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
June 28, 2002

The third 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 15 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
Rob Anderson	Peter Stiffler, Economic Insight
John Bridges	
Pat Scherzinger	
Peter Schwartz	
Sam Van Vactor	
Bill Wood	
Byron Defenbach	
Terry Morlan	
Greg Staple	
Randy Friedman	
Jane Harrison	
Jeff King	
Clay Riding	
David Hawk (by phone)	

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.

Approval of Draft Agenda for Meeting:

Terry Morlan summarized the agenda for the meeting (Attachment 2). The agenda for the meeting was adopted without change.

Approval of Minutes from April 12, 2002 Meeting:

The draft minutes of the second meeting of the Natural Gas Advisory Committee (Attachment 3) were approved after agreement on two corrections.

Comments on Draft Fuel Price Forecast Paper:

The morning was spent refining and correcting the fuel price forecast and suggesting corrections and changes to the paper. The discussion did not generally follow the paper on a page-by-page basis, but several issues were raised and discussed.

One concern was that the years 2000 and 2001 not be used as a basis for the forecast. Those are considered to be extremely unusual circumstances and not a good basis from which to forecast. Council staff agreed and will check to make sure the impression is not left by the discussion of those events that they are the basis for the forecast. The intent in the paper was to describe and explain those events because there is a lot of interest by the public.

There was some discussion of expected natural gas demand trends. There has been a decline in natural gas demand since 2000-2001 due to several factors, including better hydroelectric supplies, price induced conservation, industrial shutdowns, and introduction of some more efficient gas-fired electricity generation plants. Most expect a resumed growth in natural gas demand. Council staff asked about how important the aluminum plant shut-downs were to natural gas demand. It was not considered extremely important; one member suggested that a smelter might use 1500 to 3000 million Btu a day.

There was considerable discussion of the assumed $.10 per Million Btu price differential between AECO and Station 2. The price forecasts were based on an assumed $.20 premium at Station 2 over AECO in the winter months and zero differential the rest of the year averaging $.10 for the year. This assumption was consistent with the pattern of futures prices for the next couple of years. Some argued that increased connectivity would result in price equating between Station 2 and AECO. Others argued that the cost of moving gas west to Station 2 is about $.20 and that that would put a ceiling on the differential. There seemed to be general agreement on this point of a cap on differentials. In support of a $.20 year around assumption, a gas buyer noted that deals that can be made now include a $.10 to $.11 cent premium at Station 2 for the next year but that the premium increases to about $.20 for longer term deals. A consensus was not reached on this issue.

The issue of direct use of natural gas was raised. The question was, where and how would the Council plan to address this issue in the plan? Council staff responded that it was not clear exactly how it would be addressed. It is more of a policy issue than an analytical issue, but some analysis is necessary in order to help address the policy.

There was some concern that the expanded geographical detail of the fuel price forecasts had not been adequately discussed in the text. For example, the differentiation of east and west of the Cascades, and the state level prices in the western U.S. that feed into the Aurora model appear in the appendix tables, but there is little reference to it in the text. It was suggested that an enhanced map might be used to illustrate this expanded dimension of the forecasts. Although it was not discussed at the meeting, the same might be true for monthly patterns of fuel prices.

There was a concern that the role of Rocky Mountain supplies, delivered through Williams Northwest Pipeline, in setting natural gas prices in the Pacific Northwest west-side load centers had not been recognized. Discussion centered on the expectation that, for forecasting future natural gas prices, incremental supplies of Rocky Mountain gas would play little role. There was an expectation that the cost of expanding pipeline capacity through the Columbia River Gorge would be too expensive to allow a greatly expanded role for Rocky Mountain supplies going forward and that Sumas prices would set Westside marginal gas prices. Staff agreed to make sure that the discussion recognized that Rocky Mountain gas is a factor in historical prices and regional gas supplies.

There was a discussion of the distinction between off-system and on-system in the industrial sector natural gas price forecasts. These appear in Table 4 of the document, for example. Council staff explained that off-system referred to consumers who arranged their own gas supplies as opposed to allowing the local distribution utility to supply full service. It was clear that to most of the committee, "off-system" meant a consumer who bypassed the local distribution company system completely. Once that was clarified, there followed a discussion of whether the local distribution charge assumed was reasonable. There was a general feeling that $.20 per million Btu was low, except for very large consumers or bypass threats. A cost of $.30 per decatherm, or about the same in 2000 dollars per million Btu, was mentioned as a premium for firm distribution above an interruptible rate. Firm distribution cost can range from $.02 to $1.00 per therm for the distribution charge only. Capacity and supply are negotiated separately. Council staff noted that the calculation in Table 4 would only apply to large industrial consumers. Others are treated as a fixed difference from U.S. wellhead prices based on historical price differences. For electric generation, it was assumed that all new plants would connect directly to interstate pipeline systems.

Discussion indicated that there should not be a large difference between the price a large consumer would pay if it bought gas through the local distribution company or arranged its own supplies.

Tables 4 and 5 caused confusion. They were examples of calculations that mixed industrial and utility and east-side and west-side calculations. The title to Table 5 needs to clarify that it is an east-side calculation. Some thought it would be better to include both east and west side tables. Also it would be good to include the year of the example in the title.

It was suggested that more treatment of volatility be added to the paper. It was identified as a key feature of natural gas prices, but got little discussion in the paper. Council staff indicated that volatility is going to be addressed in the overall analysis of the power plan. Nevertheless, some discussion of the approach could be added to the fuel price paper.

There were a number of specific corrections to the paper. These included: inconsistency between the coal price table in the main body of the paper and the appendix tables; mislabeled appendix pages; need for clarification of 2001 price patterns; clarify that propane-air injection plays a miniscule role; “last summer” on page 9 should refer to summer 2000; clarify that the relatively small amount of Canadian exports in U.S. supplies, nevertheless, accounts for a large percentage of Pacific Northwest consumption (p. 9 bottom); add reduced consumption as a cause of lower prices in winter 2001-02 (p. 15); add description of role of transportation costs in setting bounds of price basis differentials in Table 3; the national base price of natural gas in Tables 4 and 5 are different; and, finally, individual members pointed out a number of typographical or other minor errors.

Monthly Natural Gas Price Patterns:

Council staff described the need to impose a monthly pattern on the fuel price forecasts for Aurora modeling purposes. Monthly patterns of historical price were presented for Henry Hub prices and Sumas. The average monthly patterns were influenced by a couple of years when winter prices were very high. The monthly patterns of NYMEX futures prices were also displayed. They appeared to be similar to the average historical patterns with the extreme years included.

It was agreed after some discussion that using historical patterns was a reasonable way to forecast future patterns. It was suggested during the presentation that price patterns that looked fairly flat on the graphs presented, were in fact significant variations. The scales were changed on the graphs to better identify the differences.

Discussion of Pipeline Capacity Cost Recovery through the Capacity Release Market:

Council staff described the purpose for wanting to identify how much of firm pipeline capacity cost might be recovered through the capacity release market. The amount recoverable becomes part of the variable cost of operating a generating plant instead of part of the fixed costs. The assumption used in the fuel price forecast is that 50 percent of the cost could be recovered when the plant is not operating.

The advisory committee discussion made it clear that a simple average percentage would be difficult to arrive at. The value of pipeline capacity will depend on the demand in the market, which will vary seasonally and will depend on the particular pipeline and, in some cases, particular segments of the pipeline. It will also depend on the conditions of the release. If there are recall provisions, a winter release may recover only 50 to 60 percent, whereas a release with no recall provisions may recovery 100 percent. Some released capacity has received greater than 100 percent under a FERC experiment that ends in the fall this year.

Nervous about simple assumptions, a couple of members nevertheless suggested that a simple assumption might be that during April through June one could recover only 10 percent, and during the rest of the year 50 percent. Transportation from the Rockies is an exception. Because of transportation constraints, releases sometimes garner prices greater than tariff rates. Other ideas were to relate it to capacity factor of gas-fired generation plants (particularly in the summer), temperature, or to the price differential between pricing points, which would be a measure of the value of pipeline capacity.

Discussion of Monthly Natural Gas Consumption Patterns and On-peak Requirements for Electricity Generation:

Council staff presented a number of graphs showing the relationship between monthly patterns of natural gas use for electricity generators and the core demands of local distribution companies. There was some discussion of what the core demand patterns included. Most seemed to think that delivery-only industrial consumers would be included in the industrial consumption data because that demand would be reported in the utilities' send-out data.

The graphs showed that historically the pattern of natural gas use for electricity generation did not coincide with gas core load patterns. In the Pacific Northwest, gas use for electricity historically occurred in August and September, where as peak core loads were during the winter in December through February. Gas use for electricity generation in California peaked in the summer historically. The question being addressed is whether there is likely to be a conflict between increased use of natural gas for electricity generation and the ability of both industries to meet their peak demands.

The projected future patterns of natural gas use for electricity generation as forecasted by the Aurora electricity market model were then presented. These results showed a smoother use of natural gas that peaks in summer, generally August, and again in March. There was considerable discussion of whether gas use peaking in March was reasonable and what the reasons behind it might be. The most promising explanation seemed to relate to the hydroelectric generation patterns in the region, Council staff is continuing to explore other factors that may explain the model results.

There was a discussion of dispatch assumptions for cogeneration plants versus regular generating plants. Some thought there should be a tendency for cogeneration plants to operate at a higher capacity factor than non-cogeneration plants. It was suggested that cogeneration units supplying enhanced oil and bitumen recovery operations will likely operate under nearly all electricity market conditions. On the other hand, it was pointed out that refinery cogen operations in Washington are operating in a dispatch rather than must-run mode. Although historically generating units have often run without firm gas transportation, most operators now run on firm.

Discussion of Natural Gas Deliverability for Winter 2002-03:

The Council staff began a discussion of winter peak day natural gas deliverability on the west side of the Cascade Mountains. A balance table was presented with preliminary assumptions (Attachment 4). The Council staff was looking for help in collecting information, especially on peak day demand. The information on demand by direct-connect consumers on Williams Northwest Pipeline and non-core interruptible industrials was considered especially weak. It was noted that most of the local distribution company forecast used were done before the market upheavals of 2000 and early 2001 and did not capture the decreased demands from the higher prices, aluminum shutdowns and economic slowdown.

Several changes were suggested in the discussion. The Burrard gas-fired generation plant in Vancouver is not likely to operate except if an extreme electricity peak coincides with the peak natural gas day. Burrard should be generally assumed off-line during peak gas demand days. Duke delivery capability through Sumas should be 1,617 million cubic feet per day instead of the assumed 1,650, which included Southern Crossing credited with 105. Southern Crossing should not be listed as a source of natural gas for balancing purposes.

Mist is currently 317 capacity instead of the 245 listed in the table. It was noted that the Tilbury LNG plant is currently empty with refill just starting. Its availability in early winter may be limited. The capacity of Williams Northwest through the Columbia Gorge should be listed as 498 instead of 485. It was noted that part of the peak day deliverability of Williams pipeline would depend on the Plymouth LNG plant. It was noted that Sumas Energy has no backup fuel capability although it was not clear what was assumed in the table.

The committee asked to be sent an updated balance table when changes have been incorporated. Several members were to check for updated demand information to fill in the table. Council staff said that they would like to extend the balance sheet out for a couple more years if the data were available.

One member provided information on natural gas receipts in the WCSB. It showed that total receipts had increased in the last year. Reports that receipts have declined do not account for all parts of the WCSB. NGTL (Nova) receipts did decrease in the 2000/01 gas year due to the start up of Alliance Pipeline, but total WCSB receipts increased. Their forecasts show continued growth in the number of wells drilled and wells connected and in natural gas produced in the WCSB. Nevertheless, there is a slowdown in growth predicted.

Future Meetings:

Council staff indicated that it was not clear whether another NGAC meeting would be needed. There was some interest expressed in having another meeting to look at the early planning results of the fuel price assumptions. Council staff also indicated that if NGAC members wanted to have another meeting to address issues of concern to them, the Council staff would be happy to schedule such a meeting.

These minutes are an accurate and complete summary of the matters discussed and conclusions reached at the Natural Gas Advisory Committee meeting held on June 28, 2002.

Certified by: ______________________________
Terry H. Morlan, Chairman

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