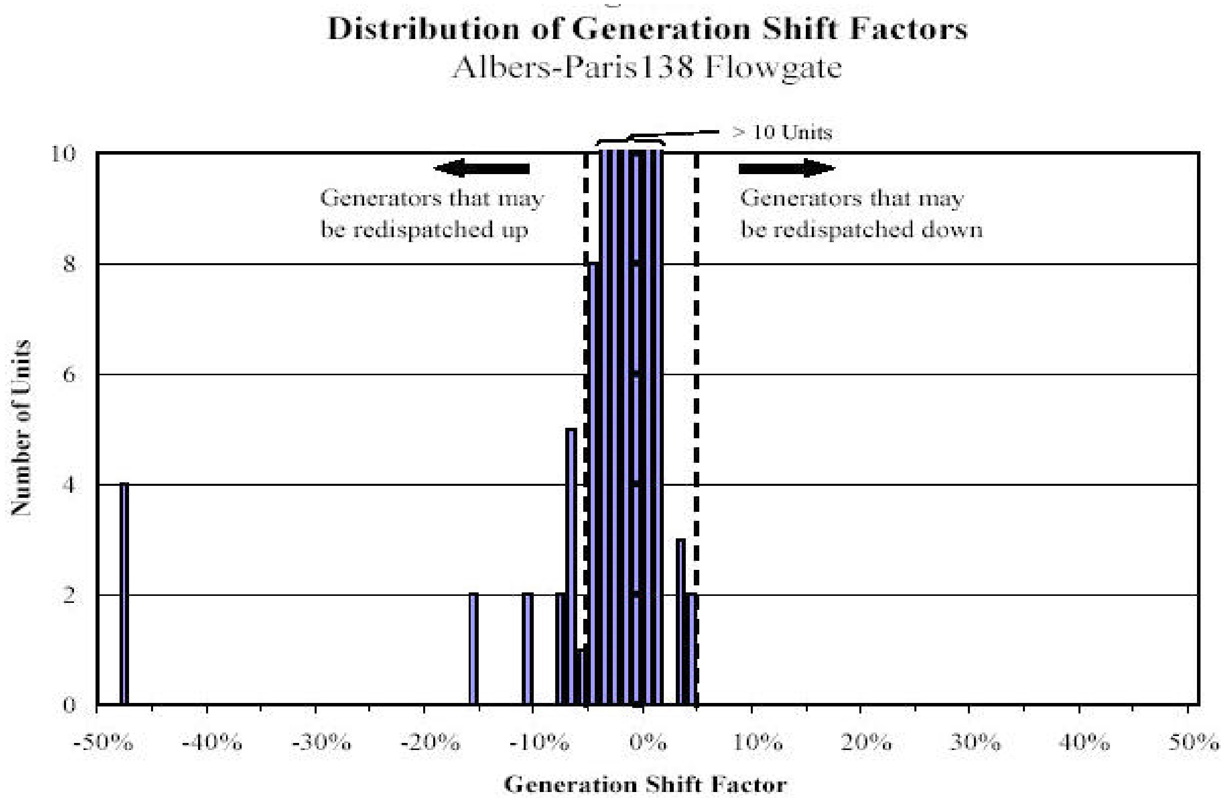


Source: Midwest ISO July 2002 AFC Load Flow Case, Potomac Economics Analysis.

Contrast this with the Albers-Paris 138 flowgate shown in Exhibit II-11. 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 20 Pivotal Suppliers were identified. These Pivotal Suppliers were associated with 13 of the 41 flowgates analyzed. This indicates that the potential for localized market power does exist in the MISO area. To mitigate the market power of Pivotal Suppliers, MISO suggests that "reliability must run" agreements be signed with those generators. In addition, the ability for MISO to adjust redispatch bids based on historical bidding could be implemented. These powers would presumably be granted to RTO's if the "Standard Market Design" Rule of Proposed Rulemaking is passed by FERC.

Exhibit II-11



7.0 Effect of Standard Market Design on Market Power and Regional Prices

7.1 Department of Energy Analysis Assessing Impacts of Standard Market Design

Members of Congress asked the Secretary of the Department of Energy (DOE) to conduct an independent study to assess various potential impacts of the Standard Market Design Rule of Proposed Rulemaking. This was formally requested in the Omnibus Appropriations Bill for fiscal year 2003. The analysis requested was to include: cost and benefit of RTO's; impacts on state regulation; financial impact on retail customers; impact on regional wholesale electricity prices; and the effect on transmission reliability. The report was delivered on April 30, 2003 as requested and is entitled *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*.

7.2 Effect of Standard Market Design on Market Power

The report concluded that the ability and incentive to exercise market power should not increase under SMD as long as two SMD conditions are met: an adequate infrastructure (generation, transmission, and demand-side resources) is maintained; and capabilities for effective regional market monitoring and market power mitigation are established and diligently applied. The responsibility for the second condition would be given to RTO's if the Standard Market Design Proposed Rulemaking is passed.

FERC proposes to require each RTO to establish a market monitoring and market power mitigation program. The market power safeguards would include:

- Close, daily monitoring of the region's day ahead and real-time markets by an independent party
- Reliability Must Run (RMR) agreements for individual units that have localized market power
- A safety net price cap of $1,000 per Mwh
- A regional resource adequacy requirement
- The potential to adjust a generator's bid downward automatically if it is out of line with its historical bidding behavior.

7.3 Effect of Standard Market Design on Regional Prices

The DOE analysis attempted to quantify the effect of SMD on regional wholesale electricity prices by using two economic models, POEMS and MAPS. These models simulate the operation of the transmission system and competitive pricing. The results of the model were reported by reliability region. The MAPP region results are shown in Exhibit II-12. The model was run assuming that SMD is not implemented and again assuming SMD is implemented. The difference between the non-SMD and the SMD case were calculated. The analysis shows projections for Imports, Exports and Total Generation for MAPP under each of the cases. It also shows projected wholesale prices and retail prices (less distribution expense) for the non-SMD and the SMD case. The cost for implementing SMD, which is primarily the cost of implementing and running MISO, is added to the SMD case when compared to the non-SMD case. Finally the results for both cases are reported for the near-term (2005-2010), Mid-term (2011-2015), and Long-term (2016-2020). According to the analysis MAPP is a net exporter. In the Non-SMD case the transmission inefficiencies associated with not having an RTO prevent some of the available low-cost power from reaching more distant load centers. As result, net exports increase in the SMD case, especially in the early years. In the Non-SMD case, MAPP is among the regions with the lowest wholesale prices. Wholesale prices rise in the near-term with SMD due to the ability to reach to higher priced markets, but the impact moderates within a few years. The wholesale prices are 10% higher in the SMD case as compared to the Non-SMD case in the Near-term. The differences moderate to 0% and -1% in the Mid-term and Long-term respectively. Retail prices are reduced in the SMD case. This is because no retail competition is assumed in the MAPP area. Therefore wholesale revenues (from increased wholesale prices and increased exports) are passed through to retail customers. Therefore consumer prices are 3% less in the SMD case as compared to the Non-SMD case in the Near-term. They are 2% less and 1% less in the Mid-term and the Long-term respectively.

Exhibit II-12

Table 3.17. MAPP Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	1	3	3	7	9	11	5	7	8
Exports	7	9	8	26	21	21	20	12	13
Generation	192	214	229	208	220	235	16	6	6
Coal	139	151	161	156	159	170	16	7	9
Natural Gas	6	14	19	5	12	15	-1	-1	-3
Other	47	49	50	48	49	50	1	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.2	—	—	—
Wholesale Prices	27	36	36	30	35	36	10%	0%	-1%
Retail G&T Prices	43	41	41	41	40	41	-3%	-2%	-1%
	Billion Dollars								
Consumer G&T Costs	7.4	7.8	8.5	7.2	7.7	8.4	-3%	-2%	-1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

8.0 Conclusion

8.1 Status of Viable Wholesale Market in the Eastern Region

The Eastern Interconnect wholesale market appears to be viable in that it has a large number of buyers and sellers. However, at times, it has limited access to reliable transmission access to either deliver into Nebraska loads or export from Nebraska generation, depending on system loading conditions. The market does appear to be viable since the number of buyers and sellers are adequate. Currently, transmission access is primarily available through the MAPP Schedule F Transmission Tariff that applies transmission reservation up to, but not exceeding 6 months in duration. Individual transmission provider's tariff may also be utilized up to 6 months in duration. Transmission access is also available through the Midwest Independent System Operator (MISO) for a period of up to one year. The presumption that the region will be served by the MISO, suggests that this viability will be maintained in the future.

8.2 Status of Viable 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.

Chapter Three

“To what extent retail rates have been unbundled in Nebraska”

1.0 Purpose

The purpose of Technical Group #3 has been to determine "To what extent retail rates have been unbundled in Nebraska." It was not our purpose to determine the merits or problems with deregulation, but to identify the current status of unbundling in Nebraska, and to give the consumer a better understanding of the complexity and costs for the current infrastructure to be unbundled. It is important to remember that all effects of retail competition are very hard to predict, as states have moved to competition with different issues and concerns.

2.0 Team Members:

Jay Anderson	Omaha Public Power District
Rich Andrysik	Lincoln Electric System
Don Cox	Hastings Utilities
Chuck Eldred	Omaha Public Power District
Jim Gibney	Wahoo Utilities
Jamey Pankoke	Perennial Public Power District
Marv Rief	Nebraska Public Power District
Donna Starzec	Nebraska Public Power District

3.0 Status of Unbundling in Nebraska

There were no new developments in 2003 regarding unbundling for Technical Group #3 to address. All issues were addressed in previous reports. Therefore a summary of the prior work is provided below for the 2003 report.

4.0 Recap of Prior Years Reports

LB901 defines unbundling as "the separation of utility bills into the individual price components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for generation, transmission, and distribution of electricity."[1]

There are various reasons why utilities may unbundle electrical service. The most compelling and the main reason that a utility unbundles is due to state statute or regulatory rule as part of a comprehensive deregulation plan. "The unbundling of retail electricity related services is a means to achieve direct access between consumers and competitive electricity supply. The overall objective of direct access is to reduce the total cost of electricity to society. Unbundling is therefore a means to develop a framework to facilitate consumer choice such that the overall cost of electricity to society is reduced."[2]

Another reason that some utilities unbundle, even not required to, is the need for better information on the costs of serving customers. In some states where deregulation has been instituted, municipal and public power entities have had the ability to opt out of deregulation, but have chosen to unbundle as a result of customer demand. Even in Nebraska one utility has chosen to unbundle and others are willing to consider it if their customers request it. Nebraska is in an enviable position of having low rates, so consumers are not pushing for deregulation. However, some consumers are requesting unbundled billing information to

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[1] State of Nebraska, Legislature of Nebraska, Legislative Bill 901, (Lincoln, Nebraska, 2000) p.3.
[2] Dr. Artie Powell, Utah Division of Public Utilities position paper presented to Utah Public Service Commission, Unbundling Electricity-Related Services (Utah: 1998) p.1.

compare the costs of individual components of their Nebraska energy bill with the electric costs at their facilities in other states. This process on its own may cause other utilities in Nebraska to unbundle as customers may begin to ask for comparisons at the same level that they are receiving in other states.

To determine "To what extent retail rates have been unbundled in Nebraska," a survey was assembled and mailed to the 162 retailing electric entities of Nebraska. Technical Group #3 received a response rate of 74.1% representing 97.4% of customers and 98.2% of total Mwh sales to ultimate consumers. The study disclosed the following main points. (Refer to Annual Report-2001 for detailed information).

--Only one utility has formally unbundled.
--The majority of utilities do not have unbundled cost of service studies.
--Half of the utilities' billing systems will accommodate unbundling.
--Over half of the utilities believe they have enough information to unbundle.
--70% of the utilities stated that they would not unbundle unless mandated.

The surveys detailed in the Annual Report-2001 were only mailed out one time. The surveys that were not returned were followed up by a phone call asking for a response. In addition to the phone call, the team also attempted to get responses by working through NPPD and the Municipal Energy Agency of Nebraska. The respondents were also asked to provide a copy of their typical residential bill.

Technical Group #3 also estimated what the total cost for unbundling in Nebraska would be, should the electric utility industry open to competition. Costs associated with moving to retail competition were addressed, but were very hard to predict.

Separating unbundling from deregulation is very complicated. Deregulation impacts the unbundling process. Therefore, when determining the costs to be included in unbundling, which is a small piece of the deregulation process, certain assumptions had to be made. The cost methodology was highly speculative and subject to many assumptions. Because there is no central rate making authority in Nebraska, most costs were estimated based on the input of OPPD, LES, NPPD, and Rural Public Power Districts. For municipalities, the technical group used information from the Nebraska Municipal Power Pool (NMPP). Various items determined to be unbundling costs were obtained. To determine the estimated costs, the entities involved completed a spreadsheet with the estimated costs that would be incurred by them. The individual results were then accumulated into categories, and a statewide total cost to unbundle was estimated. (See Annual Report-2002 for detailed information).

The Technical Group estimated the cost for only unbundling in Nebraska to be approximately $9 million. This would include an estimated one-time cost of approximately $8 million. The on-going cost per year would be approximately $1 million. A statewide consumer education program would be needed to communicate to the consumer a new billing process, so consumer education on a statewide basis was included in these estimated costs. The estimated cost per customer was based on other deregulated states. The technical group used a $1.36 average cost per customer (which was based on the information received from Pennsylvania), and then applied this cost to the number of customers in each public power entity in Nebraska.

The unbundling portion is only a small part of total deregulation costs, evidenced by the magnitude of the costs associated with unbundling and consumer education in other states. A determination of the level of unbundling for the State of Nebraska has currently not been made. However for purposes of determining a cost, we assumed generation, transmission, distribution, a customer charge, and up to two other items would be included, (i.e. probably no more than 5 or 6 line items).

These are the results that were gathered over the past two years. Technical Group #3 will continue to review the status of unbundling in Nebraska, and report the results as needed.

Chapter 4

"A Comparison of Nebraska's Wholesale Electricity Prices to the Prices in the Region"

1.0 Introduction

1.1 Purposes and Group Membership

The purpose of the fourth "condition-certain" technical group was to make "a comparison of Nebraska's wholesale electricity prices to the prices in the region." The Technical Group #4 that worked on this issue was combined with Tech Group #2 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)
Barry Campbell	-	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

Before moving toward retail competition, there should be the reasonable chance of the customers' ability to obtain lower electricity prices. 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 electricity prices in the region be at or below Nebraska's prices. This issue addresses Nebraska's electric prices compared to the region.

1.2 Approach

There are no directly comparable electric price indices available for the electricity product currently provided to and expected by Nebraska customers. The Nebraska product is firm and available 24 hours per day, seven days per week and the consumption will vary based on the individual customer's need. The regional price indices typically represent a predetermined fixed amount of energy for a specified portion of a day or week, not the customers' total electrical full requirements. To make a price comparison using these available market product indices required the conversion of Nebraska's electricity prices to market product indices.

A major component of "condition-certain" criteria is the ability to compare Nebraska costs to regional or market prices. To accomplish this task, current Nebraska wholesale electricity production costs were compared to available market price based electricity products on an equitable basis, utilizing publicly available, independent, and credible indices.

There is no formalized method to value an electricity product without the market making an offer to buy or sell the same product, so comparing Nebraska wholesale electricity production costs to available market indices is a viable approach to determining differences between Nebraska cost and regional or market prices.

2.0 Wholesale Market Terminology

2.1 Market Product Definitions

Currently, the only publicly available, independent, and credible indices for electricity products are indices known as "Monthly Forwards" and/or "Monthly Futures," as well as historical "Daily Settlement Prices" for electricity products at certain geographical locations called "markets" or "hubs."

The " Monthly Forward Price" of an asset is the price established today with a non-exchange traded bilateral contract, for delivery of the asset on a designated future date at a specified location ("hub" or "market"). The

“Monthly Futures Price” is a contract associated with a particular “hub” or “market” for future delivery of a commodity, exchange traded (physical delivery is possible, but not required).

The “Daily Settlement Price” is an index of the weighted average of trading prices for the asset within the market closing range for the day, and a multitude of daily price indices are more readily available than the limited quantity of publicly available forward prices (bilateral contracts).

The “markets” or “hubs” represent specific transmission systems where the electricity can be obtained at the price listed on the specified index.

2.2 Comparison Concepts

To be able to make the appropriate comparisons on a fair and equitable basis, the market product offerings have to be clearly defined through the determination of the product definitions for various available price indices and which of these independent price indices represents the “market” that Nebraska customers could purchase their power supply from. There are certain additional benefits that Nebraska power systems provide customers that a market product may not provide or would charge extra for the service. Examples of these services include, but are not limited to, consistency or firmness of delivery, reserve capability to serve load, ancillary services, as well as non-generation production services such as economic development, advertising and community web-site services.

2.3 Physical Product Definitions

To help understand the concept of comparisons, some basic definitions of the product and nomenclature should be clarified. When a customer flips a light switch and the light comes on, the electrical power required to turn on the bulb is considered “load," and the power that serves the load is nearly instantaneously created at a power plant and transmitted through transmission & distribution lines to serve that particular customer. Electricity that serves a given load over a specified time period (usually an hour) is called “energy," and the physical unit of energy (in large quantities) is called a Megawatt-hour (MWH). The physical capability to provide this “energy” on an instantaneous basis is called “capacity," so “energy” is different from “capacity” because “energy” is over a greater, more useful and easier measured unit of time, such as a single hour.

This description helps explain why market products are typically defined on a dollar per Megawatt-hour ($/MWH) basis over a specified time period and either include or exclude a physical capability component (capacity), or possibly a financial guarantee of performance (Firm Liquidated Damages – FLD).

2.4 Market Product Time Period

The time periods associated with market products are divided into times when there tends to be a higher demand for electricity called “Peak," and a lesser demand called “Off-peak." These general time periods are then further subdivided into days and number of hours each day as listed below:

- 5 x 16 (5 days per week – Monday thru Friday, 16 hours per day typically hour beginning 6:00 AM to hour ending 10:00 PM) – considered “Peak”
- 7 x 8 (7 nights per week, 8 hours per night typically hour beginning 10:00 PM to hour ending 6:00 AM) - considered mostly “Off-peak”
- 2 x 16 (2 days per week-ends) – considered mostly “Off-peak” some include Saturday as “Peak”
- 7 x 24 (7 days per week, 24 hours per day - around the clock) – “Peak” + “Off-peak”

2.5 Market Product Categories

The market also divides its products into categories that are defined by guaranteed and non-guaranteed availability. If the market guarantees availability it is called “firm." This “firmness” is either backed up by a pro-rata cost share of physical capability (either cost of new capacity or fixed cost of existing capacity), or the promise of money – FLD to compensate for possible additional costs to procure energy. If the customer will accept non-guaranteed availability conditions, then the price of this “non-firm” product is usually lower because the customer is sharing the risk of availability with the market, and does not need to compensate the market for guaranteed physical capability. It should be noted that these blocks of power are provided at a fixed amount, 100% of the time within the time periods, and is termed a "100% Load Factor" product. Few end-use customers require this amount of power all the time; however, the market product is priced as such since the current market price index mechanisms do not account for varying customer load patterns. For example, within a period of a year, a typical residential customer has a lower need for electrical power, as demonstrated with a "load factor" of less than 50%, whereas a commercial customer, such as a grocery store would typically be between 50 & 75%. Industrial customers load factors typically range in 60% - 95%, depending on the type of production process involved. However, on the other end of the scale, an irrigation customer may only have a load factor of 10-20%, because of the limited amount of time within a year the energy is required.

2.6 Market Price and Production Cost Difference

Prices and costs are fundamentally different concepts. The cost of producing a product can vary dramatically from the price of a product, which is determined by what customers are willing to pay.

When a particular product is in very high demand, buyers competing against each other bid the price up irrespective of the underlying cost. For example, parents competing against each other for the hottest new toy at Christmas (high demand chasing limited supply) will bid up the price to extraordinary levels.

On the other hand, if the supply of a product exceeds the number of people who want to buy it, suppliers will compete with each other driving the price downward (the same toy, after Christmas). If supply far exceeds demand, prices will even fall below the total cost of production. This is because suppliers are better off receiving some money for their product than none at all, as long as the price will cover the cost of raw materials for the product (variable costs) and contribute, even a little, to recovering cost of the production plant (fixed costs). This price-below-cost situation will prevail until: 1) the demand for the product increases; or 2) weak suppliers go out of business, reducing supply to match demand.

2.7 Market Price Volatility and Production Cost Stability

Price volatility is a measure of the rate at which price swings up & down in a market and is caused by abrupt changes in the demand and supply for a product as described above. An industry can have a fairly stable cost structure but still experience high price volatility for this reason.

The electric utility industry is a classic example of price volatility issues. Traditionally, regulated utilities with a guaranteed market could keep cost of production relatively stable by financing generation plants over long periods of time and entering into long-term fuel contracts. On the other hand, the competitive electric utility industry has very high price volatility when compared to other commodities, such as grain, oil and natural gas. This is because power markets have several unique characteristics based on the physics of electricity. Probably the most important economic characteristic of electricity is its inability to be stored easily. Unlike the market for more storable commodities in which storage ability reduces price fluctuations, electricity is primarily balanced in a real time spot market. Thus, in addition to a power market for energy, there is a value attributed to owning "capacity" (or capability to produce) in power markets which does not exist in other commodity markets.

For these reasons market prices may fall below Nebraska production costs at times, but these losses are typically made up during peak price periods, thereby contributing to higher peak season prices than Nebraska's production costs. Furthermore, if the volume the market wishes to buy or sell is large relative to the volumes traded; this single purchase itself could cause the market price to move significantly.

Power markets are specific to each region's unique supply and demand characteristics. For example, in the Illinois region, unforeseen plant outages and transmission problems combined with warmer than normal temperatures to cause the prices to spike in the summer of 1998 for a short time. In contrast, western power markets hydroelectricity plays a significant role; a dry year can cause prices to remain relatively high until the reservoirs are replenished. These types of issues can combine to provide multiple sources of considerable supply uncertainty, thereby making demand subject to high prices.

To add to this situation, there is a lack of a flexible market in financial risk management products with which to hedge physical and transmission risks. Although financial options are beginning to become part of the electric price volatility hedging tool chest, the vast majority of the trades in power settle into physical delivery.

Markets will increase price because the commodity has become more valuable and because electricity consumers virtually have an unlimited option on power supply at a fixed price, the market will recover any losses suffered earlier during times when supply was plentiful and prices were below cost to produce.

The electric consumer should therefore be aware that while low market prices may fall below the cost of production, this situation put forces into motion that will serve to correct this situation resulting in, at various times, market prices that are well above cost of production.

2.8 Market Product Price

The market price that is quoted in the indices based upon the above-defined criteria represents product availability at the particular "market" or "hub" that the price indices are named after, not delivered to the customer, unless clearly specified. For example, the "Entergy" price index is for a financially firm (includes FLD) energy product provided 5 days per week (Monday-Friday), 16 hours per day available at the Entergy transmission system which covers part of Arkansas, Mississippi, Louisiana and Texas. The "Cinergy" price is available under similar conditions at the Cinergy transmission system, which covers Central and South Indiana, Southwest Ohio and North Kentucky. The "ComEd" price represents the North Illinois region.

Since the market price is tied to these specific locations the customer would have to pay an additional charge to transmit this power to another location. This transmission charge is an additional cost to deliver that is not part of the price indices that are published, therefore, when directly comparing market prices to Nebraska costs, the transmission delivery charge should be accounted for in the comparison methodology.

2.9 Transmission Cost & Loss Considerations

As described in the 2003 documentation update for Technical Issue 2, the Mid-west Independent System Operator (MISO) transmission region covers a larger geographical area than the previous Mid-continent Area Power Pool (MAPP) transmission region, thereby increasing the physical delivery costs & losses associated with moving market-priced electricity products to the customers within the state of Nebraska. Currently, electricity traders are experiencing as much as 17% in delivery losses, which add similar percentages to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional $4 – 6 / MWH to the market product price.

2.10 Nebraska Production Cost

The cost to produce electricity by Nebraska power systems should be clearly determined on the same basis, applying the same type of definitions the market uses in order to determine a fair and equitable comparison. The issue becomes separating the various components of Nebraska power system costs to match the available market product indices, because Nebraska power systems provide a much more sophisticated product to its customers than the product as defined by the market price indices.

The Nebraska power system product includes a physical capability component (capacity) that is over and above the requirement for Nebraska electrical load in order to make sure that if a power plant fails or the weather becomes unusually severe, the Nebraska power systems have "reserves" available to serve the customers' load as expected. This "reserves" component of Nebraska costs is part of a minimum 15% capacity reserve requirement that provides a higher level of reliability that is not part of the market product pricing. Some Nebraska systems even carry additional reserves over and above the 15% minimum as a matter of policy for physical risk hedging due to severe weather fluctuations that would increase load, fuel disruptions, and/or unforeseen extended plant outages.

2.11 Long-term "Obligation to Serve" Considerations

The Nebraska power system product is based on a long-term "obligation to serve" that is not inherent in market-based electricity products. The long-term, in this case, is typically a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having "iron on the ground", and limited dependence on the market providing the power resources and prices to serve the expectations of Nebraska's electric customers. The current public power structure is based on the premise that the Nebraska state legislature expects, or "obligates", Nebraska's power systems to serve the electric customers of Nebraska in a reliable and cost-efficient manner, which translates to a long-term commitment to providing physical resources that meet or exceed Nebraska's power systems "obligation to serve". A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market–based electricity product as compared to local providers.

2.12 Various Generation Unit Types Serving Load

Power resources can be categorized as Baseload, Intermediate, and Peaking capacity, based on the number of hours (or capacity factor) a given resource is expected to operate.

–Peaking Units:	**0 - 25% of the year**
–Intermediate Units:	**15 - 75% of the year**
–Baseload Units:	**60 - 100% of the year**

Some forms of generation, such as nuclear and large fossil steam units, are well suited for Baseload operation because of their relatively low operating cost, even though their installed capital cost may be higher. Conversely, other forms of generation that have a lower installed capital cost, such as Combustion Turbines, generally have a higher operating cost (principally due to fuel and heat rate), thus making them appropriate to utilize as Peaking units. An example of an Intermediate unit would be a Combined Cycle, which has the flexibility to run at lower or higher capacity factors. Renewable technologies, such as wind generation, when compared to these conventional power resources, are considered a customer-specific option used as a "load-reducer", as opposed to a generation resource available on-demand.

2.13 Ancillary Services Component

Another component of Nebraska power systems that is not included in general market product pricing are items called "Ancillary Services." These services are additional benefits that customers can receive that provide improved power flow benefits and increase the value of the electrical product utilized. These services include Scheduling, System Control and Dispatch; Reactive Supply and Voltage Control; Regulation and Frequency Response; Energy Imbalance; and Operating Reserves (both Spinning and Supplemental). Detailed descriptions of these "Ancillary Services" were provided in Appendix 4-A of the 2001 and 2002 LB 901 Reports. The "reserves", the long-term "obligation to serve", and "Ancillary Services" should be accounted for in the comparison methodology for market prices and Nebraska costs.

2.14 Load Factor Considerations

Lastly, the Nebraska power systems are designed to serve varying customer load patterns and have lower load factors, as discussed earlier in Section 2.5, whereas the market products are for blocks of 100% load factor products, so Nebraska power system costs should be allocated appropriately over the higher load factor product in order to equitably match the market product pricing. No matter what the load factor or when the energy is required, Nebraska utilities are obligated to maintain the physical capability, or capacity, to provide the energy when needed even though it may not be utilized by every customer 100% of the time.

3.0 Market Product Pricing & Nebraska Production Cost Comparison Methodology

3.1 Alternative Comparison Methods

There are several methods of approaching a fair and equitable comparison:

(1) Send out a Request for Proposal (RFP) on electricity products to serve customers on the exact same basis as currently served,

(2) Purchase a regional electricity price application model from a vendor to determine an estimated market value,

(3) Develop a fixed and variable cost allocation tool to determine Nebraska's "cost to provide" electricity that is on an equivalent basis with market products that have price indices and are publicly available, independent and credible.

Method three, the development of a fixed and variable cost allocation tool, was deemed the best approach of the three for the following reasons:

(1) The RFP could be perceived by the market as a price discovery process only, so the respondents may not provide "real" bids, or the prices offered may be extremely low initially just to gain market entry. This implies that the prices would not be truly reflective of market value, and the process involved would be extremely time-consuming and labor-intensive to develop the RFP, let the bids, and evaluate the bids on an equitable basis just for price comparison purposes,

(2) Purchasing a regional electricity price application model from a vendor would be cost prohibitive with an estimated cost of up to $150,000 depending on level of detail and service provided, also the set-up and training required to determine equivalent electricity products could be labor-intensive,

(3) The self-developed tool approach allows for all of the Nebraska power systems to have input on how the model should work to equitably compare costs and prices; fixed and variable cost allocations can be determined by each utility on the same basis as a market product for appropriate matching; the contract-sensitive data remains confidential; the modeling can be applied quickly and efficiently for each utility and then consolidated easily for a single state-wide result; the costs are minimal, and there is Nebraska utility acceptance of process and results.

3.2 Comparison Modeling Tool Detail

To develop a modeling tool that separates the various components of Nebraska power system costs to match the available market product indices requires clearly defining these costs. Therefore, since the available market price indices are for products located at specific transmission systems outside of the state, then Nebraska's electricity production costs should be calculated for availability within the Nebraska transmission systems only, so that additional transmission charges for delivery would be price neutral in the calculations. On this basis the following represents the methodology to define Nebraska power system costs in a manner that will allow a fair and equitable comparison to market products:

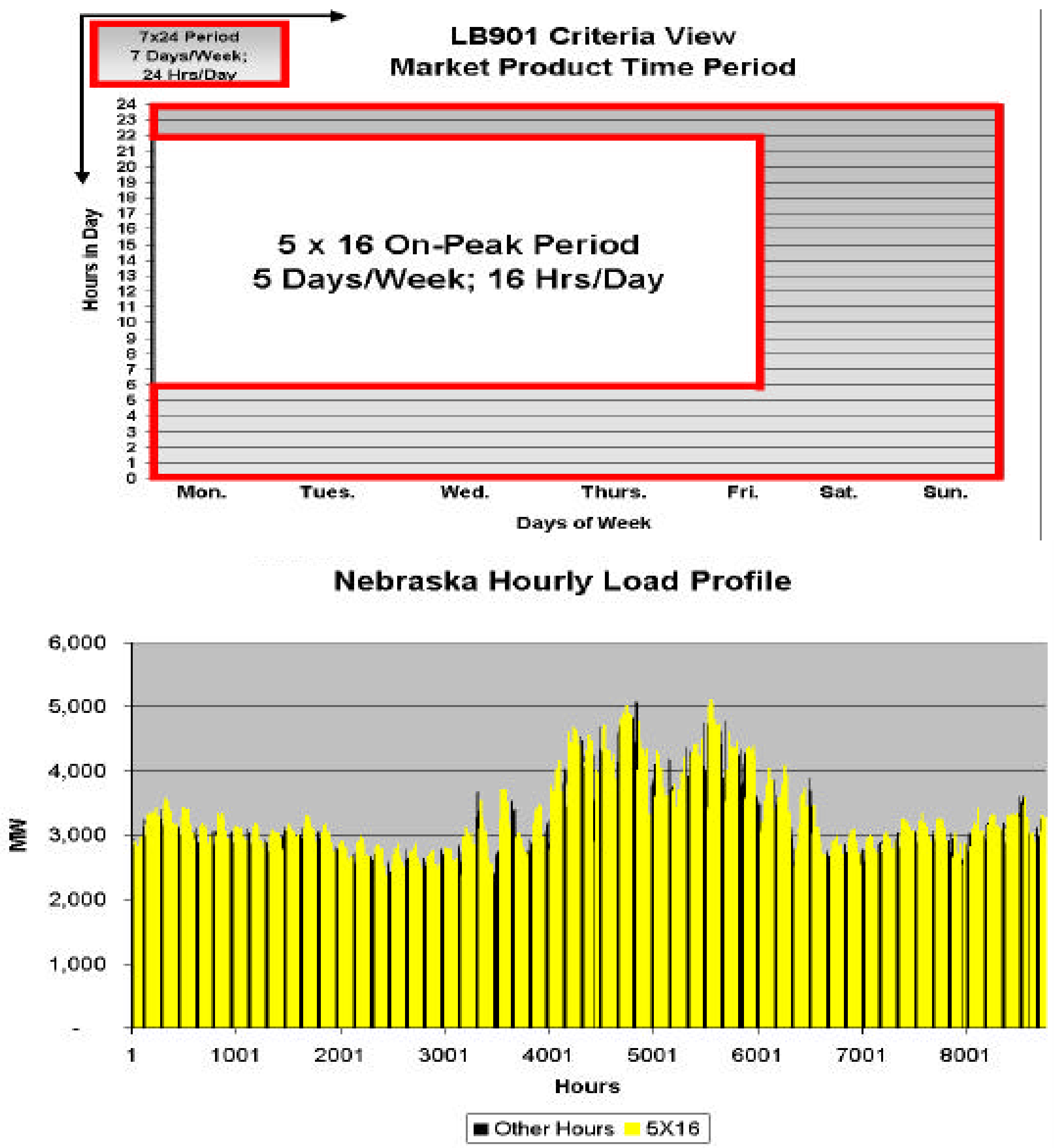
(1) Determine the total annual production revenue requirements for all the Nebraska utilities' power resources,

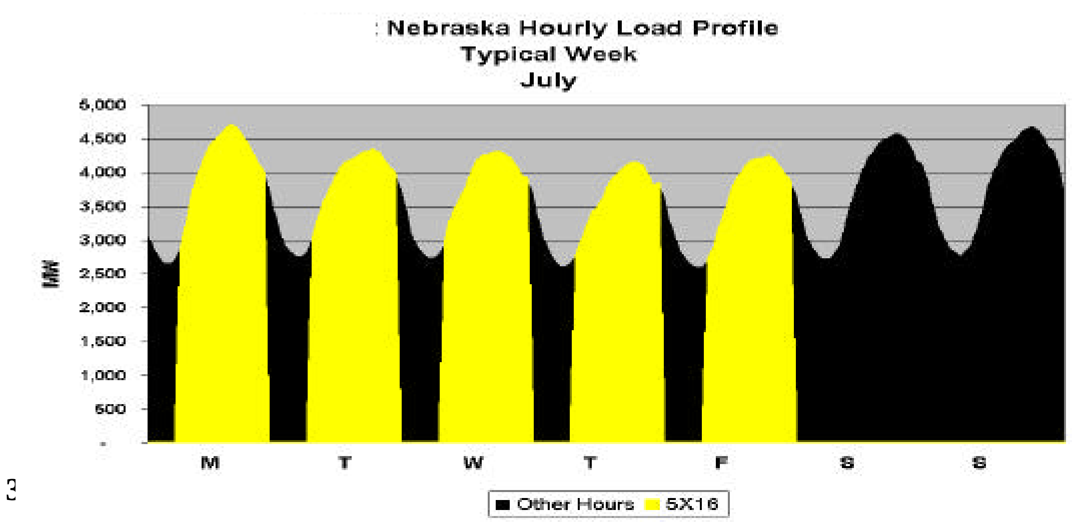
(2) Apply a consistent set of fixed and variable production cost accounts based on Federal Energy Regulatory Commission (FERC) accounting definitions to calculate the production cost to serve load,

(3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs on a per hour basis to each utility's load that each utility is obligated to serve by weighting the costs on a MWH per year or market price basis, by time period (Peak and Off-peak), calculating an hourly $/MWH cost to serve load in each of the 8760 hours of the year,

(4) Since the costs have been calculated on a $/MWH basis for each hour (as determined in (3) above), sum the hourly fixed cost and variable cost, less any obligation adders such as reserves, “obligation to serve” values and ancillary services, and adjust the load factors to match available market product indices which are on a 5 x 16 basis (5 days per week – Monday thru Friday, 16 hours per day). Exhibit IV-I below provides a graphical description of how much and during which times the load profile information is utilized.

Exhibit IV-1





Based on the definitions and methodologies described previously, a comparison model and process were developed, applied by each Nebraska utility, and then consolidated for a single, state-wide Nebraska power system cost and market price comparison based on the following criteria:

(1) Costs and prices were compared on a total annual amount calculated per month for an equivalent 100% load factor, 5 x 16 market product since there were a multitude of market price indices available for this type of product,

(2) Both "average" and "median" monthly market price history were calculated based on the daily price settlement indices utilizing the raw data from 'Platt's Global Energy - Power Markets Week - Price Index Database' as the detailed source,

(3) The market indices chosen to best represent a potential product availability for Nebraska customers located at the particular "market" or "hub" but not delivered to the customer, were "MAPP" (as available), "Cinergy," "Entergy," and "ComEd"; ("MAPP" history is available, but because of limited trading, or an "illiquid" market, no future pricing index currently exists); also, for physical resource comparison purposes, supposing customers built their own resources to serve their own load, various new generation unit types (peaking, intermediate & baseload) were priced & calculated, based on market cost allocation methods, then compared,

(4) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December monthly MWH-weighted, and (b) January thru December monthly market price-weighted; also, Ancillary Services, Planning Reserves, and Additional Capacity hedging values from existing utility price were subtracted from the utility costs in order to determine an appropriate market product price comparison,

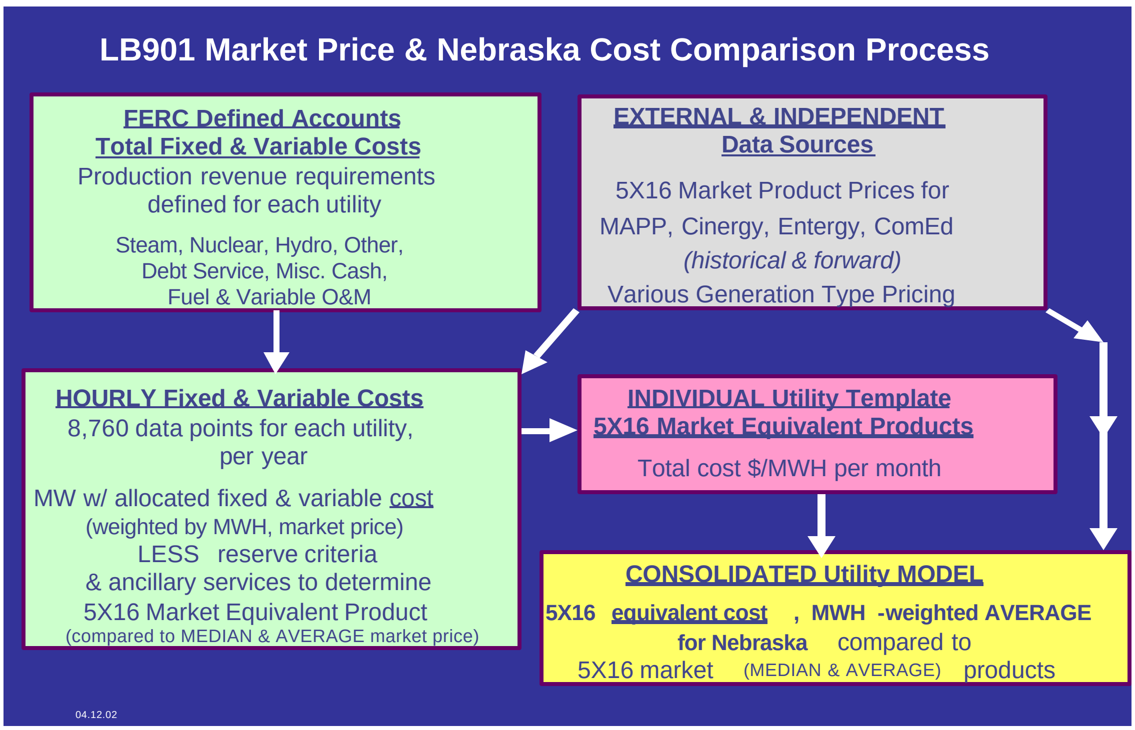
(5) For the study period, an anomaly occurred in 2000 when winter prices (specifically December) were higher than summer prices. It was recommended to "force" the fixed cost allocation when considering market price weighting of fixed costs to the summer because the single winter season of 2000 / 2001 was considered "unusual" and not typical of market pricing patterns. In March 2002, it was noted that actual January 2001 market prices were the highest prices in 2001, so the detailed market price comparison tool was updated to include the user-option of "forcing" the actual fixed cost allocations (for the market-price weighting of fixed costs portion only) into the summer months (June, July, August) so that a single winter season price anomaly would not corrupt the overall comparison results.

Also, for the Peaking unit only, the user has an option to compare Peaking unit costs when the market price warrants dispatching this type of resource (the market price is either equal to or higher than the Peaking unit cost).

(6) The cost to serve Nebraska customers from Nebraska power systems was then compared to the cost to serve Nebraska customers from the market, calculated on an annual MWH-weighted basis from which a percentage of market price was calculated to quantify differences between Nebraska power systems and available market product pricing on a rolling average basis for 2000 - 2003 (3 years of history and 1 year of future pricing); annual price volatility (fluctuation) comparisons were also performed.

A process flow diagram describing the comparison model application and model names is provided in Exhibit IV-2 below:

Exhibit IV-2



4.0 Results of Modeling Tool Comparisons

4.1 Time-period Utilized

One of the key elements to comparing prices and costs deals with the time period over which the comparisons are actually made. For example, market prices may be higher during unusually high weather or transmission-constrained years and lower in others. Nebraska costs may be higher during nuclear unit re-fueling outage or emission-constrained production years and lower than others. In order to "smooth-out" these events on both sides of the comparisons and to maximize future pricing and cost data availability, three years of history and one year future (total of four years) were chosen as the appropriate time period for comparisons. The publicly available, independent, and credible market price indices are only currently available 12 – 18 months forward, so the "future view" comparisons are limited, and future expected costs of utilities (e.g., production costs, required purchases, emission compliance impacts) can change many times over the next 18 months.

For 2003 modeling comparison purposes the time period of 2000 through 2003 is modeled and compared for the following reasons:

- The basic concept and current comparison modeling is to apply three years history and a one-year estimate that are developed on an annual basis so that a four-year rolling average is provided every year. The current time period being modeled is 2000-2003, with 2003 being the estimated year for both market pricing & production costs.

- Incorporating the future year 2004 into the modeling introduces another layer of “assumptions” & “speculation” that may reduce the credibility of an agreed upon modeling process that provides reasonable conclusions.

- Market pricing is changing on a month-to-month basis and comparing too early may provide a false signal of difference between market price and expected production costs both on a price & volatility basis. For example, the May 2001 price for an August 2001 market product was approximately $83/MWh; in June 2001 the price for the same August 2001 market product was approximately $55/MWh. With this price volatility just two months out, greater price swings can be expected 12 to 18 months out.

- Historical weighting reflects actual market prices & actual production costs which are more credible & accurate than projections or expectations. The four-year rolling average allows for anomalies & unusual fluctuations in both the market price & production costs to be smoothed out for more reasonable comparison purposes.

- Need to be cautious that legislative action is not triggered on projections or expectations which are subject to larger errors (e.g., California), but on actual experience and estimations that have a higher confidence of accuracy (e.g., just one year).

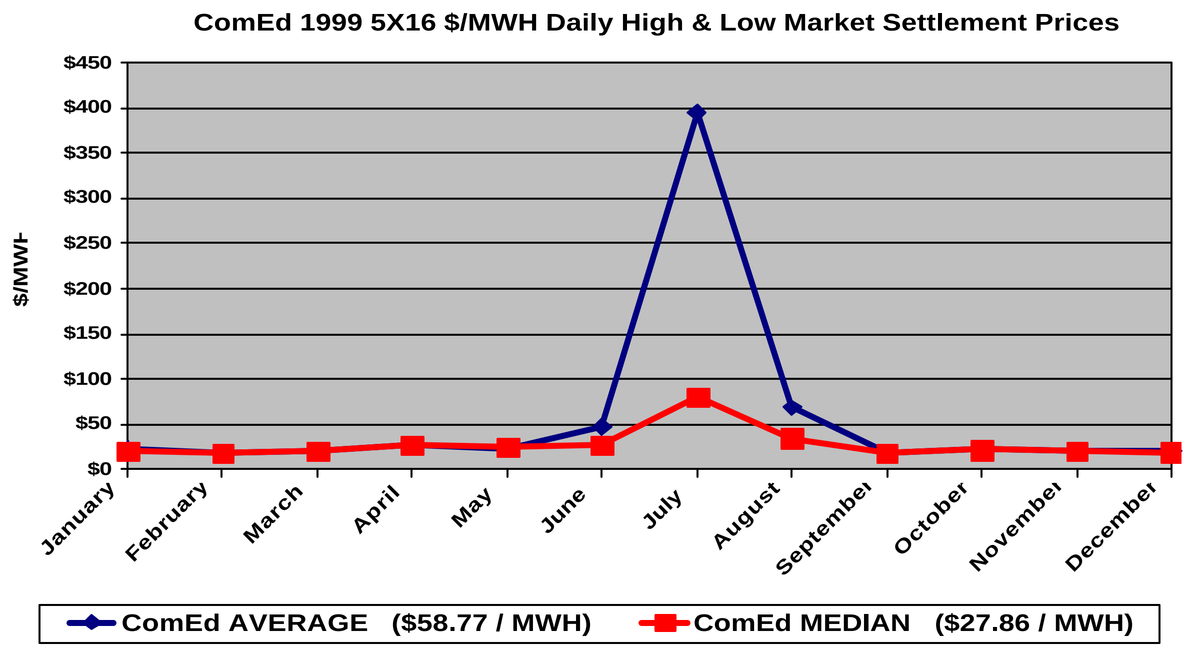
4.2 Sensitivity Cases Analyzed

Based on performing several sensitivity analyses associated with “average” and “median” market pricing, fixed cost allocation by MWH-weighting, fixed cost allocation market price weighting, for fixed cost allocations, and time period for comparisons to market, the following conclusions were calculated.

4.3 Median Market Pricing

Exhibit IV-3 below shows two distributions for 5X16 monthly market prices in the ComEd market for 1999, based on high & low daily settlement prices. One is based on the “average” of the daily high & low settlement prices, and the other is based on the “median” of the daily high & low settlement prices. The “average” represents the summation of all the prices divided by the number of prices, whereas the “median” is the middle number of the price after sorting from low to high. The “median” is considered more ”typical” since it is not biased or skewed by a single high number, whereas the “average” can be biased or skewed by a single high number. Therefore, to avoid inherent biasing of the Nebraska cost comparisons to a higher market price (possibly driven by one or two high numbers), median market pricing was chosen as the better market criteria to compare and set the threshold for Nebraska costs.

Exhibit IV-3



4.4 MegaWatt-Hour (MWH) Weighted Fixed Cost Allocations

The comparison modeling developed allows for sensitivities to be performed applying two different methods of allocating fixed costs; (1) weighted by Peak & Off-peak period evenly over every MWH produced during each month of the year, and (2) weighted by the variation in market price – the higher the market price in a particular month then the more fixed cost is allocated to that month.

The MWH-weighted fixed cost allocation method was chosen since it more closely represents how Nebraska utilities are currently allocating their fixed costs (more evenly over every MWH produced during each month of the year) and does not overstate differences to market prices. When a market price – weighted fixed cost allocation method was used, Nebraska costs differences to market were only slightly better when compared to the MWH-weighted comparison to market.

4.5 Other Cost Allocation Issues

As discussed in Sections 2.7 through 2.14 earlier in this chapter, there are other cost allocation issues that could be considered for equitable comparison purposes. For 2002, the modeling tool, that was initially developed in 2001, was updated & enhanced to include user options to incorporate transmission cost adders that reflect the additional cost of actually delivering a market product to the Nebraska system (both losses & tariffs). Although this flexibility is built into the modeling tool, the 2003 overall comparison results are based on these values being set to zero so that an equitable comparison to last year's results can be made and any market bias perception is eliminated. A model user option to include an "obligation to serve" value was also incorporated, but, again, this option was set to zero for the same reasons described above.

Additional model flexibility & information detail was incorporated to allow model users to determine the effect of allocating fixed costs when the market price would allow higher price signals, even in winter months. This is for informational purposes only, and strictly impacts the market price weighted results, so the MWH-weighted results, considered the bottom-line comparison values, are not affected. Also, in order to compare various generation resource types (baseload, intermediate & peaking), as described earlier in Section 2.12, the model is enhanced to provide informational detail & comparisons on multiple physical resources as opposed to only an intermediate-type unit that last year's model version utilized.

Again, only additional informational detail has been added to this year's modeling, no additional cost adders are included as part of this year's comparison results.

4.6 Value of Long-term Obligation to Serve

The Nebraska power system product is based on a long-term "obligation to serve" that is not inherent in market-based electricity products. Typically, there is a thirty to forty year obligation stemming from the commitment to build various physical generation unit types to provide stability in power resources that is derived from having "iron on the ground", and limited dependence on the market. This translates to a long-term commitment to providing physical resources that meet or exceed Nebraska's power systems "obligation to serve".

A market-based electricity product provider does not share this same responsibility, hence, there is downward pressure on the price for the market–based electricity product as compared to local providers. This actual value is difficult to quantify since this is a subjective criteria that may be different for each customer depending on individual risk tolerance for price changes, however, four different analytical approaches were developed & modeled, and the results are included in Section 4.8 for subjective consideration only, and are not specifically accounted for in the 2000-2003 Nebraska production cost comparison to market pricing.

4.7 Results Based on Median Market Product Pricing Indices and Applying MWH-Weighted Fixed Cost Allocations to Nebraska Production Costs for 2000 through 2003.

Exhibit IV-4 provides a tabulation of the results comparing median market product pricing indices and applying MWH-weighted fixed cost allocations to Nebraska production costs for 2000 through 2003. As shown in the table, on an equivalent basis, Nebraska production costs consistently rank below the market product indices even with nuclear unit outage and high market purchase price production cost anomalies throughout the study period. Also included, are two LB901 historical study period comparisons describing the four-year rolling average results for the various study periods completed. Differences in study period results are to be expected since market prices will fluctuate more than Nebraska Production costs as described in Section 2.7, so the differentials between them will also tend to fluctuate, as supported by the price volatility calculations provided.

Exhibit IV-4

COMPARISON TABLE for NEBRASKA PRODUCTION COSTS

PERCENTAGE BELOW MEDIAN MARKET PRICING

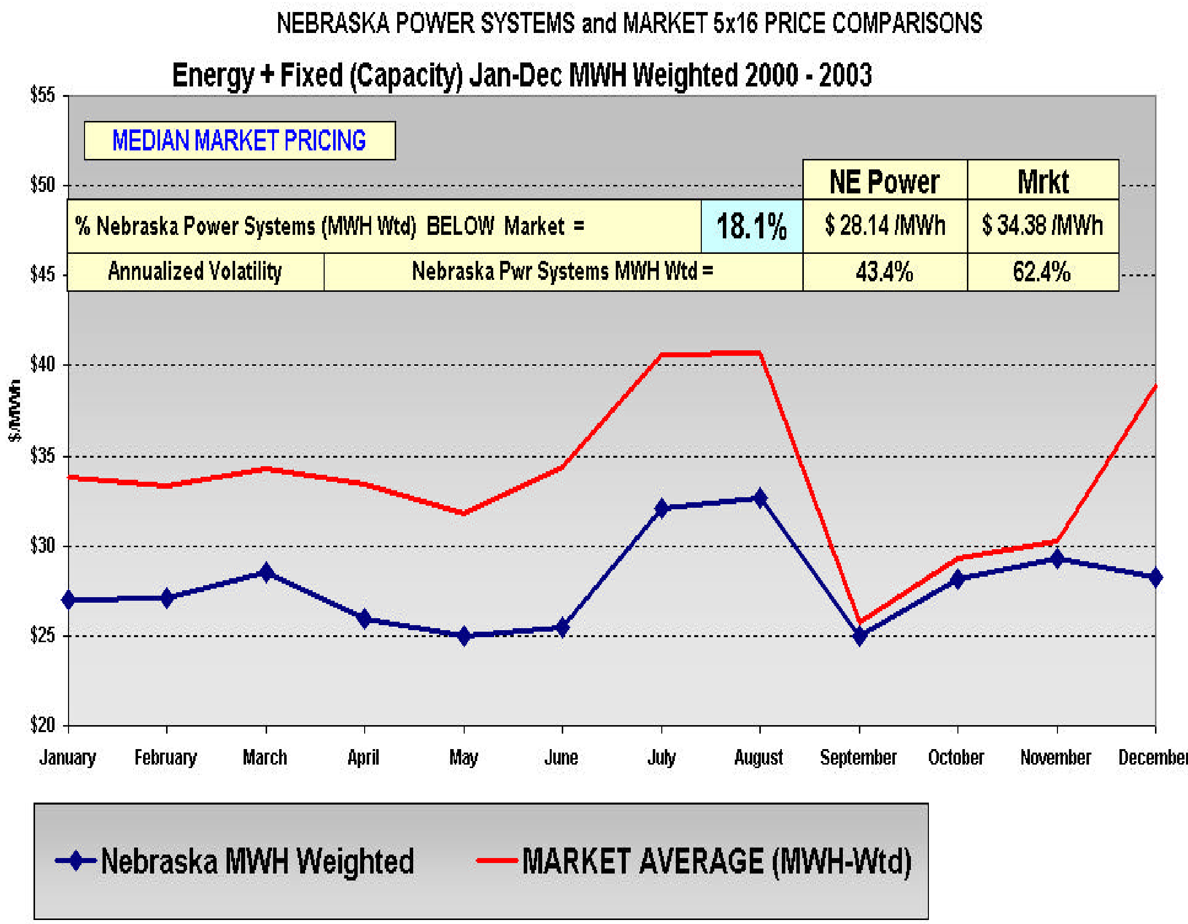
Year	MWH - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
2000	25.7%	26.7%
2001	21.2%	23.2%
2002	2.4%	2.3%
2003	20.4%	20.2%
Straight Average	17.4%	18.1%
Four Year Average (MWH-weighted)	**18.1%**	**18.8%**

HISTORICAL LB901 STUDY PERIOD COMPARISON

Study Period Years	% Nebraska Systems Below Market	Nebraska Cost Annualized Volatility	Market Price Annualized Volatility
1998 - 2001	**18.6%**	**34.4%**	**84.5%**
1999 - 2002	**15.3%**	**41.2%**	**92.2%**
2000 - 2003	**18.1%**	**43.4%**	**62.4%**

Exhibit IV-5 portrays a graph that depicts on a monthly basis for the four-year study period (2000-2003) a comparison of median market product pricing indices to Nebraska production costs with MWH-weighted fixed cost allocations applied. As shown in the graph, on an equivalent basis, Nebraska production costs protect consumers from potential market price volatility while being below market by approximately 18%. The market price volatility represents a measure of the rate of price uncertainty over time and is typically measured by determining a standard deviation over a specific period. In the results provided below, the "Annualized Volatility Calculations" block compares the rate of price uncertainty for the market product per year ("annual" basis) to the rate of price uncertainty for Nebraska production costs. The calculation demonstrates how well Nebraska production costs protect Nebraska customers from the relative uncertainties of market price changes by indicating an annualized price volatility measure of 43%, which is considerably less than the market product price volatility of 62% for the same type of electricity product over the same period.

Exhibit IV-5



For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2003 market prices and physical generation resource costs, as applied in this year's model.

Exhibit IV-6

LB901 "Condition-Certain" Criteria Historical Market Pricing for Comparison Purposes

= Manual Entry
= Calculated Value
= Special Calculation

AVERAGE 5X16 $/MWH Daily Settlements for 2003

	HISTORICAL			FORWARD INDICES (as of March 15, 2003)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	43.25	55.49	52.66	28.60	28.81	33.01	42.29	50.59	27.41	32.26	35.15	34.40
Comed	42.51	53.30	49.11	27.96	28.98	32.31	40.64	40.64	28.82	29.75	29.75	29.75
Cinergy	44.30	56.65	51.48	29.37	30.16	33.78	42.12	42.12	29.34	33.75	33.75	33.75
Entergy	41.42	57.15	48.52	30.70	31.84	35.11	39.79	39.79	31.60	36.30	36.30	36.30
MAPP CALC	101.2%	99.6%	105.9%	97.5%	95.0%	97.9%	103.5%	123.8%	91.6%	97.0%	105.7%	103.4%

MEDIAN 5X16 $/MWH Daily Settlements for 2003

	HISTORICAL			FORWARD INDICES (as of March 15, 2003)								
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	45.31	50.25	46.00	28.54	30.51	30.95	40.99	50.06	26.29	32.49	34.56	32.57
Comed	43.00	48.12	44.38	27.96	28.98	32.31	40.64	40.64	28.82	29.75	29.75	29.75
Cinergy	44.48	50.82	47.03	29.37	30.16	33.78	42.12	42.12	29.34	33.75	33.75	33.75
Entergy	41.82	47.51	42.07	30.70	31.84	35.11	39.79	39.79	31.60	36.30	36.30	36.30
MAPP CALC	105.1%	102.9%	103.4%	97.3%	100.6%	91.8%	100.3%	122.6%	87.9%	97.7%	103.9%	97.9%

MAPP Capacity Price $/kW-yr for 2003 =	15.00			
Peaking Unit real levelized $/MWH for 2003 =	64.50	@ 85% CF and Fuel of $3.97/ mmBTU	99.00	@ 10% CF
Combined Cycle real levelized $/MWH for 2003 =	37.00	@ 85% CF and Fuel of $3.97/ mmBTU		
Baseload Coal real levelized $/MWH for 2003 =	26.00	@ 85% CF and Fuel of $0.65/ mmBTU		

(All generation units EXclude transmission cost adders)
FORWARD PRICES FOR MARCH THRU DECEMBER BASED ON PLATTS FINANCIAL TIME RDI DATABASE MARCH 15, 2003 & 4th Quarter Estimates

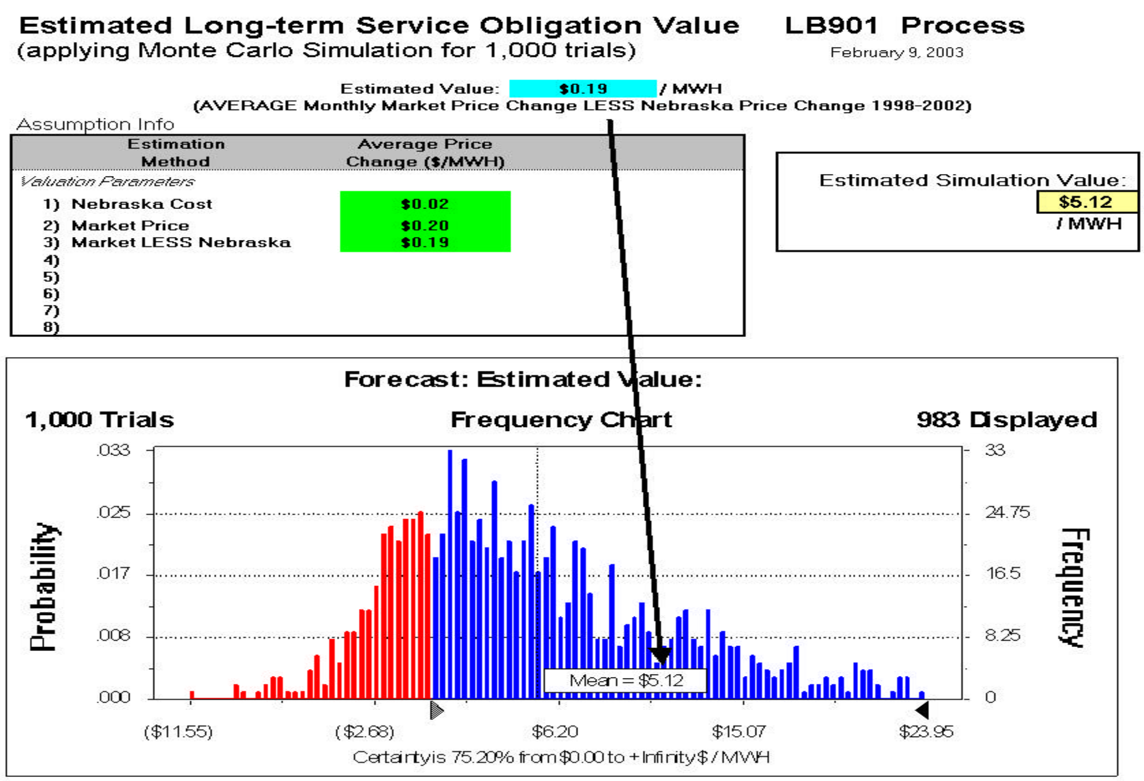
These results for the 2000 – 2003 study period are slightly higher than the results for the previous period, 1999 – 2002, due mostly to the upward trend of market prices driven by higher s natural gas prices and stable generation, as well as the four-year rolling average effect of having three higher market differential years and only one lower market differential year for Nebraska Production costs (last year's rolling average included two bad years out of four). The price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

4.8 Results of the Value of Long-Term Obligation to Serve Analyses

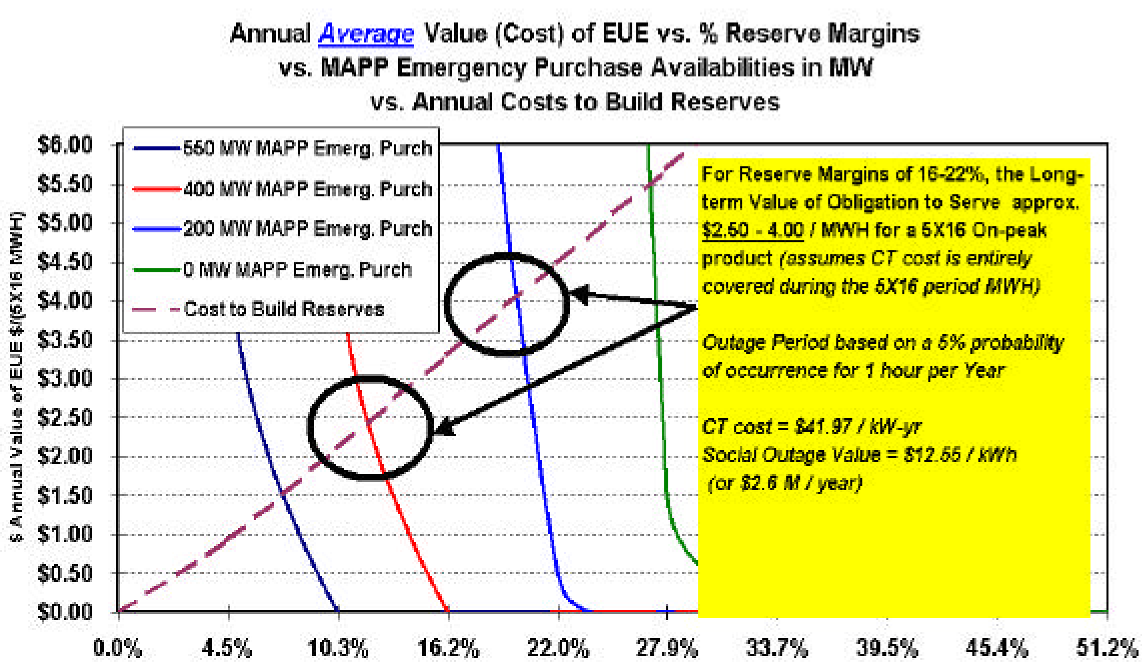
These results are based on four different analytical techniques to estimating "value", and it appears reasonable that the value of the long-term obligation to serve is approximately $3-$5/MWH for a 5X16 peaking type product.

Exhibit IV-7

(1) Applied a Monte Carlo simulation process (1,000 trials) to the change in monthly price over the last 5 years (59 history data points) to determine a mean value over the given distribution.



(2) Estimated the cost of outages to customers then translated into reserve margin costs to meet that expected level of reliability.



(3) Determined the direct difference between a technology cost and the Nebraska Production cost to serve the same market product as defined in the LB901 process

Technology Comparison

represents cost to serve new load with new physical resources

Long-term Service Obligation Value		Resource Oper. Weights
Peaker =	$ 54.93	10%
Intermediate =	$ 38.69	20%
Baseload =	$ 27.13	70%
Weighted =	$ 32.22	
Neb Price =	$ 28.14	
Weighted LESS Neb Price =	$ 4.08	
	/ MWH	

(4) Considered Industry studies on the price signal that customers are willing to "switch" electricity providers, if choice is available and Florida municipals wishing to "separate" included.

Florida Municipals Wishing to "Separate"

from current long-term supplier

Casselberry Muni Price Switching Calc

MW	LF	MWH/Yr	Growth Rate	Disc Rate	Offer ($M)	
50	60%	262,800	3%	6%	$22.7	---> 30 yrs

	1	2	3	4	5	6	7
	2004	2005	2006	2007	2008	2009	2010
MWH	262,800	270,684	278,805	287,169	295,784	304,657	313,797
Pymnt ($M)	($1.6)	($1.6)	($1.6)	($1.6)	($1.6)	($1.6)	($1.6)
$/MWH	$6.28	$6.09	$5.92	$5.74	$5.58	$5.41	$5.26

AVG $/ MWH	$4.22	(30 years)

Homestead Muni

- offered a price reduction from a long-term supplier
- equivalent to 9 – 16% per year
  - depending on amounts fund transfers & fee accounting

Estimated Long-term Service Obligation Value LB901 Process

(applying Customer Price Switching Information)

Based on previous generic market studies performed in 2000, where switching electric suppliers is an option, different customer types base their switching preference on price signals approximately 8 out of 10 times, and the rest of the time is due to customer service, outage times, customized program availability & economic development support.

With particular regard to the price signals, the price signal change point is dependent on customer type & convenience of switching, but ranges for **5 -10 %** in most cases, with some stating as much as a **16%** change in price as the threshold.

Therefore, the following analyses is offered as a "range" of possible values of the long-term obligation to serve based on the range stated, and the 4 year average price of a 5X16 peak period block as defined by the LB901 process:

	Market Price	Nebraska Power System Cost
	$34.38	$28.14
1%	$0.34	$0.28
2%	$0.69	$0.56
3%	$1.03	$0.84
4%	$1.38	$1.13
5%	$1.72	$1.41
6%	$2.06	$1.69
7%	$2.41	$1.97
8%	$2.75	$2.25
9%	$3.09	$2.53
10%	$3.44	$2.81
11%	$3.78	$3.10
12%	$4.13	$3.38
13%	$4.47	$3.66
14%	$4.81	$3.94
15%	$5.16	$4.22
16%	$5.50	$4.50
17%	$5.84	$4.78
18%	$6.19	$5.07
19%	$6.53	$5.35
20%	$6.88	$5.63

Assuming that since Nebraska Power costs are lower than the region as whole, it is not unreasonable to assume that it would take a higher percentage of reduced costs for customers, in general, to switch

Therefore, it appears reasonable, that based on this information, the value of the long-term obligation to serve appears to be in the **$3 - 5 / MWH range for a 5X16 peaking type product.**

5.0 Expected Differences Eastern Region to Western Region

5.1 North American Electrical Interconnection

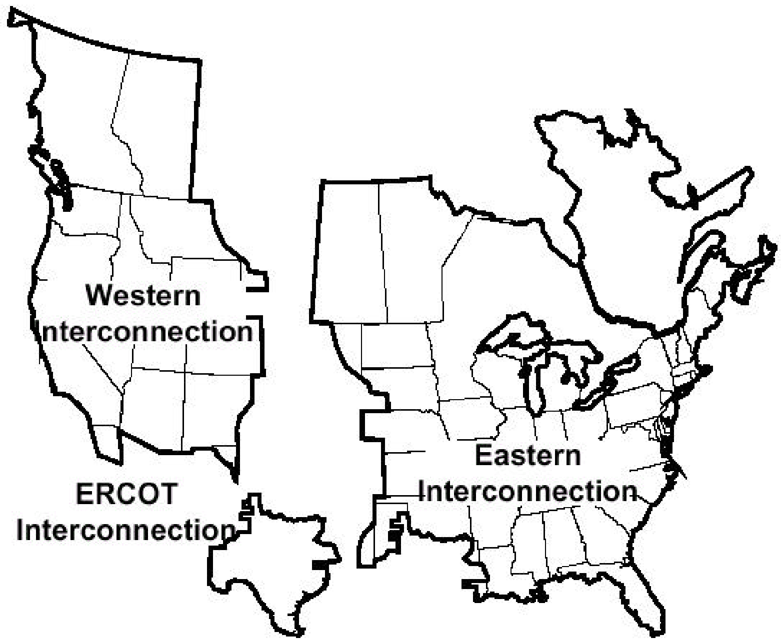
The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-7 and described below:

Eastern Interconnection - the largest Interconnection covers an area from Quebec and the Maritimes to Florida and the Gulf Coast in the East and from Saskatchewan to eastern New Mexico in the West. It has HVDC connections to the Western and ERCOT Interconnections.

Western Interconnection - second largest Interconnection extends from Alberta and British Columbia in the North to Baja California Norte, Mexico, and Arizona and New Mexico in the south. It has several HVDC connections to the Eastern Interconnection.

ERCOT Interconnection – includes most of the electric systems in Texas with two HVDC connections to the Eastern Interconnection.

Exhibit IV-8



5.2 Eastern Interconnection and Western Interconnection Generation Supply and Demand

The Eastern Interconnection is relatively large as compared to the Western Interconnection in terms of internal energy demand (586,723 MW compared to 133,228 MW) and generation (699,709 MW as compared to 166,902 MW). The interconnection capability of DC ties between the Eastern and Western Interconnection is 1,080 MW. Source: (NERC Reliability Assessment, October 2002). Nebraska's projected growth rate is approximately 1.8% and the current summer peak is approximately 5700 MW.

The Western Electric Coordinating Council's (WECC) outlook regarding the reliability of the Western Interconnection is comprised of four sub-regions – Northwest Power Pool Area, Rocky Mountain Power Area, Arizona-New Mexico-Southern Nevada Power Area, and California -Mexico Power Area. A resource assessment on a region-wide basis is not considered appropriate because of transmission constraints. This also explains the marketing limitations in the region due to the lack of firm transmission to facilitate such transactions and the limited interconnection tie capability to the Eastern Interconnection.

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. This is the sub-region that includes the western Nebraska load in the Western Interconnection and has the most direct impact when comparing utility cost of generation and market prices to those that are seen in the rest of Nebraska that is part of the Eastern Interconnection.

RMPA is projected to have demand growth rates somewhat higher than the WSCC as a whole with projected growth at a 2.9% annual rate. The RMPA is projected to have generation capacity margins above the projected load of between 18.8% and 25.9% for the next ten years.

The Mid-Continent Area Power Pool (MAPP) encompasses the Nebraska load and generation in the Eastern Interconnection. The demand forecast is for a projected demand growth of 1.9% per year through the 2011 period. Generation reserve margins in MAPP are projected to decline from 22.8% in 2002 to 13.3% in 2004. The majority of generation serving Nebraska is located in Nebraska.

In making this market comparison of Eastern to Western Interconnections, the market drivers have to be considered as well as the relationship of Nebraska's electrical capacity requirements associated with each interconnection. The market price drivers that influence the market differences include generation regulatory requirements, generation fuel type, fuel cost, generation availability/dependability, load demand, weather, and transmission availability.

The current Nebraska total capacity requirements include approximately 98% of the total residing within the Eastern Interconnection and 2% residing within the Western Interconnection. The Eastern and Western Interconnections are separate systems other than the relatively small amount of DC tie transfer capability between the systems.

5.3 Western Region Market Compared to Eastern Region Market

5.3.1 "Markets" or "Hubs"

The Eastern Interconnection "market" indices or "hubs" used for the Nebraska market in the Eastern Region (as defined in Issue #2 Section III-F) were based on the published market product prices designated as "MAPP," "Cinergy," "ComEd," and "Entergy." These are the market product indices that are geographically located closest to the Nebraska power system.

The Western Interconnection includes several "market" indices or "hubs." The published price index designated as "Palo Verde" is considered as representative of the Nebraska market that is in the Western Region (as defined in Issue 2 Section III-F).

5.3.2 Volatility and Price Comparison

Looking at the price levels for 2000 through 20032 , shows a higher volatility in the Western Region for this time frame than in the Eastern Region, although the most volatile time period was in 2000. This fluctuation of volatility has decreased to where both regions are currently seeing similar volatility.

Market price levels for both the Eastern and Western Regions have been fairly similar in recent months with the Eastern region pricing levels being slightly higher in recent months.

5.4 Nebraska Production Costs

5.4.1 Western Nebraska versus Eastern Nebraska Costs

Power costs in Nebraska reflect the cost of power primarily generated from within Nebraska. However, WAPA is a partial requirements wholesaler to a number of Nebraska utilities; Tri-State of Westminster, Colorado, serves rural systems in western Nebraska; and LES and MEAN receive some power from the Laramie River Station in Wyoming.

Nebraska's proximity to the low sulfur coal in Wyoming contributes to the state's low production costs. Nebraska has a relatively small amount of power produced by gas and oil that have a much higher cost of production due primarily to the high cost of fuel. Additional reasons that Nebraska's production costs are kept low are the WAPA purchases, sales of surplus energy into the market and returning margins.
In general terms the western Nebraska load supplied from generation in the Western Region has a similar cost of production as that of the Nebraska load in the Eastern Region. The fuel source is primarily coal from Wyoming for the generation that serves western Nebraska.

5.4.2 Stability

It is difficult to predict what Nebraska's cost of production will be in the future. However, Nebraska should generally be in a stable position through the 2004 time period. There is adequate generation to meet the load requirements per the NERC Reliability Assessment. Recent market prices in the Western Region have trended higher and been more volatile than the Eastern Region; therefore Western Nebraska does have more exposure to the market during periods that normal generation supply is unavailable due to planned or forced outages.

6.0 Conclusions

The challenge for Technical Group #4 was to develop an equitable comparison between the credible indices that were identified and the product provided by Nebraska electric utilities to their customer-owners. The product that Nebraska providers sell is a firm, total electrical requirements product, available 24 hours a day, 7 days a week, in quantities that vary hourly, weekly, monthly, seasonally, and annually. This obligation to serve includes both existing and new customers. The typical index described in the previous sections provides a price for a fixed hourly quantity of energy, possibly with a premium for financial firmness, but with no obligations on the part of the seller beyond the current month or, in the case of daily indices, beyond that day. The typical index is not a comparable product to that provided by a Nebraska utility to its customers.

When a Nebraska utility decides to build a power plant, they are not building it to serve a customer for a day or month. They are in effect building the plant to serve a forward obligation for the next 30 to 40 years. The forward market does not have a published product that goes beyond an 18 to 24 month period.

The results of the comparison between the market product indices and the Nebraska production costs show that Nebraska production costs are approximately 18% lower than the equivalent wholesale "median" market price based on the period 2000 – 2003 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market price, Nebraska production costs are approximately 21% lower than the "average" market price.

These results for the 2000 – 2003 study period are slightly higher than the results for the previous period, 1999 – 2002, due mostly to the upward trend of market prices driven by higher s natural gas prices and stable generation, as well as the four-year rolling average effect of having three higher market differential years and only one lower market differential year for Nebraska Production costs (last year's rolling average included two bad years out of four). The price volatility associated with Nebraska Production costs remains stable compared to market price, providing a fairly consistent, less volatile, cost expectation for Nebraska's ratepayers.

In addition, the results of an analyses that applied four different approaches to determining the value of the long-term obligation to serve that is provided by Nebraska utilities appears to be in the $3 – 5 / MWH range, and this is added value that Nebraska utilities provide customers over & above market products.

Currently, electricity traders are experiencing as much as 17% in delivery losses (equivalent to approximately $5 / MWH), which add to the price of a market product. Also, the standard market transmission tariffs associated with delivering these market products from external regions to Nebraska customers can add an additional $4 – 6 / MWH to the market product price.

These additional differential impacts (obligation to serve, transmission losses, transmission tariffs), together result in potential cost adders of $7 - 16 / MWH for a market product to be delivered to Nebraska ratepayers even if the market product price and the Nebraska production costs were exactly the same.

The "median" market price comparison, approximately 18% lower than the market price, compares favorably with retail rate comparisons. The Energy Information Administration (EIA) annually compiles data from the Form EIA-861 for approximately 3,300 public and investor-owned electric utilities including active power marketers and other energy service providers. The most current data for 2001 shows that Nebraska's average retail rate of 5.39 cents/kWh is approximately 26% lower than the national average retail rate of 7.32 cents/kWh.

That Nebraska production costs are lower than the market price is not by accident. Nebraska utilities have several financial advantages that include: their non-profit status and their ability to access tax exempt financing. Many Nebraska utilities have an allocation of low-cost federal preference power (WAPA) from the six dams on the Missouri River. In addition, the public power utilities in the state have made good resource planning decisions in that the generation portfolio mix is diverse with coal, hydro, natural gas, nuclear, oil, and most recently renewable resources. The state has invested in base-load capacity and therefore Nebraska utilities generate very little energy with premium (expensive) fuels such as natural gas and oil. Also, the state has a geographic advantage in that it is in close proximity to coal in Wyoming, Nebraska utilities are further able to keep electric rates low by selling surplus energy into the wholesale market and using the margins to stabilize rates.

Chapter 5

"Any other information the board believes to be beneficial to the Governor, the Legislature, and Nebraska's citizens when considering whether retail electric competition would be beneficial, such as, but not limited to, an update on deregulation activities in other states and an update on federal deregulation legislation."

1.0 Purpose

Provide information on deregulation activities in other states, an update on federal deregulation legislation, and other public policy developments relating to electric deregulation.[1]

2.0 Team Members

Doug Bantam – Lincoln Electric System
Jay Holmquist – Nebraska Rural Electric Association
John McClure – Nebraska Public Power District
Tom Richards – Omaha Public Power District

3.0 Introduction

3.1 Deregulation Overview

The material presented below is an addendum to last year's update on the status of actions to implement retail choice in the electricity industry. Proponents of deregulation argue that competitive markets are more efficient than government regulated economic activities. Professor Willis Emmon's recent book on deregulation and privatization states: "Deregulation is a broad concept that encompasses easing or eliminating government restrictions in three major areas: a firm's freedom of entry into a market, its freedom of action within a market, and its profitability (maximum or minimum) within the market."[2] One of the biggest public policy challenges in achieving successful deregulation is the creation of truly competitive markets. The LR 455 Phase II Report, December 1999, analyzed the driving forces of retail electric deregulation and discussed the impacts of deregulating other industries in Nebraska such as airlines and telecommunications. See pp.8-16. As the Report clearly pointed out, in Nebraska "competitive markets" often bypass rural or sparsely populated areas, especially when the deregulating industry is capital intensive such as airlines, railroads, and telecommunications.

Skepticism about the consumer benefits of electric deregulation in Nebraska, along with Nebraska's competitive energy costs, were two key factors leading to the "condition certain" approach recommended in the LR 455 Phase II Report and adopted in LB 901 (2000).

Retail deregulation gained considerable popularity between the late 1990s and January 2001 with 25 state legislatures or regulatory agencies committing to various forms of retail customer choice. This trend reversed considerably by June 2003 when only 18 states and the District of Columbia were pursuing such action and some of these states have retail choice on only a very limited basis. See groups of states below and Exhibit V-1.

Pursuing Retail Choice (19)

Arizona	New Hampshire (to commence in 2004)
Connecticut	New Jersey
Delaware	New York
District of Columbia	Ohio
Illinois	Oregon (non-residential only)
Maine	Pennsylvania
Maryland	Rhode Island
Massachusetts	Texas
Michigan	Virginia
Nevada (non-residential only)	

Retail Choice Suspended or Repealed (5)

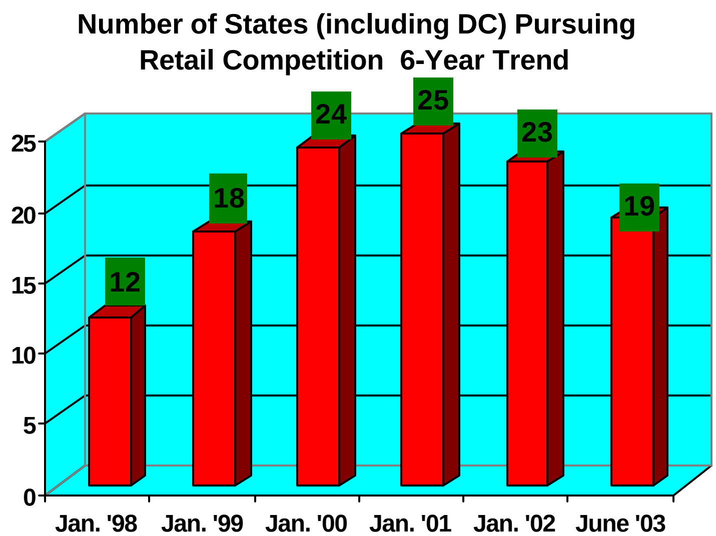
Arkansas
California
Montana
New Mexico
Oklahoma

[1] This report reflects deregulation developments through August 20, 2003.
[2] Willis Emmons, *The Evolving Bargain*, "Strategic Implications of Deregulation and Privatization," 2000: p. 2.

Retail Choice Not Being Pursued (27)

Alabama	Missouri
Alaska	Nebraska
Colorado	North Carolina
Florida	North Dakota
Georgia	South Carolina
Hawaii	South Dakota
Idaho	Tennessee
Indiana	Utah
Iowa	Vermont
Kansas	Washington
Kentucky	West Virginia
Louisiana	Wisconsin
Minnesota	Wyoming
Mississippi	

Exhibit V - 1



4.0 Status of Retail Competition in Selected States

Each year, the Center for the Advancement of Energy Markets (CAEM) -- a Virginia based energy think tank that advocates for retail customer choice -- releases its annual RED Index ranking the 50 states (and DC) and a number of foreign countries on the development of competitive energy markets. In 2001, Pennsylvania was identified as the leading state because of the development of its electricity market. George Spencer, publisher of *RestructuringToday* wryly observed, “To be number one in the nation today isn’t saying very much with all the retail markets effectively closed.”[3]

This year (2003), Ken Malloy, CEO of CAEM noted that Texas is now at the "head of the class" as number one among competitive electricity markets in the US. But Malloy quickly qualified his observation of Texas by noting, "But it's a pretty stupid class. The sad truth is that in the war for competitive energy markets, we're losing."[4]

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[3] George Spencer, Publisher of *Restructuring Today* commenting on the relative “success” of Pennsylvania’s retail competition scheme. June 22, 2001.

[4] "Malloy sees Texas leading in retail power", *Restructuring Today*, March 20, 2003, p.2.

The CAEM Red index ranked the state of Nebraska (for the sixth straight year) as last among the 51 jurisdictions in the United States for the development of a competitive retail electricity market. The report notes that, "as a result of the California crisis -- the (Nebraska) legislature is even less likely to enact legislation creating retail choice."[5]

4.1 Significant Legislative Actions Affecting the Implementation of Retail Choice

- Arkansas – During 2003, legislation (HB 1114) was enacted to repeal retail choice provided however that the Arkansas PSC would study the possibility of retail choice for the largest power users.
- New Mexico – Legislation was enacted during 2003 (SB-718) to repeal the implementation of retail choice.
- Oregon – Retail choice has now commenced for non-residential customers only after prior delay imposed by legislature. There are no immediate plans to implement retail choice in the residential market.

A number of internet web sites contain comprehensive state-by-state summaries of the status of electric retail competition. The sites provide the status of restructuring legislation and regulation and details on the structure of the approach taken. However, because much of the recent regulatory and legislative activity on electricity restructuring has been to delay and/or repeal prior initiatives toward retail competition, none of these web sites was completely up to date as of the drafting of this report. Despite the many limitations of these sites regarding timeliness and accuracy, one can find useful information on the status of restructuring.

American Public Power Association
www.appanet.org

Edison Electric Institute
www.eei.org

C.H. Guernsey & Company
www.chgeconmics.com

National Association of Regulatory Utility Commissioners
www.naruc.org

National Rural Electric Cooperative Association
www.nreca.coop

US Department of Energy (Energy Information Administration)
www.eia.doe.gov

William Spratley Associates
www.spratley.com

The following pages contain a brief summary of the status and implementation of retail competition in several states. The reader is encouraged to review the updates contained in this addendum in conjunction with the material published in last year's report. Proponents of retail choice now look to Texas as their best hope of demonstrating how retail choice can achieve the many promises that have been made with respect to market competition.

4.1.1 Arizona

On August 27, 2002 the Arizona Corporation Commission unanimously voted to eliminate a key provision of the state's electric competition plan that would have required Arizona Public Service (APS) and Tucson Electric Power (TEP) to move their power plants into a separate subsidiary or sell them to another unrelated company. A press release of the Arizona Corporation Commission quoted Commissioner Jim Irvin as saying, "This should now set the

[5] "2003 Red Index", Center for the Advancement of Energy Markets, (www.caem.org).

course for what is vitally necessary, which is a process that protects ratepayers from the kind of disaster that befell California utility customers."[6]

4.1.2 California

By late June 2003 new developments were emerging in California's efforts to restore stability to its electricity markets. First, the state's largest utility, Pacific Gas & Electric, reached a tentative settlement with the staff of the California Public Utility Commission on a plan to allow the company to emerge from bankruptcy and once again pay dividends to common stockholders. Under the terms of the accord, the utility would issue some $8 billion in new debt and electric consumers would pay higher rates over the next nine and a half years. However, residential customers would see some rate relief as early as 2004. The plan still needs the blessing of the PUC Commissioners as well as a federal bankruptcy court but it does send a strong signal that regulators in the state are serious about allowing the utility to return to financial stability. Consumer activists in the state are criticizing the plan as, "a massive bailout of PG&E…developed entirely behind closed doors," and "a strategy to make ratepayers pay for every penny of deregulation."[7]

Also, in late June 2003, the California Legislature was working on a proposal to dismantle the state's retail choice law and return to traditional rate regulation. Some 50,000 commercial and industrial customers who succeeded in locking in lower priced power under retail choice were working to retain the right to receive electricity under the preferential rates and to continue to shop for power under the new regime. The Legislature is experiencing enormous difficulty in writing the new law in the face of significant opposition from consumer, business, and utility interests.

In June 2003, the State of California's legal effort to recoup nearly $12 billion in energy costs under contracts signed during the height of the 2000-2001 wholesale power crisis was set-back when the Federal Energy Regulatory Commission (FERC) voted 2-1 to uphold the contracts despite massive evidence of market manipulation during the time frame under which they were entered into. The State PUC has vowed to fight on in court on the matter.

Despite the legal, regulatory, and legislative developments mentioned above, the Bay Area Economic Forum, a public-private partnership of senior business, government, university, labor and community leaders, found in a May 2003 report that, "Despite California's aggressive response to the 2000-2001 energy crisis and the ongoing work of regulators to reach policy consensus, there is still a meaningful risk that future power supplies will come up short. One of the key drivers of this risk is a highly uncertain investment climate. In addition, the State's power policy still has significant flaws that will challenge long-term reliability and will contribute to continued high retail electricity costs for consumers."[8]

4.1.3 Montana

On March 24, 2003, the Montana Public Service Commission (PSC) approved guidelines for NorthWestern Energy to follow as the company procures electricity on behalf of its 290,000 mostly residential and small business customers who have not chosen an alternative supplier. In its role as default supplier, NorthWestern must assemble a portfolio of supply contracts to provide electricity to these retail customers. By law, the company must be able to recover its prudently incurred costs for that service. The guidelines will provide the basis for PSC reviews of the prudence of NorthWestern's default supply resource planning and procurement actions and, if followed by the company, will enhance the likelihood of the PSC granting the company full recovery of its default supply-related costs.

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6 "Divestiture Rule Dies After Unanimous Vote, Commission Ushers in Changes in Direction of Electric Competition", Press Release, Arizona Corporation Commission, August 28, 2002.

7 "PG&E Bankruptcy Judge Distributes Settlement", Dow Jones Newswires, June 20, 2003.

8 "California is Still Coming Up Short on Electricity: The State's power sector remains troubled and is at risk of a future supply shortfall", published by the Bay Area Economic Forum, May 2003.

Key elements of the approved guidelines include:

- Identifying NorthWestern's default supplier responsibility to plan and manage its electricity resource portfolio in a manner that results in adequate, reliable, efficient and long-term default supply services at the lowest total cost.
- Provisions that promote the incorporation in the portfolio of cost-effective energy conservation and efficiency resources.
- An emphasis on the importance of NorthWestern using an open and transparent planning and procurement process that produces resource plans that can be understood by everyone. NorthWestern should document its default supply portfolio planning, management and procurement activities to justify the prudence of its decisions.
- Direction to NorthWestern to establish and consult with a default supply portfolio advisory committee comprised of representatives of a broad array of stakeholders in the procurement process.[9]

4.1.4 Pennsylvania

Exhibit V-2 provides the latest statistics compiled by the Pennsylvania Office of Consumer Advocate on the extent to which customers are switching to competitive electricity suppliers.

Exhibit V-2

Percentage Switched As of April 2003

	Residential	Commercial	Industrial	Total
Allegheny Power	**0.2**	**.1**	**0.0**	**0.2**
Duquesne Light	**26.3**	**18.8**	**34.8**	**25.6**
GPU Energy	**0.3**	**0.3**	**2.2**	**0.3**
PECO Energy	**7.3**	**9.7**	**5.2**	**7.5**
Penn Power	**0.4**	**0.2**	**0**	**0.4**
PPL	**0.2**	**2.1**	**3.0**	**0.4**
UGI	**0.1**	**0.04**	**0**	**0.1**

A measure of the deterioration of retail choice in Pennsylvania can be seen in the following two graphs that show the number of megawatts of energy sold by competitive providers. Exhibit V-3 shows the energy sold by competitive providers to all customers and Exhibit V-4 shows the quantity of energy sold by competitive providers to industrial customers. In both instances, the more recent sales are considerably below that of three years ago.

According to statistics published by the Energy Association of Pennsylvania, the state generates well over 33,000 megawatts (MW) of energy per year -- about 5% of the total US capacity. Pennsylvania is second only to Texas in the amount of electric energy generated. Thus, as shown in the graphs, the quantity of energy sold by competitive providers is not a substantial factor in the total state market.

Pennsylvania's retail market is also experiencing other difficulties. In December 2001, the Pennsylvania Office of Consumer Advocate announced that about 800 former customers of "Utility.com" would be receiving approximately $50,000 in refunds. Refunds of about $70,000 had previously been distributed to 1,000 former "Utility.com" customers. "Utility.com" was an electric generation supplier located in Emeryville, California that did business primarily over the internet until it abruptly stopped serving customers and went out of business.

[9] Press release of the Montana Public Service Commission dated March 24, 2003.

The residential market in Pennsylvania once had some 500,000 customers being served by alternative energy providers. Today, that number has been cut in half and continues to fall quarterly. The number of MW of power sold by alternative providers to residential customers is now only 568 -- a mere fraction of what it was two years ago. Sonny Popowski, Pennsylvania's State Consumer Advocate -- and a chief proponent of retail choice -- acknowledges that the residential choice market is essentially a niche market for customers seeking green power.[10]

Exhibit V-3
Total Customer Load (MW) Served by Alternative Suppliers in Pennsylvania

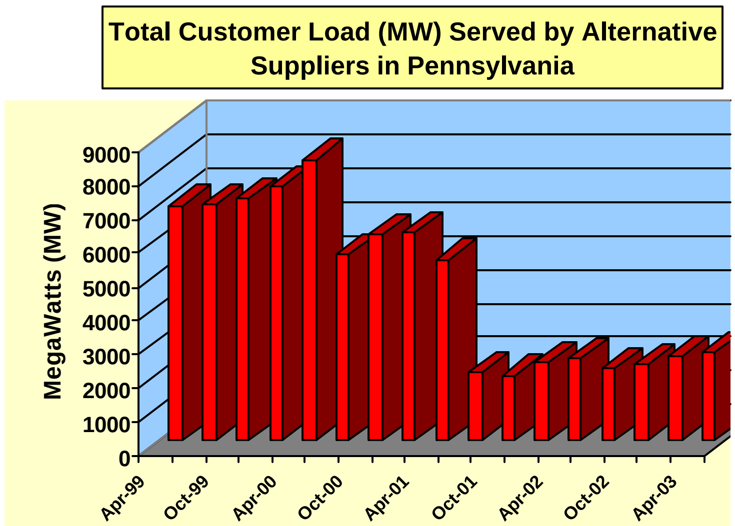
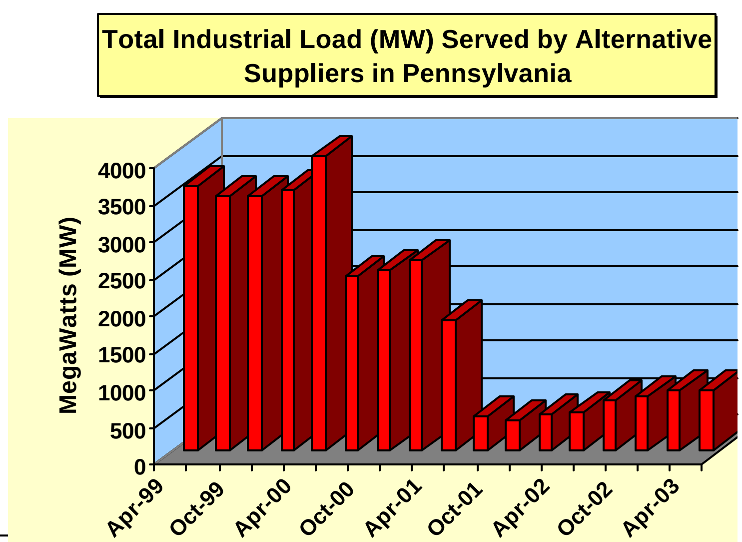


Exhibit V-4
Total Industrial Load (MW) Served by Alternative Suppliers in Pennsylvania



[10] "Pennsylvania homes buy less power in market"; Restructuring Today; January 6, 2003, P.3.

In an effort to artificially "jump start" the moribund residential market, the Pennsylvania Public Utility Commission voted 3-2 in May 2003 to approve a plan devised by the Philadelphia based, PECO Energy Company to re-assign about one third of PECO's residential customers to service by alternative energy providers. The customers will be selected at random and will have the opportunity to opt-out of the switching plan. PUC Chairman Glen Thomas remarked that, "Revolutionizing Pennsylvania's electricity markets will take time and, occasionally, a little prodding."[11] However, the plan to re-assign customers is running into significant difficulties and as to date, no competitive supplier has shown an interest in serving them.

The *Philadelphia Inquirer* noted that, "An earlier attempt to shed residential customers under the deregulation requirement failed when the chosen alternative supplier -- New Power Co., an ENRON Corp. spin-off -- bailed out of the market in April 2002. Nearly 300,000 New Power customers, who had been guaranteed a 2 percent discount from PECO's rates, were returned to PECO because New Power could not afford the climbing wholesale price of electricity. PECO honored the 2 percent discount.[12]

Pennsylvania, like many jurisdictions, has experienced some initial reduction in retail electric rates. However, rates have recently been increasing.

4.1.5 New York

The website of the New York Public Service Commission provides the following data as of March 2003 on the extent of customer switching in the New York retail electric market (see Exhibit V-5).

Exhibit V-5

New York State Customer Migration as of March 2003	TOTAL		Non-residential		Residential	
	Customer Accounts	Load (MWh)	Customer Accounts	Load (WMh)	Customer Accounts	Load (MWh)
Customer and load migration	394,094	2,142,549	70,970	1,930,779	323,124	211,769
Total Eligible	7,336,567	9,506,947	918,605	5,741,332	6,417,962	3,765,615
% Migration	5.4%	22.5%	7.7%	33.6%	5.0%	5.6%
% Change from March 2002	7.9%	29.6%	26.9%	31.1%	4.4%	17.4%

4.1.6 Connecticut

Although retail choice has technically been in effect since July 2000, the concept remains more theory than reality as most suppliers have shown little interest in the Connecticut market. According to one of the state's leading

[11] "Electricity customers set for transfer"; *Philadelphia Inquirer*, May 2, 2003.
[12] "Electricity customers set for transfer", *Philadelphia Inquirer*, May 2, 2003.

newspapers, *The Connecticut Post*, "companies aren't exactly jumping into the Connecticut market and those that are in are getting out. Green Mountain Energy Co. announced it was pulling out of the market as of Friday (Jan. 17, 2003), … after less than a year of being in Connecticut."[13]

A second news article from Connecticut found that, "The much debated, discussed and ballyhooed restructuring of the electric industry has so far provided very little change for the average customer. Prices have remained stable and the vast majority of consumers are buying electricity as they always have. It appears that none of that is likely to change any time soon."[14]

Much of the difficulty in the Connecticut market relates to the manner in which the original deregulation statute was written by the legislature. In order to protect consumers, the legislature required that the incumbent utilities sell electricity at a "standard offer" price set at 10% below the 1996 retail price of power. Thus, consumers, by simply doing nothing different, reaped benefits from the new law and competitive suppliers were discouraged from entering the market.

However, in May 2003, the Connecticut legislature enacted a statute that extends the retail choice program and revises the calculation of "standard offer" price upward in a manner designed to attract competitive suppliers into the market. Under the new law, the previous timetable for the implementation of a renewable portfolio standard is extended and the definition of "renewable resource" is expanded. In addition, the law revives customer education programs and requires the Connecticut Department of Public Utility Control to post information about competitive suppliers on its website.

4.1.7 Maine

The chart below, taken from the web page of the Maine PUC, shows the progression of the percentage of load served by competitive suppliers for the three customer classes for the period July 2000 through January 2003 (see Exhibit V-6 and V-7).

The citizens of Maine have historically been favorable to the development of renewable energy resources that are abundant in the state but are not fully utilized due to cost. Maine's new Governor John Baldacci has pledged to commit the state government to purchasing at least half of its electricity needs from renewable sources and a coalition of two-dozen organizations known as the Maine Green Power Connection is attempting to sign-up 60,000 customers for a green pricing program by 2008.[15]

[13] "Some Fear Changes to Connecticut's Energy market Will result in Higher Bills", *The Connecticut Post*, January 19, 2003.
[14] "Electric Industry remains Relatively Unchanged in Connecticut", *The Day*, December 31, 2002.
[15] "Maine target -- 5% green by 2008", *Restructuring Today*, March 17, 2003, p.2.

Exhibit V-6

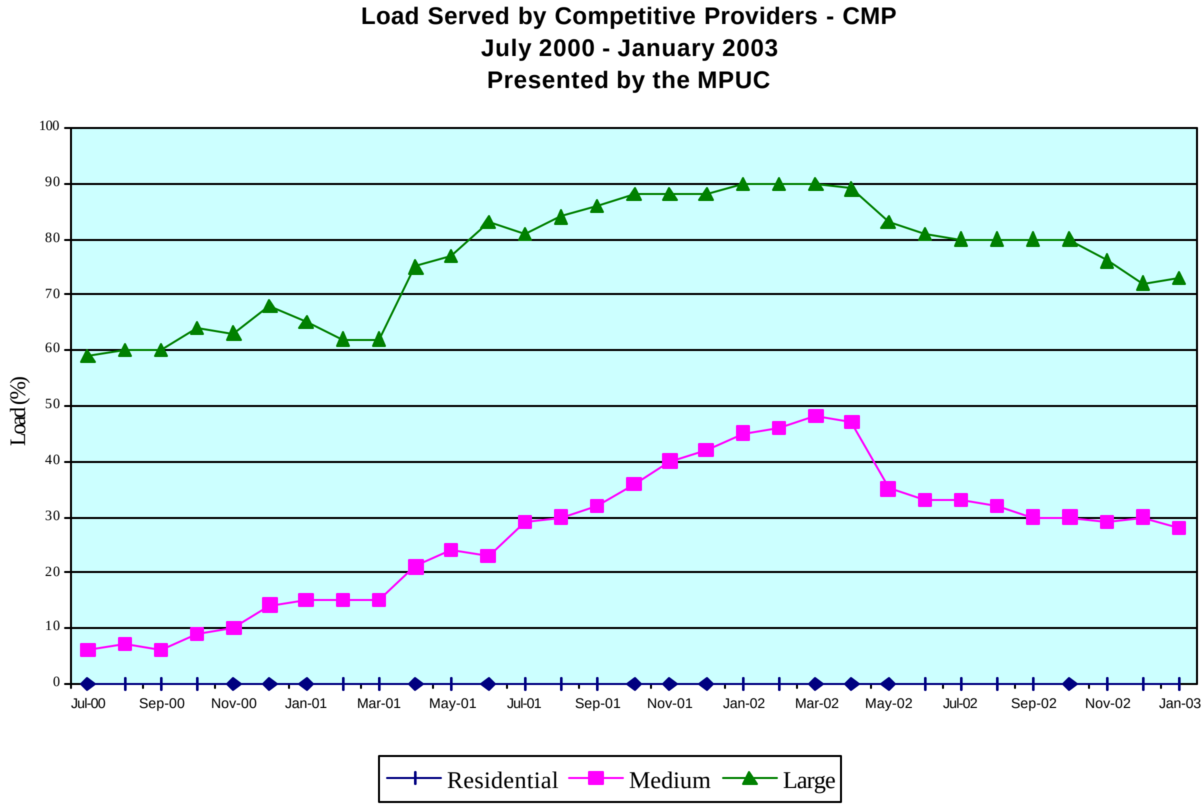


Exhibit V-7

Maine's Electricity Load Served by Competitive Providers Expressed as a Percentage of Total Load As of June 1, 2003			
	Central Maine Power	**Bangor Hydro Electric**	**Maine Public Service**
Residential/Small Commercial	**<1%**	**<1%**	**34%**
Medium	**25%**	**27%**	**68%**
Large	**77%**	**36%**	**100%**
Total	**34%**	**17%**	**60%**
Total state load served by competitive providers: 33%			

4.1.8 Rhode Island

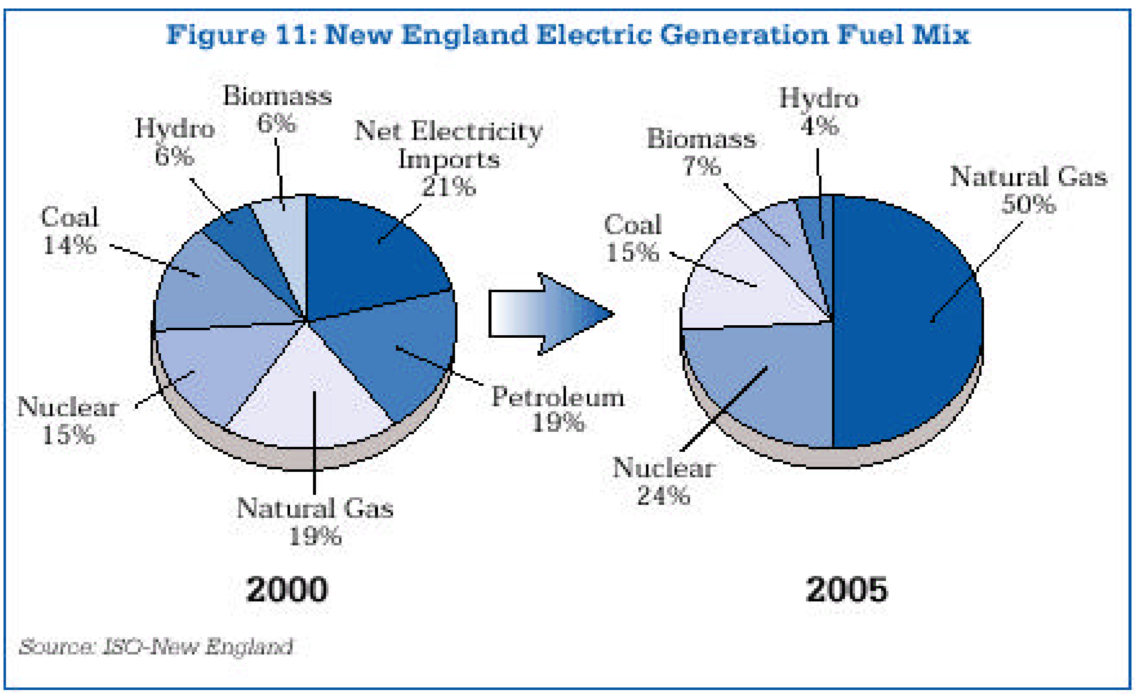
The Rhode Island PUC web site contains no recent information on retail choice in the state. Their web page continues to show a report to the Rhode Island Legislature dated February 2001 -- no update has been prepared. A phone call to the agency confirmed that there is only very minimal retail competition in the state and that it is limited to the largest customers with the most attractive load profiles. For all practical purposes, there is no competition in the residential or commercial markets.

4.1.9 Massachusetts

As a percentage of the total electricity market, retail choice in Massachusetts is quite small -- probably in the range of about 15% of all electricity sold. The overwhelming percentage of energy sold in the competitive market is sold to the largest customers (see Exhibit V-9). There has been some minimal success in marketing to residential customers via a municipal aggregation program in the Cape Cod region of the state. As shown in the graphic below (see Exhibit V-10), the competitive market suffers from wide swings due to the volatility of wholesale prices. As a result, many suppliers have found that marketing to customers other than those with ideal load profiles is far too expensive with too little pay-back.

Some analysts of the New England electricity market are now raising flags of caution on the region's increasing reliance on natural gas as the fuel of choice for new generating facilities. The region's fuel diversity is now undergoing substantial revision due to environmental concerns and the cost of construction associated with coal and nuclear generation. According to a 2003 report of the Associated Industries of Massachusetts, "New England’s reliance on natural gas to fuel all new plants (see Exhibit V-8 below) has raised concerns that new plants may cause existing natural gas pipeline capacity to be approached or exceeded within a few years. In addition, up to 75% of the new power plants being built or currently in operation are located on just two of the region’s five major pipelines. As a result, the security of the gas grid is becoming increasingly important to the reliability of the electric grid."[16]

Exhibit V-8



[16]"Electric Industry Restructuring in Massachusetts: After the Revolution, the Evolution ", published by the Associated industries of Massachusetts, Winter 2003, p.28

Exhibit V-9

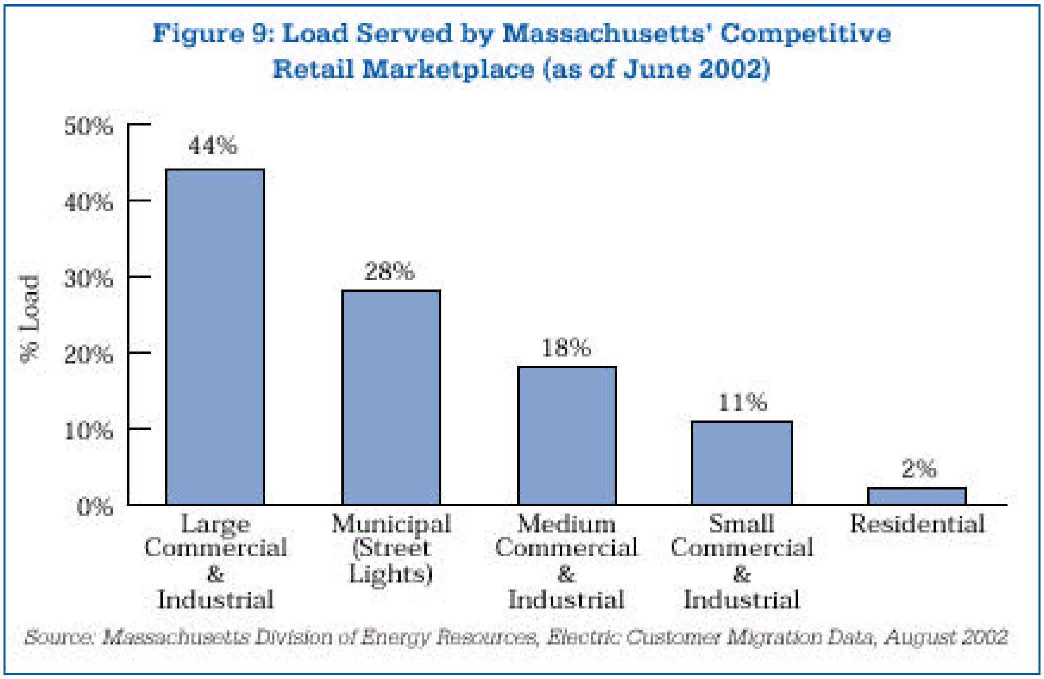
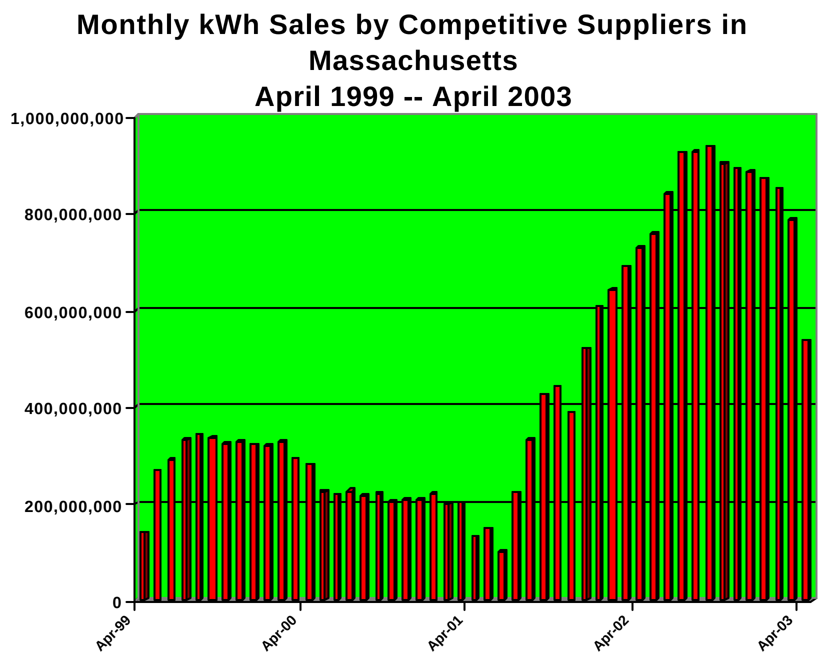


Exhibit V-10



5.0 Recent Adopters of Retail Choice

5.1 Ohio

In May 2003, the Ohio Public Utility Commission issued a progress report to the Ohio Legislature on the status of retail choice in the state. The Executive Summary of the report indicates that most of the success reported by the Commission to the Legislature is a result of the customer aggregation provisions of the retail choice law in Ohio. For example, the report notes that in the first two years of retail choice…

> • More than 150 local governments passed ballot issues and were certified by the Public Utility Commission of Ohio to allow local units of government to represent their communities in the competitive electricity market. Ohio is home to the Northeast Ohio Public Energy Council (NOPEC), the largest public aggregator in the United States. NOPEC represents 112 communities in eight counties and more than 350,000 residential customers.
>
> Of those customers who have switched in Ohio, aggregation programs account for:
>
> • Nearly 93 percent of residential customers who have switched in Ohio (see Exhibit V-11).
>
> • More than 88 percent of commercial customers who have switched in Ohio.
>
> • Nearly 20 percent of industrial customers who have switched in Ohio.
>
> • In the residential market, the megawatt hours sold by alternative suppliers reached 60 percent in the Cleveland Electric Illuminating Company territory, 36 percent in the Toledo Edison Company territory, 22 percent in the Ohio Edison company territory, and 2 percent in the Cincinnati Gas and Electric Company territory.
>
> • In the commercial market, the megawatt hours sold by alternative suppliers reached 50 percent in the Cleveland Electric Illuminating Company territory, 51 percent in the Toledo Edison Company territory, 38 percent in the Ohio Edison Company territory, 32 percent in the Cincinnati Gas and Electric Company territory, 9 percent in the Dayton Power and Light Company, and 6 percent in the Columbus Southern Power Company territory.
>
> • In the industrial market, the megawatt hours sold by alternative suppliers reached 32 percent in the Ohio Edison Company territory, 28 percent in the Dayton Power and Light Company territory, 20 percent in the Cleveland Electric Illuminating Company territory, 18 percent in the Cincinnati Gas and Electric Company territory, and 5 percent in the Toledo Edison Company territory.[17]

A press release issued by the Ohio PUC dated May 28, 2003 quotes PUC Chairman Alan Schriber as stating that, "Of the twenty-four states in the United States that have adopted electric choice, Ohio's experience has been among the best. While it is difficult to argue that

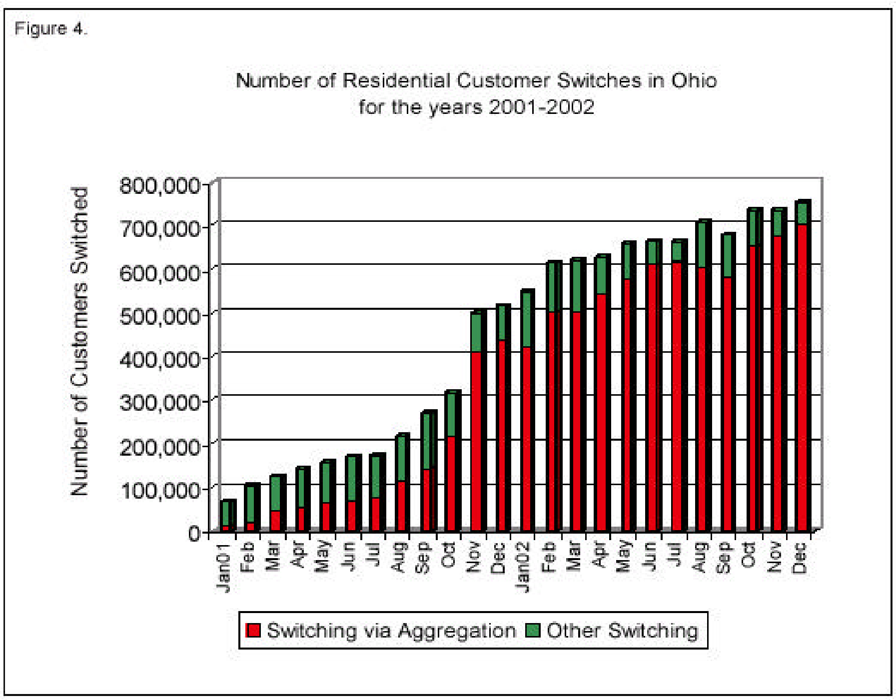
[17] The Ohio Retail Electric Choice Programs Report of Market Activity 2001 - 2002, published by the Ohio Public Utilities Commission, May 2003, Executive Summary.

electric choice has been pervasive anywhere, under the circumstances, Ohio's program has so far been a success."[18]

However, Schriber's view is tempered by statements from others including Schriber himself. Richard Marsh, chief financial officer for Akron-based FirstEnergy the parent company for Toledo Edison, said commercial, industrial, and residential customers are being served at rates far below even wholesale rates because Ohio's deregulation plan locked them into such prices through 2005. Customers of FirstEnergy could be in for "rate shock" after 2005 when deregulation in Ohio is complete and the utility can raise rates, possibly well above current locked-in prices. PUC Chairman Schriber concurred and acknowledged that his agency is "very concerned" about the potential for rate shock. "We're thinking about it a lot. It consumes us actually."[19]

David Hughes, Executive Director of Citizen Power -- an Ohio citizen watchdog group -- dismisses all of the talk of success in the Ohio retail electric market. "The numbers (on switching) look good because PUCO does not tell us who those alternate suppliers are. If you look closely, you will see that the vast majority of customers have not switched to a real alternative because PUCO counts switches to utility affiliates as a competitive switch. That's one way to inflate the numbers and make it look like there is competition." Hughes also contends that the fear of "rate shock" just around the corner, "is warranted because there is nothing to stop unregulated monopolies like DP&L and Ohio's other utility companies from charging whatever they want once the market development period ends."[20]

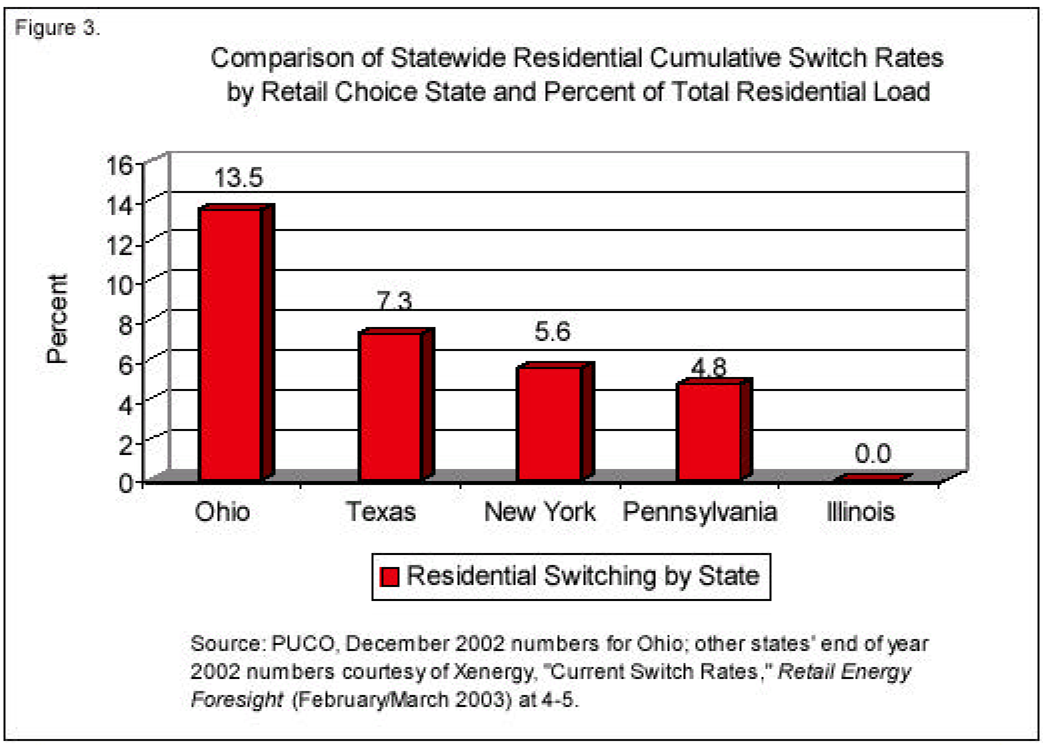
Exhibit V-11



[18] Press release of the Ohio PUC dated may 28, 2003: "PUCO Issues Electric Choice Market Activity Report to Ohio General Assembly".
[19] "Electricity Rate Shock Predicted when Ohio Deregulation Expires", *The Toledo Blade*, March 27, 2003.
[20] "Consumer watchdog calls for end of Ohio deregulation", *Restructuring Today*, June 3, 2003.

Exhibit V-12 below displays an estimate of the percentage of total residential load purchased from alternative suppliers as of year-end 2002 in five selected states according to an analysis conducted by the Xenergy consulting firm.

Exhibit V-12



5.2 Illinois

The May 2003 report of the Illinois Commerce Commission to the Illinois General Assembly presents data (see Exhibit V-13) on the extent to which customers have switched to alternative suppliers. On the surface, the data seem to show that the two largest investor-owned companies serving Illinois (Commonwealth Edison and Illinois Power) have suffered significant losses of revenue due to customer switching. However, these two companies are controlled by holding companies (Exelon and Dynergy respectively) that also own non-regulated energy marketing companies who have been certified by the Illinois Commerce Commission to "compete" with the incumbent utilities. The Illinois Commerce Commission provides no data on the percentage of revenue "lost" by the incumbent utilities that is actually due to the switching of customers from the incumbent to a sibling marketing company owned and controlled by the same parent energy holding company. In any event, of the 15 alternative energy suppliers certified by the Illinois Commerce Commission, none have requested certification to serve residential customers.

Exhibit V-13

Table 1: Customer Switching and Transition Charge Data

Electric Utility	Number of Customers That Have Elected Delivery Services		Amount of Usage Switched to Delivery Services (kWh million)		Revenue Loss Resulting from Customers Switching to Delivery Services ($ million)		Transition Charge Revenue Collected ($ million)	
	2002	2001	2002	Cumulative[2]	2002	Cumulative	2002	Cumulative
Ameren CILCO	AmerenCILCO reported no activity.							
AmerenCIPS	747	770	1,462	2,165	0.0	3.5	2.5	5.1
AmerenUE	0	0	0	3	0.0	0.1	0.0	0.0
ComEd	21,652	18,268	22,710	54,081	566.2	1,308.8	309.5	576.6
Illinois Power	1,051	853	5,106	10,978	86.1	202.9	32.7	54.4
Interstate	Not applicable; no customers have selected delivery services from Interstate.							
MidAmerican	9	82	1	74	0.0	2.8	0.0	0.0
Mt. Carmel	None reported.							
South Beloit	Not applicable; no customers have selected delivery services from South Beloit.							
Total	23,459	19,973	29,279	67,301	652.3	1,518.1	344.7	636.1

5.3 Texas

Because of the national significance of the public policy choices adopted in Texas, the material below contains background on the Texas retail electric program as well the most recent results of their efforts.

Legislation was enacted in 1999 to begin the process. Under the new law, the Texas PUC will begin the process of certifying competitive retail electric providers. On June 1, 2000 a pilot retail competition program commenced and on January 1, 2002 full retail choice began for all customers at which time retail rates were reduced by 6%.

Following are the key provisions of the new law:

- Froze electric rates for investor-owned electric utilities in Texas through 2001.
- Prohibits large utilities from lowering their rates for residential and small commercial customers before 2005, or until 40 percent of their customers are served by competitors.

- Exempts electric cooperatives and city-owned electric companies from customer choice unless their governing boards decide to open their markets to competition.
- Allows customers the choice of using renewable energy (wind and solar power for example).
- Requires older electric generators to meet current environmental rules by 2003 or be shut down.
- Creates a fund to pay for lower rates for low-income families and property tax losses for affected school districts.
- Provides for automatic enrollment of qualified low-income families in low-income assistance programs.
- Prohibits disconnection of service for nonpayment during periods of extreme weather.
- Allow customers to receive one bill for their electric service in an easy-to-read format and understandable language.
- Creates a Do Not Call list for customers who do not wish to be called by telemarketers on behalf of electric service providers.
- Provides customer protection against discrimination, against being billed for unauthorized charges (cramming), against unauthorized change of service provider (slamming) and other unfair, misleading and deceptive practices.

Texas has noted it is considerably different than California in its approach to retail deregulation. Generation capacity has been expanded within the state, so it does not rely on imports of electricity. Peak demand for the summer of 2001 was approximately 67,000 megawatts and statewide capacity was at 83,000 MW which provided a 24 percent reserve margin according to a June 20, 2001, news release from the Public Utility Commission of Texas. However, transmission investment has not kept up with generation expansion. Also, more than 45 percent of the generation is gas fired, leading to some concerns about future volatility in gas prices.

Deregulation of retail sales of electricity in southeast Texas was delayed until 2003 due to the lack of a regional transmission organization (RTO). Investor utilities serving southeast Texas did not draw competition during the pilot program. With an RTO there are hopes to get out-of-state competitors to ship electricity into southeast Texas. Also in northwestern and southwestern Texas, deregulation has also been delayed because those were not considered ready.

Under the Texas deregulation program, electric utilities were divided into three areas: retail, power generation and transmission and distribution. Any investor-owned companies that wish to enter the retail market must create an affiliate company. To ensure deregulation, the Texas Public Utilities Commission created a price-to-beat for investor-owned affiliates that will remain in place until 2005 or until 40% of customers switch to another retail company.

On January 15, 2003, the Texas PUC published a comprehensive report to the Texas Legislature on the status and progress of retail competition in the state after one full year of implementation. The cover letter to the report makes the following observations:

- "The Commission's estimates in this report show that retail customers have saved, at a minimum, over $1.5 billion in electricity costs during the first year of competition as compared to the regulated rates in effect during 2001. Additionally, low-income customers have received almost $70 million in discounts through the System Benefit Fund through October 2002."

- "In all areas open to competition, there are multiple retail electric providers (REPs) offering service to all customer classes, with as many as ten REPs offering service to residential customers in some areas. Customers are continuing to exercise their opportunity to choose an electric provider in increasing numbers."

- "The Commission has administered a customer education campaign to inform customers in Texas about the choices available to them in the new market, including the distribution of over 5 million copies of the *"Power Guide to Electric Choice"* to customers throughout the state."[21]

The PUC's glowing letter is backed up with data and graphical presentations of a competitive market that is small but trending upward. The report notes that, "as of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area. This number represents approximately 6.8% of all customers in areas open to customer choice. Of these premises, 319,297 (80%) are residential customers. Approximately 18% (71,691 customers) of the customers are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price to beat." (See Exhibit V-14)

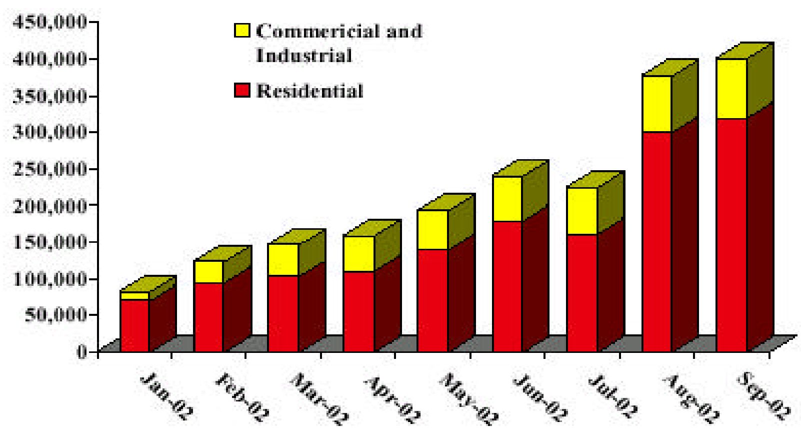
"A total of 6,070,477 megawatt hours (MWhs) were served by non-affiliated REPs in September 2002. This represents approximately 25% of the total MWhs sold in September. This number is higher than the percentage of customers who have switched because the larger commercial and industrial customers comprise a significant portion of the energy consumption in the state. While commercial and industrial customers only account for 20% of the customers who have switched, these customers comprise over 90% of the megawatt hours (MWh) served by non-affiliated REPs in areas open to competition."[22]

"What I look for as a measure of success is a continuing trend line," says Rebecca Klein, chairwoman of the Texas PUC. "I'm not looking for a spike or a double-digit figure today; rather, I would like to see the switch rate trend upward over the course of time. Competition is here to stay and it's not an experiment."[23]

"By-and-large, we have done it right…and have accomplished what we set out to do," says Tom Noel, CEO for the Electric Reliability Council of Texas (ERCOT), an independent system operator. "However, until customer's issues have been resolved satisfactorily and until we can say that every time a customer decides to switch that the process is done quickly, efficiently and smoothly, we won't be satisfied."[24]

Exhibit V-14

Figure 14: Number of Customers Served by a Competitive REP in ERCOT

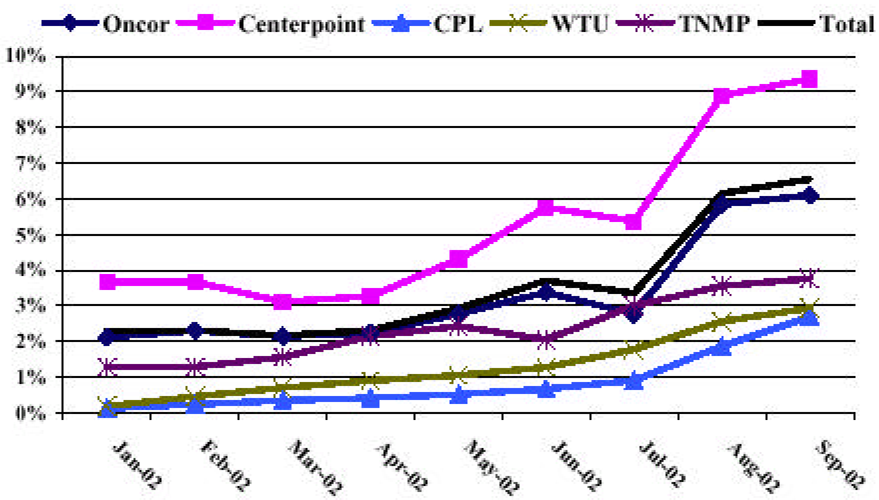


SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

[21] January 15, 2003 letter from the Texas PUC to the members of the Texas Legislature
[22] "Scope of Competition in the Electric Market in Texas", 2003 report of the Texas PUC to the Texas Legislature, January 2003, pp. 88-89
[23] "Texas Committed to Deregulation", by Ken Silverstein, Utilipoint Issue Alert, December 20, 2003
[24] "Texas: The Turning point for Energy Deregulation", by ken Silverstein, Scientech Issue Alert, July 18, 2002

Exhibit V-15

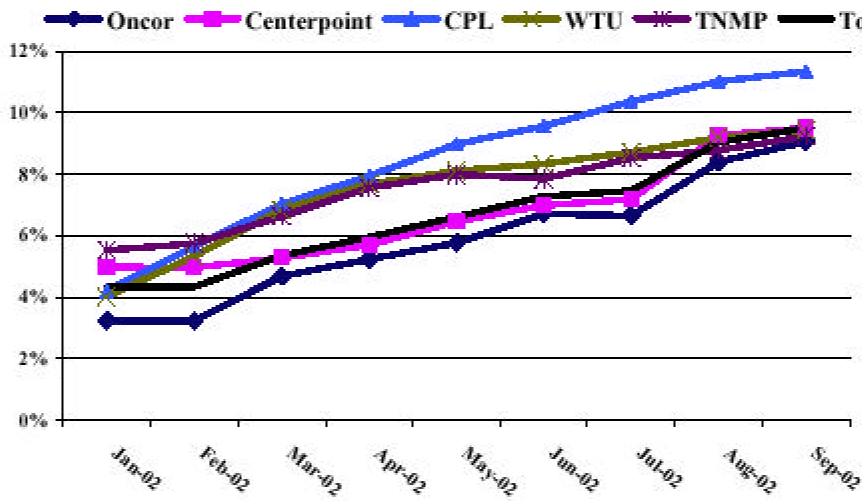
Figure 16: Percentage of Residential Customers Served by a Competitive REP



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

Exhibit V-16

Figure 17: Percentage of Small Commercial Customers Served by a Competitive REP



SOURCE: Texas PUC 2003 Electric Scope of Competition Data Responses from TDUs.

The progress shown in the above two charts (Exhibits V-15 and 16) is further corroborated by more recent information from the Texas PUC (see Exhibit V-17). In a June 12, 2003 conference call with financial analysts, Texas PUC Chair Rebecca Klein released the data in the chart below that shows that the percentage of residential and small commercial customers who are switching to competitive suppliers continues to grow. In many instances such customers are taking advantage of a web site (www.powertochoose.org) that allows customers to enter their zip code and then be presented with instant information on competitive supply offers including price and fuel mix of the various providers.

Exhibit V-17

	Percentage of Residential Customers Served by Non-affiliated Retail Electric Provider		Percentage of Small Commercial Customers Served by Non-affiliated Retail Electric Provider	
TDSP Service Area	Sept 26, 2002	June 2, 2003*	Sept 26, 2002	June 2, 2003*
AEP Texas Central	2.7%	9.2%	11.5%	17.1%
AEP Texas North	2.9%	9.2%	9.4%	13.9%
Centerpoint	9.4%	10.5%	9.5%	14.5%
Oncor	6.1%	10.8%	9.1%	14.8%
TNMP	3.8%	6.5%	9.2%	9.1%

The Texas retail choice model has not been without its problems. The *Houston Chronicle* reported that, "when the Texas electricity market opened in January 2002, New Power was one of the more aggressive marketers. It signed up about 78,000 customers in the Dallas and Houston areas. The company, based in Purchase, NY, filed for Chapter 11 bankruptcy protection in June (2002). It struck a deal to give its 34,000 Houston-area customers to Dallas-based TXU Energy."[25]

Technical glitches have delayed hundreds of thousands of bills and blocked some switching requests. The *Dallas Morning News* reported that in November 2002 the Texa s PUC received 1,500 complaints, five times more than it received in November 2001. PUC Chair Rebecca Klein said that, "the increase is to be expected when you consider the fact that we've transformed significantly in the electricity market."[26]

A far more serious problem emerged in March 2003 when a surge in wholesale power prices indicated evidence of market manipulation. Jess Totten, director of policy at the Texas PUC told Reuters News Service, "I hate to say it, but I think we need some regulation of people in the merchant energy business. Some merchants are using 'gaming' practices including taking advantage of congestion in the design of the power line system to help drive prices higher. In a sense, they were playing some of the same kinds of games that people out in California were doing. Traders have also overstated expected trading volumes, then revised those volumes lower when officially registering the deals, which can drive up average prices."[27]

6.0 Reconsideration of Retail Choice

6.1 Nevada

In 2001, Assembly Bill No. 369 was enacted that effectively repealed the implementation of retail choice. The preamble of the repeal legislation provides insight into the view of the state legislature on this question. Here are some excerpts from the preamble of the repeal legislation.

[25] "Texas Commission Fears Bankrupt Electric Company Will Leave Customers in Lurch", *Houston Chronicle*, September 12, 2002.
[26] "Texas Electricity Firms, Consumers Voice Deregulation Concerns", *The Dallas Morning News"*, December 13, 2002.
[27] "Texas power market hit by price spikes, gaming", Reuters News Service, March 13, 2003.

- *Several of the major industries in this state are particularly dependent upon electricity. Under present market conditions in the electric industry, comprehensive and effective regulation of electric utilities in this state is vital to the economy of this state and is essential to protect the health, safety and welfare of the residents of this state. Until present market conditions have changed and adequate mechanisms have been developed to allow this state to adjust its comprehensive regulation of electric utilities in Nevada, this state has a compelling interest in continuing its comprehensive regulation of electric utilities to protect the consumers in this state, to safeguard the economy of this state and to ensure that the electric utilities in this state provide adequate and reliable electric service at just and reasonable prices.*

- *In recent years, the western United States has experienced a severe and ongoing crisis in the electric industry marked by critical shortages in the supply of electricity and extreme volatility in the price of electricity in the wholesale and retail markets. The severe and ongoing crisis in the electric industry in the western United States is both an immediate threat and a continuing danger to the economy of this state and to the health, safety and welfare of the residents of this state.*

- *Until the severe and ongoing crisis in the electric industry in the western United States has sufficiently abated, this state must maintain its comprehensive regulation over electric utilities and its traditionally broad jurisdiction and control over electric generation assets to promote stability and predictability in the electric industry, to foster confidence in the financial markets, to ensure that consumers have adequate and reliable electric service and to protect the public from unjust and unreasonable utility rates.*

Also enacted in the 2001 legislative session was AB 661 that allows larger customers (annual consumption of 1 MW or more), as well as educational institutions, local governments and hospitals, to choose an alternative supplier. Such customers must document a public interest benefit and win state regulatory approval before exiting. On May 29, 2003, The Palms Casino became the 12th large customer to win regulatory approval to purchase power from a competitor of Nevada Power Company. Not all of these customers have actually switched providers but Reliant Resources of Houston, Coral Power (an affiliate of Shell Oil Co.), Arizona Public Service, and Sempra Energy are all actively marketing to the large users in Nevada with varying degrees of success.

6.2 Arkansas

The Arkansas General Assembly enacted retail choice legislation in 1999 and amended it during the 2001 session. The amended bill postponed the start of retail competition in Arkansas from Jan. 1, 2002, until at least October 2003 and no later than October 2005. Then, in early 2003, the Arkansas Legislature spoke again on this question and enacted HB 1114, the Electric Utility Regulatory Reform Act that repealed the 1999 law.

The preamble to the new legislation provides that retail choice should be repealed because, "the environment in the electric utility industry has changed, and it is in the public interest to continue regulating electric rates for the foreseeable future and the Arkansas Public Service Commission has determined that Arkansas' electric ratepayers would be unlikely to benefit from, and could be harmed by, retail electric competition for the foreseeable future, and has recommended to the General Assembly that implementation of retail electric competition in Arkansas either be delayed for a significant period of years or be repealed."[28]

Section 17 of the bill provides that, "The Arkansas Public Service Commission shall conduct a collaborative meeting to study the feasibility of a large user access program for electric service choice, including a commitment to insure there is no cost shifting to any other class of customers, and report to the General Assembly on or before September 30, 2004."

[28] HB 1114 (2003), introductory language, Arkansas State Legislature.

7.0 Federal Issues

This section is intended to replace section 9.0 of last year's report.

Driven in large part by the electricity supply and reliability problems in the western United States, the issues of restructuring have now been expanded to include energy supply and infrastructure concerns. Transmission across the United States is frequently inadequate to support retail deregulation. Legislation addressing regional transmission entities, eminent domain, transmission reliability standards, and other issues have been the focus of both Congress and the FERC. Infrastructure/pipelines for natural gas supply have not kept up with growing demand for natural gas which has become the most common fuel for generating facilities built in the last 10 years.

A major focus of both the Bush Administration and Congress has been on development and passage of national energy policy legislation.

Background

- Bush Administration National Energy Policy Development Report Released – May 2001
- House of Representatives responded quickly and passed H.R.4 – August 2, 2001.
- Senate delayed consideration of energy policy legislation until early 2002. S.517 passed Full Senate – April 25, 2002.
- House/Senate Energy Conference failed to reconcile differences between H.R.4 and S.517 – legislation died at the end of the 107th Congressional Legislative Session in November 2002.
- Lack of consensus on electricity provisions contained in S.517 was largely responsible for the failure of last year's House/Senate energy conference.

House Energy Legislation – H.R.6

- Draft legislation, released on February 20, 2003, contained 10 Titles/Sections, including an electricity title (Title VII).
- Markup of H.R.6 at the House Energy and Commerce Committee was concluded quickly and the legislation passed the Full House on April 11, 2003.

Some of the Major Electricity Provisions in H.R.6 Include:

- Repeal of the Public Utility Holding Company Act of 1935
- Reform of the Public Utility Regulatory Policy Act of 1978
- Transmission reliability standards
- Continuation of Renewable energy production incentives – REPI
- Consumer protections – FERC merger review authority
- FERC-lite (see below)
- Uniform Refund Authority (see below)
- Service Obligation (see below)

Some of the Major Public Power Priorities in H.R.6 Include:

- FERC-lite – provisions are included that provide limited extension of FERC jurisdiction over public power to ensure non-discriminatory open access to the nation's transmission system.
- Uniform Refund Authority – provisions are included that would grant FERC new authority to order refunds from public power in the event that a utility violates market rules in place at the time of the sale. Limited to spot market sales of 24 hours or less.
- Service Obligation – provisions are included that attempt to protect transmission capacity for those customers whom utilities have an obligation to serve and also paid for the transmission assets.

Senate Energy Legislation – S.14

- S.14 passed the Senate Energy and Natural Resources Committee on April 30, 2003.
- S.14 contains 11 Titles/Sections, including an electricity title.

Some of the Electricity Provisions in S.14 Include:

- Transmission reliability
- FERC-lite
- PURPA reform
- Service Obligation
- Voluntary RTO development – FERC's Standard Market Design (SMD) rules delayed until July 2005
- Consumer Protections

Status

- S.14 was passed by the Senate Energy and Natural Resources Committee by a partisan vote of 12 to 11.
- Senate floor action on S.14 has begun with action likely on an "on-again, off-again" basis until final Senate passage, which is anticipated in late July 2003 or after the August Congressional recess; numerous amendments are expected.
- House/Senate energy conference to resolve differences between H.R.6 and S.14 is not likely to conclude until sometime this fall with anticipation of the final bill being forwarded to the President for his signature in October or November 2003 (if agreement can be reached).

8.0 Conclusions

The establishment of the "condition-certain" approach in LB 901 has proven to be a wise policy decision by the State of Nebraska. This approach recognized the necessity of conditioning retail choice upon the establishment of adequate regional wholesale energy markets and adequate transmission networks, among other issues. Several of the states which opened retail electricity markets or were scheduled to do so on a "date certain" basis have retrenched and are now paying far greater attention to the need to establish viable regional wholesale markets prior to further implementing retail choice.

The following summarizes the conclusions of the report of Technical Group No. 5.

- Rates in retail choice states have been reduced primarily through regulatory mandates and capped during transition periods
- Wholesale prices have increased throughout most of the nation but declined significantly in June 2001 across the western United States
- Marketers have withdrawn or scaled back in many states with retail choice programs
- Few customers have switched suppliers in most retail choice states (and many of them have returned to their incumbent utility)
- California/West Coast Energy Crisis has slowed national interest in retail choice
- Retail choice has taken a back seat to energy supply and other wholesale issues at the federal level
- Promises of wholesale or retail competition driving down energy prices have been generally unfulfilled thus far
- Retail choice is still alive and continues to evolve
- Must get wholesale markets right prior to implementing retail choice legislation
- Adequate power supply and reserves are crucial
- Adequate transmission is crucial
- Increased stability of fuel prices is needed for retail choice programs to function properly
- Better customer response to wholesale price signals are needed
- Development of a comprehensive energy policy has gained significant attention in Congress and the Bush Administration, but details are far from decided due, in part, to narrow political majorities
- FERC is actively involved in developing and addressing the transition to a more competitive wholesale market

GLOSSARY

Ancillary Services: Interconnected operations services for operating reserve, voltage control, regulation and frequency response, scheduling and system control and dispatch, and other power supply necessary to effect a reliable transfer of electrical energy at specified contract terms between a buyer and seller.

Availability: A measure of time that a generating unit or transmission line, or other facility is capable of providing service, whether or not it is actually in service, Typically this measure is expressed as a percent available for the period under consideration.

Avoided Cost: The cost the utility would incur but for the existence of an independent generator or other energy service option. Avoided cost rates have been used as the power purchase price utilities offer independent suppliers.

Baseload: The minimum amount of power delivered or demanded over a given period at a constant rate.

Bilateral Contract: A direct contract between a power producer or end user outside a centralized power pool.

Bottleneck Facility: A point on a system, such as a transmission line, through which all electricity must pass to get to it's intended buyers. If there is limited capacity at this point, some priorities must be developed to decide whose power gets through. It also must be decided if the owner of the bottleneck may, or must, build additional facilities to relieve the constraint.

BPA: The Bonneville Power Authority is one of five federal power marketing administrations that sell electric power produced by federal hydro electric dams.

Broker: An agent that arranges power transactions. The agent may aggregate customers and arrange for transmission, firming and other ancillary services as needed. The broker does not take title to the power supply.

Bulk Power Supply: This term is often used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines and related equipment and can refer to one utility or a group of interconnected utilities.

Capacity: The continuous load carrying ability, expressed in megawatts [MW] or mega volt-amperes [MVA] of generation, transmission, or other electrical equipment.

Capacity Factor: The ratio of total energy generated by a plant for a specified period of time to the maximum possible energy it could have produced if operated at the maximum capacity rating for the same period, expressed as a percent.

Competitive Power Supplier: A supplier of retail energy and capacity and ancillary services, other than the incumbent supplier, that may own generation, buy and resell, and who has title to the electricity.

Competitive Transition Charges: A charge that allows utilities to recover historic costs related to electric generating facilities and power purchase contracts.

Contract Path: The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to occur over the contract path not withstanding the fact that power flow in the network will distribute in accordance with network flow conditions.

Control Area: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Control Area Operator: The operator of a Control Area in which transmission facilities used for transmission services are located.

Cooperative Electric Utility [Co-op]: An electric utility owned and operated for the benefit of those using its service.

Cost Based Electricity: A term used by consumer-owned electricity meaning that only the costs of generation, transmission and distribution are included in the cost, and that there is no "margin" or "profit" included.

Cost of Service Study: An analysis of all of a utility's costs at a very detailed level for purposes of assigning these costs to the various customer classes.

Customer Classes: A term used in ratemaking to segregate customers by types such as residential, commercial and industrial. The main segregation occurs due to the amount and way customers use electricity.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service.

Default Provider: In the case where an electric consumer does not choose a new supplier once competition begins, a supplier is automatically assigned. This supplier is known as a 'default supplier'.

Demand: The rate at which electric energy is delivered to or by a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

Direct Access: The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than thru a local distribution company.

Distribution Charges: Charges for the use of local wires, transformers, substations and other equipment used to deliver electricity to homes and businesses.

ECAR: East Central Area Reliability Coordination Agreement.

Economic Dispatch: The allocation of demand to individual generating units on line to effect the most economical production of electricity.

EPAct: The Energy Policy Act of 1992 addresses a wide range of energy issues. The legislation created a new class of power generators, exempt wholesale generators that are exempt from the provisions of the Public Utilities Holding Company Act and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid.

ERCOT: The Electric Reliability Council of Texas.

Federal Energy Regulatory Commission [FERC]: The FERC regulates the price, terms, and conditions of power sold in interstate commerce, and regulates the price, terms and conditions of all transmission services.

Firm Power: Power that is guaranteed by the supplier to be available at all times during a period covered by a commitment.

Franchise: A franchise is a grant of right or privilege to occupy or use public streets, ways and facilities located on public streets and ways to deliver service to customers. Local governments typically grant franchises.

Franchise Fee: A payment to a city or government for the exclusive right to sell a product in a specified area.

FRCC: Florida Reliability Coordinating Council

Generation: The process of producing electricity from other forms of energy.

Generation Charges: The charge for generating or creating the electricity used. This charge includes the cost of fuel and power plant costs, but not the cost of delivering the electricity to the customer.

Generation Dispatch and Control: Aggregating and dispatching generation from various generating facilities, and providing backup and reliability services.

Grid: A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the to as a payment in lieu of taxes.

Independent System Operator [ISO]: An independent system operator is an independent third party who takes over ownership and/or control of a regions transmission system for the purpose of providing open access to retail and wholesale markets for supply.

LB 901: The Nebraska State Legislature passed LB 901 on April 11, 2000. LB 901 encompasses the elements of the "condition certain" approach to electric deregulation in Nebraska that resulted from the prior LR 455 studies.

LES: Lincoln Electric System

Load: An end use device or customer that receives power from an electrical system.

Load Factor: A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of the average demand expressed as a percentage.

Local Distribution Company: The regulated electric utility company that constructs and maintains the distribution system that connects the transmission grid to the end use customer requirements of the customers connected to the grid at various points.

Gross Revenue Tax: A tax that is applied to the gross revenue of a utility. Often referred to as a payment in lieu of taxes.

LR 455: Legislative Resolution 455 was a three- year review of the electric industry in Nebraska, commissioned by the Nebraska State Legislature in1997, that recommended and formed the basic premise of the "Condition Certain" approach to electric deregulation in Nebraska.

MAAC: Mid-Atlantic Area Council

MAIN: MidAmerican Interconnected Network

MAPP: See Mid-Continent Area Power Pool

Megawatt (MW): One million watts

Metering: The process and methods of utilizing devices to measure the amount and direction of electrical energy flow.

Meter Reading Charges: The supplier's costs of providing customers with metering and/or meter reading services.

Mid-Continent Area Power Pool [MAPP]: One of the nations nine electricity reliability councils that covers a geographic area including the eastern two-thirds of Nebraska, South Dakota, North Dakota, Montana, Minnesota, western Wisconsin, Iowa, and parts of Saskatchewan and Manitoba.

NAERO: North American Electricity Reliability Organization. (Also see NERC).

NERC: North American Reliability Council. (Also see NAERO).

NPCC: Northeast Power Coordinating Council

NPPD: Nebraska Public Power District

Nuclear Decommissioning: Mandated charges to pay for dismantling nuclear power plants after they are retired from service.

Open Access Same Time Information System [OASIS]: An electronic information system posting system for transmission access data that allows all transmission customers to view the data simultaneously.

OPPD: Omaha Public Power District.

Pancaking: Refers to multiple transmission tariffs that are applied when electricity is transferred across multiple utility systems.

Parallel Path Flows: The flow of electricity on an electric system's transmission facilities resulting from scheduled electric power transfers between two electric systems. Electric power flows on all interconnected parallel paths in amounts inversely proportional to each paths resistance.

Payments in Lieu of Taxes: Payments made to local governments in lieu of property and other taxes.

Peak Load or Peak Demand: The electric load that corresponds to a maximum level of electric demand in a specified time period.

Power Exchange: An entity that would provide a centrally dispatched spot market power pool.

Public Power: Consumer-owned electric utilities, either political subdivisions of the state such as public power districts and municipal systems, or cooperatives owned by their members.

Public Purpose Funds: State mandated programs, such as low-income discounts and energy efficiency programs.

Restructuring: The reconfiguration of the vertically integrated electric utility. Restructuring refers to the separation of the various utility functions into individually operated and owned entities.

Retail Sales: Sales of electric energy to residential, commercial and industrial end use customers.

Retail Competition: A market system under which more than one provider can sell to retail customers, and retail customers can buy from more than one supplier.

Regional Transmission Group [RTG]: A voluntary group of transmission owners and users interested in coordinating transmission planning and expansion on a regional basis.

Regional Transmission Organization [RTO]: An umbrella term used to describe a variety of transmission organizations.

Rural Utility Service [RUS]: Under the U S Department of Agriculture, a program that provides direct loans and loan guarantees to electric utilities to serve customers in rural areas.

SERC: Southeastern Electricity Reliability Council.

Spot Market: A market in which commodities are bought and sold for cash and delivered immediately.

SPP: Southwest Power Pool.

Stranded Benefits: Public interest programs and goals that could be compromised or abandoned by a competitive market for electric services.

Stranded Costs: Above market costs of utilities and other power producers that would be stranded by consumers choosing a different power supplier.

Transmission Charges: Charges associated with transporting electricity over long distances, such as from generating stations to substations in the consumer's neighborhood.

Transition Costs [Charges]: These include existing costs that are stranded, and incremental costs of the new market system for both start-up and on-going expenses ranging from consumer protection to power exchange and access fees.

Unbundling: The separation of utility bills into the individual price components for which an electric supplier charges its retail customers, including, but not limited to, the separate charges for generation, transmission, and distribution of electricity.

Uniform Business Practices: A consensus driven set of uniform business practices for competitive electricity markets.

Vertically Integrated Utilities: Utilities that own the generating plants, transmission system, and distribution lines to provide all aspects of electric service.

WAPA: Western Area Power Administration