Minutes of the
Northwest Power Planning Council's

Demand Forecasting Advisory Committee

Held at the Council's Offices
851 SW Sixth Ave., Suite 1100, Portland, OR
July 31, 2002

The second meeting of the Demand Forecasting Advisory Committee (DFAC) for the Council's 5th power plan was called to order at 9:40 AM by chair Terry Morlan. There were 7 persons in attendance.

These minutes are not intended to reflect exactly what was said at the meeting, but rather what the Council staff heard as the basic advice during the meeting.

Attendance:

Members	Visitors
Ham Nguyen, PGE	Charlie Grist, NPPC
Randy Barcus, Avista Utilities	
Hank McIntosh, WUTC	
Ken Corum, NPPC	
Jon Hirsch, BPA	
Terry Morlan, NPPC	

Welcome and Introductions:

Given the small number of attendees and their previous acquaintance, introductions and welcomes were handled before the meeting was called to order. There were no changes to the agenda (Attachment 1).

Approval of Minutes for April 18 Meeting:

The minutes of the April 18, 2002 meeting of the DFAC (Attachment 2) were approved with minor editorial corrections.

Review of the Draft Demand Forecast Paper:

Council staff worked through a PowerPoint presentation as a means of focusing discussion of the preliminary draft demand forecast paper (Attachment 3). There were few general comments on the paper. One DFAC member noted that the paper was a pretty good discussion of the forecasts. Staff asked that any editorial or other comments be forwarded in some form to the Council staff.

Several issues were discussed in reviewing the forecasts. One suggestion was that the DSIs be treated differently from the probability distribution of the rest of the forecast demand. The DSIs should be handled in more of a scenario fashion instead of as a probability distribution.

A question was raised about why 2000 is used for the base of the forecasts, instead of a more recent point. There were a couple of reasons for using 2000. One was to pick a relatively normal consumption level so that long-term growth rates wouldn't be distorted by an extremely low consumption base like 2001 or 2002 would be. A second reason for using 2000 was that it is the last reasonable actual sales data that we have available. The committee suggested adding that discussion to the paper so readers would understand the choice of 2000 as the base year.

Most of the discussion of the long-term demand forecasts related to the commercial sector. Much of it was deferred to a later agenda item. One utility reported actual decreases in commercial sales over the last 9 months. They found this surprising and said that it implied much more price elasticity than they expected from that sector, and that the recovery from the recession might be slower that they had expected. In later discussion, another utility, however, reported seeing no such weakness in commercial sales. They showed data that commercial customers consumption had been surprisingly constant for five years. The decrease in 2002 was small relative to their price increase and implied a very small short-term elasticity.

The committee reviewed the monthly distribution of electricity sales. There was agreement with using the patterns in the 4th plan that were estimated using the Council's Load Shape Forecasting System (LSFS), or using 1999. It was agreed that 2000 and 2001 would not be normal patterns to use for allocation of annual sales forecasts to months. It was suggested that the 2001 pattern be added to the graph to further support the choice of LSFS or 1999 monthly patterns.

The discussion of peak loads mostly centered on the observed growth of summer peak loads in the region over the last several years. The forecast of summer load factors did not show much decrease in monthly load factors. There was significant decrease in the winter load factors through the forecast period. Members noted that planners were becoming more concerned about summer peak loads more than winter ones. There was discussion of how much of this concern related to generating capability rather than just summer peak loads increasing.

Staff described forecasts of western states electricity demand growth. The exact method of forecasting varied by state, but except for Pacific Northwest states and California, the approach was to multiply an historical growth in electricity use per capita by a forecast of population growth in the state. A copy of part of the Excel spreadsheet used for these calculations was distributed to the DFAC (Attachment 4). It was recognized that this is a very simple approach and that other indicators of electricity growth, such as personal income, employment, or gross state product, could be used.

Nevertheless, the population approach was considered defensible given the resources available to do the analysis. Two suggestions were made to improve the forecasts. One was to check the historical period used for the growth rate of electricity use per capita to make sure that atypical starting or ending years are not used. In the forecast paper, the period 1990 to 1999 was used for all states. The other suggestion was to see if other population growth forecasts could be found to drive the outlook. Staff did this in the case of Nevada, and members thought some of the other state forecasts also seemed strange. The population forecasts for most state came from a Census Bureau forecast that was done in 1996. Specifically, it was suggested that staff look at Pacificorp's population forecast for Utah that was included in their IRP work.

Discussion of Commercial Sector Forecast Issues:

Staff presented some analysis of commercial sector electricity demand that they had done (Attachment 5). They were looking for some guidance on the fact that commercial sector demand forecasts were growing more slowly than either residential or industrial forecasts, whereas historically commercial has been the fastest growing sector. A number of issues were raised including, the accuracy of the historical consumption data, the forecast of declining use per employee and per square foot, and the model's sensitivity to price changes, especially for space heating.

One possible cause of an observed data shift in 1996 might be traced to a change in classification of some customers from industrial to commercial around that time. Demand elasticity in the commercial sector was discussed. One member noted that their estimated demand elasticity had increased since the last couple of years of price increases were added to the database. Another member noted very small price elasticity. There was some agreement that the addition of energy efficiency codes would have the effect of decreasing price elasticity in the forecast. This has probably occurred in the commercial forecasting model and would therefore be incorporated in the forecast already. However, a test done by the Council staff indicated that changes in natural gas prices are estimated to have a significant effect on commercial heating fuel choice.

Although there was clearly discomfort with the idea that commercial sector demand growth would be slower than either residential or industrial growth, one member said that he expected that the historical growth in use per square foot of building space has about reached its maximum, implying slower electricity growth than historically if other factors are held constant. There seemed to be general agreement that commercial demand growth was probably too slow. However, there was little agreement about the cause of the low growth forecast or how much it should be adjusted. Later it was agreed that the forecast should be released for public comment to see if additional information might come in through public comments.

Discussion of Demand Response in Electricity Markets:

Staff presented some analysis on ways to increase the demand side-response in electricity markets (Attachment 6). There was little enthusiasm for real-time electricity prices, although most members agreed that more demand-side response could moderate price spikes in the wholesale electricity markets. A major concern was that most consumers need to be isolated from the extremes of market price variation and that that was one of the responsibilities of regulators.

Advice from DFAC members included that staff should not neglect the fact that demand response programs will have implementation costs that should be considered. The issue was raised that the experience of other areas with demand response programs are generally concerned with hourly peaking. They may not be effective in the Pacific Northwest where our concerns are more likely to be of longer duration, e.g. sustained peaking over a period of 3 to 5 days. That is, programs that move consumption from on-peak to off-peak periods may not be adequate for our region.

Discussion of Future Council Forecasting Strategies:

There was little time left for this topic. Council staff simply indicated that at the next meeting of the DFAC we would be looking for suggestions about how the Council should structure its demand forecasting system for future power plans. This is one of the issues that the 5th power plan is expected to address.

A date was not set for the next DFAC meeting. Members asked that they be given plenty of notice so they can put the date on their calendars to avoid conflicts and can arrange better airfares.

These minutes are an accurate and complete summary of the matters discussed and conclusions reached at the Demand Forecasting Advisory Committee meeting held on July 31, 2002.

Certified by: ________________________________
Terry H. Morlan, Chairman

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