Minutes of the
Northwest Power Planning Council's

Natural Gas Advisory Committee

Held at the Council's Offices
851 SW Sixth Ave., Suite 1100, Portland, OR
April 12, 2002

The second meeting of the Natural Gas Advisory Committee for the Council's 5th power plan was called to order at 9:40 by chair Terry Morlan. There were 29 persons in attendance. The sign-up sheet is included as Attachment 1.

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
Mark Ebberts, BPA (for Rob Anderson)	Ken Corum, NPPC
John Bridges	Bryan Mills ,EPIS, Inc.
Phil Carver	Peter Stiffler, Economic Insight
Kevin Christie	Deborah Austin-Smith , EPIS, Inc.
Colin Coe	Mark Litterman, PGE
Bob Gruber, Avista Corp. (for Dick Winters)	Michael Schilmoeller, NPPC
Byron Defenbach	
Ian MacDonald, BC Gas (for Cynthia Des Brisay)	
Bill Donahue	
Randy Friedman	
Rick Harper	
Reed Harris	
Jane Harrison	
Jeff King	
Arne Olsen	
Terry Morlan	
Greg Staple	
Paula Pyron	
Fred Scott	
Pat Scherzinger	
Peter Schwartz	
Sam Van Vactor	
Bill Wood	

Introductions:

Terry Morlan welcomed the members to the Natural Gas Advisory Committee (NGAC) meeting and thanked them for their attendance. Each attendee introduced himself to the group. Terry Morlan summarized the agenda for the meeting (Attachment 2).

Approval of Minutes from February 28, 2002 Meeting:

The draft minutes of the first meeting of the Natural Gas Advisory Committee (Attachment 3) were approved after agreement on two corrections. There was not general agreement the Station 2 prices would be related directly to Chicago prices and Alliance Pipeline costs, as stated in the draft minutes. It was clarified that the $.36 cost for Williams Northwest pipeline pertained to future prices after recent expansions.

Natural Gas Price Forecast:

Terry Morlan summarized the changes made to the natural gas price forecast since the first meeting of the NGAC. The first agenda item was to discuss these changes and refine them if necessary. The discussion started with wellhead price assumptions and then moved on to the various assumptions about basis differentials and transportation costs. Several items were sent out to the committee prior to the meeting. These appear as Attachments 4 through 7.

Wellhead Prices

Terry Morlan described the increase in wellhead price assumptions since the first NGAC meeting. The medium forecast was increased significantly, but the high forecast was not significantly changed. The proposed medium forecast in nominal dollars for 2003 through 2008 averaged 40 percent higher than average prices in the previous decade as measured by 1993 through 1998. The forecast was still about 15% below the NYMEX futures price average for the same forecast period. The revised forecast included a rebound in prices for 2003 based on an assumed return to normal weather conditions and inventory levels.

Extensive discussion followed. Many thought that the prices declined too quickly after 2003. There was general agreement that the current tightness in the supply of natural gas would extend for 5 years or more. The committee offered several reasons that they thought natural gas had entered a new phase that implied a permanent shift to higher prices above $3.00. Some of these reasons were; the end of a “secondary” Canadian gas bubble (or supply overhang) during the late 1990s, some thought that prices in excess of $3.00 were necessary in the long run to bring on substantial new supplies including Alaskan gas or LNG, the need to add nearly double the new gas supplies each year than historically, and shorter well lives due to more rapid production for technological and economic reasons. The movement toward a just-in-time natural gas inventory, in some members minds, implied a closer link between current natural gas prices and marginal development costs.

There was some discussion of the role of technology in limiting price increases in the future. The role of substitute fuels was also discussed. It was suggested that the Council staff should check the relative prices of residual oil and coal in its fuel price assumptions. Some thought that the relevant comparison to natural gas might now be distillate fuel or some average of distillate and residual oil.

Several of the members observed that future prices could be above the high forecast, but no one seemed to believe that prices could be below the low forecast. There was general agreement that the high forecast should be raised and should at least cover the current NYMEX futures prices. Someone suggested simply raising all of the forecast cases up to the next one above it in the draft, and creating a new higher high case.
Committee members ultimately suggested that a straw vote be held to make sure of the full committee's opinion regarding the natural gas price forecast. It was decided to vote on both the short-term assumptions (2005) and the longer term (2020). The choices were to increase, decrease, or not change the draft forecasts presented by the Council staff.

The results of the voting were as shown in the table below.

	Increase	Decrease	Unchanged
2005	14	2	6
2020	6	4	9

Clearly, there was substantial diversity of opinion. However, the tendency was to raise the near term forecast, while many thought the long-term forecasts were more reasonable.

Transportation Costs to End Users

The committee reviewed the transportation costs used in the forecast. A new distinction was raised in the discussion of transportation costs; summer/winter differential. In particular in-kind fuel charges, capacity release costs, and some regional price differentials should be substantially higher in winter.

In-kind fuel percentages were considered correct. It was mentioned that the in-kind fuel charge for the Evergreen expansion of Williams Northwest Pipeline is 2.25 percent, higher than the current percentage of 1.7 percent. It was stated that winter fuel percentages are higher than summer.

It was pointed out that the incremental pipeline cost of $.46 in 2010 only included one pipeline's cost. Incremental cost needs to be added for the other pipeline segments in Canada. It was generally agreed that the $.46 is too high for a single pipeline. There was some agreement that the total incremental might be in the neighborhood of $.60 ($.40 for Williams NW and $.20 for Duke/Westcoast) for the full incremental pipeline requirements from Station 2 to west-side PNW locations, but only after about 2005. On the east-side, incremental costs were expected to be $.36 to $.38 in the long term.

For the period through 2005 incremental costs are expected to be significantly lower, however. A value of $.31 was suggested for the east side as typical deals available for the next few years. It was suggested that there be lower incremental costs for the period before 2005, followed by a step increase and some amount of real growth after 2005.

The Duke/Westcoast pipeline has a $.02 motor fuel tax charge on transportation that has been left out of the variable cost component of its transportation costs. It was mentioned that a change is being considered in the ratio of fixed and variable costs on Duke/Westcoast after 2003; an increase in the variable component relative to the fixed component.

In reviewing the capacity release or interruptible pipeline costs, the committee decided that here too the differences between summer and winter rates were substantial. It was agreed that for the west-side full rates should about $.48 ($.28 on Williams, $.20 on Duke) in the winter and 50 percent of full rates for the summer. On the ANG system, a 10 percent premium over firm capacity costs was suggested for winter, and 50 percent of firm capacity costs for summer. PG&E GTN from Kingsgate to Stanfield should be full tariff in winter and 50 percent in summer. However the summer/winter differential is reduced substantially on the south end of the PG&E GTN pipeline. There may be little differential at Malin.

It was noted that for short periods of high demand costs for released capacity could exceed the full firm tariff rate substantially. FERC has experimented with uncapped capacity release prices.

There was an inconclusive discussion of whether the changes in transportation costs and basis differentials would result in an unreasonable difference in the cost of gas-fired generation on the west and east sides of the Cascades.

Regional Price Differentials

There was general agreement with the AECO – Henry Hub differential of $.44. While it was expected that this differential will be highly variable, it was not expected to be a seasonal variation. There seemed to be some agreement that a range of values could be used for the different forecast cases. One member said that he didn’t expect the AECO – Henry Hub differential to be sustainable over $.60 or below $.20 (the variable transportation cost). It will be the producers goal to keep Chicago and AECO prices connected.

There seemed, at first, to be some difference of opinion about the differential between AECO and Station 2 prices. However, the difference apparently reflected the difference between a firm winter time differential and an annual average one. It was agreed that the differential should be expected to be seasonal, about $.20 in winter and even parity in summer.

There was a discussion of the Rockies – Henry Hub differential. Some members expected that the Rockies price might continue to be low compared to other western pricing points. Others expected that over time pipeline capacity would be added out of the region so that prices would move up.

Other Natural Gas Issues

There was a brief discussion of natural gas supply and transportation agreements likely to be used for new power generation plants. It was noted that firm pipeline capacity is required in order to get financing for a new plant. This was qualified to some degree by noting that firm pipeline capacity is needed at least to the nearest liquid pricing point. Natural gas supplies can be arranged on a shorter-term basis and are not as crucial for plant financing.

Oil Prices:

The committee discussed the Council staff's draft oil price assumptions. There did not seem to be serious disagreement with the medium price of $22 per barrel (2000 dollars). However, the point was made that until recently there has been a substantial excess capacity in the Middle East. There is no shortage of oil in the ground, but additional investments are needed to increase production capacity. This may imply narrower capacity margins and more volatility similar to the situation in natural gas markets. On the other hand, growing investments in non-OPEC countries may diversify the supplies of oil and give OPEC less effective control over production and prices. This investment would be cautious, such that prices would tend to remain on the margin. It was noted that at $20 to $22 a barrel oil prices there would likely be continued investment in tar sands processing in Alberta.

The committee recommended that the oil price projections should have some upward real trend over time similar to the EIA forecasts that were compared to the Council's. This would be consistent with the need for investment in the near-term. The Council staff should pay attention to the relative prices of natural gas and residual and distillate oil. Oil provides substitution possibilities that may limit natural gas prices over time.

Council staff asked about the likelihood that oil backup would be used for new gas-fired generating plants. Generally the committee seemed to think this was unlikely. In California, economic use of backup fuel is not allowed for environmental reasons. In other areas, the use of backup fuel is severely limited. In addition, modern combustion turbines do not burn oil easily. Conversion takes time, increases maintenance requirements and risks damage to the generating turbines.

Coal Prices:

Terry Morlan explained the methods used to develop coal price forecasts. The key component is a forecast of the trend of western mine-mouth coal prices. Delivered coal prices in western states are then related to the western mine-mouth forecasts by markups based on historical price relationships.

The main advice for the Council on coal prices was that coal prices should not be expected to decline as rapidly as they did in the past. There was some opinion that the rate of productivity improvement is likely to slow. In addition, it was noted that part of the historical decline observed in coal prices were a result of electric utilities gradually escaping from long-term and too highly priced coal contracts. There was some agreement that the high forecast case should not have a real decline in coal prices.

If coal use were to increase significantly, due to higher natural gas price forecasts for example, there would be some upward pressure on coal prices as new production capacity would need to be added.

Like oil, members of the committee stated that there is not really any scarcity of coal in the ground. However, coal burning does face significant environmental challenges that are likely to limit its future energy role to some degree.

Future Meetings:

Terry Morlan explained that he will now take the advice he has received and revise the fuel price forecasts. The revised forecast will be completed near the end of April or early in May. The Council will then need to approve its release for public comment. The comment period may be about 2 months and in the midst of that period the NGAC should meet again to review the draft report and discuss other issues. Some of the other future agenda items might include, reliability of natural gas supplies and delivery during a peak crisis, the role of natural gas storage in providing peaking supplies and mitigating price volatility, and the issue of space and water heating fuel conversions.

The next meeting date was not set. It is expected to be sometime in June depending on the timing of the revised draft forecast and the public comment period.

These minutes are an accurate and complete summary of the matters discussed and conclusions reached at the Natural Gas Advisory Committee meeting held on April 12, 2002.

Certified by: __________________________________
Terry H. Morlan, Chairman

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