Approved: Carl Dean Holmes
Date 1-29-99

MINUTES OF THE HOUSE COMMITTEE ON UTILITIES.

The meeting was called to order by Chairperson Rep. Carl Holmes at 9:06 a.m. on January 26, 1999 in Room 522-S of the Capitol.

All members were present except:

Committee staff present: Lynne Holt, Legislative Research Department
Jo Cook-Whitmore, Committee Secretary

Conferees appearing before the committee:

Others attending: See Attached List

The Chair asked for introduction of bills. There were none.

The Chair introduced Lynne Holt, Legislative Research Department, who presented the interim report from the Joint Committee on Economic Development on Electric Generation Capacity Constraints (Attachments 1 and 2). She included in her presentation references to an article titled "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes", which appeared in Public Utilities Fortnightly on November 15, 1998 (Attachment 3). Also included in the presentation was a copy of the letter sent to Kansas Corporation Commission Chairman, John Wine, from Senator Pat Ranson, Chairperson of the Joint Committee on Economic Development (Attachment 4). Ms. Holt concluded her presentation by answering questions from the committee. Larry Holloway, Kansas Corporation Commission Chief of Electric Rates, assisted Ms. Holt in answering committee questions.

Testimony was given by Jim Ludwig, Western Resources, regarding the problem of meeting consumer electric needs during the summer of 1998 (Attachment 5).

Chris Giles, Kansas City Power & Light Company provided testimony on KCPL's generation expansion plan and included information on the problems associated with meeting consumer electric needs during the summer of 1998 (Attachment 6).

Frank DeBacker of WestPlains Energy, provided testimony on the WestPlains' load and resource forecast (Attachment 7).

Mr. Ludwig, Mr. Giles and Mr. DeBacker answered questions of the committee.

Rep. Alldritt moved that the minutes of the January 19, January 20, and January 21 meetings be approved. Rep. Compton seconded the motion. Motion carried.

Meeting adjourned at 10:55 a.m.

Next meeting is Wednesday, January 27 at 9:00 a.m.

HOUSE UTILITIES COMMITTEE GUEST LIST

DATE: January 26, 1999

NAME	REPRESENTING
DICK CARTER	ENRON
J.C. LONG	UCU
FRANK DeBACKER	UCU
Scott Keith	UCU
James Hockett	WRI
CHUCK HODSON	WRI
DOUG LAWRENCE	KEC
BRUCE GRAHAM	KEPCo
Mikel Kline	KEPCo
Steve Miller	Sunflower
David Bybee	KDOCH
Larry Holloway	KCC
Patrick J. Hurley	KCPL
Chris Giles	KCPL
Kelly B. Harrison	WRI

HOUSE UTILITIES COMMITTEE GUEST LIST

DATE: ______________________

NAME	REPRESENTING
Jim Ludwig	Western Resources
ED SCHAUB	" "
John BOTTENBERG	WESTERN Resources
Whitney Damron	Empire District Electric Co.
Leslie Kaufman	Ks Farm Bureau
Larrie Ann Brown	KS Gov't Consulting
TOM DAY	KCC
Charles Benjamin	Kansas Natural Resource Council Kansas Sierra Club
Cory Lee Cannon	Intern - Don Dahl
Erin Carlson	Intern - Carl Holmes
Dave Holthaus	Western Resources
WALKER HENDRIX	CURB

Electric Generation Capacity Constraints

Joint Committee on Economic Development

November 6, 1998

Electric Generation Capacity Constraints

Definitions

- Firm customers – Customers whom utilities are obligated to serve, barring any unforeseen circumstances, such as natural disasters.
- Interruptible customers - Customers who receive a special rate from the utility company in exchange for agreeing to having their service reduced or temporarily stopped under certain circumstances. Circumstances for service interruption may be periods of high demand or high cost periods of short supply for the utility and/or system emergencies.

HOUSE UTILITIES

DATE: January 26, 1999

ATTACHMENT 1

Electric Generation Capacity Constraints (p. 1; Background)

Summer 1998 – Western Resources' Actions:

- Requested 59 *interruptible* commercial and industrial customers to reduce electric consumption for 51 hours over an 8-day period
- Requested 100 largest *firm* customers to voluntarily reduce consumption on four days
- Requested *all* customers to conserve energy on July 20 and 21

Electric Generation Capacity Constraints (p. 1; Background)

No outages occurred although the threat of outages and requests for reduced consumption caused considerable hardship for certain industrial customers, particularly those served by Western Resources (KGE) in Wichita.

Electric Generation Capacity Constraints (p. 1; Background)

Purpose of Joint Committee's Hearing

- To explore reasons for electric capacity shortages in the Midwest
- To identify the potential short-term and long-term effects of those shortages

Electric Generation Capacity Constraints (pp. 1-3)

Factors that Contributed to Western Resources' Capacity Constraints

- Wholesale electricity market
- Mixture of wholesale and retail electricity markets
- Generation capacity

Electric Generation Capacity Constraints (p. 2)

Wholesale Electricity Market

- Largely deregulated market
- Transition to deregulation occurred much more quickly than had been anticipated
- Entrance of new nonutility marketers
- Increased pricing volatility and greater unreliability in wholesale purchases

Electric Generation Capacity Constraints (p. 2)

Mixture of Wholesale and Retail Electricity Markets

- Problems with balancing supply (sometimes dependent on wholesale, largely deregulated transactions)and demand from firm retail customers (in the regulated market)
- Transmission systems not designed for dynamic wholesale competition
- Retail wheeling authorized in several states before system can effectively handle wholesale market

Electric Generation Capacity Constraints (pp. 2-3)

Generation Capacity Unable to Meet Demand
Western Resources

- Circumstantial factors
- Systemic factors

Electric Generation Capacity Constraints (p. 2)

Circumstantial Factors

- Unusually hot weather
- Unscheduled unit outages
- Shut down of several large nuclear plants in Midwest

Electric Generation Capacity Constraints (pp. 2-3)

Systemic Factors

- A greater increase in peak demand obligation than Western Resources had projected
- Conservative projected electric capacity margins set by the Southwest Power Pool
- Insufficient generating capacity owned by Western Resources to meet future summer peak demand
- The lack of an overarching body to determine, and enforce compliance with, uniform standards, criteria, and procedures to ensure reliability of the North American interconnected systems

Electric Generation Capacity Constraints (p. 3)

The Southwest Power Pool is one of the ten regional reliability councils comprising the North American Electric Reliability Council

Electric Generation Capacity Constraints (p. 3)

Southwest Power Pool's Responsibilities:

- Helps to reduce transmission capacity constraints
- Identifies and attempts to correct weak links in the transmission system connecting utilities
- Invokes emergency procedures to prevent cascading blackouts

Electric Generation Capacity Constraints

Southwest Power Pool Projected Capacity Margins (Source: Nick Brown, SPP)

Peak Demand Growth	1999	2000	2001
1.1%	14.4	12.3	10.7
2%	13.5	10.7	9.3
3%	12.6	8.9	6.6
4%	11.8	7.2	3.8

Electric Generation Capacity Constraints (p. 3)

Conclusion About Capacity Margins

For each of the past ten years, peak demand has been greater than forecasted!

Example: 1998 summer peak growth in region was 5-7 percent, although only 2-3 percent had been projected

Electric Generation Capacity Constraints (p. 3)

Why Utilities Do Not Build Plants

- Concern of stranded investment if retail wheeling is authorized
- Long lead time for construction but growth in customer load is uncertain
- Interconnection has encouraged utilities to purchase power rather than build

Electric Generation Capacity Constraints

Region	1986-1996	1997-2005	Difference
MAIN	2.8	1.4	-1.4
ECAR	3.2	1.5	-1.7
SPP	3.5	1.5	-2.0
SERC-Southern	3.4	1.8	-2.6
SERC-TVA	3.2	2.0	-1.2
Simple Ave	3.2	1.6	-1.6

Systematic Under-Forecasting of Electric Energy Growth
10-Year Average Growth (%)
(Source: Judah L. Rose, PUF, November 15, 1998, p. 47)

Electric Generation Capacity Constraints (pp. 3-4)

Limitations of Reliability Councils' Powers and Forecasting Accuracy

- Utilities are voluntary members of reliability councils; may leave one council and join another
- Several councils do not impose penalties on member utilities for noncompliance with capacity margin requirements
- Utilities do not plan for interruptible demand in determining capacity reserves
- Nonmembers need not submit data on their capacity projections

Electric Generation Capacity Constraints (p. 4)

Kansas Corporation Commission Action

Issued an order initiating an investigation of the future of Kansas electric generation capacity (November 4, 1998)

Electric Generation Capacity Constraints (p. 4)

Western Resources' Plans for Expanded Capacity

- Summer 1999 — restoration of KGE's nonoperational Neosho plant to service
- Summer 1999 — purchase of additional capacity from McPherson municipal utility
- Spring 2000; Spring 2001 — construction of three combustion turbines

Electric Generation Capacity Constraints (pp. 4-5)

Impact on Certain Industrial Customers

- Changes to employees' schedules (Boeing/Raytheon)
- Very expensive to purchase power (Vulcan Chemicals/Farmland)
- Inefficient use of electricity in production processes (Vulcan Chemicals)
- Unable to meet all needs of certain customers (Vulcan Chemicals)

Electric Generation Capacity Constraints (p. 5)

Committee Recommendations

- Chairperson Ranson to write a letter to Kansas Corporation Commission (KCC) Chairperson, John Wine, relaying Committee's concern about implications of capacity constraints for economic development in Kansas
- KCC encouraged to periodically update the Legislature on Commission proceedings on generation capacity and Farmland complaint re: interruptible contracts

JOINT COMMITTEE ON ECONOMIC DEVELOPMENT

ELECTRIC GENERATION CAPACITY CONSTRAINTS

CONCLUSIONS AND RECOMMENDATIONS

The Committee recommends the Chairperson of the Committee write a letter to Chairman John Wine and the other Commissioners of the Kansas Corporation Commission, with a copy to be forwarded to the Governor. This letter should encourage the Commission to proceed expeditiously with its investigation of the adequacy of future Kansas electric generation capacity. In addition, this letter should relay the Committee's concerns about the implications of energy capacity constraints for economic development in Kansas. The Committee also encourages the Commission to periodically update the Legislature on the Commission's proceedings on generation capacity and the complaint filed by Farmland Industries requesting an investigation of interruptible contracts.

BACKGROUND

During the Summer of 1998, many electric utilities in the Midwest experienced electric capacity shortages. In Kansas, these shortages caused Western Resources to request its 59 commercial and industrial customers with interruptible contracts to reduce their electrical consumption for 51 hours spread over an eight-day period. Western Resources requested its 100 largest customers, even those with firm contracts, to voluntarily reduce electric consumption on four days. (Customers with interruptible contracts pay considerably less than customers with firm contracts in exchange for accepting a lower priority of service; if curtailments are necessary, interruptible customers will be asked to reduce consumption before firm customers.) On July 20 and 21, Western Resources asked all its customers to conserve energy because of concerns about rotating electric outages. Ultimately, no outages occurred although the threat of outages and the requests for reduced consumption caused considerable hardship for certain industrial customers, particularly those served by Western Resources (KGE) in Wichita. The Committee held a hearing on November 6 to explore the reasons for the electric capacity shortages in the Midwest, including Kansas, and to identify the potential short-term and long term effects of those shortages.

COMMITTEE ACTIVITIES

The Committee heard presentations from the Chief Electric Engineer of the Kansas Corporation Commission (KCC); the Vice President of Southwest Power Pool (SPP); the Director of Rates, Western Resources; and spokespersons for four large industrial companies which purchase electricity from Western Resources—Farmland Industries, Boeing, Vulcan, and Raytheon. The Committee was informed about the factors contributing to the electric capacity constraints; the SPP's regional planning activities; the KCC's actions to address this issue; Western Resources' plans for expanded capacity; and the represented industries' experiences with the mid-summer shortages.

Factors Contributing to Electric Capacity Constraints. The following is a list of several factors that might have contributed to Western Resources' electric capacity constraints during the Summer of 1998. This list is a synthesis of various conferees' perspectives.

HOUSE UTILITIES

DATE: January 26, 1999

ATTACHMENT 2

- *Wholesale Electricity Market.* The wholesale electricity market is largely deregulated and the transition from regulation to deregulation has occurred much more quickly than had been anticipated. The wholesale market, in this context, refers to electric power transactions between a utility and another utility or an independent power plant or between a utility and a governmental entity. In 1992, Congress ordered federally regulated electric utilities to allow any wholesaler to use the transmission lines. To implement this mandate, utilities have separated control of transmission lines from control of power generation. This mandate has also led to the entrance of new nonutility marketers, many of whom only deal in financial transactions. However, since many of the transactions are not backed by the ability to physically deliver power, pricing has become increasingly volatile, as was evident in the Summer of 1998. The entities controlling the transmission system have the power to limit or stop electricity from flowing, regardless of contractual agreements between a buyer and seller. Consequently, purchases from one utility to another can be suddenly curtailed, creating immediate and unexpected reliability problems. Deregulation in the wholesale market has resulted in greater uncertainty in commodity pricing and greater unreliability in wholesale purchases.

- *Mixture of Wholesale and Retail Electricity Markets.* Even though wholesale markets operate with few price constraints and no utility service obligations beyond contractual agreements between buyers and sellers, retail markets are fully regulated and utilities are therefore still obligated to serve retail customers at fixed rates. If utilities must purchase electricity on the wholesale (spot) market and pay very high prices to meet retail obligations, utilities could realize major financial losses. The coexistence of a largely deregulated wholesale market and a largely regulated retail market has created problems for utilities in balancing supply (some of it is dependent on wholesale purchases in the largely deregulated market) and demand from firm retail customers (in the regulated market). Transmission systems were not designed to accommodate dynamic competition in the wholesale market, thus causing an increasing number of transmission constraints. In addition, several states have introduced retail wheeling before the system to effectively coordinate the wholesale market has evolved.

- *Generation Capacity.* Utilities, such as Western Resources, must rely on the restructuring wholesale market if their own generating capacity is insufficient to meet peak demand —the maximum hourly amount of energy demanded during the year. Several factors affect a utility's capacity to meet that demand —some are circumstantial and some are systemic. With respect to Western Resources' capacity constraints in the Summer of 1998, the circumstantial factors included: unusually hot weather which caused air conditioners to run for long periods of time; unscheduled unit outages, such as Western Resources' Lawrence and La Cygne plants; and the shut down of several large nuclear plants in the upper Midwest which contributed to shortages in the entire region. Systemic factors include:

    - A greater increase in peak demand obligations than Western Resources had projected.
    - Conservative projected electric capacity margins set by the SPP, a regional reliability council. In addition to other functions, the SPP establishes the minimum standards for energy resources needed (capacity margin) to ensure reliable electric transmission and generation in this region. The SPP's capacity margin is based on aggregate forecasting projections submitted by regional utilities. Utilities are required to reserve a percentage of capacity, determined by the SPP, above their peak responsibility level; however, actual growth in peak demand has exceeded projected growth in each of the past ten years and reserve margins will be dangerously low within two years if this pattern of understated growth projections

continues.

- Insufficient generating capacity owned by Western Resources to meet summer peak demand in the future (addressed below).
- The lack of an overarching body to determine, and enforce compliance with, uniform standards, criteria (such as capacity margin criteria), and procedures to ensure reliability of the North American interconnected electric system. Western Resources and other utilities, state and federal regulatory agencies, and nonutility power plants are members of the SPP, but policies adopted by that council differ from decisions made by reliability councils in other regions. This raises the question of how to ensure reliability on the system beyond the immediate region since transmission of power can affect multiple regions. Despite their necessary dependence on an interconnected system, utilities have become increasingly self-sufficient in meeting their own energy resource needs due to the lack of transmission system reliability.

SPP's Regional Planning Activities. The SPP is the oldest of the ten regional reliability councils which currently comprise the North American Electric Reliability Council. The SPP coordinates, promotes, and communicates about maintaining the critical and delicate balance between electric system reliability and economic and equity issues. The SPP helps to reduce transmission capacity constraints, identifies and attempts to correct weak links in the transmission system connecting utilities, and invokes emergency procedures to prevent cascading blackouts or reduce power due to an unanticipated shutdown of a regional generating facility. One of its other responsibilities, as noted above, is the determination of electric generation capacity margins. The minimum SPP capacity margin was 13 percent for years through 1998. That percentage has been reduced to 12 percent in 1999. This number is based on the projected occurrence of power outages for any particular area once every ten years within the region.

The SPP issued a report in July 1998, which indicates a decrease from 1997 in forecasted capacity margin for Kansas utilities with a potential generation shortfall in Kansas by 2002. An analysis by the KCC staff reveals that Kansas utilities lowered from 1997 both their anticipated peak summer demand forecasts for future years and their planned capacity resources. The Vice President of the SPP informed the Committee that the reserve capacity margin in the region could be as low as 3.8 percent in 2001, assuming peak demand growth of 4 percent. For each of the past ten years, peak demand has been greater than forecasted. For example, the summer peak growth in 1998 was 5-7 percent for the region although only 2-3 percent had been projected.

Why Utilities Do Not Build Plants. Electric utilities have been reluctant in recent years to build new power plants, due to a concern of stranded investments in a restructuring environment. A long lead time is needed for plant construction; however, growth in customer load (electric consumption at any given time) is very uncertain, particularly when the "rules" governing wholesale and retail power transactions are in a state of flux. Because utilities are interconnected, they have been more inclined in recent years to purchase power, as needed, from other providers. However, capacity constraints occur when demand exceeds supply and there is no more available power or no affordable power to purchase.

Limitations of Reliability Councils' Powers. Utilities are voluntary members of the reliability councils. Several councils do not impose penalties on member utilities which are in noncompliance with the capacity margin requirements. Nonmembers may elect not to reserve capacity. Moreover, utilities may opt to leave reliability councils which further complicates those councils' efforts to project capacity margins with any accuracy. Another factor complicating regional forecasting by reliability councils, which also contributes to understated projections, is that utilities do not plan for interruptible demand in determining capacity reserves. Therefore, this type of demand is not reflected in the councils' respective regional projections. Finally, nonmembers need not submit data on their capacity projections to reliability councils, thus making the councils' regional projections less accurate. As noted, capacity margin criteria and penalties for utility noncompliance with required reserve capacity margins are not uniform among reliability councils. This limitation prevents councils from effectively coordinating efforts to realize the advantages and cost efficiencies of an interconnected transmission system.

KCC's Plans. To address several of the issues outlined above, the KCC issued an order initiating an investigation of the future of Kansas electric generation capacity (November 4, 1998). Specifically, the Commission indicated plans to investigate the capacity margin projected for Kansas utilities for the years 1998 through 2007. The initial phase of this proceeding is the collection of information on demand forecasts and planned capacity resources from both Kansas electric utilities belonging to the SPP and Kansas electric utilities that do not. Two sets of questions for each type of utility (SPP members and nonmembers) are appended to the order. The Commission directed staff to compile a summary of responses to these questions. Based on the summary of responses, the Commission indicated its intent to issue an order establishing further proceedings, including, but not limited to, roundtable discussions involving interested parties.

Western Resources' Plans for Expanded Capacity. The Director of Rates, Western Resources, informed the Committee that the company recognized the need for additional capacity even earlier than Summer 1998. KPL has not built a new power plant since 1983 and KGE since 1985, when Wolf Creek was completed. During the Summer of 1999, Western Resources intends to restore KGE's nonoperational Neosho power plant to service. In addition, the company plans to build three combustion turbines, to be partly operational in the Spring of 2000 and fully operational in the Spring of 2001. These turbines will add approximately 300 MW of peaking, gas-fired generating capacity to the company's capacity resource complement. Both KPL and KGE will take shares of the new capacity, which amounts to a 5 percent increase in the total capacity owned by Western Resources. As peaking capacity, the new turbines are expected to operate less than 10 percent a year. The plants will be located at KGE's Gordon Evans plant site near Colwich, northwest of Wichita. The direct cost is estimated at $120 million and, with additional facilities, $140 million. The Committee learned that the company did not view this additional capacity as a long-term solution for meeting customers' electric power needs. Finally, the Committee was informed that the company planned to submit to the Legislature proposals relating to tax incentives and streamlining or eliminating the Siting Act. From the company's perspective, these measures would reduce the company's exposure to investment risks in light of a transforming industry over the next several years.

Kansas Industry Experiences with Mid-Summer Shortages. The Committee received testimony from spokespersons from The Boeing Company, Farmland Industries, Vulcan Chemicals, and Raytheon Aircraft Company.

- Boeing's testimony raised concerns about the justification for Western Resources' off-system contractual obligations when firm customers, such as Boeing, in the utility's certificated areas were being asked to reduce consumption. The power shortages affected 1,000 company employees who had to switch their work hours because of requested load shedding.
- In addition to sharing Boeing's concerns about off-system contracts, Farmland Industries' spokesperson questioned whether KGE's action to curtail its interruptible customers in June 1998 was warranted given its acceptable reserve margin (assumed to be 27.45 percent) at the time.
- An interruptible customer like Farmland Industries, Vulcan Chemicals was without power for five days during the Summer. The company was able to purchase very expensive power on three days but it was insufficient to meet the company's needs. Vulcan's testimony outlined three concerns:

  - the company was forced to be very ineffi-

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cient in its use of electricity given its production process;
- the company was forced to inform some of its customers it could not meet all of their needs because of power constraints; and
- the future reliability of Western Resources power delivery is unclear given the recent events.

Also emphasized were the adverse economic development implications of these capacity constraints. Vulcan proposed retail wheeling as a solution for reducing uncertainty of large energy users.

- Like Boeing, Raytheon Aircraft had to change production schedules to comply with the request for consumption curtailment. Like Boeing, Raytheon is a firm customer. The company shared the same concerns with the other companies regarding Western Resources' accommodation of out-of-state off-system companies when its firm in-state industrial customers were threatened with blackouts. The company suggested that costs for the new turbines proposed by Western Resources be borne by off-system wholesale customers.

Conclusions and Recommendations

The Committee recognizes that Kansas has fared better than many states in terms of meeting capacity requirements. Moreover, the Committee understands that uncertainties in power supply and transmission are regional, as well as national problems. Nonetheless, a company's lack of access to reliable and affordable energy is an economic development issue. Potential economic growth will be impeded in terms of industrial relocation and expansion plans, if businesses cannot rely on their electric utilities to supply them with contractually promised power. The power shortages experienced by certain large commercial and industrial customers during the Summer of 1998 had adverse impacts on their production cycles, employee schedules, and finances.

This situation deserves serious scrutiny from the KCC so that measures can be taken to prevent a recurrence of power curtailments. The Commission, the industrial consumers, and the electric utilities in Kansas need to carefully assess all the economic development implications of power curtailment measures and develop a strategy to ensure that there will be adequate capacity in future years.

To that end, the Committee recommends the Chairperson of the Committee write a letter to Chairman John Wine and the other Commissioners of the KCC, with a copy to be forwarded to the Governor. This letter should encourage the Commission to proceed expeditiously with its investigation of the adequacy of future Kansas electric generation capacity. In addition, this letter should relay the Committee's concerns about the implications of energy capacity constraints for economic development in Kansas. The Committee also encourages the Commission to periodically update the Legislature on the Commission's proceedings on generation capacity and the complaint filed by Farmland Industries requesting an investigation of interruptible contracts.

Missed Opportunity:

What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes

Contrary to findings, the conditions seen in June 1998 were not that unusual. And next year could promise prices even worse—or, for the first time, real reliability problems. By Judah L. Rose

THE RECENT REPORT BY THE STAFF OF THE FEDERAL Energy Regulatory Commission on the causes of the power price spikes that occurred in the Midwest performs an important service—it acknowledges that in competitive markets, the price of wholesale power can be quite high in periods of peak demand.

Nevertheless, the staff went wrong in reporting that the conditions behind the price spikes were unusual.

In fact, given the uncertainty of the current transition period, the next year might likely see a repeat of the 1998 spikes, or worse. That's because the transition to full deregulation is likely to prove a bit more messy than the staff report might lead one to believe.

The FERC's misunderstanding stems from its failure to

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undertake a loss-of-load study. The staff report also misses the opportunity to explain more clearly the extent to which policy mistakes have and appear likely to continue to help make the transition more difficult than it needs to be. A number of reforms are urgently needed during this transition, such as (1) explicit rules on generation reliability, (2) publication of independent data about reliability, (3) identification of a lead regulatory authority, and (4) a rapid finish to key parts of wholesale and retail deregulation.

Price spikes are linked inextricably with reliability problems and blackouts. Most retail customers cannot participate in wholesale markets. Instead, they must rely on utilities and policy makers. Only government action can help.

Situation: Worse Than Acknowledged

In late June 1998, in the Midwest, prices briefly reached $7,500 per megawatt-hour. That price was "extraordinarily high," in the words of the recent FERC staff report entitled "Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest during June 1998."[1] The report, however, goes on to downplay the event by noting that average prices were closer to $40/MWh in August and that no blackouts occurred, nor did there occur any curtailments of service to firm customers.

Most importantly, the report concludes that "combination of factors was not typical, is not likely to recur, and is not representative of how wholesale markets usually work."

These statements represent both a service to industry and a missed opportunity. They reinforce the fact that deregulated wholesale prices will on occasion be extremely high—even hundreds of times higher than on average. Publicizing this fact is especially welcome, since one motivation for the study was to allay concerns that the high prices reflected market manipulation and should be suppressed.[2] However, the report fails to highlight the fact that the current transition period could

Table 1: Systematic Under-Forecasting of Peak Demand Growth

Region	Historical Actual Peak (1986-1996)	Forecast (1997-2005)	Difference
	10-Year Average Growth Rate (%)		
MAIN	2.6	1.5	-1.1
ECAR	2.7	1.6	-1.1
SPP	2.5	1.6	-.9
SERC-Southern	3.1	2.5	-.6
SERC-TVA	2.4	1.9	-.5
Simple Average	2.7[1]	1.8	-.8

[1] 1990-1996 growth was 2.8 percent
Source: NERC ES&D

Reading this table: Utilities forecast a slowdown in demand, which is not consistent with the historical record.

Table 2: Systematic Under-Forecasting of Electric Energy Growth

Region	Historical Actual Peak (1986-1996)	Forecast (1997-2005)	Difference
	10-Year Average Growth Rate (%)		
MAIN	2.8	1.4	-1.4
ECAR	3.2	1.5	-1.7
SPP	3.5	1.5	-2.0
SERC-Southern	3.4	1.8	-2.6
SERC-TVA	3.2	2.0	-1.2
Simple Average	3.2[1]	1.6	-1.8

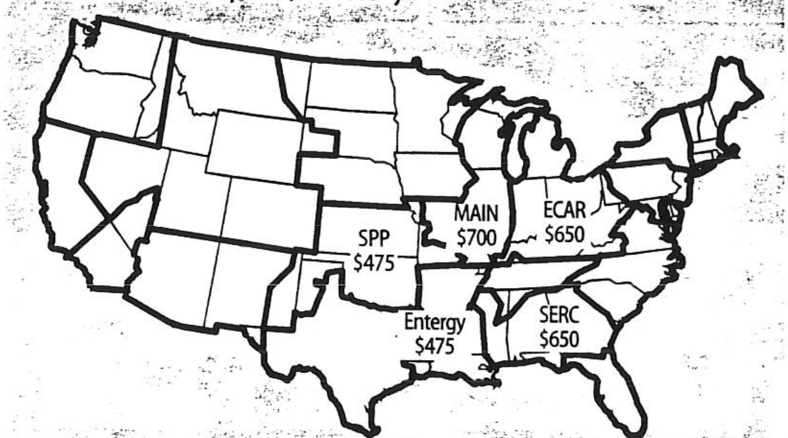
[1] 1990-1996 growth was 3.3 percent
Source: NERC ES&D

Reading this table: Utilities forecast a slowdown in demand, which is not consistent with the historical record.

3-2

Figure 1: Five Regions Had the Highest On-Peak Prices During Summer 1998

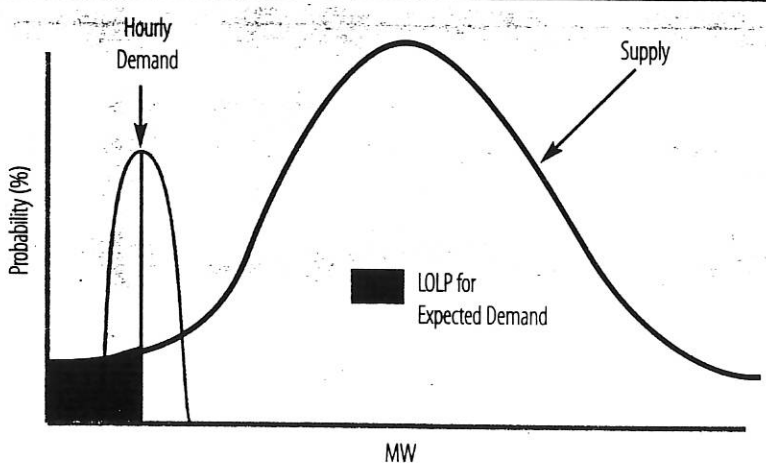
(Only MAIN, ECAR, SPP, SERC and Entergy Had Prices Above $125/MWh[1,2])



1 Weekly averages from Power Markets Week. No other region had peak prices above $120/MWh.

2. Until 1998, Entergy was part of SPP.

Figure 2: Calculation of Hourly Loss of Load Probability



To understand this graphic:

- Supply is uncertain due to unexpected outages at plants. There is a small chance of no generation capacity, a small chance of all generation capacity being available, and a large chance of most—but not at all—being available.
- Demand is uncertain. A correct demand estimate is net of interruptible load—i.e., firm load.
- When demand is greater than supply, there is a loss of load—a polite term for blackouts.

well prove much more difficult than expected, with blackouts or prices higher than equilibrium levels.

A price of $7,500/MWh is extremely high—even if the FERC correctly concludes that some very high price spikes are part of a regulated power business. Were those prices to prevail for even 48 hours, the owners of a combustion turbine could pay off the costs of the investment in just two days, earning profits from all future sales for the next 30 years.[3] A more reasonable equilibrium price is below the current "into Cinergy" futures prices (prices for the futures contract at the Cinergy trading hub).

The FERC staff correctly notes that there were no blackouts in the Midwest, but it under-emphasized the fact that there were voltage reductions—one step away from blackouts. Even more important, the past summer was not as unusual as the report concludes it was.[4] The Midwest has insufficient capacity and could have a similar generation shortage in 1999. This problem could even continue for the next few summers.

Had it realized how bad the situation really is, the FERC staff might have drawn the correct conclusions about the urgency of additional action. The region is sufficiently close to having future blackouts next summer—so close that regulators and others should make it a primary concern to remove all impediments to deregulation and take proper steps to manage generation reliability during the transition to full deregulation. If we continue to move forward half-regulated and half-unregulated (i.e., with the wholesale market deregulated and the retail market regulated), then one of two transition strategies is required. Planning reserve margins sufficient to protect end users should be put in place and enforced with clear penalties,[5] as in NEPOOL. In the alternative, policy makers should rely on the market alone to set reserves. If the market route is chosen, the public should

3-3

be warned of the potential for rolling generation shortage-caused blackouts, especially in major urban areas, and especially during the transition.

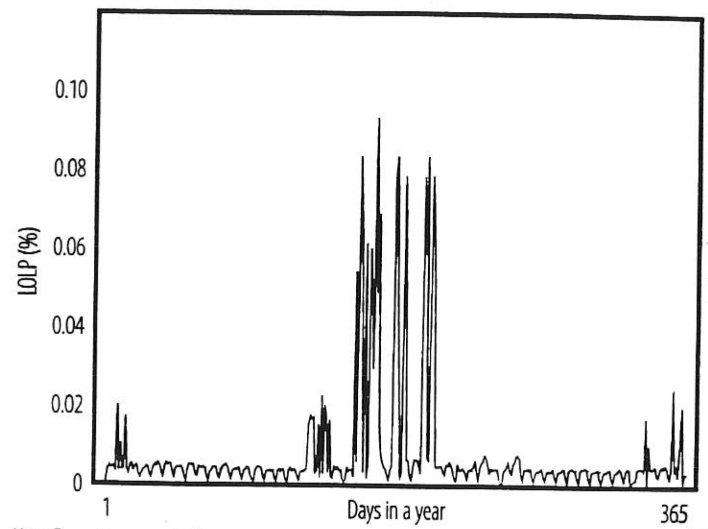
Capacity: The Specter of Shortage

The origins of this capacity shortage must be understood rather than minimized as in the FERC staff report.

First, the report notes that Midwest utilities have underestimated load growth over the last two years. However, the report fails to note that the industry has repeatedly and systematically underestimated load growth in the affected areas, those being MAIN, ECAR, SPP, SERC-TVA, and SERC-Southern. Note that these five areas were the only areas with super-high prices. (*See Figure 1.*) That fact emerges by comparing long-term forecasts of electricity demand growth with actual figures recorded over several recent years. It is not uncommon for actual demand to grow by two to four percent, but for utility forecasts to call for growth at only one to two percent. (*See Tables 1 and 2.*) Over the long run, these differences are huge; they are outside the range of forecast error (remember, these are 10-year averages). For example, a discrepancy of one percent a year for the identified five regions means an annual under-forecast of twelve 250 megawatt-sized plants and a 10-year under-forecast of over 120 individual plants sized at 250 MW.

The reason for this systematic problem is well known to insiders, though there are no depositions that one can identify to support this view. It is not simply that long-term average demand growth is difficult to forecast. Rather, utilities do not want to build new plants in the current in-between state of regulation and deregulation. The easiest way to avoid the need is to claim it does not exist. The greatest need to avoid appearances of impending shortages has emerged in the regions where this problem is most acute.

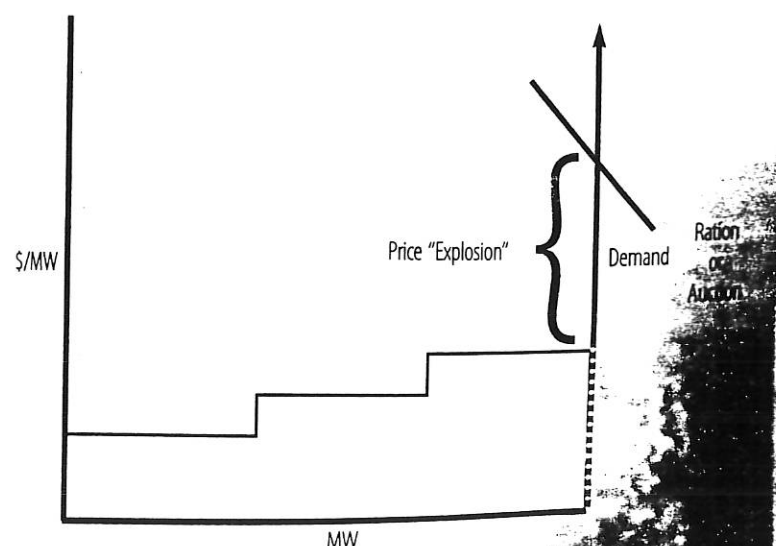
Figure 3: Hourly Capacity Pricing



Note: Figure is representative.

To understand this graphic:
— Loss of Load Probability (LOLP) largely occurs in summer peak.
— High price spikes occur when LOLP is significant.

Figure 4: Hourly "Pure" Capacity Pricing – Prices Explode When Capacity Runs Short



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Where has FERC been on the issue of load forecasts?

The state regulatory authorities have acquiesced in this situation for three main reasons. First, they do not want to have to raise customer rates to pay for new capacity. Second, they do not want to admit that the conservation estimates from their investments in demand-side management were exaggerated. Third, no one is really in charge in the mixed-up regulatory structure we currently have.

The FERC points out the problem in its own quotable argot, "The FERC does not have primary jurisdiction over all matters that may affect whether future spikes occur." Yet the grid is by its physical nature the supreme example of interstate commerce. If FERC does not take the lead, how can we expect anything but a very messy transition?

Reliable Information: Still Lacking

Where has FERC been on this issue of load forecasts? Not only has it been silent over these past few years; even today, the FERC remains relatively silent in the face of a transition crisis. In its staff report, the FERC failed to emphasize appropriately the essence of the problem: a chronic abuse of the public's need to have access to fair, independent forecasts from authorities with responsibility for grid generation reliability.

Another cause of this problem is the lack of transparent information from independent sources that reports the true state of the grid. The FERC staff did not address in its report the following issues:

- **BLACKOUTS**—There is a significant chance of blacking out[6] Midwest firm customers. In the jargon of the industry, there is a significant loss of load probability (LOLP) in many U.S. markets, especially in the Midwest. There is no mention of the term "loss of load probability" anywhere in the report (even in the footnotes or glossary).
- **LOLP ANALYSIS**—The report provides no explanation of the relationship between LOLP and high prices. Since wholesale prices explode because of the lack of capacity, it is impossible to separate a discussion of price spikes and reliability of firm load.
- **PUBLIC DATA**—The report should have demanded published, transparent LOLP planning estimates and for the supply of related information on plant availability, line capacity, and demand uncertainty.
- **ISOs**—The report made no clear demand for accelerating the creation of independent system operators. How could the report not attribute the poor functioning and surprising character of the market in any way to the fact that there was no ISO in the Midwest? Even today, there are no clear boundaries set for regional Midwest ISOs.

Significantly, the appropriate analytic structure for analyzing June 1998 was completely ignored in the report.

First, loss of load occurs when firm demand exceeds supply. This is assessed probabilistically, accounting for uncertainty in supply and demand, including transmission limits. (*See Figure 2.*) For example, FERC shows that during the week of June 22, 1998, ECAR and MAIN averaged outages of 17,500 MWs or about 12 percent of capacity. If this fact had been set in a probabilistic analysis, it would not have been seen and described as unusual, but as falling in the range of events to be expected, given the situation with nuclear plant availability.

Note that every outage, whether plant or transmission, is unique, but the average effect and average variation is the proper focus of analysis. The same is true of demand, which was less extreme than indicated. For example, most MAIN utilities did not experience their annual peak during June because the weather was not uniformly hot. Usually, there is more correlation between MAIN utility peaks.

Second, it is true that a market in equilibrium will tend to have some period of significant LOLP during the summer peak. (*See Figure 3.*) However, a capacity-short market will have too much LOLP, too many shortages, and too many spikes.

Third, a significant LOLP correlates with the chance that

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the market will end up on the vertical section of the supply curve, where buyers set the price. The buyers in this case are utilities acting as agents, expressing their willingness to pay to avoid a blackout. (*See Figure 4.*) This situation reflects an implicit "contract" between customers and utilities, arbitrated by regulatory authorities. Decisions are ideally based on the survey literature, which indicates that the average end user is willing to pay about $7,000/MWh or higher to avoid a blackout.

If the FERC staff report had applied this three-step approach, in combination with microeconomic theory and common sense, it would have reached several conclusions:

- **1998**—Prices reflected the fact that the market was very close to generation shortages and blackouts.
- **1999**—Prices will likely be lower, but only if weather is normal. Hot weather over a broad Midwest area next summer could well mean 1999 will be worse than 1998.
- **UNCERTAINTY**—Hot weather and sudden retirements could make the transition even tougher than expected.

There is currently no procedure in place to prevent retirement of existing units, especially nuclear units, during the transition to competition. The retirement without warning and explicit make-up actions of the huge Zion nuclear plant in Illinois was a leading cause of the 1998 price spikes, though it was not described as such by the FERC staff report.

Moreover, the seeming complacency about the lack of ISOs in the Midwest (the recently approved Midwest ISO still leaves most of the region outside an ISO structure) only adds to problems. This lack leaves no independent forum for Midwest decision making on reliability. It also prevents any comprehensive approach in providing credible information on such key parameters as demand, plant availability, LOLP, and transmission. Price information is important but other information is also crucial, especially as long as nearly all end users are dependent on events in the wholesale markets in which they cannot legally participate.

There were no blackouts, but the FERC staff under-emphasized the voltage reductions—one step away from blackouts.

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Deregulation: A Too-Slow Transition

The complacency about retail wheeling is blocking moves to obtain more explicit interruptible contracts and remote control of loads. Contrary to the popular view that retail wheeling should go slow to avoid mistakes, true competition is needed to create incentives to pursue potentially controllable or interruptible load.

This failure to complete the transition to complete deregulation—to have ISOs in place, to have state and federal governments commit to a market with adequate information and known rules—is inhibiting construction of new plants. Investors, already befuddled by the lack of basic information, are understandably hesitant to invest when the rules of the game are not clear. For example, will states suddenly insist on over-construction of new rate-based peaking units—thus killing merchant investments in peaking units—or will they rely on the market? Will there be transition arrangements like enforceable planning reserves (e.g., structures like NEPOOL and PJM) or complete reliance on the wholesale market? In other words, can politicians credibly claim that they know who is in charge of generation reliability, or that deregulation is so organized and coherent as to warrant reliance on market forces?

The failure to identify the unique circumstances in the Midwest blocks actions to resolve them. This failing is especially glaring in a report on the Midwest. Specifically, in the Midwest, combustion turbines are urgently required. These plants are suitable only for meeting power demand at the super peak. Their economic viability depends on super high prices, which are highly uncertain. Further, there is little experience building and financing peaking plants in a deregulated market. Turning to Wall Street for debt financing or new capitalization initiatives for what amounts to a new sector will be possible but will take time—all the more if deregulation remains incomplete and inefficient.

The uniqueness of the Midwest capacity situation is only fully seen by contrast. In New England, a huge construction boom is under way. Thus, one might expect a smooth transition to market-based construction in the Midwest. In New England, the revenue of the new plants appears more certain and more familiar to investors. These new plants do not depend on the exact balance between supply and demand at the extreme summer peak, but on the fact that their fuel costs are lower than old-style steam units now on line. These new plants employ new technology. They are thermally more efficient, for a given input in fuel cost. Their power production costs run about 30- to 40-percent lower. Thus, these plants are almost guaranteed to generate at least some income to cover debt obligation. These plants are also hedged. As fuel costs of new gas-fired combined cycles go up, so do power prices as they reflect the marginal costs of inefficient, old gas steam units. By contrast, Midwest peaking units could flip from feast to famine and have little or no income for debt.

Going Forward: At Least Identify the Risks

It is important that the market work as efficiently as possible. The market can ultimately handle the need for reliable supply—even for peaking plants in the Midwest. However, regulators must acknowledge the urgent need to get rules in place, finish the work of deregulation and, until then, inform the public of the risks inherent during the transition period.

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The public will ultimately benefit from deregulation. That fact gives all the more reason to understand and properly manage the precariousness of the current transition. Nearly all users lack hourly meters, remote control of load, explicit interruptible contracts, and hence, currently rely on utilities and regulators to act as their agents to obtain reliable power. They cannot yet legally participate in the markets. We owe them at least fair, impartial warnings about transitional risk, if not explicit protection.

Is it too difficult to imagine rolling blackouts, due to lack of generation? Skeptics should call Alberta or Colorado, where blackouts occurred this past summer, or Midwest power operators implementing emergency procedures last June. F

Judah L. Rose is a vice president of ICF Kaiser International Inc., and a frequent contributor to *Public Utilities Fortnightly.*

1 Sept. 22, 1998.

2 Artificial price limits combined with partial deregulation would clearly be the worst of all possible worlds; generation shortages would occur as regulators rediscover supply and demand.

3 $\$7{,}000 \text{ per MWh} \times \frac{\text{MW}}{1{,}000 \text{ KW}} \times 48\text{hours} =$ \$336/kW per year

4 If circumstances were so unusual, why was this event forecasted? See J. Rose, "Last Summer's Pure Capacity Prices: A Harbinger of Things to Come," *Public Utilities Fortnightly*, December 1997, p. 36; J. Rose and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly*, December 1995, p. 20.

5 Current procedure in MAIN, as described, is to use "peer pressure" to enforce planning reserve margins; peer pressure, not surprisingly, does not seem to be working.

6 Or voltage reductions or public appeals informing the public of the need for emergency customer self-curtailment.

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KANSAS SENATE

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COMMITTEE ASSIGNMENTS
CHAIRPERSON: JOINT COMMITTEE ON ECONOMIC DEVELOPMENT
VICE-CHAIRPERSON: COMMERCE
MEMBER: JUDICIARY
LOCAL GOVERNMENT
ELECTIONS, CONGRESSIONAL & LEGISLATIVE APPORTIONMENT & GOVERNMENTAL STANDARDS

December 18, 1998

John Wine, Chairperson
Kansas Corporation Commission
1500 Southwest Arrowhead Road
Topeka, Kansas 66604-4027

Dear Commissioner Wine:

On November 5, 1998, the Joint Committee on Economic Development held a hearing on electric generation capacity constraints. At that meeting, the Committee heard presentations from: Larry Holloway; Nick Brown, Southwest Power Pool; Earnie Lehman, Western Resources; and conferees from Farmland Industries, Boeing, Vulcan, and Raytheon.

Mr. Holloway reviewed for the Committee the order issued by the Commission on November 4, initiating an investigation of the future of Kansas electric generation capacity. On behalf of the Committee, I would strongly urge Commissioners Moline, Claus, and you to proceed expeditiously with your investigation. The Committee was very concerned about the projections for reserve capacity margins in the region based on information relayed by both Mr. Holloway and Mr. Brown. Of particular note was Mr. Brown's projection that the reserve capacity margin in the region could be as low as 3.8 percent in 2001, assuming peak demand growth of 4 percent. The Committee learned that for each of the past ten years, peak demand has been greater than forecasted. For example, the summer peak growth in 1998 was 5-7 percent for the region although only 2-3 percent had been projected. These projections, coupled with the power curtailments of large Kansas commercial and industrial customers this past summer, raised questions about whether the existing and planned capacity of Kansas utilities will adequately meet growth demands in the state over the next ten years.

Also of concern to the Committee was Western Resources' request to its firm customers within its certified service territories to "shed load" on June 25-26 and July 21-22. The Committee heard several presentations from KGE customers that raised the issue of Western Resources' obligations, when confronted with power constraints, to retail customers within its certified service territories and its obligations to wholesale customers, especially out-of-state wholesale customers. The Committee encourages the Commission to consider in its deliberations whether the utility proceeded correctly in its treatment of retail customers and wholesale customers during those four days in June and July.

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The Committee was particularly concerned about the implications of energy capacity constraints for economic development. If large companies, especially firm customers, cannot rely on their electric company for the requisite amount of power needed to meet their needs, they could decide to generate their own electricity, thus increasing the burden on other ratepayers, including residential ratepayers. Unreliable power supply can affect a company's plans to relocate to Kansas, expand in Kansas, or even remain in Kansas. Therefore, the Committee would encourage you in your deliberations about the adequacy of capacity to carefully analyze the assumptions underlying the demand forecasts and planned capacity resources. Consistently understated demand forecasts and resource planning intended to meet only identified existing needs may have adverse long-term implications for economic development in Kansas.

The Committee requests that the Commission periodically update the Legislature on the Commission's proceedings on this investigation and the complaint filed by Farmland Industries requesting an investigation of interruptible contracts.

Should you have any questions about these requests, please feel free to call me at (316) 838-3066.

Sincerely,

Pat Ranson

Senator Pat Ranson, Chairperson
Joint Committee on Economic Development

PR/sp

cc: Governor Bill Graves
Commissioner Brian Moline
Commissioner Cynthia Claus
Larry Holloway

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Testimony Before
The House Utilities Committee
by
Jim Ludwig
Western Resources
January 26, 1999

Chairman Holmes and members of the Committee:

Thank you for inviting Western Resources to appear before you today. I'll talk about the events of last summer that created some concern about our ability to provide enough electricity to meet the growing needs of our customers, how we determine those needs, the role played by interruptible service and wholesale service in meeting those needs and holding retail rates down, and our plans to restart and add additional generating capacity over the next several years. I'll also explain how Wolf Creek remains a resource fully used and required to be used to serve KGE customers.

Let me begin with several key points that will help you understand what follows.

1) Historically, the wholesale electricity market and interstate transmission network have allowed utilities to provide reliable service with fewer power plants. The wholesale market has allowed utilities to share risks, keeping overall costs lower. Recent profound changes in both the wholesale electricity market and control over the interstate transmission network to encourage wholesale competition have reduced reliability.

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2) Federal regulatory policy is driving utilities to cede substantial control over their transmission lines to independent parties. These parties can and do limit or stop electricity from flowing, regardless of the agreement between the buyer and seller of the electricity. This means purchases from other utilities can be suddenly curtailed, creating immediate and unexpected reliability problems.

3) Wholesale electricity markets are now largely deregulated with few price constraints and no utility service obligations beyond those stated in a contract between buyer and seller. With retail markets still fully regulated and utilities obligated to serve retail customers at fixed rates, utilities that have to buy electricity on the wholesale market can be financially whipsawed.

4) As excess generating capacity diminishes throughout the Midwest, the role played by interruptible customers in helping utilities maintain service to firm customers becomes more critical. Customers choosing interruptible service need to understand what it means, and how they can harm other customers if they refuse to be interrupted.

5) Western Resources is committed to providing the electricity needed to keep Kansas growing through cooperation with customers, other electric suppliers, transmission system operators, and regulators. We may ask for legislative assistance in simplifying or eliminating the Kansas Siting Act (for which no parallel exists in nearby states). Compliance with Siting Act requirements will add cost and could potentially delay

completion of urgently needed new generating capacity. We also anticipate asking the legislature to remove tax barriers and implement tax incentives for Kansas power plants.

The Summer of '98

The problems faced by Western Resources in meeting customer needs this summer were not unique to Western Resources but were shared by most utilities in the region. The bottom line is not one KPL or KGE customer was forced to reduce electric use unless they were contractually obligated to do so. Of course, many customers voluntarily reduced their electric use in response to our appeals for conservation. We can't thank those customers, perhaps including you, enough for that assistance.

Western Resources and other electric utilities do not operate in isolation. For over 30 years, and with government encouragement, utilities have become increasingly interdependent in the way we plan and use our transmission systems, and in relying on those systems to deliver electricity hundreds of miles to our customers. Western Resources and the other utilities in the Southwest Power Pool are part of a much larger group of interconnected utilities from the High Plains to the East Coast commonly called the Eastern Interconnection. Other groups of interconnected utilities exist in the western states and in Texas.

The summer of 1998 stressed the Eastern Interconnection's ability to serve customer load, caused rotating blackouts in other states and caused numerous transmission service curtailments. Part of this stress was caused by summer peak responsibility growth across the region of 5-7% instead of the projected 2-3% growth. (KGE's peak responsibility grew by 5.8% and KPL's by 4.8%.) Additional stress was created by the shutdown of several thousand MWs of nuclear generation in the upper Midwest (Wisconsin, Illinois, Michigan and Ohio). These shutdowns, combined with unscheduled unit outages (like the ones at our Lawrence and La Cygne power plants), created a shortage of generation at times throughout the Eastern Interconnection.

Many of the problems of serving the summer peak responsibility have been blamed on the weather, an inefficient energy market and artificially high energy prices. This is only part of the story. These problems occurred on numerous days from late May through September, not just on the hottest days. Even when energy was available on a daily and hourly basis, new difficulties arose in moving the energy from generators to customers. The difficulties are associated with new transmission arrangements to enhance wholesale competition that were put in place this year, including the Southwest Power Pool transmission tariff and new line loading relief procedures. In general, utilities have less control over their transmission systems, making delivery of purchased power less certain. There were times when electricity could not be delivered, and times when the market price of the available electricity rose.

Western Resources is committed to working with the Southwest Power Pool, other power pools and other power suppliers to restore smoothly functioning wholesale power markets and improve access to emergency electricity. We support the Federal Energy Regulatory Commission's order of December, 1998 requiring all utilities in the Eastern Interconnection to have in place transmission line loading relief and congestion management procedures by this coming summer.

These steps will reduce future price spikes like those that caused electricity in the summer of 1998 to cost as much as 100 times what it normally costs in the summertime.

Western Resources in the Summer of '98

In 1998, Western Resources experienced a peak responsibility of 4,287 MW. Our total capacity is 4,960 MW, of which 528 MW were unavailable because of forced outages, to meet this peak responsibility. The weather was certainly a factor during the summer. It was the warmest in Wichita since the scorcher of 1980. Nights were also unusually warm, causing many air conditioners to be run continuously for long periods. In addition, there was strong growth in non-weather sensitive peak responsibility. Western Resources' peak responsibility is estimated to have grown by roughly 30 MW more than normal. This underlying growth probably reflects the strong economy and job growth throughout our service territory and particularly in the Wichita area.

Western Resources and all other utilities are required by their power pools to maintain certain margins of generating (or purchased) capacity above their peak responsibility level. These reserves allow customers who are paying for uninterrupted service to be assured service, even if some generation has to be removed from service or extreme heat causes predicted peak responsibility levels to be exceeded. Unexpected generating outages during peak load conditions can force Western Resources into the mostly deregulated and less reliable wholesale power market to buy enough electricity to meet its peak responsibility. Fortunately, we were able to meet our peak responsibility with a combination of our own generating capacity and power purchased in the wholesale market, even though some of our generating capacity was out of service.

Now I'll explain more about how we measure peak responsibility and determine the generating capacity available to meet that peak responsibility.

Utilities make capacity decisions with long-term financial impacts (like building new power plants) based on predicted (not actual) peak loads. These predictions are updated at least annually and, during peak periods in the summertime, daily. Because of the mechanics of implementing interruptions, our system controllers must decide by midmorning whether to call for interruptions on a given day. Of course, should conditions change, system controllers can and will cancel their call for interruptions. Also note that we can and will work with customers that have a unique hardship in fully or timely complying with a specific request for interruption.

Peak responsibility includes retail and wholesale customers who are paying for firm service but does not include retail and wholesale customers who are paying lower rates for interruptible service. Western Resources does not include 191 MW of interruptible load from KGE and KPL retail customers in its peak responsibility projections. This is a normal, accepted practice in utility planning. Interruptible customers pay considerably less than firm customers in exchange for accepting a lower priority of service. The exact savings vary widely depending on the size of the customer and how steadily the customer uses electricity through the day, month and year. Savings from 20% to 40% below rates paid by firm customers are common.

Some wholesale customers pay for service from specific generating units. These are called capacity sales. To the extent portions of generating units are dedicated in this manner they cannot be used to meet peak responsibility. Service to these customers is interrupted if the specified generating units stop running or run at a reduced rate.

If interruptible customers do not curtail service when the utility requests, the utility is forced to count such customers as part of its peak responsibility and must continue to serve them. This service may be incredibly costly if the utility must buy additional electricity in the wholesale market.

If large interruptible customers choose to switch to firm service, the utility's predicted peak responsibility immediately jumps, and can force the utility to provide new generating capacity. This is unmanageable and costly considering the multi-year lead time to build capacity.

These rules are not unique to Western Resources. They are administered through regional power pools and the North American Electric Reliability Council, and cannot be controlled by individual utilities or states.

There were 51 hours spread over eight days last summer when KPL and KGE interruptible customers were requested to reduce their electrical consumption. Large customers were requested to voluntarily reduce consumption on four days. On July 20 and July 21 ALL customers were requested to conserve because of our concern about rotating electric outages. In the end, no outages were necessary.

Some interruptible customers apparently believe that wholesale customers with a higher service priority should have been interrupted first. Unfortunately, interrupting a firm supply to another utility in this highly interdependent region would have added to the risk of region-wide shortages. Diverting generating capacity from firm wholesale customers to interruptible retail customers would also violate our federally-approved contracts with those wholesale customers. In hindsight it appears that, because of receiving years of uninterrupted electricity at much lower prices, some interruptible customers viewed their service as firm, or at least viewed KGE's supply of excess capacity as inexhaustible. Perhaps some customers agreed to be interrupted without considering the consequences of interruptions to their own operation.

Some people may not realize the benefits that retail customers get when we make wholesale power sales. The Kansas Corporation Commission approves the rates KPL and KGE charge retail customers. In determining the revenues we can charge retail customers, the KCC makes reductions to reflect revenues collected from wholesale customers. If Western Resources did not make these wholesale sales, firm retail rates for BOTH KPL and KGE would have to be higher.

Adding Generating Capacity

While Western Resources met its obligation to serve its customers' peak loads last summer, there is an obvious need for more generating capacity here and in much of the country. We recognized this need even before last summer. Although KPL has not built a new power plant since 1983 and KGE has not built one since Wolf Creek was completed in 1985, we have invested in efficiency improvements at existing power plants to increase their output. Western Resources has added 118 MW of capacity at the coal-fired La Cygne and Jeffrey generating stations. This summer, 1999, we will restore KGE's mothballed Neosho power plant to service, adding 67 MW of capacity. The Neosho plant burns natural gas. We are purchasing 83 MW of peaking generating capacity from the McPherson municipal utility in addition to the 115 MW we purchased from McPherson last summer. We are also pursuing similar transactions for this summer with several other municipalities.

Even though both KPL and KGE need to add generating capacity, some KGE customers believe some portion of Wolf Creek should be assigned to KPL customers, apparently on the theory that they are already using Wolf Creek "electrons". Remember my earlier remarks about the Eastern Interconnection. Strictly speaking, every power plant connected to the Eastern Interconnection feeds electricity into the grid, while utility substations take electricity off the grid and deliver it to customers. Electrons aren't the issue. Each utility's balance of resources is the issue. A utility will run its generating plants based on their operating costs, with the cheapest-to-run plant generating first. In KGE's case, that plant is Wolf Creek. For KPL it is the Jeffrey Energy Center. KGE's peak responsibility this summer was 1,982 MW. Even on a mild spring or fall day, KGE firm customers demand roughly 1,200 MW of electricity. KGE's 47% share of Wolf Creek equals 560 MW, less than half what is required even on a mild day. Thus, when Wolf Creek is running, all power from the plant is needed to serve KGE customers.

Returning to the issue of new capacity, we recently announced our intention to build three combustion turbines adding approximately 300 MW of peaking, gas-fired generating capacity, partly in the spring of 2000 and partly in the spring of 2001. Both KPL and KGE will take shares of the new capacity, which amounts to a 5% increase in the total capacity owned by Western Resources. While this new capacity will meet our customers' needs for several years, it is not a long-term solution. As peaking capacity, the new turbines will typically operate less than 10% of the year. We are planning to locate the new turbines at KGE's Gordon Evans plant site near Colwich, northwest of Wichita in Sedgwick County. Their cost is estimated at $120 to $140 million. We are also pursuing joint ownership or participation in other new generating plants.

Despite the widely recognized need for this new capacity, we face a variety of hurdles in meeting the aggressive timetable we have set. A permit must be obtained from the Kansas Department of Health and Environment. We also need approval of a siting application by the KCC, which we filed December 2, 1998. The KCC staff has indicated a willingness to help expedite consideration of our application. Approval by April 15, 1999 will be essential to helping us meet our deadlines for installation of these new units.

It is difficult to plan to meet the needs of our customers when the electric utility industry is undergoing so much change. We expect those changes to continue. However, in accordance with our obligation to serve retail customers in our certified service territory, we must and will continue to provide reliable and reasonably priced electricity to our customers. It would certainly help if Kansas chose to encourage construction of additional generation, even while retaining regulatory control. The legislature can help by enacting tax incentives and streamlining or eliminating the Siting Act.

Thank you for the opportunity to testify today. We would be pleased to answer any questions you may have.

House Utilities Committee
Testimony of Chris Giles
Kansas City Power & Light Company
January 26, 1999

My name is Chris Giles. I am Director Regulatory Services and am pleased to be here on behalf of Kansas City Power & Light Company (KCPL). I was asked to provide information regarding KCPL's generation expansion plans. I will describe those generation expansion plans and briefly discuss the price spikes experienced in the summer of 1998 and some implications of those spikes for customers and retail competition or retail wheeling.

KCPL employs a complex and thorough long-term planning process which covers at least a 20 year period. Each year KCPL planners prepare a "needs assessment" which supplements the long-term plan. The "needs assessment" is utilized to both ensure adequate capacity is available in the near term and that decisions are made in a timely manner to either purchase capacity or construct generating equipment. Based on the Company's peak mw demand forecast, it's existing generating capability and capacity purchases, a capacity deficiency of 120 mw was identified for the summer of 2000.

KCPL plans to repower the steam generator at the formerly retired Hawthorn 4 unit, by adding a Heat Recovery Steam Generator (HRSG) to capture waste heat from the existing Hawthorn 6 unit. This will achieve an additional 140 mw of capacity. This capacity is scheduled to be operational by April 2000. Two additional simple cycle combustion turbines will be installed at the Hawthorn site. Each of these combustion

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turbines are rated 77 mw. The first unit is scheduled to be operational by June 2000 and the second unit by September 2000. Total additional capacity of 294 mw will be adequate until 2001 and possibly 2002. The Company filed the application required by the Kansas siting act for these units with the Commission the first week of January 1999. Approval of the application will be needed by July 1999 in order to meet the current operational schedule for this new capacity.

I will now direct my comments to the price spikes of 1998. Much has been written about the cause of the spikes in the summer of 1998. I agree with the majority of the points made in the report on this topic of the Joint Committee on Economic Development. However, I will make a few observations from KCPL's perspective.

KCPL has not historically under forecasted it's peak demand. As the chart attached to my testimony shows KCPL has historically over forecasted it's peak demand. In fact, KCPL's forecast accuracy is quite good. KCPL's peak demand on July 20, 1998 was 3136 mw compared to a forecast of 3115 mw. The actual highest peak demand during the summer of 1998 was 3175 mw. However, KCPL did not request curtailment of it's interruptible customers on that date so it is not a valid comparison to forecast. KCPL had adequate capacity available to serve it's customers in 1998. That does not mean KCPL was not subject to extremely high and volatile prices in the wholesale power markets.

On June 25, 1998 KCPL was close to paying prices as high as $4000 per mwh. That figure equates to $4 per kwh compared with a price that would be considered high but not unusual in 1997 of 8 cents per kwh or $80 per mwh. The highest price KCPL paid in 1998 was $1800 per mwh. Although, generation outages, storm related transmission outages, and other factors may have contributed to these unusual price spikes, prices experienced during the remainder of the summer indicates the price of power is going up and it will remain volatile until an efficient wholesale market develops. The high norm of $80 per mwh has been replaced with a high norm of $350 to $500.

Suggestions by some that more rapid implementation of retail competition or retail wheeling will alleviate this problem are totally unfounded. In fact, adding additional participants, retail customers, to this existing, ill defined and inefficient market, will magnify the problems and not only affect those retail customers currently billed under real time pricing rates (wholesale type pricing) and utilities, but all retail customers. Retail customers essentially become wholesale customers in a retail wheeling environment. How then is the problem to be resolved?

The transmission system is reliable, generation capacity is adequate and to the extent additional capacity needs to be constructed in the future to meet demands for power it will be built under either a competitive or regulated environment. However, until an Independent System Operator (ISO) is established to manage transmission constraints and an efficient spot market develops, prices will continue to be extremely volatile. An ISO with a formal power exchange as a function of the ISO could serve as a spot market and would alleviate much of this price volatility. This is the system that is in place in each state that has implemented retail competition. Retail wheeling should not be permitted until a wholesale market is established.

One final comment, customers currently billed under real time pricing tariffs or contracts are justifiably upset with the wholesale price volatility, as are the utility companies. However, these are the same customers that typically propose retail competition. These customers want lower prices but at the same time they want the risk protection afforded them today through regulated prices. To ensure customers receive access to potentially lower prices that they expect, but not the volatility in the current immature wholesale market, which they can't tolerate, the wholesale market must become efficient and effective before retail competition. I urge retail customers that await the dawn of competition to take a step back and evaluate whether sufficient market mechanisms, prior to competition, are in place to protect customers.

Thank you. I will be happy to answer any questions.

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Exhibit 1
Actual vs. Forecast Peaks

	Actual	Forecast	Act/Fore
1986	2373	2382	0.9962
1987	2531	2496	1.0140
1988	2656	2578	1.0303
1989	2541	2677	0.9492
1990	2711	2727	0.9941
1991	2751	2773	0.9921
1992	2624	2807	0.9348
1993	2819	2884	0.9775
1994	2714	2938	0.9238
1995	2909	2996	0.9710
1996	2987	2982	1.0017
1997	3044	3055	0.9964

Mean Act/Fore	0.9817
Std. Dev.	0.0320
Count	12

HOUSE UTILITIES
DATE: January 26, 1999
ATTACHMENT 7

WESTPLAINS ENERGY - KANSAS
LOAD AND RESOURCE FORECAST
January, 1999

	SYSTEM PEAK RESPONSIBILITY (MW)									RESERVE MARGIN		
YEAR	NATIVE LOAD NET 1-HR	WPECO SALE	TOTAL SYSTEM PEAK RESP.	TOT SYSTEM RESERVE RESP.	CAPACITY SALES	CAPACITY REQD	ACCREDITED GENERATING CAPACITY	SEC PURCH	TOTAL SYSTEM CAPACITY	CAPACITY BALANCE	CAPACITY MARGIN	RESERVE MARGIN
1999	500	20	520	78	6	604	558	50	608	4	13.7%	15.8%
2000	508	20	528	80	6	614	558	60	618	4	13.8%	15.9%
2001	517	20	537	81	3	621	558	65	623	2	13.4%	15.5%
2002	526	20	546	82	3	631	558	75	633	2	13.4%	15.4%
2003	536	20	556	84	3	643	558	85	643	0	13.1%	15.1%
2004	545	20	565	85	3	653	558	95	653	0	13.1%	15.0%
2005	555	20	575	87	0	662	558	0	558	(104)	-2.6%	-3.0%
2006	565	20	585	88	0	673	558	0	558	(115)	-4.0%	-4.6%
2007	575	20	595	90	0	685	558	0	558	(127)	-5.4%	-6.2%
									Minimum Capacity Margin:		13.04%	

ACCREDITED GENERATING CAPACITY

GENERATING UNIT NAME	CAPACITY, MW	TYPE	FUEL
Arthur Mullergren #3	90.5	Base/Int. (ST)	Nat. Gas
Cimmarron River #1	58.0	Int./Peak (ST)	Nat. Gas
Cimmarron River #2	14.0	Peak (CT)	Nat. Gas
Clifton #1	71.0	Peak (CT)	Nat. Gas
Clifton #2	2.5	Peak (IC)	#2 Oil
Judson Large #4	142.8	Base/Int. (ST)	Nat. Gas
Jeffrey Energy Ctr #1	59.7	Base (ST)	Coal
Jeffrey Energy Ctr #2	59.7	Base (ST)	Coal
Jeffrey Energy Ctr #3	59.7	Base (ST)	Coal
TOTAL CAPACITY	557.9		