Chapter 4

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

1.0 Introduction
1.1 Purpose 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)
Bruce Abernethy	-	Lincoln Electric System (LES)
Deeno Boosalis		Omaha Public Power District (OPPD)
Doug Erickson	-	The Energy Authority (TEA)
Kevin Gaden	-	Municipal Energy Agency of Nebraska (MEAN)
David Ried	-	OPPD
Barry Campbell	-	Nebraska Public Power District (NPPD)
John Krajewski	-	MEAN
Derril Marshall	-	Fremont Utilities
Allen Meyer	-	Hastings Utilities
Burhl Gilpin		Grand Island Utilities

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 2002 documentation update for Technical Issue 2, the Midwest 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 to $ 6 per 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” are provided in the attached Appendix 4-A. 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 $300,000 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:

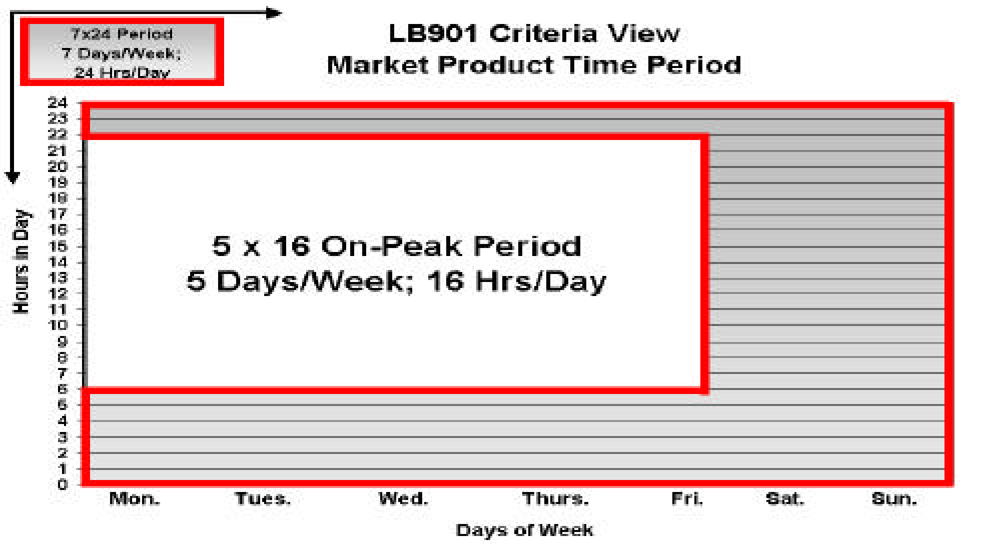
(1) Determine the total annual production revenue requirements for all the Nebraska utilities' power resources,

(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,

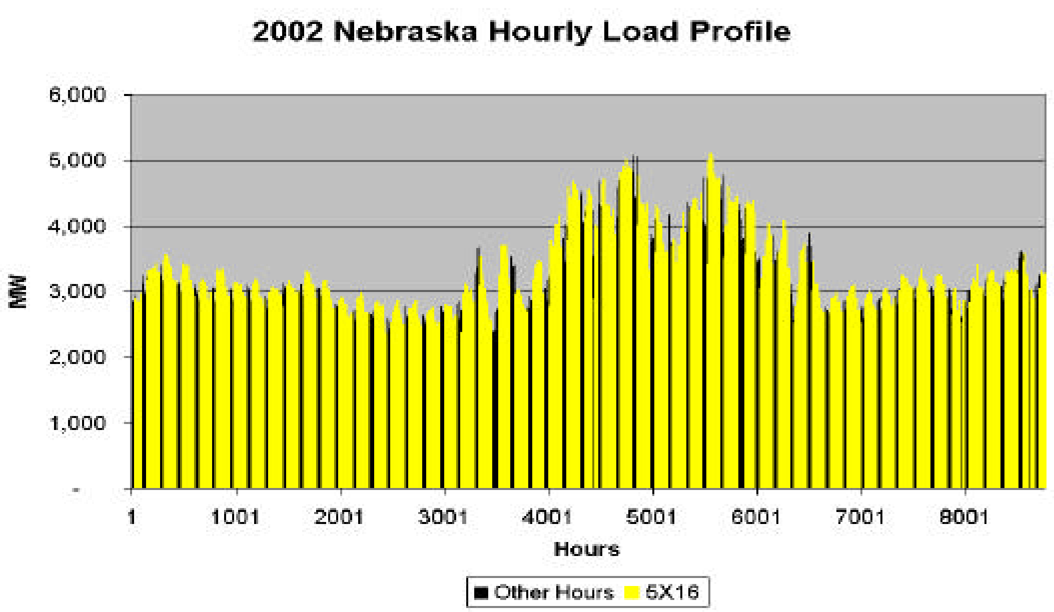
(3) Break down the total cost to serve (as determined in (2) above) to an hourly basis to determine a cost per hour to serve each utility's load based on an hourly load shape for each year (typically 8760 hours per year), which is accomplished by appropriately allocating the fixed and variable costs 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 following provides a graphical description of how much and during which times the load profile information is utilized.

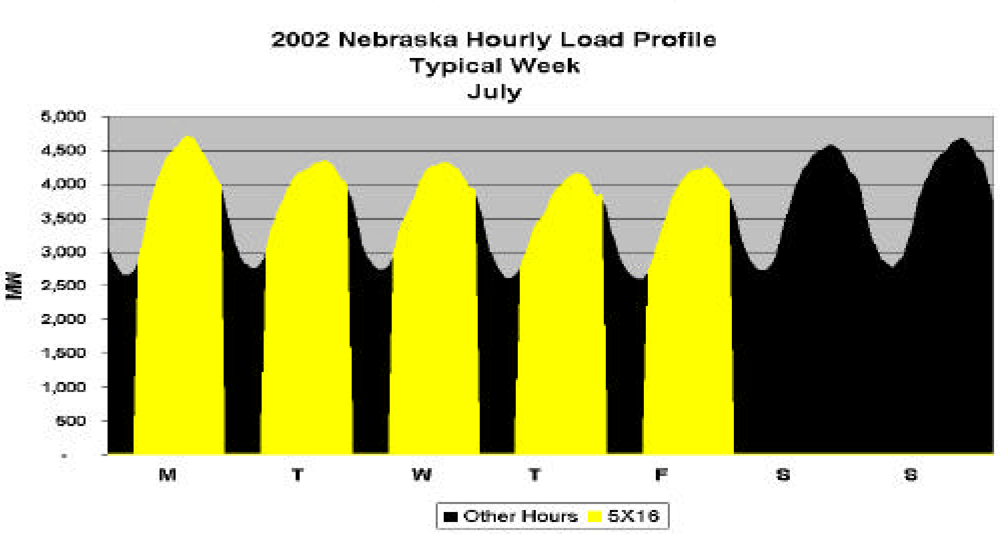
Exhibit IV-1



7x24 Period
7 Days/Week;
24 Hrs/Day
LB901 Criteria View
Market Product Time Period
5 x 16 On-Peak Period
5 Days/Week; 16 Hrs/Day
Hours in Day
Mon.
Tues.
Wed.
Thurs.
Fri.
Sat.
Sun.
Days of Week



2002 Nebraska Hourly Load Profile
MW
6,000
5,000
4,000
3,000
2,000
1,000
1
1001
2001
3001
4001
5001
6001
7001
8001
Hours
Other Hours
5X16



2002 Nebraska Hourly Load Profile
Typical Week
July
MW
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
M
T
W
T
F
S
S
Other Hours
5X16

3.3 Comparison Modeling Tool Application

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, assuming 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,

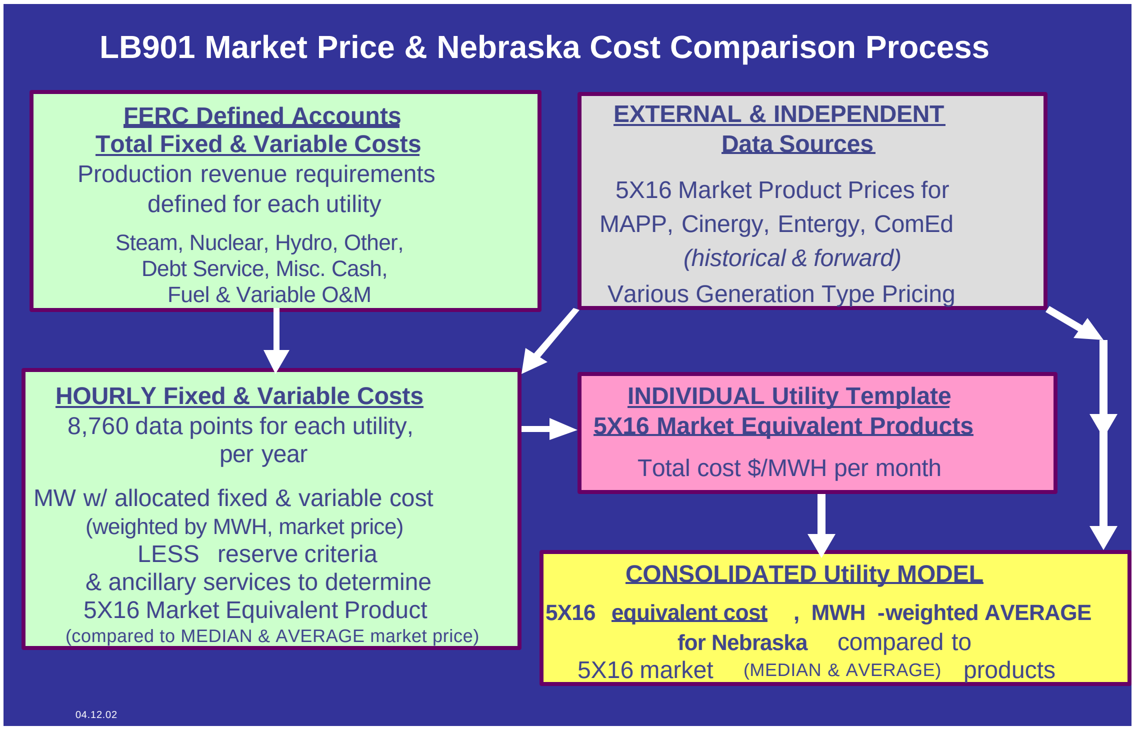
(4) Two different methods of allocating the fixed costs of existing power resources for each utility were modeled in order to provide a range of possibilities in cost allocations for discussion to determine how most utilities would allocate fixed costs; these two methods were (a) January thru December 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 1999 - 2002 (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 2002 modeling comparison purposes the time period of 1999 through 2002 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 1999-2002, with 2002 being the estimated year for both market pricing & production costs.

- Incorporating the future year 2003 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).

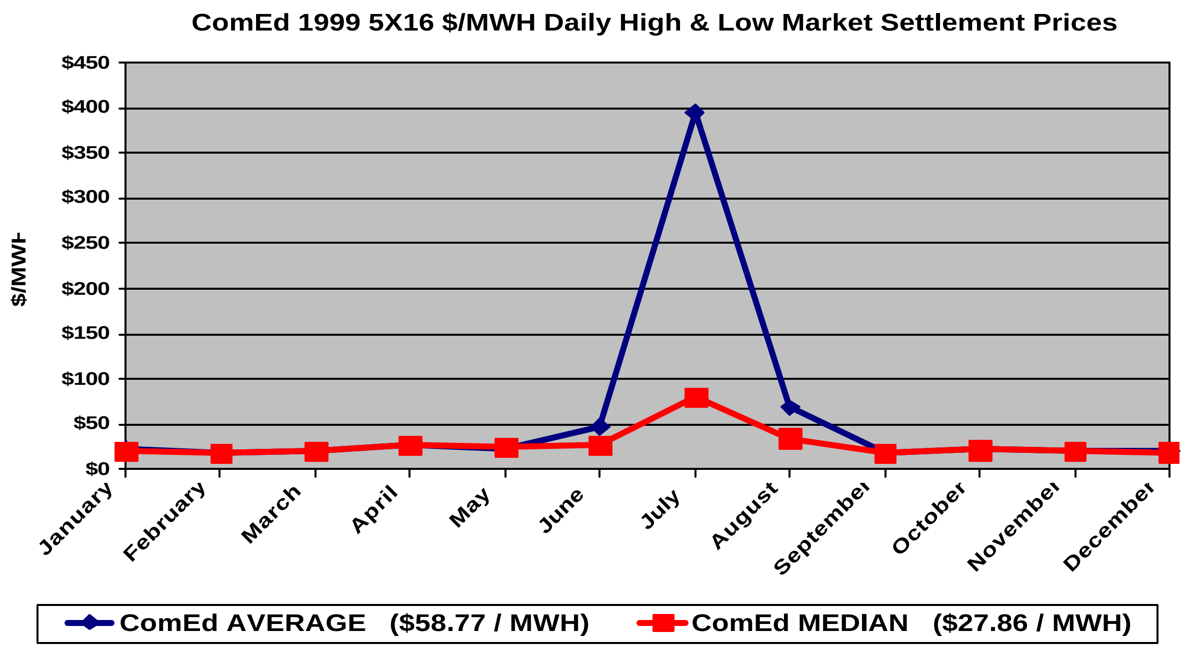
4.2 Sensitivity Cases Analyzed

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 last year, 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, this year's overall comparison results are based on these values being set to zero so that an equitable comp arison 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 Results Based on Median Market Product Pricing Indices and Applying MWH-Weighted Fixed Cost Allocations to Nebraska Production Costs for 1999 through 2002.

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 1999 through 2002. 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, is a LB901 historical study period comparison 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

TABLE DESCRIBING NEBRASKA PRODUCTION COSTS

PERCENTAGE BELOW AVERAGE MARKET PRICING

Year	MWH - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
1999	52.7%	53.6%
2000	28.1%	28.1%
2001	31.3%	31.3%
2002	13.0%	13.1%
Straight Average	31.3%	31.5%
Four Year Average (MWH-weighted)	**32.4%**	**32.9%**

PERCENTAGE BELOW MEDIAN MARKET PRICING

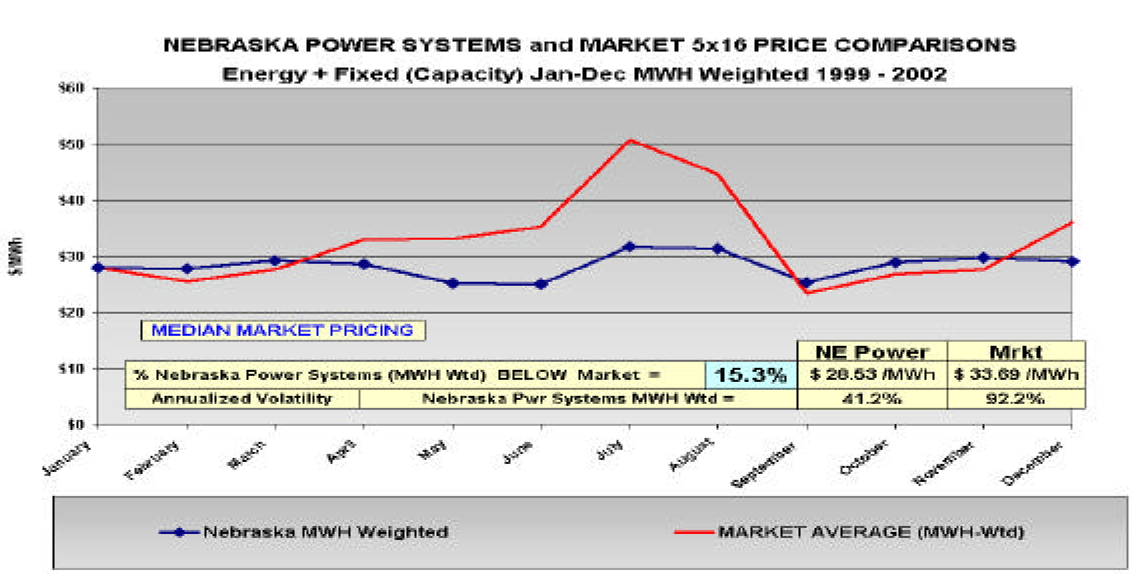
Year	MWH - Weighted Fixed Cost Allocations	Market Price - Weighted Fixed Cost Allocations
1999	1.9%	3.8%
2000	24.2%	24.1%
2001	31.8%	31.8%
2002	11.9%	12.3%
Straight Average	17.5%	18.0%
Four Year Average (MWH-weighted)	**15.3%**	**16.3%**

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%**

Exhibit IV-5 portrays a graph that depicts on a monthly basis for the four-year study period (1999-2002) 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 15%. 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 41%, which is less than one half of the market product price volatility of 92% for the same type of electricity product over the same period.

Exhibit IV-5



5x16 Price $/MWH Comparisons	1999 - 2002	LB 901 "Condition-Certain" Criteria	
	Statewide		
	4 Year AVERAGE		
CONSOLIDATED M[illegible]ON for INFORMATION AGGREGATION			
MEDIAN MARKET PRICING			
		NE Power	Mrkt
% Nebraska Power Systems (MWH Wtd) BELOW Market =	15.3%	$ 28.53 /MWh	$ 33.69 /MWh
% Nebraska Power Systems (MRKT Wtd) BELOW Market =	16.3%	$ 28.21 /MWh	$ 33.69 /MWh
Annualized Volatility	Nebraska Pwr Systems MWH Wtd =	41.2%	92.2%
Annualized Volatility	Nebraska Pwr Systems MRKT Wtd =	80.1%	92.2%

5x16 Price $/MWH Comparisons	1999 - 2002	LB 901 "Condition-Certain" Criteria	
	Statewide		
	4 Year AVERAGE		
CONSOLIDATED MO[illegible]SION for INFORMATION AGGREGATION			
AVERAGE MARKET PRICING			
		NE Power	Mrkt
% Nebraska Power Systems (MWH Wtd) BELOW Market =	32.4%	28.53 /MWh	$ 42.20 /MWh
% Nebraska Power Systems (MRKT Wtd) BELOW Market =	32.9%	28.31 /MWh	$ 42.20 /MWh
Annualized Volatility	Nebraska Pwr Systems MWH Wtd =	41.2%	166.2%
Annualized Volatility	Nebraska Pwr Systems MRKT Wtd =	109.0%	166.2%

For comparison purposes, Exhibit IV-6 is provided to describe the detail associated with the 2002 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 2002

	HISTORICAL				FORWARD INDICES (as of May 1, 2002)							
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	20.71	21.14	25.09	28.38	34.48	36.76	54.01	55.33	29.61	29.41	29.81	31.79
Comed	20.16	20.67	23.29	28.52	31.50	37.70	50.33	50.33	30.25	28.80	28.80	28.80
Cinergy	19.81	20.83	23.32	28.48	33.00	37.88	50.50	50.50	29.03	28.75	28.75	28.75
Entergy	19.48	20.82	26.11	31.23	34.38	39.38	50.38	50.38	29.50	30.25	30.25	30.25
MAPP CALC	104.5%	101.7%	103.5%	96.5%								

MEDIAN 5X16 $/MWH Daily Settlements for 2002

	HISTORICAL				FORWARD INDICES (as of May 1, 2002)							
	January	February	March	April	May	June	July	August	September	October	November	December
MAPP	20.00	20.51	23.44	26.25	35.32	38.45	54.64	52.33	25.86	29.24	29.86	31.64
Comed	19.34	20.16	22.62	26.09	31.50	37.70	50.33	50.33	30.25	28.80	28.80	28.80
Cinergy	18.48	20.14	22.87	26.06	33.00	37.88	50.50	50.50	29.03	28.75	28.75	28.75
Entergy	18.99	20.11	26.01	29.73	34.38	39.38	50.38	50.38	29.50	30.25	30.25	30.25
MAPP CALC	105.6%	101.6%	98.3%	96.2%								

MAPP Capacity Price $/kW-yr for 2002 = 17.00

Peaking Unit real levelized $/MWH for 2002 =	40.54	@ 85% CF and Fuel of $3.00/ mmBTU	66.43	@ 10% CF
Combined Cycle real levelized $/MWH for 2002 =	32.40	@ 85% CF and Fuel of $3.00/ mmBTU		
Baseload Coal real levelized $/MWH for 2002 =	29.31	@ 85% CF and Fuel of $0.75/ mmBTU		

(All generation units EXclude transmission cost adders)
FORWARD PRICES FOR MAY THRU DECEMBER BASED ON INTERCONTINENTAL EXCHANGE May 1, 2002 @ 6:52 am

These 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.

5.0 Expected Differences Eastern Region to Western Region

5.1 North American Electrical Interconnection

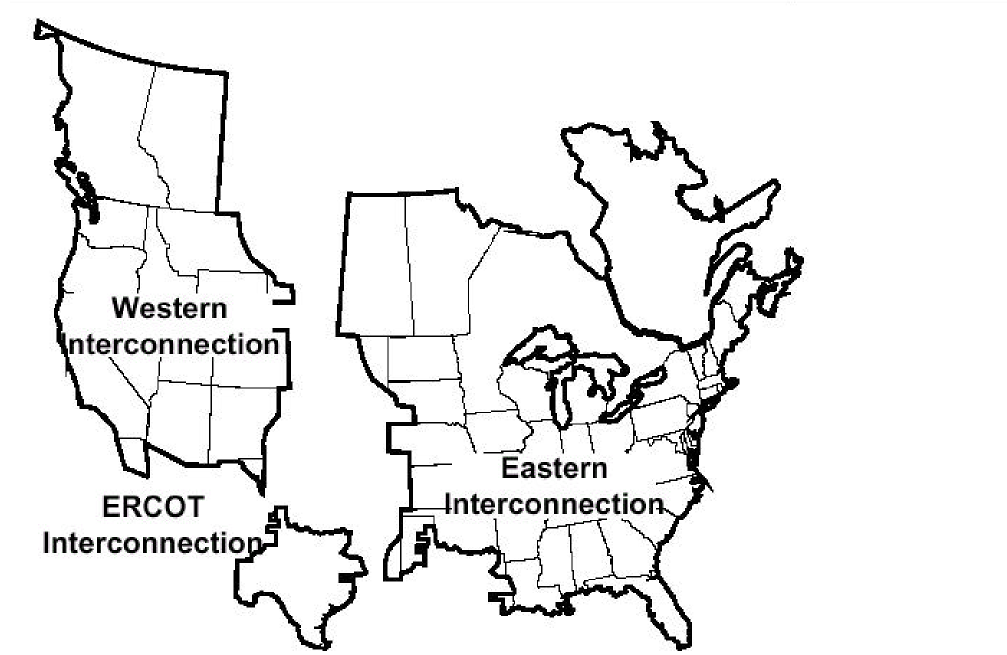
The majority of the electric systems in North America are comprised of three Interconnections as shown on Exhibit IV-7 and described below:

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-7



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 (584,503 MW compared to 135,186 MW) and generation (671,364 MW as compared to 166,269 MW). The interconnection DC tie capability between the Eastern and Western Interconnection is 1,080 MW. Source: (NERC Reliability Assessment, October 2001). Nebraska's projected growth rate is approximately 1.8% and the current summer peak is approximately 5700 MW.

The Western Systems Coordinating Council's (WSCC) 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 2010 period. Generation reserve margins in MAPP are projected to decline from 20% in 2001 to 15% in 2005. 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

The price fluctuation or volatility in the Eastern Region market has overall been significantly higher than the volatility for the Western Region market. This is primarily due to the extreme price levels in the Eastern Region markets during the summer of 1999. Looking at the price levels only for 2000 through 2002 however, shows a higher volatility in the Western Region for this time frame than in the Eastern Region.

While volatility has been greater overall for the Eastern Region, the average $/MWh price of the Western Region has averaged 67% higher than prices for the Eastern Region for the 1999 through 2002 time period (1-1-99 through 3-1-02). This is due to the significantly higher average price level for the Western Region since May 2000, despite the extreme price action seen in the Eastern Region during the summers of 1999. Market price levels for both the Eastern and Western Regions have decreased in recent months.

5.3.3 California Influence

The California market is beyond the Region, as defined in the report; however, the California market did influence the overall market. This could be seen in terms of an immediate psychological influence on the overall market as well as a direct influence on Nebraska and the market in terms of increased credit risk when dealing with power suppliers that operated in the California market as well as the Eastern and Western Regions. Some regulatory changes have occurred already as a result of the California deregulation experience such as price caps for the Western Interconnection.

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; MEAN serves some western Nebraska municipals; 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. However, the purchased wholesale power from the Western Region is currently trending higher than that of power purchased in the Eastern Region.

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 2003 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 usually 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 15% lower than the equivalent wholesale "median" market price based on the period 1999 – 2002 (three years actual, one year projected), and weighted based on MWH. Based on the "average" market price, Nebraska production costs are approximately 32% lower than the "average" market price.

These 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 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 price comparison, approximately 15% 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 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.

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.

Appendix IV-A – ANCILLARY SERVICES DEFINITIONS

SCHEDULE 1.

Scheduling, System Control and Dispatch Service (FERC Acct. 561)

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Service Provider (if Service Provider is the Control Area operator) or indirectly by Service Provider making arrangements with the Control Area operator that performs this service for Service Provider's Transmission System. The Transmission Customer must purchase this service from Service Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 2.

Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on Service Providers' transmission facilities within acceptable limits, generation facilities (in the Control Area where Service Providers' transmission facilities are located) are operated to produce (or absorb) reactive power. Thus. Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on Service Providers' transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Service Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by Service Provider making arrangements with the Control Area operator that performs this service for Service Providers' Transmission System. The Transmission Customer must purchase this service from Service Provider or the Control Area operator. The charges for such service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by the Control Area operator.

SCHEDULE 3.

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with Service Provider (or the Control Area operator that performs this function for Service Provider). Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 4.

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

Service Provider shall establish a deviation band of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

SCHEDULE 5.

Operating Reserve – Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Spinning reserve Service obligation. The amount of and charges for spinning Reserve Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator.

SCHEDULE 6.

Operating Reserve – Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line, but unloaded by quick-start generation, or by interruptible load. Service Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Service Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are to be based on set rates. To the extent the Control Area operator performs this service for Service Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Service Provider by that Control Area operator