Approved:
Date [redacted] 3-1-01

MINUTES OF THE SENATE UTILITIES COMMITTEE.

The meeting was called to order by Chairman Senator Stan Clark at 9:30 a.m. on February 20, 2001 in Room 231-N of the Capitol.

All members were present except:

Committee staff present: Raney Gilliland, Legislative Research
Tom Severn, Legislative Research
Bruce Kinzie, Revisor of Statutes
Lisa Montgomery, Revisor of Statutes
Ann McMorris, Secretary
Chris Crowder, Intern to Senator Clark

Conferees appearing before the committee: none

Others attending: See attached list

Approval of Minutes
Moved by Senator Lee, seconded by Senator Taddiken, approval of Senate Committee meeting minutes for February 19, 2001 with addition of the words "*none or*" under **SB 177**, paragraph 3, line 4 after the word 'and', be approved. Motion carried.

Chairman announced an article on Storage of Natural Gas copied from the Internet was distributed. On February 27, 2001 the committee will be holding hearings on Storage. Legislators from the Hutchinson area are invited to be a part of the committee for these hearings. (Attachment 1)

An article entitled "Providing the Proper Climate to Stimulate Construction of Generation and Transmission Facilities in the State of Kansas was provided by Midwest Energy Inc. (Attachment 2)

Chairman Clark opened for continuation of discussion on:

SB 177 - Independent Power Producer Property, taxation, assessed rate

Larry Holloway, KCC chief of energy operation, provided a letter of clarification on qualifications of existing generating units and offered language for a new part (f) to Section 1 pf **SB 177.** (Attachment 3)

Moved by Senator Brownlee, seconded by Senator Tyson, to amend **SB 177** by adding to Section 1 language for a new part (f) "*Additional generating capacity achieved through efficiency gains by refurbishing or replacing existing equipment at generating facilities placed in service before January 1, 2001 shall not qualify under section 1 (e) of this act.*" Motion carried.

Cynthia Smith, Kansas City Power & Light, provided a balloon for **SB 177** with language for part (c) in New Sec. 2. (Attachment 4) This new section includes accounts for all types of generation as itemized in FERC code of federal regulations on plant accounts and defines for purposes of property & ad valorem taxes.

Moved by. Senator Wagle, seconded by Senator Tyson, amend **SB 177** by adding to New Sec. 2, page 2, paragraph "*(c) For purposes of property and ad valorem taxes, independent power producer property of the nature itemized in Federal Energy Regulatory Commission plant accounts (i) 101 - 312, 313, 314, 315, and 316; (ii) 101- 322, 323, 324, and 325; (iii) 101 - 332, 333, 334, 335, and 336; or (iv) 101 - 342, 343, 344, 345 and 346 of the Code of Federal Regulations, shall be tangible personal property.*" Motion carried.

Discussion on other proposed additions to **SB 177** by Kansas City Power and Light. No action taken.

Moved by Senator Barone, seconded by Senator Brownlee, **S.B. 177** be passed out favorably as amended. Motion carried.

Chairman announced he is asking for **SB 112, SB 144 and SB 299** to be blessed. Hearings on these bills will be held on March 7, 8 and 9.

Next meeting of Senate Utilities Committee will be held on Tuesday, February 27, 2001.

Adjournment.

Respectfully submitted,

Ann McMorris, Secretary

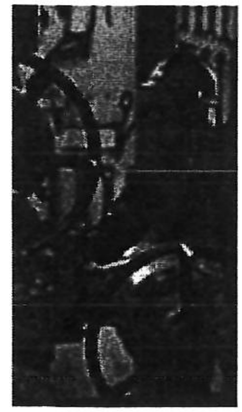
Attachments - 4

SENATE UTILITIES COMMITTEE GUEST LIST

DATE: **February 20, 2001**

Name	Representing
John Crowder	Sen. Clerk
SHANNON GREEN	KCPL
JOHN C. BOTTENBERG	West. Res.
Whitney Damron	KS Gas Service
Andy Shaw	SWKIA
[illegible]	KCC
TOM DAY	KCC
Dan Holthaus	WR
BRUCE GRAHAM	KEPCo
Cynthia Smith	KCPL
JC Long	UCU
Chris Wilson	KGC

Storage


Source: NGSA

When natural gas reaches its destination from a pipeline, it is often stored prior to distribution. It acts as a sort of buffer between the pipeline and the distribution system. Storage allows distribution companies to serve their customers more reliably by withdrawing more gas from storage to meet customer demands during peak use periods. It also allows the sale of fixed quantities of natural gas on the spot market during off-peak periods. Having local storage of gas also reduces the time necessary for a delivery system to respond to increased gas demand. Storage also allows continuous service, even when production or pipeline transportation services are interrupted. For example, adequate storage allowed gas service to customers despite the damage caused to gas facilities by Hurricane Andrew in 1992.

There are more than 400 underground storage sites in 27 states across the United States and Canada. Together, these sites can hold upwards of 3 quads of natural gas, ready to be withdrawn at any time. Despite these high numbers, storage capacity is always increasing in order to accommodate increased gas usage and improve reliability. A **MORE..** map of natural gas storage in the lower 48 states.

Underground storage, in common usage, is gas transferred from the reservoir of discovery to other reservoirs, usually closer to market areas, where it is stored until needed to meet market demand. Natural gas is stored in underground reservoirs primarily to ensure the capability of the gas industry to meet seasonal fluctuations in demand. Underground storage supplements the industry's production and delivery systems, allowing supply reliability during periods of heavy gas demand by residential and commercial consumers for space heating. Storage is also used occasionally as a conservation measure to prevent flaring and other waste when production rates exceed marketability.

The three principal types of underground storage sites used in the United States today are:

1. depleted reservoirs in oil and/or gas fields,
2. aquifers, and
3. salt cavern formations.

Each type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation costs, deliverability rates, cycling capability), which govern its suitability to particular applications.

The most important characteristic of an underground storage reservoir is its capability to hold natural gas for future delivery. The measure of this is called working gas capacity: the amount of natural gas inventory that can be withdrawn to serve customer needs. In addition to working (top storage) gas, underground storage reservoirs also contain base (cushion) gas and, in the case of depleted oil and/or gas field reservoirs, native gas. Native gas is the gas that remains after economic production ceases and before conversion to use as a storage site. Upon development of a storage site, additional gas is injected and combined with any existing native gas in order to develop and maintain adequate storage reservoir pressure to meet required service. The resulting (permanent) inventory is referred to as the base or

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cushion load. During heavy demand periods, some base gas may be withdrawn temporarily and delivered as working gas, but over the long term, base levels must be maintained to ensure operational capability.

Relatively small quantities of gas are stored as liquefied natural gas (LNG) in specially constructed insulated containers, and small volumes of compressed gas are stored in tanks commonly referred to as gas holders. For short periods the pipes themselves are used for storage by compressing more gas into the same space; this is called line packing. Peak demands (peaking service) are also met by synthetic gas or propane and other natural gas liquids.

In 1915, natural gas was first successfully stored underground in Welland County, Ontario, Canada. Several wells in a partially depleted gas field were reconditioned. Subsequently, gas was injected into the reservoir and withdrawn the following winter. In the United States, in 1916, Iroquois Gas Company placed the Zoar field, south of Buffalo, New York, into operation as a storage site. In 1919, the Central Kentucky Natural Gas Company repressured the depleted Menifee gas field in Kentucky. By 1930, nine storage pools in six different States were in operation with a total capacity of about 18 Bcf. Before 1950, essentially all gas storage was in partially or fully depleted gas reservoirs.

In some areas of the country, particularly the Midwest, suitable depleted gas/oil fields were unavailable for potential conversion to storage fields. As a result, the concept of using an aquifer formation for storage was tested and developed. Although the testing was done in the 1930's, it was not until the early 1950's that attention was turned to the use of aquifers for storing natural gas.

Types and Uses of Underground Storage

Most existing gas storage in the United States is held in depleted natural gas or oil fields located close to consumption centers. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections. The geology and producing characteristics of a depleted field are also well known. However, choices of storage field location and performance are limited by the inventory of depleted fields in any region.

In some areas, most notably the Midwestern United States, natural aquifers have been converted to gas storage reservoirs. An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive.

Salt caverns, the third main type of storage, provide very high withdrawal and injection rates compared with their working gas capacity. Base gas requirements are relatively low. The large majority of salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast States. Salt caverns leached from bedded salt formations in Northeastern, Midwestern, and Western States are also being developed to take advantage of the high volume and flexible operations possible with a cavern facility. Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn.

Storage facilities may be classified as seasonal supply reservoirs (depleted gas/oil fields and aquifers for the most part) and high-deliverability sites (mostly salt cavern reservoirs). Seasonal supply

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sites are designed to be filled during the 214-day nonheating season (April through October) and drawn down during the 151-day heating season (November through March). High-deliverability sites are situated to provide a rapid drawdown (or rebuilding) of inventory to respond to such needs as volatile peaking demands, emergency backup, and/or system load balancing. Compared to seasonal storage, high-deliverability sites can be drawn down in 20 days or less and refilled in 40 days or less.

High deliverability can be achieved in a depleted oil or gas reservoir if the reservoir rock has high porosity and permeability (allowing a rapid flow of gas), and the reservoir has sufficient base gas pressure and a sufficient number of wells to maximize withdrawal. Additionally, it would be desirable to be able to refill a reservoir in a reasonably short time. Salt cavern storage is ideal for high deliverability, as the entire cavern is one large "pore." On average, salt storage facilities can withdraw their gas in 12 days, versus 71 days for aquifers and 64 days for all depleted oil or gas reservoirs. Newly introduced horizontal drilling techniques permit storage in older depleted gas/oil field reservoirs). Seasonal supply sites are designed to be retrofitted to increase deliverability. during the 214-day nonheating season (April through October) and drawn down during the 151-day heating season (November through March). High-deliverability sites are situated to provide a rapid drawdown (or rebuilding) of inventory to respond to such needs as volatile peaking demands, emergency backup, and/or system load balancing. Compared to seasonal storage, high-deliverability sites can be drawn down in 20 days or less and refilled in 40 days or less.

Depleted Gas or Oil Fields

Underground storage in depleted gas/oil fields is used when gas can be injected into reservoirs with suitable pore space, permeability, and retention characteristics. All oil and gas reservoirs share similar characteristics in that they are composed of rock with enough porosity so that hydrocarbons can accumulate in the pores in the rock, and they have a less permeable layer of rock above the hydrocarbon-bearing stratum. The hydrocarbon accumulation in the porous rock is pressurized by the weight of hundreds or thousands of feet of rock on top of the reservoir. When a well hole penetrates the impermeable cap layer of rock, the hydrocarbon under pressure is exposed to the much lower atmospheric pressure, and gas can flow into and out of the well.

Depleted oil and gas reservoirs are the most commonly used underground storage sites because of their wide availability.They use the pressure of the stored gas and, in some cases, water infiltration pressure to drive withdrawal operations. Cycling (number of times a year the total working gas volume may be injected/withdrawn per year) is relatively low, and daily deliverability rates are dependent on the degree of rock porosity and permeability, although the facilities are usually designed for one injection and withdrawal cycle per year.

Daily deliverability rates from depleted fields vary widely because of differences in the surface facilities (such as compressors), base gas levels, and the fluid flow characteristics of each reservoir. Retention capability, which is the degree to which stored gas is held within the the reservoir area, however, is highest of the three principal types of underground storage. Depleted field storage is also the least expensive to develop, operate, and maintain.

In order to use an abandoned gas reservoir for storage, one or more of the wells used for extraction are typically used to inject gas. As with extraction, the more porous the rock, the rate of injection can be. As pressure builds up in the reservoir, the rate of injection slows down (pushing the gas in against higher pressure requires more force). Similarly, when the reservoir is at peak pressure, the rate of extraction is greater than at minimum pressure.

The factors that determine whether a gas reservoir will make a good storage reservoir are both

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geographic and geologic. The greater the porosity of the rock, the faster the rates of injection and withdrawal. In some cases, where the reservoir rock is "tight" or of low porosity, then some form of stimulation of the reservoir may also be performed. This would include various methods to introduce cracks into the reservoir rock, thus increasing the opportunities for the hydrocarbon to flow towards the well hole. (See hydraulic fracturing).

The size of the reservoir (the thickness of the gas-bearing rock stratum and the extent to which the stratum is covered by cap rock) is another factor. Location is also a factor. If the reservoir is not close to existing trunk pipelines or market areas and distribution lines, then greater expense will be incurred to establish connecting pipelines.

Aquifers

An aquifer storage site is a water-only reservoir conditioned to hold natural gas. Such sites are usually used as storage reservoirs only when depleted gas or oil reservoirs are not available. Aquifers have been developed exclusively in market areas. In general, aquifer storage is more expensive to develop and maintain than depleted gas or oil reservoir storage.

Today, aquifer storage accounts for only 11 percent of the total working gas capacity and daily deliverability in the United States. Most of the aquifer storage is located in the States of Illinois (18), Indiana (8), and Iowa (4). In fact, all of the underground storage sites in Iowa are aquifers. The remaining eight aquifer sites are scattered among five different States. See map of storage sites in lower 48 states.

There are several reasons why an aquifer is the least desirable site for natural gas storage. First, it takes much longer to condition the site: on average about 4 years, which is twice as long as for an average depleted gas or oil field. Unlike a depleted site, the geology of an aquifer site is unknown beforehand. As a result, seismic testing must be performed to determine its geologic profile. Important also are such characteristics as the confinement area of the reservoir, the location and type of the "cap" rock ceiling barrier, existing reservoir pressure, and the porosity and permeability of the reservoir rock. The potential capacity of the reservoir is also unknown and can only be determined as the site is further developed.

Second, all new facilities must be installed, including wells, pipelines, dehydration facilities, and compressor operations. Aquifer storage sites may also require additional facilities such as greater compression for injection purposes (to push back the water), more extensive dehydration facilities (which are not always needed at gas reservoir sites), and "collector" wells drilled into formations above the cap rock, which recover gas that may penetrate out of the storage zone. An important consideration is that the design of the facilities specifically meet the peak-period needs of the customers expected to use the service. Because of the additional support of an aquifer's water (pressure) drive, in most instances, higher sustained deliverability rates than gas or oil reservoirs can be designed and incorporated at the site.

Third, no native gas is present in an aquifer formation. Thus, once initial testing has been completed and site development approval has been granted, base or cushion gas must be introduced into the reservoir to build and maintain deliverability pressure. While base gas in gas/oil storage reservoirs usually is about 50 percent of total capacity, base gas in aquifer storage may constitute as much as 80 to 90 percent by the time the site is fully developed for gas storage.

Needless to say, the need to acquire such large volumes of base gas to maintain operational integrity is a crucial component in assessing the economic viability of the overall project. Most, if not

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all, of this base gas is not recoverable (even when the site is abandoned). Many of the sites in operation today were developed when the market price for natural gas was very low. In today's market, developing aquifer storage can be a very expensive undertaking.

Aquifer storage deliverability during the heating season is designed around specific customer requirements. These requirements may be for deliveries over a set period of time, for instance, 20, 60, or 120 days. The overall facility design reflects these combined requirements. These requirements also delimit the degree of cycling, that is, the number of times total working levels may be depleted and replenished during a heating season, that may occur at an aquifer site. The sustained delivery rate cannot exceed design limits. Otherwise, unlike depleted oil and gas reservoir storage where cushion gas can be tapped when needed, tapping cushion gas in an aquifer storage site can have an adverse effect upon reservoir performance.

Lastly, and perhaps the most important constraint on the future use of aquifer formations for natural gas storage, is the environmental qualifier. In the early 1980's, the U.S. Environmental Protection Agency (EPA) issued regulations that tightly restrict the future development of aquifer storage in an effort to avoid further or potential contamination of available water supplies. A permit for aquifer storage will be issued only if the potential site has salinization levels that make the water unusable for drinking or most agricultural purposes. Additional restrictions also apply.

Salt Formations

Salt formations have several properties that make them ideal for storing natural gas. A salt cavern is virtually impermeable to gas and once formed, a salt reservoir's walls have the structural strength of steel. Thus, gas cannot easily escape the large hollowed-out shape that forms a salt storage cavern.

There are two basic types of salt formations used to store natural domes and beds. Salt domes are very thick salt formations. A salt dome formation might be a mile in diameter, 30,000 feet in height, and begin about 1,500 feet below the surface. The depth of the caverns that are hollowed out within the formation is critical for reasons of pressure and structural integrity. The pressure at which the gas can be stored is a function of the depth of the cavern. However, at extreme depths, as temperature and pressure increases, salt behaves as a plastic and will creep or flow, which can become a major consideration in cavern construction possibly leading to cavern closure. Thus, salt storage is generally limited to depths shallower than 6,000 feet.

A salt bed storage site, on the other hand, is generally developed from a much thinner salt formation (1,000 feet or less) located at shallower depths. As a result, the height-to-width ratio of the leached cavern is much less than with dome reservoirs, which are relatively high and narrow. Salt bed storage formations also contain much higher amounts of insoluble particles (shale and anhydrite rock) than salt dome formations. These materials remain in the reservoir after the leaching process and affect the flow velocity and capacity of the reservoir itself. In addition, because the height/width aspect is thin, the flatter reservoir ceiling is subject to greater stress and potential wall deterioration. As a result of these as well as other factors, salt bed storage development and operation can be more expensive than that of salt dome storage.

Salt bed or dome storage is prepared by injecting water (leaching) into a salt formation and shaping a cavern. It is the most costly of the three types of facilities to develop, often two to three times more expensive. Because they are susceptible to cavern wall deterioration over time and to salt water incursion, these facilities may incur high workover costs, as well as attracted LDC's as well as additional expenses for special equipment on site. However, deliverability rates are high because a salt formation reservoir is essentially a high-pressure storage vessel (that is, an underground tank). Base gas

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requirements are low (about 25 percent) and can usually be withdrawn fully in an emergency. On average, salt formation storage is capable of multiple cycling of inventory per year, in comparison to the typical one cycle or less for depleted gas/oil field and aquifer storage. As such, salt formation storage is well suited for meeting large swings in demand.

Eleven of the existing natural gas salt storage formation sites once were used to store natural gas liquids (NGL) or brine and were converted to natural gas storage. Although more than 100 salt formation caverns in the United States and Canada are used to store NGL's, not too many conversions are expected because most of them are extremely small in size. A salt cavern site occupies a much smaller area than an oil or gas reservoir. On average, the amount of acreage taken up by a depleted gas/oil field reservoir is more than a hundred times the amount of acreage taken up by a salt dome. Consequently, a salt cavern storage operation is generally easier to monitor than a gas/oil field reservoir operation made up of many wells. Development time is also much less for salt formation storage than for gas/oil field reservoirs. On average, it takes about 18 to 24 months to develop a salt reservoir while a gas/oil field reservoir takes 24 to 36 months. Thus, a new salt formation storage site will begin to pay off sooner than a gas/oil field reservoir.

For the same working gas capacity, new salt formation storage reservoirs are also capable of yielding much greater revenues for a heating season than conventional gas/oil field reservoirs. This is because the working gas capacity of a salt formation storage facility can be turned over three, four, or more times during a heating season while generally a gas/oil field operation can be turned over only once. Most of the Nation's salt dome storage facilities are located in Texas, Mississippi, and Louisiana. Although used effectively by electric utilities in the South to satisfy daytime peak cooling loads during the summer, several salt cavern operations located in Louisiana and Mississippi have attracted LDC's as well as other types of customers located in the Northeastern United States. Perhaps in response to this demand, several salt storage sites are being developed in New York State. These facilities would augment directly the operations of nearby gas distribution companies.

In summary, although they are the most expensive type of storage to develop and maintain, salt formation storage facilities permit withdrawals at high rates and can be drawn down quickly in emergency situations. As such, salt formation sites are well suited for peaking operations to meet dramatic swings in gas demand.

Storage Played a Key Role During the Record Cold in January 1994

The severe winter of 1993-94 placed enormous demands upon the natural gas industry. Record cold temperatures and heavy snowfall in the Northeast and Midwest during January 1994 led to record monthly natural gas demand, with consumption nationwide reaching 2,538 billion cubic feet (Bcf), 10 percent higher than during the previous January. Storage facilities were extensively used to respond to the immediate needs of space-heating customers. Many companies reached all-time daily withdrawal and sendout levels, particularly during the third week of January. On January 19, Consumers Power, Michigan's largest gas and electric utility, and Michigan Consolidated delivered record volumes (3.1 and 2.5 Bcf, respectively) of which about 70 percent was from storage. On both January 18 and 19, ANR Pipeline withdrew a record 3.3 Bcf per day from its Michigan fields-almost 4 percent of working gas levels at the beginning of the heating season and substantially more than the previous peak of 2.8 Bcf per day.

Working gas levels were drawn down sharply during the month with withdrawals totaling 756 Bcf, equivalent to 30 percent of gas consumed. During the extremely cold third week of the month, the volume of total working gas in storage dropped 253 Bcf, as estimated by the American Gas Association (AGA). This change was 33 to 54 percent greater than the decline in each of the previous 2 weeks and

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was 11 percent of the working gas in storage on December 31. The most extreme drawdowns in January occurred in the AGA's Consuming East Region (mainly the gas-consuming States east of the Mississippi River), where estimated net withdrawals of 489 Bcf were approximately 36 percent of the gas consumed. The interstate pipeline and local distribution companies (LDC's) serving this area rely on storage withdrawals for a substantial portion of supply during the heating months and have extensive storage facilities already in place. In the producing States, during the heating season, storage facilities are used primarily to balance flows on main interstate transmission lines. However, in the single week from January 14 to 21, working gas levels in the Producing Region declined significantly (76 Bcf), showing that producers and marketers were relying on storage as well as wellhead production from the region to meet gas demands. This drop in the level of working gas was 49 to 90 percent greater than the decline that occurred in each of the previous 2 weeks in this region.

Markets in the West are less weather-sensitive and seasonal storage requirements are correspondingly lower. In addition, extensive transmission capacity is now available into California and other major western markets. The Consuming West Region had the lowest level of working gas in storage during January, and activity was unaffected by the eastern cold spell. The region's decline in working gas from January 14 to 21 was only 14 Bcf-lower than the 16 to 25 Bcf declines that occurred in this region during each week of February.

Overall storage withdrawals during January 1994 were 27 percent higher than during the previous January and second only to the 822 Bcf withdrawn in December 1989 when frigid weather in the supply region caused some disruptions in production. Today's pipeline system is quite different from that in 1989, with much more import capacity available from Canada and more system flexibility to enable gas to move quickly during peak demand periods. For example, the large Iroquois Pipeline in the Northeast was designed to handle peak summer loads for electricity generation and thus has sufficient capacity during the winter to allow extensive linepacking, which is a method for using the pipeline for short-term gas storage. When emergency supplies were needed by Consolidated Edison of New York during January 1994, Iroquois was able to deliver gas from linepacking, and several companies were able to divert their supplies to Consolidated Edison and then replace them with propane and liquefied natural gas from storage.

The additional storage capacity placed in service since 1989 also played a role in supporting the successful delivery of gas to markets during January 1994. From 1990 through 1993, 136.5 Bcf of working gas capacity and 5.7 Bcf per day of deliverability were added, representing increases of 3.8 and 9.2 percent, respectively, over levels in 1989.

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SOURCES

Bill Gerger and Kenneth Anderson's *Modern Petroleum: A Basic Primer of the Industry, 3rd Edition*
Copyright 1992 by PennWell Publishing and,
Arlon R. Tussing and Bob Tippee's *The Natural Gas Industry: Evolution, Structure, and Economics, 2nd Edition*
Copyright 1995 by PennWell Publishing.

Publications of the Natural Gas Council, Natural Gas Supply Association and Independent Petroleum Association of America.

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American Gas Association, Storage Reports, 1994.
Natural Gas Intelligence, Articles, 1994.
Most of the body of the text was adapted from the Energy Information Administration's various publications and reports available in PDF format from the EIA's natural gas site, http://www.eia.doe.gov/fuelnatgas.html.

Exploration Extraction Production Transport Storage
Distribution End Use Supply Environment Policy
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Table 11. Underground Natural Gas Storage Capacity by State, December 31, 1999
(Capacity in Billion Cubic Feet)

State	Salt Caverns		Aquifers		Depleted Fields		Total		
	Number of Active Fields	Capacity	Number of Active Fields	Capacity	Number of Active Fields	Capacity	Number of Active Fields	Capacity	Percent of U.S. Capacity
Alabama	1	3	0	0	0	0	1	3	0.04
Arkansas	0	0	0	0	2	24	2	24	0.29
California	1	2	0	0	8	386	9	388	4.72
Colorado	0	0	0	0	9	100	9	100	1.21
Illinois	0	0	17	745	13	153	30	899	10.92
Indiana	0	0	17	95	11	19	28	113	1.38
Iowa	0	0	4	273	0	0	4	273	3.32
Kansas	1	4	0	0	17	298	18	301	3.66
Kentucky	0	0	3	10	22	210	25	220	2.67
Louisiana	6	34	0	0	8	530	14	564	6.85
Maryland	0	0	0	0	1	62	1	62	0.75
Michigan	2	4	1	31	46	1,037	49	1,072	13.02
Minnesota	0	0	1	7	0	0	1	7	0.09
Mississippi	3	31	0	0	4	103	7	134	1.63
Missouri	0	0	1	31	0	0	1	31	0.38
Montana	0	0	0	0	5	372	5	372	4.52
Nebraska	0	0	0	0	1	39	1	39	0.48
New Mexico	0	0	1	12	2	85	3	97	1.17
New York	1	1	0	0	21	174	22	175	2.13
Ohio	0	0	0	0	24	575	24	575	6.99
Oklahoma	0	0	0	0	13	395	13	395	4.80
Oregon	0	0	0	0	3	12	3	12	0.14
Pennsylvania	0	0	0	0	59	685	59	685	8.32
Tennessee	0	0	0	0	1	1	1	1	0.02
Texas	13	105	0	0	21	579	34	684	8.32
Utah	0	0	2	12	1	110	3	122	1.48
Virginia	1	1	0	0	1	4	2	5	0.06
Washington	0	0	1	37	0	0	1	37	0.45
West Virginia	0	0	0	0	36	733	36	733	8.91
Wyoming	0	0	1	10	6	96	7	106	1.29
Total	**29**	**185**	**49**	**1,263**	**335**	**6,781**	**413**	**8,229**	**100.00**

Note: Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration (EIA), Form EIA-191, "Underground Gas Storage Report."

Table 11 has been revised to present storage capacity by type of facility.

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Providing the Proper Climate to
Stimulate Construction of Generation and Transmission Facilities
In the State of Kansas

Midwest Energy, Inc.

Kansas, like so many other states in the United States, has seen very little construction of new generation and transmission facilities in the past decade. Fortunately, Kansas came into the 1990s with an adequate margin of reserve generation, so there was some "headroom" to work with. Over the past few years a substantial part of that headroom has evaporated. The reason for this reduction in generation reserve margin, and developing constraints on transmission systems in the region, is really quite simple. The electric load has grown while the resources available to meet the load obligations have not kept pace.

In the mean time, the regulatory framework for both generation and transmission has shifted. Generation has undergone significant "re-regulation", particularly at the federal level. The largest change is that utilities are not the only ones that can build and operate generation facilities. In many states, nearly all the new generation planned or under construction is being developed by independent merchants. Obviously these merchants are relying on the laws of economics to drive their decisions as to when and where to build. This is in sharp contrast to utilities, which historically have built generation to serve their native load obligations and sought to place this generation in their rate base. Their economic equation was different than a merchant – they anticipated the allowed maximum rate of return they could hope to realize on the investment as directed by the regulatory bodies having jurisdiction. Market forces did not drive their forecasts for revenue streams.

The picture is even bleaker for transmission construction of late, since very little transmission has been built by anyone other than utilities. Again, their economic analysis has been driven by the hoped-for allowed maximum rate of return. As to the construction of either, the investment required is very large, and the potential returns have been both capped and uncertain. The risks faced by anyone considering developing generation or transmission facilities include regulatory risk, environmental opposition/risk, siting risk, and of course financial risk. A merchant can assess all of these risks and make an independent decision as to whether the potential gains

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outweigh the risks. A utility faces the same risks, with a limitation on its ability to earn on the investment, and more often than not has concluded that the risks outweighed the benefits.

That leaves Kansas, and many other states, with a dilemma. How can a state provide the appropriate incentives and economic signals to anyone, merchant or utility, to stimulate the development of new generation and transmission resources? The answer lies in a combination of financial incentives and easing of barriers.

The general formula is not really all that hard. We need to treat development of electric production and delivery facilities the same way we treat any other economic development project: as a commercial investment. Every state, county or city has an economic development initiative in place, whereby they offer a variety of incentives to businesses to locate in their area. One of these tools involves special considerations on property tax issues. Considering the size of the investment required to build new generation facilities or transmission lines, property taxes are a significant expense for the owner. One possible solution is to lower the assessment rate for new generation and transmission facilities both to more closely match that for commercial facilities. This will not only make Kansas more competitive with surrounding states as it competes for new facilities, but also sends a signal to developers that we want this type of investment in Kansas. If we start to treat electric production and transmission as a business, then we can expect business people to invest in Kansas.

The State of Kansas can also have some effect in lowering barriers to construction of new, or expansion of existing, facilities. Siting of these facilities is a major hurdle in the development process, and certainly slows the progress. Though nobody would suggest that the rights of property owners or others should be trampled upon, the current "NIMBY" climate (not in my back yard) has made it very difficult, if not impossible, to site construction or expansion projects. In its role of maintaining the good of the general public, the issues related to adequacy of energy supply need to receive at least equal weight with the other aesthetic or political interests. All that any developer would ever ask for is a fair chance. A number of other barriers, including environmental issues and regulatory treatment of transmission assets, are most directly controlled by agencies of the federal government. While the State of Kansas may not be able to unilaterally alter these barriers, it can certainly support developers in their efforts to receive equitable treatment at the federal level as well.

Midwest Energy, Inc. made a conscious decision several years ago to move away from the operation and ownership of generation facilities, and rather purchase capacity from other entities. This decision was based primarily on the perceived mission of a company like Midwest Energy, Inc. – we are an energy delivery company. As our load continues to grow we must expand our portfolio of capacity holdings. This has been done primarily through the purchase of capacity from, or participation in units owned by, other utilities or independent producers. We have found it increasingly difficult to acquire this capacity, and the associated energy, from sources within the state of Kansas. In simple terms, this means we are sending more money out of state than we did ten years ago. Only the development of new generation resources in Kansas can reverse this tide.

Having said all this about generation, we cannot ignore the importance of transmission. Without the ability to move energy from its point of production to local areas where it is consumed, the new generation is of limited value. Transmission systems throughout the region have seen loadings increase substantially in recent years, and in some cases constraints have developed. This has resulted in situations where remote sources of energy have been identified, but adequate transmission capacity was not available to move the energy. Consequently more expensive energy must be purchased on some occasions. More importantly, this could lead to disruptions of service if left unchecked. All the foregoing discussion about providing the appropriate climate for the development of new generation applies equally to transmission.

Midwest Energy, Inc. does own a significant amount of transmission facilities – over 1,000 miles of line operating at voltages ranging from 34,000 volts to 230,000 volts, and millions of dollars worth of substations. In order to continue to expand the transmission network, financial and/or tax incentives are appropriate. It is worth noting that the definition of "transmission" should not be dictated by a particular voltage (above 161,000 volts vs. 69,000 volts), but rather by a facility's function. Indeed, the Federal Energy Regulatory Commission has identified a "seven factor test" to determine if a facility is performing a transmission function. While one system may have settled on a standard whereby the lowest voltage facility they use as transmission is 161,000 volts, other utilities may use facilities down to 69,000 volts in a transmission function. The bottom line: any legislation or regulation regarding transmission should resist the temptation to define itself solely on voltage, but rather should rely on sound principles of functionality.

The time is right to identify ways the State of Kansas can stimulate the development of new generation and transmission facilities within our borders. This will allow Kansas to continue to develop all sectors of its economy, without the risk of energy shortages, and in the long run will help to restore stability to electric energy prices.

Kansas Corporation Commission

Bill Graves, Governor John Wine, Chair Cynthia L. Claus, Commissioner Brian J. Moline, Commissioner

Utilities Division
February 20, 2001

The Honorable Senator Stan Clark
Chairman Senate Utilities Committee
State Capitol - Room 449-N
Topeka, KS 66612

Subject: Senate Utilities Committee Concerns Regarding SB177

Chairman Clark:

It is my understanding that the Senate Utilities Committee has a concern with the current provisions of SB 177. Specifically, there are concerns regarding qualification of existing generating units that may complete equipment upgrades allowing them to increase generation capacity. Per our discussion, you were interested in assuring that the bill would not allow a utility to make slight equipment improvements increasing plant efficiency, and thereby removing a small portion of the generating plant from the definition of public utility, complicating the regulation and taxation of the unit.

In particular, the concern was that future plant modifications such as the recent Sunflower Holcomb upgrades, or the Jeffrey turbine reblading projects, *should not* qualify under this legislation. For example, if a utility were to reblade a turbine at a 600 megawatt coal unit and achieve an additional 30 megawatts of generation capacity, you do not believe the additional 30 megawatts of capacity should automatically qualify for the regulatory and tax relief considered under this bill.

On the other hand, as we discussed, there is not a similar concern with the qualification of entirely new generators at an existing unit. As I understand, you would like to include the addition of another generating unit, including such projects as the addition of an entirely new "thermodynamic cycle." An example of this would be the addition of a heat recovery boiler and a steam generator to utilize the wasted exhaust heat of a simple cycle combustion turbine, or the addition of an entirely new generating unit at an existing plant site.

It is my belief that the following (or similar) language, added as a new part (f) to section 1, would address this concern and *exclude* slight capacity gains by replacing and improving existing equipment (such as turbine blading, rebuilding boilers, upgrading cooling towers, etc.) and *include* entire new capacity gained by installing an additional generator (such as increasing capacity by adding a steam generator to an existing combustion turbine or adding an entirely new unit at an existing generating station):

1(f) *Additional generating capacity achieved through efficiency gains by refurbishing or replacing existing equipment at generating facilities placed in service before January 1, 2001 shall not qualify under section 1 (e) of this act.*

I hope this language addresses your concerns. If I can be of further service please do not hesitate to ask.

Sincerely,

Larry W. Holloway
Chief of Energy Operations

cc: Senate Utilities Committee

Senate Utilities Committee
February 20, 2001
Attachment 3-1

Session of 2001

SENATE BILL No. 177

By Committee on Utilities

1-31

AN ACT concerning certain electric generation facilities; relating to regulation and taxation thereof; amending K.S.A. 2000 Supp. 66-104 and 79-5a01 and repealing the existing sections.

Be it enacted by the Legislature of the State of Kansas:

Section 1. K.S.A. 2000 Supp. 66-104 is hereby amended to read as follows: 66-104. *(a)* The term "public utility," as used in this act, shall be construed to mean every corporation, company, individual, association of persons, their trustees, lessees or receivers, that now or hereafter may own, control, operate or manage, except for private use, any equipment, plant or generating machinery, or any part thereof, for the transmission of telephone messages or for the transmission of telegraph messages in or through any part of the state, or the conveyance of oil and gas through pipelines in or through any part of the state, except pipelines less than 15 miles in length and not operated in connection with or for the general commercial supply of gas or oil, and all companies for the production, transmission, delivery or furnishing of heat, light, water or power. No cooperative, cooperative society, nonprofit or mutual corporation or association which is engaged solely in furnishing telephone service to subscribers from one telephone line without owning or operating its own separate central office facilities, shall be subject to the jurisdiction and control of the commission as provided herein, except that it shall not construct or extend its facilities across or beyond the territorial boundaries of any telephone company or cooperative without first obtaining approval of the commission. As used herein, the term "transmission of telephone messages" shall include the transmission by wire or other means of any voice, data, signals or facsimile communications, including all such communications now in existence or as may be developed in the future.

(b) The term "public utility" shall also include that portion of every municipally owned or operated electric or gas utility located outside of and more than three miles from the corporate limits of such municipality, but nothing in this act shall apply to a municipally owned or operated utility, or portion thereof, located within the corporate limits of such municipality or located outside of such corporate limits but within three miles thereof except as provided in K.S.A. 66-131a, and amendments

thereto.

(c) Except as herein provided, the power and authority to control and regulate all public utilities and common carriers situated and operated wholly or principally within any city or principally operated for the benefit of such city or its people, shall be vested exclusively in such city, subject only to the right to apply for relief to the corporation commission as provided in K.S.A. 66-133, and amendments thereto, and to the provisions of ~~K.S.A. 66-131a and~~ K.S.A. 2000 Supp. 66-104e, and amendments thereto. A transit system principally engaged in rendering local transportation service in and between contiguous cities in this and another state by means of street railway, trolley bus and motor bus lines, or any combination thereof, shall be deemed to be a public utility as that term is used in this act and, as such, shall be subject to the jurisdiction of the commission.

(d) The term "public utility" shall not include any activity of an otherwise jurisdictional corporation, company, individual, association of persons, their trustees, lessees or receivers as to the marketing or sale of compressed natural gas for end use as motor vehicle fuel.

(e) At the option of an otherwise jurisdictional entity, the term "public utility" shall not include any activity or facility of such entity as to the generation, marketing and sale of electricity generated by an electric generation facility or addition to an electric generation facility which:

(1) Is placed in service on or after January 1, 2001;

~~*(2) (A) is coal-fired, or (B) uses natural gas to generate electricity,*~~ *and*

(3) is not in the rate base of: (A) An electric public utility that is subject to rate regulation by the state corporation commission; (B) any cooperative, as defined by K.S.A. 17-4603 and amendments thereto, or any nonstock member-owned cooperative corporation incorporated in this state; or (C) a municipally owned or operated electric utility.

New Sec. 2. (a) As used in this section, "independent power producer property" means property used solely in the generation, marketing and sale of electricity generated by an electric generation facility described in subsection (e) of K.S.A. 66-104, and amendments thereto.

(b) For all taxable years commencing on or after January 1, 2001, independent power producer property is commercial and industrial property assessed at the rate of 25% for the purposes of taxation of real property and tangible personal property.

c) For purposes of property and ad valorem taxes, independent power producer property of the nature itemized in Federal Energy Regulatory Commission plant accounts (i) 101-312, 313, 314, 315, and 316; (ii) 101 – 322, 323, 324, and 325;(iii) 101 – 332, 333, 334, 335, and 336; or (iv) 101- 342, 343, 344, 345 and 346 of the Code of Federal Regulations, shall be tangible personal property.

Sec. 3. K.S.A. 2000 Supp. 79-5a01 is hereby amended to read as follows: 79-5a01. (a) As used in this act, the terms "public utility" or "public utilities" shall mean every individual, company, corporation, association of persons, lessees or receivers that now or hereafter are in control, manage or operate a business of:

(1) A railroad or railroad corporation if such railroad or railroad corporation owns or holds, by deed or other instrument, an interest in right-of-way, track, franchise, roadbed or trackage in this state;

(2) transmitting to, from, through or in this state telegraphic messages;

(3) transmitting to, from, through or in this state telephonic messages;

(4) transporting or distributing to, from, through or in this state natural gas, oil or other commodities in pipes or pipelines, or engaging primarily in the business of storing natural gas in an underground formation;

(5) generating, conducting or distributing to, from, through or in this state electric power;

(6) transmitting to, from, through or in this state water if for profit or subject to regulation of the state corporation commission;

(7) transporting to, from, through or in this state cargo or passengers by means of any vessel or boat used in navigating any of the navigable watercourses within or bordering upon this state.

(b) The terms "public utility" or "public utilities" shall not include: (1) Rural water districts established under the laws of the state of Kansas; or (2) any individual, company, corporation, association of persons, lessee or receiver owning or operating an oil or natural gas production gathering line which is situated within one county in this state and does not cross any state boundary line; (3) any individual, company, corporation, association of persons, lessee or receiver owning any vessel or boat operated upon the surface of any manmade waterway located entirely within one county in the state; ~~or~~ (4) for all taxable years commencing after December 31, 1998, any natural gas distribution system which is owned and operated by a nonprofit public utility described by K.S.A. 66-104c, and amendments thereto, and which is operated predominantly for the purpose of providing fuel for the irrigation of land devoted to agricultural use; *or (5) for all taxable years commencing on or after January 1, 2001, at the option of the taxpayer, the taxpayer's business of generating, marketing and selling electricity generated by an ~~electric~~ generation facility described in subsection (e) of K.S.A. 66-104, and amendments thereto.*

Sec. ~~4~~ 6. K.S.A. 2000 Supp. 66-104, 66-128 and 79-5a01 are hereby repealed.

Sec. ~~5~~ 7. This act shall take effect and be in force from and after its publication in the statute book.

New Sec. 4. The following described property, to the extent herein specified, shall be exempt from all property or ad valorem taxes levied under the laws of the state of Kansas:

(a) All electric generation facilities, including pollution control devises, described in subsection (e) of K.S.A. 66-104, and amendments thereto.

(b) The provisions of this section shall apply for the 10 taxable years immediately following the taxable year in which construction of such property is completed.

Section 5. KSA. 2000 Supp. 66-128 is hereby amended to read as follows: 66-128. (a) The state corporation commission shall determine the reasonable value of all or whatever fraction or percentage of the property of any common carrier or public utility governed by the provisions of this act which property is used and required to be used in its services to the public within the state of Kansas, whenever the commission deems the ascertainment of such value necessary in order to enable the commission to fix fair and reasonable rates, joint rates, tolls and charges. In making such valuations the commission may avail itself of any reports, records or other things available to the commission in the office of any national, state or municipal officer or board.

(b) For the purposes of this act, property of any public utility which has not been completed and dedicated to commercial service shall not be deemed to be used and required to be used in the public utility's service to the public, except that, any property of a public utility may be deemed to be completed and dedicated to commercial service if: (1) Construction of the property will be commenced and completed in one year or less; (2) the property is an electric generation facility that has a capacity of 100 megawatts or less and converts wind, solar, biomass, landfill gas or any other renewable source of energy; or (3) construction of the property has been authorized by a siting permit issued under K.S.A. 66-1,158 et seq. or 66-1,177 et seq., and amendments thereto.

NEW

(c) For the purpose of establishing retail electric rates, the commission shall allow a premium of 300 basis points on the return allowed on electric transmission property as defined in this section. This premium shall be in addition to the return on equity allowed by the commission on the remainder of the utility property.

(1) All electric transmission lines used for the bulk transfer of 161 or more kilovolts of electricity, including all towers, poles, and other necessary appurtenances to such lines and the right-of-way on which such lines are located.

(2) The provisions of this section shall apply to property the construction of which is completed after December 31, 2000.

(d) The following described property, to the extent specified, shall be exempt from all property or ad valorem taxes levied under the laws of the state of Kansas:

(1) any additions or capital expenditures completed on or after January 1, 2001 on electric generation facilities, (i) regulated by the state corporation commission and (ii) existing as of January 1, 2001.

(2) the provisions of this section shall apply to the 10 taxable years immediately following the year in which construction of such property is completed.

– END –