200601235101 Received FERC OSEC 01/23/2006 04:45:00 PM Docket# AD06-2-000

January 23, 2006

Honorable Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426

RE: FERC Docket AD06-2 - Assess Demand Response Resources Tech Conf Comments

Dear Ms. Salas:

Pursuant to the Commission's January 13, 2006, Notice of Agenda and Procedures for Technical Conference in the above-captioned docket, Xcel Energy submits the attached comments for use at the January 25, 2006, conference.

Sincerely,

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REGIONAL PERSPECTIVE PANEL
FERC TECHNICAL CONFERENCE ON DEMAND RESPONSE AND ADVANCED METERING

PRESENTATION OF
KEVIN LAWLESS
XCEL ENERGY

I. Xcel Energy Overview and Service Territory

Xcel Energy is one of the nation's largest gas and electric utilities, serving the central portion of the United States. Our 5 million customers are spread across 10 states, spanning from the Canadian to Mexican borders and from the Rocky Mountains to the Great Lakes.

We supply electricity to our customers with a diverse fleet of power plants and contracts that utilize nuclear, coal, natural gas and wind. We have a relatively unique perspective on transmission given our activities within three different transmission regions. Other key characteristics and accomplishments include:

- We are the 2nd largest purchaser of wind power in the country and have announced plans that will make us the largest purchaser of wind power in the country within the next few years.
- We are executing a $2 billion re-powering of metropolitan power plants in Denver and the Twin Cities, which is creating more than a 95% reduction in key emissions from the existing plants while increasing our generating capacity.
- Our Northern States Power operating companies, in partnership with our customers, run some of the most extensive demand reduction programs for several decades, making us one of the few companies who maintained these programs even in face of the significant changes to the industry's structure.

II. Status of Demand Response Programs and Time-Based Rates

Demand response works! This past summer, on a hot, humid June 23rd in the Upper Midwest, our demand response programs sent the signals for customers (or our equipment) to manage customer's energy use patterns. On a day on which we expected a peak of almost 9200 MW, our demand response partnerships with over 300,000 customers limited our actual demand to 8438 MW, a reduction of 757 MW (8.2%, see Chart 1). This is a quick -- but definitive -- example of how a long-term, corporate commitment to demand response works. Based on our experience, to be successful, demand response programs must work in creative partnerships with customers, be backed by a consistent regulatory framework for cost recovery, and encouraged through state policies and performance incentives, creating win-win situations for all parties. Over the last two decades, we have worked hard to make our high demand days a rewarding experience for participating customers (through direct savings) and for other customers and our shareholders (by providing a cost-effective means to manage system investments).

Since 1990, the NSP operating companies of Xcel Energy have invested almost $700 million in conservation, load control and load management, and now demand response. Regulatory policy makers have been very supportive of these efforts. State law in Minnesota, for example, encourages investments in demand-side management and renewable energy, and the state commission has provided direct cost recovery and performance-based incentives, which have allowed us to earn over $100 million over the past 15 years. In 2006, we will be working with our regulators on our 2007-2009 triennial DSM plan and expect that plan to build on our proposals in our most recent Resource Plan. We have proposed changes to make returns more competitive for demand-side management and an expanded set of goals for the next 15 years. Our proposals have attracted significant interest from many parties and have generally met with a very positive response from environmental groups and regulators.

In recent years we have also expanded our DSM efforts in the Public Service of Colorado (PSCO) territory. This effort culminated in our recent commitment to a $196 million expansion of our Colorado demand response and conservation efforts. Last year, we introduced our electric customers to seasonal rates and our gas customers to a monthly gas cost adjustment; both mechanisms -- while somewhat imperfect demand response tools -- are introducing the last major portion of our service territory to seasonal price signals.

To take a more high level look at our 2006 plans, we expect to spend over $70 million across our territory on demand-side programs and new pricing mechanisms. This investment reflects our commitment to continue to lead in these areas of our business. We are also expanding our load control and pricing programs and re-focusing our conservation efforts on industrial customers. Finally, we are implementing pricing proposals that will allow us to assess our customers' response under a wide variety of pricing options. We expect to gain valuable experience from these efforts that will be useful throughout our service territory.

III. Challenges

Much like investing in our individual retirement plans, a long-term, consistent investment in demand-side activities compounds into a significant resource over time. Our NSP programs have reduced our generation needs by the equivalent of seven -- going on eight – 250-MW combined cycle power plants. These programs drive our customers to respond as standard business practice, rather than on an emergency-only basis. Having a diverse set of programs and pricing mechanisms allows a flexible response to the specific situation.

However, we now find that this effort must now evolve to achieve energy savings and response in expanded applications and to adapt to a changing regulatory and industry structure. To be successful in this effort, we must overcome a number of challenges and barriers, including the competitiveness of returns, customer transitions, technology, shifting cost responsibility, and willingness to send strong price signals.

The single most important challenge is the competitiveness of returns, especially compared to those achieved on new transmission or generation investments. Investors in demand-response activities need to be able to recover costs with certainty earn attractive returns and have those returns be fully competitive with other investment opportunities. If competitive returns are missing, investments in demand response will not occur. At the next system emergency, customers will question our system adequacy rather than respond to the signals we as an industry should have in place. Our proposals primarily address this challenge.

A second challenge is customer transitions from legacy programs and pricing structures to new ones. As the nature of our programs changes from the on-off simplicity of our legacy programs, it is not going to be easy to achieve high participation rates. Customers may not readily accept programs incorporating new technology and more complex pricing signals, as we would like. Gaining customer acceptance will be an ongoing challenge for our marketing and pricing staffs: keep participation simple, provide easy-to-understand benefits, and maintain our commitments to customers who also may be making investments to participate. This challenge will be complicated if the responsibility for gaining customer participation is spread across regulated distribution companies, RTOs, and marketers.

Technology is also a challenge. Smart meters, smart thermostats, broadband over power line and other technologies all hold a degree of promise. The challenge though will be to implement wisely, where the largest benefits can be gained, competitive returns can be harvested, and customers are likely to participate. Hardware, software and marketing efforts have to seamlessly combine to make this happen.

Finally, we need to acknowledge the shifting cost responsibilities among classes of customers that will occur under new demand response models. New customer classes will emerge, and our systems will need to be accountable for managing the changes. Linking new pricing models to the customers most likely to participate, rather than the traditional customer classes, will be a challenge for our systems, our people and our regulators.

IV. Proposals

In a number of proceedings in the past year we have made proposals to address the competitiveness of returns issue. We based these proposals on the premise that returns in this area are either lacking or not competitive, depending on the jurisdiction. Our current Minnesota DSM incentive does not compensate us for the lost earnings opportunity on new investment in supply resources. Continued earnings growth is important to the financial viability of utilities; DSM lowers earnings growth by eliminating or delaying the need for capital investment. Because we are regulated in all our jurisdictions, our proposals are mostly directed to state commissions.

Xcel Energy has made proposals to address this barrier. First, in a recent natural gas rate case, we proposed a "partial decoupling" mechanism to partially address the trend of declining use per customer partially caused by aggressive demand-side programs. This trend results in the utility not fully collecting its costs between rate cases, all other things equal. There was opposition to this proposal on legal grounds, and it was not included in a settlement of issues in this case.

More recently – and more on point to the issue – we have proposed a "Financial Neutrality Factor" mechanism that would directly compensate us for lost earnings opportunities associated with expanded DSM investments. The mechanism would trigger off the goals established in our Resource Plans and would provide a per-kW achieved award based on the earnings that would have been made on a comparable supply-side investment. We developed this proposal at the same time as committing to meeting expanded DSM goals, goals that will increase our already aggressive level of savings by 25 percent.

We believe it is vital that regulatory mechanisms be implemented to support state and federal efforts for expanded conservation, DSM, and renewable energy. Such mechanisms should align the interests of customers, government, and utilities. In addition, it is important that the full financial impact of various resource options be clear and understood, so that the best resources are selected for meeting customer needs.

Another area of focus is expanding our suite of pricing mechanisms to increase customer understanding and acceptance of time-varying rates. We are achieving this objective using a stepped approach, beginning by implementing some of the most common time-varying rates if they are not in existence in a jurisdiction. In Colorado for instance, within the last 15 months we have implemented a monthly gas cost adjustment, seasonal rates for all electric customers, and mandated time-of-use rates for customers over 500 kW.

We have also proposed several initiatives that expand the use of time-of-day pricing in our service offerings. These include:

- A time-differentiated fuel clause adjustment. Under this proposal, made in our pending Minnesota electric rate case, we will allocate fuel and purchased power costs among the customer classes in a manner that reflects usage patterns and cost differences, thus providing an improved price signal over the current approach of allocating fuel clause costs on an average basis. We believe this will help set the stage for even additional demand response capabilities to be put in place.

- Mandatory time-of-day rates. Our Minnesota case also proposes to require customers larger than 500 kW to be on a time-of-use rate. While we currently offer TOU options, this proposal will require customers to take service under a TOU tariff, thus ensuring that all customers of this size receive a more appropriate, cost-based price signal. We believe that customers of this size have the expertise and ability to respond to these price signals, and – as noted above – we are developing expanded DSM offerings for our industrial customers that will assist in this regard. The best opportunity for effective time-of-use pricing is when they are mandatory.

- In Colorado, we are in the midst of installing time-of-use meters for 4,000 customers as the start of our pilot. This pilot will address a number of different mechanisms including two- and three-part time-of-day rates and peak-day pricing mechanisms.

Overall, we believe greater use of accurate price signals should be undertaken to encourage appropriate and efficient use of energy. In light of rapidly changing and volatile energy prices, it is important that customers face accurate price signals so that they may make appropriate choices regarding their consumption.

IV. Role in Regional and Transmission Expansion Planning

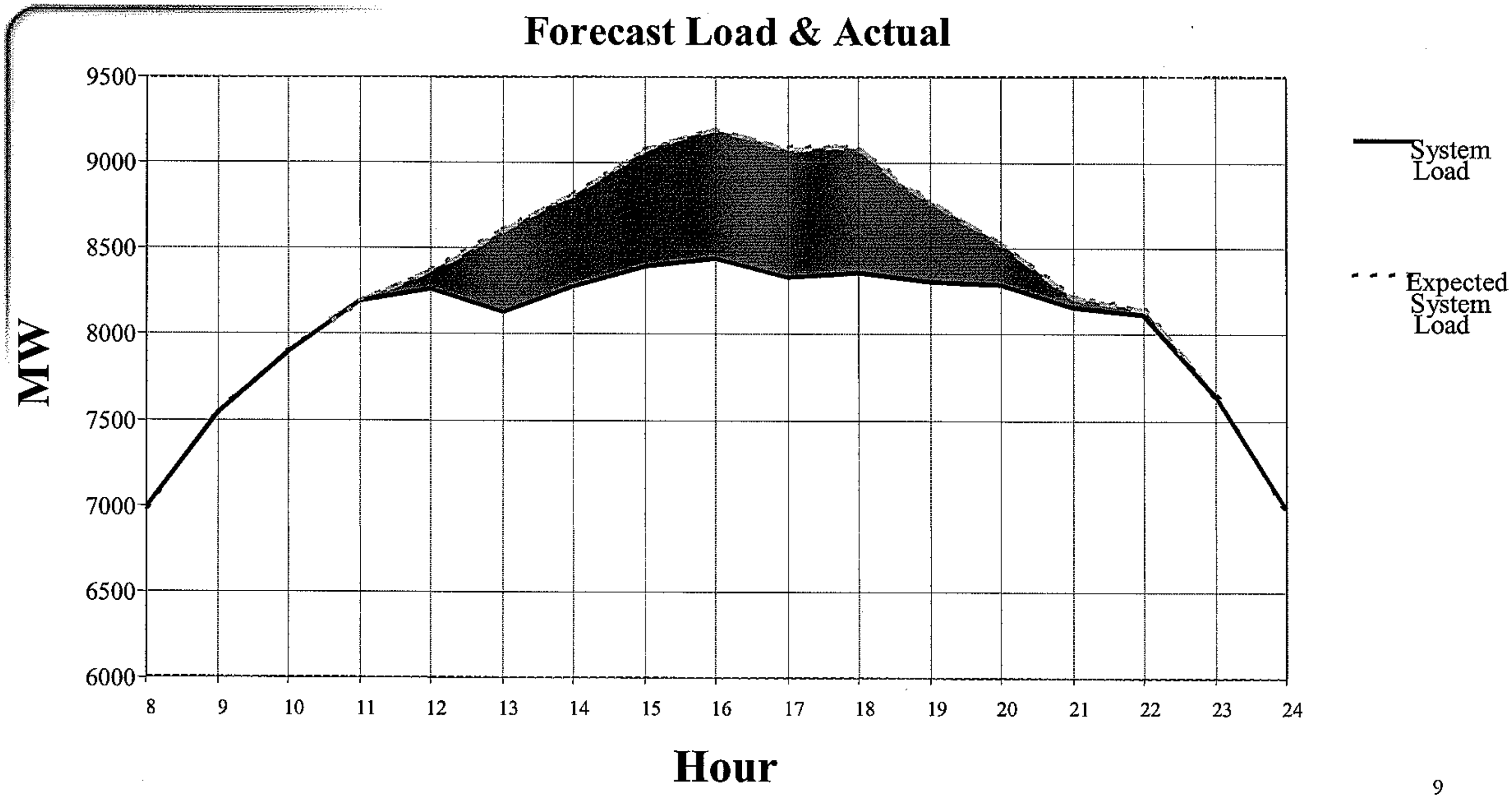
Both DSM and pricing should be considered in regional and transmission planning. Currently, DSM and pricing impacts are reflected in our resource planning decisions, such that the load planned for reflects the impact of anticipated DSM and pricing accomplishments. In this context, the cost-effective and achievable levels of DSM and load control are projected for the planning period, as well as the load curve. Resources are then planned for the remainder of the identified resource need.

We believe it is important that planning efforts accurately evaluate all resources and make appropriate selections. We further believe that the information obtained from DSM and pricing efforts feed back into the planning process. For example, in the Midwest, the Midwest Independent Transmission System Operator ("MISO") uses locational marginal pricing, which prices the cost of transmission congestion. Such information needs to feed back to the planning process so that additional, cost-effective resources needed to relieve congestion costs are undertaken.

Currently, we do not believe that the appropriate mechanisms exist between RTOs and the states for a regulated utility to go well beyond our current and proposed product line. But we are here today to discuss the development of new mechanisms that incorporate the needs of RTOs and the pricing structures they are putting into effect. Developing appropriate demand response programs based on price signals from the regional transmission organizations is on our agenda.

Xcel Energy

NSP System – June 23, 2005



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