Presentation to the House Energy Committee

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Regulation of Utility Retail Prices by the Minnesota PUC

Only investor-owned utilities (IOUs), which account for about 65 percent of Minnesota's retail electricity sales, are subject to PUC price regulation. Electric cooperative associations (coops) may elect to be price regulated (§ 216B.026), but only one (Dakota Electric) has done so.

Other types of utilities are subject to PUC regulation of non-price aspects of their operation. For example:

- Generation and transmission cooperatives and Municipal Power Authorities are subject to the state's Renewable Energy Standard, which requires that a certain portion of electricity sales be generated from renewable sources (§ 216B.1691).
- Both coops and municipal utilities are required to participate in the Conservation Improvement Program, which requires utilities to invest revenues to improve their customers' energy efficiency (§ 216B.241).
- Both coops and municipal utilities are subject to the state's Cold Weather Rule, which prohibits a utility from disconnecting certain customers from their heat source during winter if the customer is making regular payments under a mutually-agreed upon payment plan (§§ 216B.096; 216B.097).

(Generation and transmission cooperatives do not serve retail customers directly; they sell and deliver wholesale energy to distribution cooperatives that do so. Municipal Power Authorities perform the same function for municipal utilities.)

The reason IOUs are price regulated is connected to the very capital intensive nature of utilities. Competition among utilities for customers would result in the replication of very expensive equipment (e.g., transmission and distribution lines) in several service areas, driving up rates for all customers. For this reason, utilities have exclusive geographic service areas (§ 216B.37 et. seq.), preventing the duplication of equipment, but at the price of removing the cost-minimizing force of a competitive market. Price regulation by the PUC is a substitute for market competition.

With respect to price regulation, the PUC's goal is that prices are just, reasonable and non-discriminatory (§§ 216B.03, 216B.06, 216B.07). The commission does not regulate all components of utility rates. Most notably, the price of fuels that serve as inputs to the generation of electricity – coal, oil, natural gas, and uranium – are unregulated. The federal government regulates electric transmission and natural gas pipeline rates. The Minnesota PUC has jurisdiction over the local utility operations that turn fuel delivered to and generated in Minnesota into useful energy and deliver it to retail customers.

All the plant and equipment a utility uses to do this—generating units, substations, pipelines, transmission and distribution lines—are part of a utility's rate base, on which the utility is allowed to earn a rate of return, set by the PUC in a rate case proceeding. A rate case resembles a judicial procedure, and lasts the better part of a year. It is held before an Administrative Law Judge (ALJ) from the state's Office of Administrative Hearings. Parties participating in the case submit written testimony on several topics: what items should be included in the rate base; the rate of return the company should be allowed to earn; how the utility's costs are to be allocated among customer classes; how rates are to be designed, etc. Witnesses are cross-examined on their testimony. After the hearing, the ALJ, based on the evidentiary record developed in the rate case, submits a report to the PUC containing findings of fact and recommendations for decisions on each of the issues addressed in the rate case. The Commission can accept, reject, or modify the ALJ's report in an order to the utility containing its final decisions on these matters.

Other Regulatory Procedures

Other regulatory procedures examine the rationale for items utilities would like to place in their rate bases well before a rate case is heard. Every three years, utilities are required to file an Integrated Resource Plan (IRP) for Commission review and approval that contains the utility's estimate of energy demand over the next 15 years and how the utility proposes to meet it (§ 216B.2422). A utility proposing a new generating plant or high-voltage transmission line must obtain a certificate of need from the Commission under a procedure similar to that of a rate case to determine whether the facility is needed and is the least-cost method of meeting the utility's customer demands for energy (§ 216B.243). The PUC must also review and approve transmission plans that identify inadequacies in the transmission system that can inhibit energy transfers (§ 216B.2425).

Cost Recovery

Utilities want to recover expenditures made for plant and equipment as soon as possible after the items are installed. Rate cases are complex, expensive and time-consuming; as a result, utilities often let many years go by between rate cases. Utilities have sought, and the legislature has often granted, a quicker cost recovery method outside of the confines of a rate case. The PUC still must review and approve the expenditures in question, but the time frame is much shorter. Accelerated cost recovery is allowed for the following types of expenditures:

- Moving natural gas infrastructure due to public projects such as roads (§ 216B.1635);
- Replacing electricity infrastructure that saves energy or uses it more efficiently (§ 216B.1636);
- Installing pollution control equipment to reduce mercury emissions under a 2006 statute that applies to a handful of the state's large power plants (§ 216B.683);
- Converting Xcel's High Bridge and Riverside coal-generating plants to natural gas (in 2006 and 2008, respectively), and upgrading pollution control equipment at its A.S. King plant (§ 216B.1692).

Energy Conservation

Under the Conservation Improvement Program, Minnesota utilities have been required to make investments to increase the energy efficiency of their customers since 1991. Until 2007, they were required to spend a given proportion of their gross operating revenues (0.5 percent for gas utilities; 1.5 percent for electric utilities) to accomplish this (§ 216B.241, subd. 1a). This level of investment resulted, on average, in saving about 0.3 percent of annual utility retail natural gas sales, and 0.8 percent of electricity sales.

In 2007, the legislature replaced the spending target with a performance goal: utilities must spend an amount sufficient to result in savings of 1.5 percent of gross electricity sales and 1.0 percent of natural gas sales annually (§ 216B.241, subd. 1c). Data collected by the Department of Commerce shows that spending in 2010 on the electricity side ($186 million) was more than double that of 2007, and energy savings had increased by 89 percent.

Another 2007 law established a program with the University of Minnesota to continually develop energy performance standards for the new construction and renovation of commercial, industrial, and institutional buildings. The initial target for those standards was to make buildings 60 percent more energy efficient than a "typical" 2003 building by 2010. The targets increase by 10 percent every five years through 2025 (§ 216B.241, subd. 9).

Support for Renewable Energy Development

State support for renewable energy development in Minnesota was given a big boost by the failure of the federal government to fulfill its mandate to develop a permanent repository for spent nuclear fuel from commercial reactors. None of the nuclear power plants constructed in the 1970s, as were Minnesota's, made provision for storage of this material beyond the pools constructed to allow the radioactivity in spent fuel assemblies to diminish over a period of years.

In 1989, Xcel Energy (then Northern States Power Company) filed a petition with the Minnesota PUC to obtain a Certificate of Need to construct a dry cask storage facility at its Prairie Island plant. The PUC issued the Certificate of Need, but the Minnesota Court of Appeals ruled that the storage was "more likely than not" permanent and therefore, by dint of an existing statute, required legislative approval.

The issue became the subject of intense and fractious debate during the 1994 session of the Minnesota Legislature. Legislation was enacted allowing construction of a facility holding 17 casks to proceed, but the compromise that allowed for passage contained a number of provisions supporting the development of renewable fuels, including:

- Xcel was required to develop 825 megawatts of wind and 125 megawatts of biomass by the end of 2002 (§§ 216B.2423, 216B.2424); and
- The company was directed to establish a Renewable Development Account to which it would contribute, beginning in 1999, $500,000 per year for each cask housed at Prairie Island (§ 116C.779). The fund was to be used for the "development of renewable energy sources."

Subsequent legislation expanded these initial efforts. As Xcel was reaching the end date of its wind and biomass mandates, the concept was extended to include both more technologies and more utilities. In 2001, the legislature established a Renewable Energy Objective that applied to IOUs, generation and transmission cooperatives, and municipal power authorities (§ 216B.1691). By 2005, at least one percent of electricity retail sales were to be generated from renewable sources (now including solar energy and hydropower plants with a capacity below 60 megawatts), which was to grow by one percent a year to reach 10 percent in 2015. Utilities were to make a "good faith effort" to achieve this goal. In 2003, energy from hydrogen and solid waste incineration were made eligible to contribute to the goal, and the objective was made a mandate for Xcel Energy.

In 2007, the "good faith" objective became a Renewable Energy Standard (RES), a mandate for <u>all</u> utilities subject to it. The target itself was expanded, culminating in a requirement to generate 25 percent of electricity from renewable resources by 2025 (30 percent by 2020 for Xcel). The PUC was given authority to delay or modify these standards under certain conditions: significant rate impacts, delays in receiving equipment, transmission constraints, etc. So far, none of these "off-ramps" has been invoked, and the most recent PUC report indicates that all utilities are on schedule to meet the standard. In 2010, a bill was passed requiring utilities to report the impact on customer bills of efforts taken to meet the RES.

The Renewable Development Account established in 1994 has since collected over $200 million from Xcel electric ratepayers. The current annual amount deposited into the account is about $24.5 million; the average residential customer contributes about $7 annually.

The account funds a competitive grant program that supports research and development into renewable technologies. It has also been subject to direct appropriation by the legislature for energy projects. For example, about $30 million has gone to the University of Minnesota's Initiative for Renewable Energy and the Environment (IREE) to support research and renewable. $10 million was directed to the Mesaba coal gasification plant. In 2010, $21 million from the account was tapped to provide rebates for Minnesota-made solar collectors installed in the state.

The biggest and longest-lasting effort the legislature has funded from the account is the Renewable Energy Production Incentive (REPI) program (§ 216C.41), which in its initial years was funded by the General Fund. Since 2006, the account has paid 1.5 cents per kilowatt-hour generated to about 200 wind turbines, and a handful of small hydropower and anaerobic digester projects. This supplementary revenue stream—to be paid to project owners for ten years—was designed to make initial financing of the projects easier. A cap on the amount of wind eligible for these incentives was set at 200 megawatts.

REPI expenditures peaked at $9.9 million in 2011, and will begin to decline as projects reach their ten-year limit. Payments in 2013 are estimated to be $7.9 million, and are forecast to decline to $2.2 million in 2018.

Current issues

1) Reduced growth in electricity demand

In its 2011 update to its 2010 Integrated Resource Plan, Xcel Energy forecast future demand growth in its service area at 0.5 percent annually for the next 15 years, almost half the rate it had forecast only a year earlier, and well below its historical average growth rate. Partly as a result of this dampening of demand, Xcel projects that it will not need additional generation capacity until 2018, when it expects to add 400 to 600 megawatts of natural-gas fired capacity.

2) Increased use of natural gas to generate electricity

The proportion of electric generation fueled by natural gas has sharply increased across the country during the past decade. Eighty-one percent of the additions to capacity from 2000 to 2010 were fueled by gas, which now represents 39 percent of U.S. generating capacity. In Minnesota, natural gas deliveries to electric generating plants grew from ten billion cubic feet in 2000 to 35 billion cubic feet in 2007.

The reasons are not hard to find. Combined cycle gas plants are highly efficient, because waste heat is utilized to make steam and produce electricity from a second generator. These plants are also cheaper and faster to construct than coal plants: about half the cost per megawatt of capacity, and they can be completed in two to three years. They can also be built at a relatively small scale (100 megawatts) and are modular. Finally, they create less than half the carbon dioxide emissions that a coal plant produces.

3) Federal mercury and air toxics standards for new and existing powerplants

Electric generating facilities are the nation's largest source of mercury air emissions (50 percent of the total) and acid gas emissions (77 percent). Recently-passed federal emission limits for these pollutants and particulate matter will require utilities to determine whether it makes economic sense to terminate the operation of some of their older coal-burning facilities rather than pay to retrofit them to meet the new standards or switch to a cleaner burning fuel. Utilities have four years to comply with the new standards.

Approximately 12,000 megawatts of capacity in 13 states in the Midwest, including Minnesota, will be affected by these new standards. Not all of these facilities can convert to natural gas, because pipeline capacity is insufficient to absorb such an increase in demand. Some Minnesota utilities have already made decisions on this issue. For example, Rochester Public Utility has announced it will shut down its Silver Lake plant in 2015; the city of Austin will convert its coal plant to natural gas.