## Section 8.2: Electricity Generation: Demand, Capacity

### Topic / Issue Description

According to the most recent data, Kansas consumed 39.8 million megawatt-hours (MWh) of electricity in 2006. Commercial consumers accounted for 37.2% of this demand, with residential and industrial consumers accounting for 34% and 28.8%, respectively. Based on historical trends, demand for electricity within Kansas is expected to grow at a rate of 1.0% to 1.5% per year.[1]

Electricity consumption (also called "load") is divided into three categories: base, peak, and intermediate load. Base load refers to demand that occurs continuously, day and night, seven days a week. Peak load, on the other hand, refers to maximum demand that occurs within a given period of time. Intermediate load is a more generic term applied to demand that occurs between base and peak load. Electricity peak loads in Kansas are the greatest during the summer months, primarily due to the electricity needs of air-conditioning systems. In 2006 (the most recent data available), the utilities in the Southwest Power Pool (SPP) had a total summer peak load of 42,266 megawatts (MW). SPP members had a combined capacity resources of 46,564 MW, resulting in a capacity margin (percentage generation capacity in excess of demand) of 9.2%. Kansas' utilities account for approximately 24% of SPP resources.[2]

Electricity differs from other commodities in that it can not be stored on a commercial scale: in other words, electricity stored through currently available mechanical and chemical means encounters very large losses in efficiency. Therefore, in order to provide reliable service, utilities must have enough capacity—defined as instantaneous electrical production—to meet the greatest peak loads experienced.[3] This capacity can be provided either from their own generation assets; long-term power purchase agreements; or "real-time" purchases in the spot market.

In order to cost-effectively meet the varying demand of their customers at different times of the year and even different times of the day, most utilities maintain a diverse portfolio of electric power plants (e.g., generating units) that use a variety of fuels. These generating units can be distinguished according to the type of power they produce (firm vs. intermittent) as well as the type of load they are designed to meet (base, peak, or intermediate).

Generating units that rely on fuel sources whose availability can be controlled by the operators of the plant are said to provide *firm power*. Power plants that generate

---

[1] Based on preliminary data compiled by KEC staff for forecast load and capacity summaries. According to the EIA, overall U.S. demand is expected to increase 1.1% annually: Annual Energy Outlook with Projections to 2030: http://www.eia.doe.gov/oiaf/aeo/electricity.html (accessed September 2008).

[2] EIA, 2007, Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region: http://www.eia.doe.gov/cneaf/electricity/epa/epat3p2.html (accessed September 2008).

[3] In practice utilities are required to maintain capacity well in excess of forecasted peak loads. Southwest Power Pool (SPP) requires (with few exceptions) that all members maintain capacity margins 12% greater than forecasted peak load.

electricity from most conventional sources of electricity (e.g., fossil fuels, nuclear, and hydro), as well as some non-conventional sources such as geothermal and landfill wastes, are considered firm power. On the other hand, generating units that rely on fuel sources, such as wind and solar energy, whose availability can not be controlled by the operators of the unit are said to provide *intermittent power*. Because intermittent resources cannot be depended on to supply electricity at any given moment, units relying on these resources must be accompanied by power plants that provide firm power. For example, dedicated (load-following) units, which operate on standby, can be used to meet demand during periods when the intermittent resource is unavailable, as when the wind is not blowing or the sun is not shining.

Power plants are also differentiated based on whether they are designed and built to meet base-load or peaking demand. Power plants that are used to meet the minimum or "base load" of the system are referred to as base-load generating units; they are run continuously and operated, in general, so as to produce electricity at a constant rate. *Base-load units* are operated to maximize system mechanical and thermal efficiency and minimize system operating costs. Costs are minimized by operating units with the lowest fuel costs for the most hours in the year (i.e., at a high capacity factor). Generally, base-load units include nuclear, coal-fired, geothermal, hydropower, and waste-to-energy plants.[4] *Peaking units* are normally reserved for operation during the hours of highest daily, weekly, or seasonal loads—that is, they are turned on or "dispatched" as demand increases above the base load. Peaking plants are expensive to operate, typically fueled by refined oil products or natural gas, because they have a higher per-kilowatthour (KWh) fuel cost than base-load units. On the other hand, peaking plants are generally less expensive to build (see Table 1, Chapter 8 Overview).

In order to maintain reliability, utilities must plan to increase capacity to meet future demand, which historically has increased over time. Utilities can accomplish this by investing in new generating units, by increasing operating efficiency, or by purchasing capacity from surrounding utilities through wholesale power contracts. Wholesale power contracts come in many forms, but in general wholesale power contracts between utilities can be looked at as a promise one utility makes to another to provide an agreed-upon amount of capacity whenever it is needed by the second utility to satisfy loads within its control area. Depending on a utility's needs, there may be no electricity transferred within a given year, even though there exists a contract negotiated for that very purpose.

## Existing Policies and Programs

1. Chapter 66 of the Kansas Statutes deals with the state's public utilities, including but not limited to electric utilities. Chapter 66, Article 1 includes the statutes delineating the powers of the Kansas Corporation Commission (KCC).

[4] Hydroelectric dams can be operated in either base or peaking mode by increasing water flow through the dam during periods of peak demand, and reducing the flow during off-peak periods.

2. K.S.A. 10-1202 allows municipalities to issue and sell revenue bonds to cover the costs associated with acquiring, constructing, altering, repairing, improving, or enlarging the municipal utility.

3. FERC Order No. 888 requires all public utilities that own, operate, or control interstate transmission to file tariffs that offer other utilities the same transmission services they provide for themselves, with comparable terms and conditions. FERC Order No. 889 requires that utilities implement a standard of conduct and an Open Access Same-time Information System (OASIS) to ensure that transmission owners do not have an unfair competitive advantage in using transmission to sell power.[5]

4. FERC Order No. 2000 further encourages competition in the wholesale electricity market; it encourages utilities to voluntarily join Regional Transmission Organizations (RTOs) that have (1) independence from market participants, (2) an appropriate scope and configuration, (3) operational authority over transmission facilities within the region, and (4) exclusive authority to maintain short-term reliability. On June 23, 2006, Southwest Power Pool, which serves Kansas, was granted RTO status by FERC.[6]

[5] Convergence Research, 1996, Commission Orders Sweeping Changes for Electric Utility Industry: http://www.converger.com/fercnopr/888_889.htm (accessed December 15, 2008).
[6] See Energy Information Agency, 2000, Status of Bulk Power Transmission Systems: http://www.eia.doe.gov/cneaf/electricity/epav1/bulkpower.html (accessed December 15, 2008); see also, Federal Energy Regulatory Council, 2008, 124 FERC ¶ 61,220 Background: http://www.ferc.gov/EventCalendar/Files/20080903174851-RT04-1-023.pdf (accessed December 15, 2008).