BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 233

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In the Matter of	)
	)
IDAHO POWER COMPANY	)
	)
Request for a general rate revision	)
	)

JUNE 20, 2012 TESTIMONY OF THE
CITIZENS' UTILITY BOARD OF OREGON

June 20, 2012

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Our names are Gordon Feighner and Bob Jenks, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

There are two critical issues remaining in this docket:

1) Should a prudence review of environmental controls examine the environmental controls one by one—in a piecemeal fashion—as they are added to rates?
2) Does a minority owner, in this case with a one-third interest in a power plant, have the same due diligence obligation to ensure that decisions affecting that plant are prudent and consistent with the least-cost principle?

CUB believes that the answers to the two questions posed are as follows:

1. No. A regulator should not conduct the prudence review of environmental controls in a piecemeal fashion. The scrubber upgrade at issue in this case, if considered with all of the other environmental controls required to make the plant compliant with BART, is not a prudent investment on its own. It does not comply with BART, and will not allow the plant to stay open past 2015. To stay open will require additional investment in the plant, including an SCR. A prudence review should consider the entirety of the costs that the Company is committing to invest in order to be BART compliant.
2. Yes, a minority owner should have the same due diligence obligation as the majority owner to ensure that decisions affecting the plant are prudent and consistent with the least-cost principle. One-third of a coal plant is a significant investment and must be managed well. The minority owner has a responsibility to ensure investment decisions that are made are cost effective and will benefit customers.

II. How Should the Commission Conduct a Prudence Review?

CUB is surprised by Idaho Power’s insistence that the only investment that should be subject to prudence review in this docket is the scrubber upgrade investment. The Company’s unwillingness to even answer data requests concerning the SCR is troubling because without the SCR, the scrubber upgrade is not used and useful. It is CUB’s position that the used and useful standard is as much at issue in this docket as is the prudence principle. Idaho Power made the investment in the scrubber upgrade in order to comply with Regional Haze Rules. But those rules have not been finalized and, notwithstanding recent dramatic changes in gas prices, Idaho Power has neglected to reanalyze the effectiveness of its plan to invest in additional pollution control to meet the Regional Haze Rules. These plans include the addition of an expensive— and likely unnecessary—SCR.

A. The Used and Useful Standard/Stranded Costs

The used and useful standard requires the Commission to make a determination as to whether the scrubber upgrade that was added to the plant was and is used and useful. Clearly the scrubber upgrade has been added to the plant, and the plant is operating with it, meaning it is used. But is it useful? By itself, it does not allow the plant to meet Regional Haze Rules. Therefore, by itself it is not “useful.” The scrubber upgrade is only useful if, when paired with other controls, the set of controls collectively allow the plant to meet the Regional Haze Rules. Thus, without consideration of the additional SCR needed to meet the Regional Haze Rules, it is not “useful” in meeting regulatory requirements.

As we will demonstrate later in our discussion of the specifics of the various Bridger 3 studies conducted by IPCO’s partner PacifiCorp, CUB believes that there is a very good chance that when the companies update the Clean Air Investments analysis of this unit, they will conclude that they should convert the unit to gas. If such a decision is ultimately made, the scrubber upgrade, while still likely attached to the plant, will no longer be needed—it will no longer be used and useful. It will instead be a stranded cost.

As a stranded cost, the scrubber upgrade will not be eligible for recovery unless the Commission finds its retirement was in the public interest. At that point IPCO will no longer be allowed to earn a return on the scrubber upgrade investment.

B. The Problem with Piecemeal Review of Clean Air Investments

Much of the problem with piecemeal review of clean air investments stems from the fact that each element of the investment comes before the Commission individually as it occurs in the test year, but the Regional Haze Rule investments as a project never come collectively before the Commission. This is a problem because, as discussed above, the investments are only used and useful when combined as a total project. An analogy to this situation would be if a utility decided to bring individual pieces of a new plant to the Commission in a piecemeal approach. One year the Commission reviews the building, the next year it reviews the turbine, and the year after that it reviews the smokestack, but it never reviews the whole coal plant as a total project. The coal plant does not function as required until all of the pieces are online and used at the same time. The plant could not in fact be considered used and useful until it has all of its parts reviewed collectively. The same is true for clean air investments designed to bring a coal plant into compliance with existing and future clean air regulations.

Of course, piecemeal review of a generating plant is not allowed because a utility cannot bring construction work in progress to the Commission to place into rates. Until a power plant is used and useful—until it is complete and operating and all of its parts can be collectively considered—it cannot be included in rates. CUB believes that Naughton 3 and Bridger 3 demonstrate that it is time to consider taking a similar approach with regard to review of Regional Haze Rule investments.

C. Regional Haze Rules and Construction Work in Progress

Regional Haze Rule investments could be treated like Construction Work in Progress (CWIP) until a coal unit is compliant with the rules. Only at that point would the project be used and useful. For example, if the compliance deadline is 2015, then the elements required to meet that deadline would be considered a single project—nothing would be used and useful until the entire project was completed. If the first deadline is one of many under a particular environmental rule (for example, an environmental rule that has a compliance deadline for 2015 and another for 2017), then the utility would have to show how compliance with the 2015 deadline fits into its plan to meet the 2017 deadline, or perhaps it could show that the 2015 compliance will be cost effective in two years so that its prudence is unconnected to the compliance with the 2017 deadline.

In suggesting this, CUB recognizes that complying with environmental rules is different than meeting RPS targets. A wind facility that is designed to meet a 2015 RPS target does not become stranded if the other planned units are not built. But a clean air investment will become stranded if all of the other investments planned to meet the compliance deadline do not get built because the consequences are different—the plant then has to shut down.

This leads us to question whether a minority owner with a one-third interest in a power plant has the same due diligence obligation to ensure that decisions affecting that plant are prudent and consistent with the least-cost principle. While Idaho Power is not claiming that a minority owner does not have the responsibility to act with due diligence, its actions seem to suggest that it simply delegated, whether actively or passively, its responsibility to PacifiCorp.

D. Was Idaho Power Duly Diligent?

The primary study that PacifiCorp claims was done before the investment to determine whether the scrubber upgrade was cost effective was the 2008 study. While

CUB will have more to say about that study later, we note that Idaho Power received the study on April 26, 2012.[1] At the time of receipt of this study, Idaho Power was not attempting to meet its due diligence obligation and incur investment costs that were least-cost to customers, but rather was defending its shareholders from a prudence disallowance requested by CUB.

CUB Exhibit 301 shows the data responses CUB has received in this docket related to due diligence, or the lack thereof, by the Company in regard to compliance with clean air regulations. These data responses reveal that Idaho Power was not engaged in active management of the Bridger Unit 3 plant. Idaho Power, for example, cannot tell us "the exact dates of the planned outage during which the work was completed nor the exact date that the work was completed."[2] Idaho Power never reviewed the contractor's work.[3] Idaho Power does not know when the actual work on the project began[4] or the dates of the competitive bidding process relating to the scrubber upgrade.[5]

Before work on the project began, it seems as if the only study IPCO reviewed was the CH2M Hill study discussed in earlier testimony. That study was not an attempt to determine if the BART projects were cost effective, but instead was an attempt to determine the least-cost option for complying with BART. Based on that study, the current BART investment, which includes an SCR, is not the least cost.[6]

It is CUB's position that, regardless of whether Idaho Power in fact engaged in a due diligence review of the clean air compliance regulations and the technological fixes

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[1] CUB Exhibit 301, IPCO Data Response to CUB DR 48
[2] CUB Exhibit 301, IPCO Data Response to CUB DR 46
[3] CUB Exhibit 301, IPCO Data Response to CUB DR 45
[4] CUB Exhibit 301, IPCO Data Response to CUB DR 44
[5] CUB Exhibit 301, IPCO Data Response to CUB DRs 42 and 43
[6] UE 233/CUB/200/7.

required to come into compliance with the regulations, IPCO is none-the-less responsible for its clean air compliance investments in the plant and the Commission must determine whether those investments were prudent and least cost.

III. The Studies

A. Idaho Power Tipping Point Analysis

IPCO included a Tipping Point Analysis (TPA) in its 2011 IRP. This TPA study is not, however, adequate to support a prudence finding. We will explore the reasons for the TPAs' failure to support a prudency finding below.

i. The TPA Failed to Look at Bridger 3

The Company describes the TPA as a high level study.[7] The study was not an attempt to look at Bridger 3 and whether the investment required under the Wyoming Regional Haze Rules was cost effective. Instead, the TPA was a combined look at both the Bridger and Valmy plants.[8] This is very concerning to CUB, because it is not clear whether PGE would have agreed to close Boardman early if it had been permitted to average Boardman with Colstrip. It is also not clear that PacifiCorp would have agreed to close Carbon 1 and 2 early, and to convert Naughton 3 to gas if it had been permitted to average those three plants across its fleet of 26 units. Averages tell us very little.

ii. The TPA Is not Consistent with the 2012 PacifiCorp IRP Update

PacifiCorp's IRP Update shows that Bridger is on the edge between continuing to operate and being converted to natural gas. In three of the six Bridger scenarios we reviewed, the plant could be converted to gas.[9] Thus, while IPCO believes that the $120

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[7] UE 233 Idaho Power/1400/Carstensen/6.
[8] UE 233 Idaho Power/1400/Carstensen/6.
[9] UE 246 CUB/100/Feighner-Jenks/36.

million difference from its TPA demonstrates that there is no need to look more closely at closure of that plant, the PacifiCorp study shows that Bridger 3 will either barely survive as a coal plant or be converted to gas.

iii. The TPA Does not Consider Options Regarding Closure Dates or Replacement Resources

This high level analysis assumes that a plant would be replaced by a CCCT,[10] but does not consider any other options such as converting to natural gas. In addition, the study did not consider seeking early closure as an option to reduce pollution control costs, as PGE did with Boardman.

iv. The TPA Study Was Conducted After the Investment

Finally, we note that this high level study was conducted after the investment was already made so it is not relevant to what the Company knew when it originally consented to the investment.

The TPA study, if it was in fact reliable, could tell us something about the impact of the investment decision. However, now with the March 2012 PacifiCorp IRP Update, we have a better analysis to review the status of Bridger 3's clean air investments.

B. PacifiCorp's 2012 IRP Update

PacifiCorp's 2012 IRP Update is now on the record in this case. CUB's discovery concerning that study was mostly directed to PacifiCorp and not to IPCO. Given that IPCO has now made the PacifiCorp IRP Update relevant to this docket, and the fact that there are several important pieces of information contained in that Update, CUB—

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[10] UE 233 Idaho Power/1400/Carstensen/6.

without revealing confidential information from another docket—will attempt to summarize the important features of the study.

First, the PacifiCorp IRP Update analyzed six scenarios with Bridger 3 and concluded that in three of those scenarios, low gas, high CO_2, or both, it would be cost effective to covert the plant to natural gas.[11] Second, PacifiCorp committed to updating its analysis before making further investments:

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> [redacted].[12]

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Third, according to the update, the gas forward price curve contained therein is dated from August 2011:

> The 2012 business plan portfolio modeling was based on the August 31, 2011 price curves, downloaded from the Company's forward price system. The price curves reflect June 30, 2011 MIDAS12 power and gas curves blended with market forwards as of August 31, 2011.[13]

But gas prices have continued to fall. If the gas costs were updated, the Company might find that the plant should be repowered with gas because updated natural gas forecasts are moving towards the low gas scenario. A recent check with the Energy Information Agency shows gas prices have fallen by $2.375/MMBtu since last year.[14] The 2012 EIA Annual Energy Outlook has lower forward prices than the 2011 EIA Annual Energy Outlook.[15] The gas price forecast that was contained in the Oregon Gas

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[11] UE 246 CUB/100/Feighner-Jenks/36.
[12] UE 233 Idaho Power/1404/Carstensen/95.
[13] LC 52, IRP Update, March 30, 2012, page 37.
[14] http://www.eia.gov/dnav/ng/hist/rngc1d.htm. Accessed 11 June 2012.
[15] http://www.eia.gov/forecasts/aeo/er/.

Update Report provided to the PUC are below the Low Gas Price forecast in the PacifiCorp IRP Update.[16] If PacifiCorp updated the forward price curve contained in the Oregon Gas Update Report, it could find that Bridger 3 should be converted to gas.

Fourth, the scrubber upgrade costs that are in the current UE 246 GRC were considered sunk; they could not be avoided. The PacifiCorp IRP Update was the first study that robustly considered more options than just market purchases. The IRP Update was the first study to consider more than just one future scenario for gas prices and CO_2 prices. But the IRP Update study comes midway into the process to make the plant compliant with Regional Haze Rules. The PacifiCorp IRP Update no longer considers some of the costs as unavoidable. If all costs associated with meeting the Regional Haze Rules were in fact still avoidable, the additional costs being contemplated would make continuing to burn coal at Bridger less appealing. But, the Company has never conducted a robust study including all of the RHR costs.

Fifth, the Company continues to look at the pollution control decisions and closure from a binary perspective. Either the SCR investment is made next year or the plant is converted to gas. But, as we discussed above, there is another way to look at this issue, another variable. If the plant were scheduled to close in 2018 or 2020, for example, it is doubtful that an SCR would have been considered cost-effective pollution control for meeting the RHR. Instead, running a coal plant without as much pollution control for an additional three to five years would have reduced the costs and made closure cost-effective, since the plant would produce power more cheaply than either a coal plant repowered for gas or a coal plant with significantly higher capital investment.

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[16] See CUB exhibit 302—Gas Price Forecast.

Sixth, with EPA proposing to partially reject the Wyoming SIP application,[17] the costs of pollution control may be greater than modeled.

Given all of these points, this PacifiCorp IRP Upgrade study did little to demonstrate that the scrubber upgrade is cost-effective. Instead, it raised questions about whether the scrubber upgrade will remain used and useful.

C. 2008 Study

The third study is the 2008 study. As we noted above, Idaho Power received this study in April,[18] so it is not something the Company knew about when it made the decision to invest in the plant.

CUB has analyzed PacifiCorp's 2008 study already in the PacifiCorp IRP docket (LC 52). Though some of that information is confidential and not on the record in this docket, we will summarize our findings here:

PacifiCorp signed a contract for work on the scrubber in 2008,[19] but construction did not commence until July 6, 2010, and the scrubber update was installed during a plant outage between April 30, 2011 and June 30, 2011.[20] PacifiCorp compared its then-expected cost for clean air investments to closing the plant and relying on market purchases. PacifiCorp concluded that the advantage to customers from making clean air investments and retaining the plant is a net present value of BEGIN CONFIDENTIAL $[redacted].[21] END CONFIDENTIAL There are several serious flaws in this study.

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[17] 77 FR 33022 (2012).
[18] CUB Exhibit 301—IPCO Response to CUB DR 48
[19] UE 246 PAC/500/Teply/84.
[20] UE 246 PAC/500/Teply/84-85.
[21] UE 233 Idaho Power/1400 Carstensen/9.

i. Closure Date

This study assumed the alternative to this investment was closure in 2008 and replacement with market purchases.[22] This assumption, however, makes no sense. The requirement for a future investment in the scrubber upgrade was not adopted by Wyoming until March 2009.[23] So the alternative closure date had no relationship to the completion date of the project, the deadline for pollution control, or even the date that the state required an upgrade in the future. As of the date of CUB's testimony, Wyoming does not have a SIP that has been approved by the EPA.[24]

CUB's understanding from participating in the Oregon DEQ's BART process is that the deadline for these investments is 2015. This means that PacifiCorp's model closed the plant 8 years early. A significant amount of the savings identified in this study comes from these 8 years of uneconomic closure of the plant.

ii. Future Electric Prices

PacifiCorp's 2008 study was conducted just before the US went into a deep recession. The effect of that recession was to significantly change forward price curves.

CUB Exhibit 303 depicts the Northwest Power and Planning Council's (NPPC's) graph of historic and future electric prices. It shows that the price of wholesale electricity decreased significantly from 2008 to 2010, when construction on the upgrade began.[25] If PacifiCorp had updated its study at the end of 2008, or anytime in 2009, the change in forward prices would have had a significant effect on the 2008 study results.

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[22] PAC/500/Teply/85.
[23] PAC/500/Teply/81.
[24] 77 FR 33022 (2012).
[25] CUB Exhibit 303—NPPC's 6th Power Plan

iii. Additional Pollution Control

In addition, because the scrubber upgrade was not sufficient to meet the BART requirements and a SCR and other investment was required, Idaho Power and PacifiCorp should have been updating PacifiCorp's analysis on a regular basis to ensure that the overall project (defined as compliance with RHR) was still cost-effective. The 2008 study was done before Wyoming had finished its determination of BART and long before a Wyoming SIP was approved by the EPA (in fact, this still has not happened).[26] Because of the uncertainty concerning the needed level of clean air investment, the Company should have done a sensitivity analysis to demonstrate whether the plant would still be economic to continue to operate if the clean air investment costs rose significantly. But the Company did not do such an analysis. In addition, the Company could have updated the study, since construction did not begin until 2010. By not updating the study before making the scrubber upgrade investment, PacifiCorp was taking a risk that future costs related to meeting the Regional Haze Rules would cause the plant to stop burning coal and the cost of the scrubber update would be stranded.

According to PacifiCorp, the 2008 study included all the "then-current cost forecasts for environmental compliance projects required under the Wyoming SIP."[27] As the SIP continued to be developed, additional costs were added without revisiting the forecast and the analysis.

iv. Alternative Investments

In the 2008 study, PacifiCorp limited itself to market purchases to replace the plant, making the study very dependent on its forward price curve. But in the 2012

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[26] 77 FR 33022 (2012).
[27] UE 246 CUB/100/Feighner-Jenks/35.

PacifiCorp IRP update, the Company has now found that converting a plant to gas is the best alternative in three of the six scenarios considered.[28] This investment in Bridger was never compared to the costs of switching the plant to gas or any other replacement power option other than PacifiCorp's forward price curve.

v. Alternative Shutdown Dates

In the 2008 study, PacifiCorp never considered any alternatives other than to run the plant indefinitely and shut it down in 2015. For a plant like Bridger that is now on the edge of viable economic operation—three scenarios advocate ceasing to burn coal, and three scenarios advocate continuing to burn coal[29]—reconsidering the plant's useful life would likely lead to a better alternative. Operating the plant on coal plant for a few years, rather than converting it to a gas plant next year, would reduce the cost of operation during those years and lead to a total lower cost for customers. The lack of interest the Company has shown in even considering alternative shutdown dates is troubling, because it suggests IPCO is not being diligent in looking for the least-cost options for generation. The EPA's proposed partial rejection of the Wyoming SIP should give the Company a chance to rethink this.

IV. Conclusion

The evidence in this docket demonstrates that Idaho Power did not properly exercise its due diligence with regards to environmental controls at the Bridger 3 plant. This is unfortunate, because, if the Company had been looking over PacifiCorp's shoulder, certain decisions such as the assumption that the alternative to investments designed to meet a 2015 compliance deadline is a 2008 plant closure might have been

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[28] UE 246 CUB/100/Feighner-Jenks/36.
[29] *Ibid*.

revisited. Rather than joint ownership providing the Commission with double the due diligence review of plans and options for the plant, however, we find that, as the minority owner of the plant, IPCO simply ignored its responsibility to participate in any decision making for the plant related to clean air compliance investments. This might not have caused customers injury had PacifiCorp acted prudently in its decision making, but unfortunately, CUB has been forced to conclude that PacifiCorp was not operating prudently with regard to this plant. As a result, customers have been, and are continuing to be, injured by both companies' failure to appropriately determine the least-cost method for complying with clean air regulations.

CUB urges the Commission to deny rate recovery for the scrubber upgrade at issue in this docket. IPCO, having failed to conduct due diligence in regard to decisions made for the Bridger 3 plant, should not be rewarded with rate making treatment of the investment costs incurred as a result of its imprudent decision making.

In the alternative, CUB points out to the Commission that it could find that the scrubber upgrade is simply not used and useful at this time and that it will not be used and useful without the SCR. The Commission could then deny rate recovery for the scrubber upgrade until the time that the investment is found to be used and useful.

<u>CUB'S DATA REQUEST NO. 42</u>:

On what date did the PacifiCorp competitive bidding process referenced in Idaho Power/1400 Carstensen/3 line 4 commence?

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 42</u>:

PacifiCorp, as the operator of the Jim Bridger plant, oversaw the competitive bidding process and construction related to the scrubber upgrade project at Jim Bridger Unit 3. As such, Idaho Power does not possess information responsive to this request.

CUB'S DATA REQUEST NO. 43:

On what date was the PacifiCorp competitive bid process, referenced in Idaho Power/1400 Carstensen/3 line 4, completed and a contract let for the work to be started?

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 43:

PacifiCorp, as the operator of the Jim Bridger plant, oversaw the competitive bidding process and construction related to the scrubber upgrade project at Jim Bridger Unit 3. As such, Idaho Power does not possess information responsive to this request.

CUB'S DATA REQUEST NO. 44:

When did the Jim Bridger Unit 3 Scrubber Upgrade Project contractor first start work?

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 44:

PacifiCorp, as the operator of the Jim Bridger plant, oversaw the competitive bidding process and construction related to the scrubber upgrade project at Jim Bridger Unit 3. As such, Idaho Power does not possess information responsive to this request.

CUB'S DATA REQUEST NO. 45:

At what points during the Jim Bridger Unit 3 Scrubber Upgrade Project was the contractors work reviewed by:

- **a. PacifiCorp**
- **b. Idaho Power**
- **c. What was the impetus for the contractor work review at each time the contract work was reviewed?**
- **d. Was the contract work ever halted for any reason? If so what reason?**

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 45:

PacifiCorp, as the operator of the Jim Bridger plant, oversaw the competitive bidding process and construction related to the scrubber upgrade project at Jim Bridger Unit 3. As such, Idaho Power never reviewed the contractor's work and does not possess information responsive to this request.

CUB'S DATA REQUEST NO. 46:

Idaho Power/1400 Carstensen/3 lines 6-8 provides that: "Construction work on the Jim Bridger Unit 3 Scrubber Upgrade Project was completed during a planned outage in 2011."

a. **What were the exact dates of the planned outage during which this work was completed?**

b. **On what exact date was the Jim Bridger Unit 3 Scrubber Upgrade Project work completed?**

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 46:

PacifiCorp, as the operator of the Jim Bridger plant, oversaw the competitive bidding process and construction related to the scrubber upgrade project at Jim Bridger Unit 3. As such, Idaho Power does not possess the exact dates of the planned outage during which the work was completed nor the exact date that the work was completed.

CUB'S DATA REQUEST NO. 48:

Idaho Power Company/1400 Carstensen/8 lines 7 -14 provides: *"Q. Has the Company since reviewed any additional analysis that demonstrates that the Jim Bridger Unit 3 Scrubber upgrade Project is still the least cost option?* A. Yes. In the past week, PacifiCorp has provided Idaho Power an analysis, entitled "CAI Capital Projects Study for Jim Bridger U3 — Dec. 2008 . . . "

a. What date did Idaho Power receive this study from PacifiCorp?

b. Had Idaho Power ever seen or been briefed on the study prior to the date listed in response to question 48.a. above?

c. If "yes" on what dates did Idaho Power see this study prior to its physical receipt of a copy of this study?

d. If "yes" to part 48.b. on what dates was Idaho Power briefed on the study prior to the date listed in response to question 48.a. above?

e. When was the CAI Capital Projects Study completed?

f. By whom was the study drafted? What is that person/entity's contact information?

g. Did this study include a SCR?

h. Was this study updated after Idaho Power and PacifiCorp became aware that a SCR would also be required? If so, please provide a copy of that updated study.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 48:

a. Idaho Power received the CAI Capital Projects Study on April 26, 2012.

b. No.

c. Please see (b) above.

d. Please see (b) above.

e. Idaho Power does not know when the CAI Capital Projects Study was completed.

f. Idaho Power does not know who drafted the CAI Capital Projects Study.

g. Based on review of the study, it appears an SCR was included.

h. Idaho Power is not aware of an update.

Natural Gas Update

Ken Zimmerman, Ph.D.
Senior Analyst
Oregon Public Utility Commission
Electric & Natural Gas Division
Resource & Market Analysis

Summer 2012

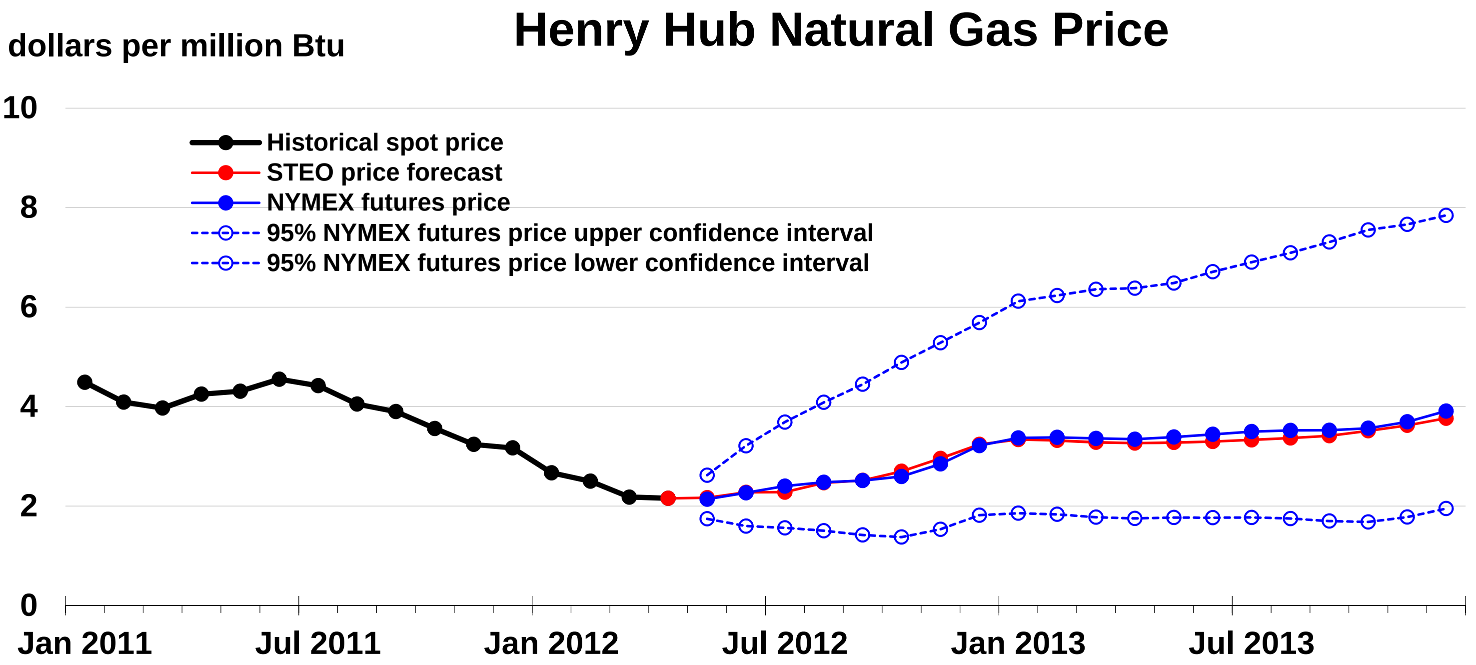
The views expressed in the Update do not necessarily represent those of the OPUC, any Commissioner, or the Staff of the OPUC on the issues considered.

Summer 2012 Natural Gas Price Projections

In its April 2012, Short-term Energy Outlook ("STEO") the EIA indicates that it expects natural gas prices will average $2.51 per MMBtu in 2012. That same STEO also projects natural gas at the Henry Hub to average about $2.39/MMBtu for the summer of 2012.

Almost all business and government forecasters agree with the EIA's projections, some projecting even lower prices. Since early April prices have hovered around the $2.00 mark. On April 14th price at the Henry Hub dropped below $2.00. These are the lowest gas prices since 1997. Many market participants expect the near-term downtrend in prices to continue, with some traders expecting prices to fall to $1.85 in the short-term and eventually testing the all-time low of $1.02 hit in 1992 in the long-term. The April 2012 STEO projection for summer 2012 is in the Figure below.

Figure 1

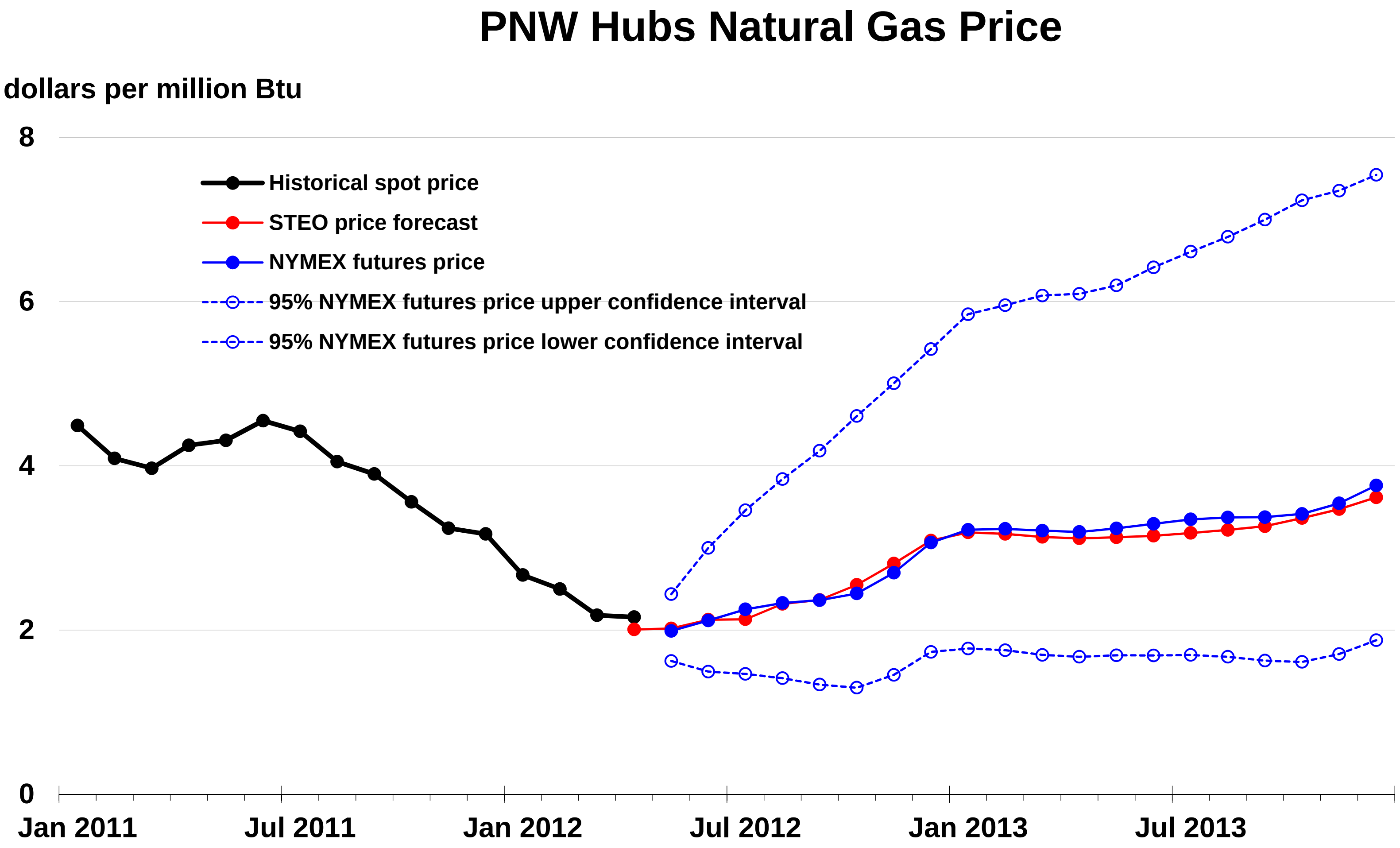


Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options

Source: Short-Term Energy Outlook, April 2012

Unless the basis difference between the Henry Hub and the PNW Hubs grows over the next few months prices here in Oregon and the rest of the PWN should closely mirror prices in most of the remainder of the nation.

Figure 2

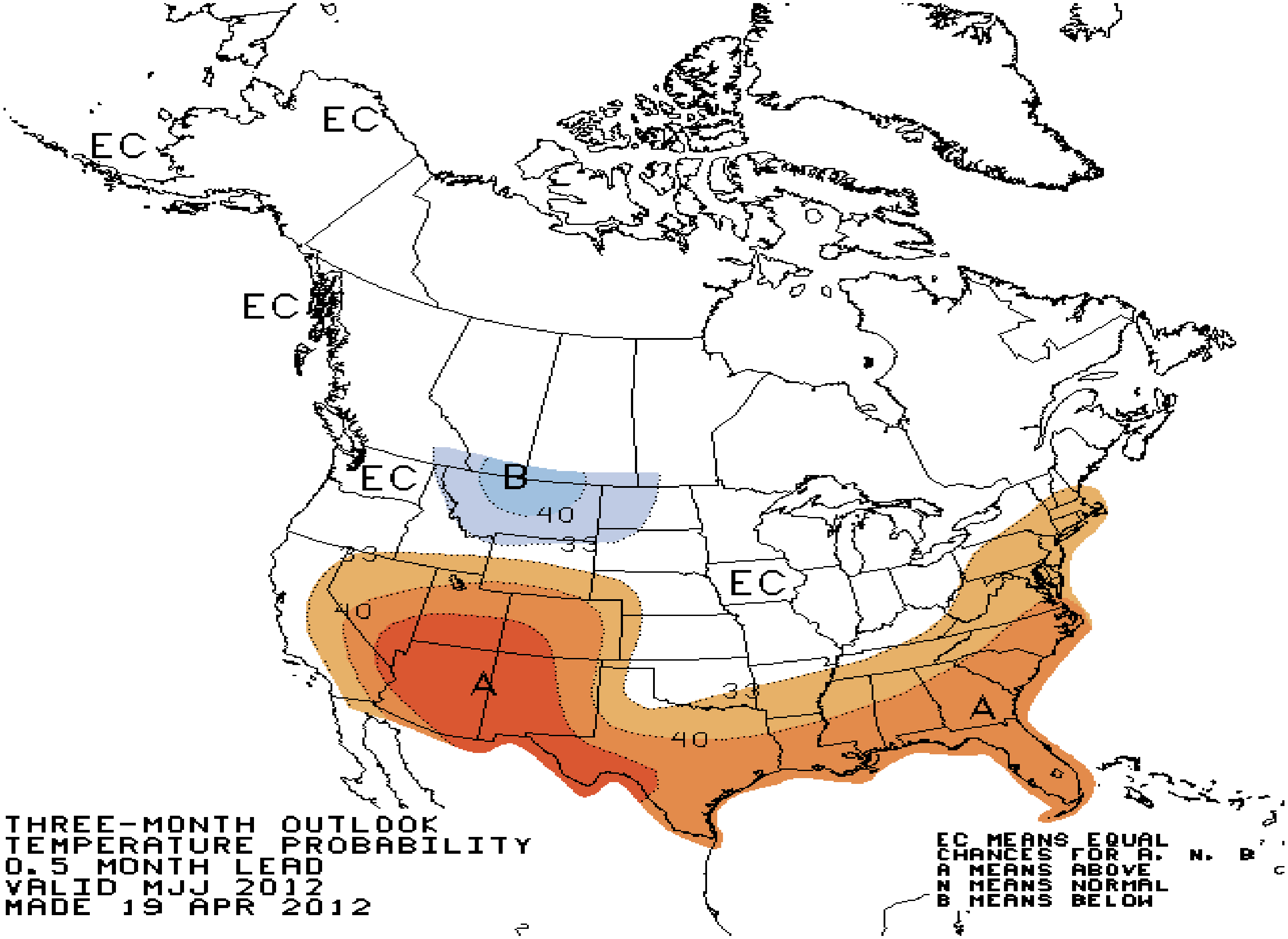


Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, April 2012 As edited by Ken Zimmerman

Map 1 and Map 2 below are the latest projections from the Climate Prediction Center for temperature and rainfall for the country. Note that the PNW's temperature is not expected to be outside the historical normal, while the PNW rainfall is projected to be below the normal.

Map 1



Map 2

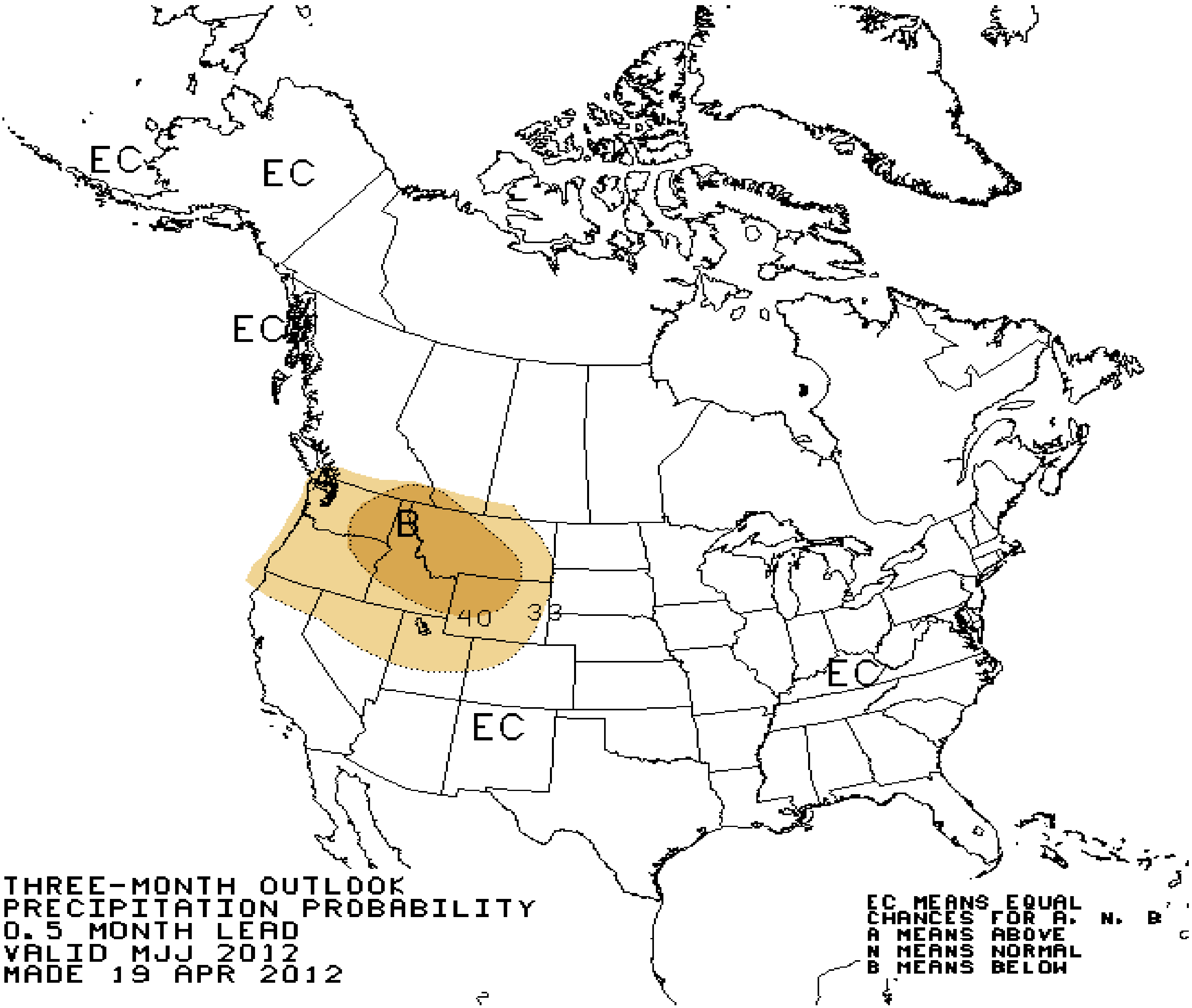
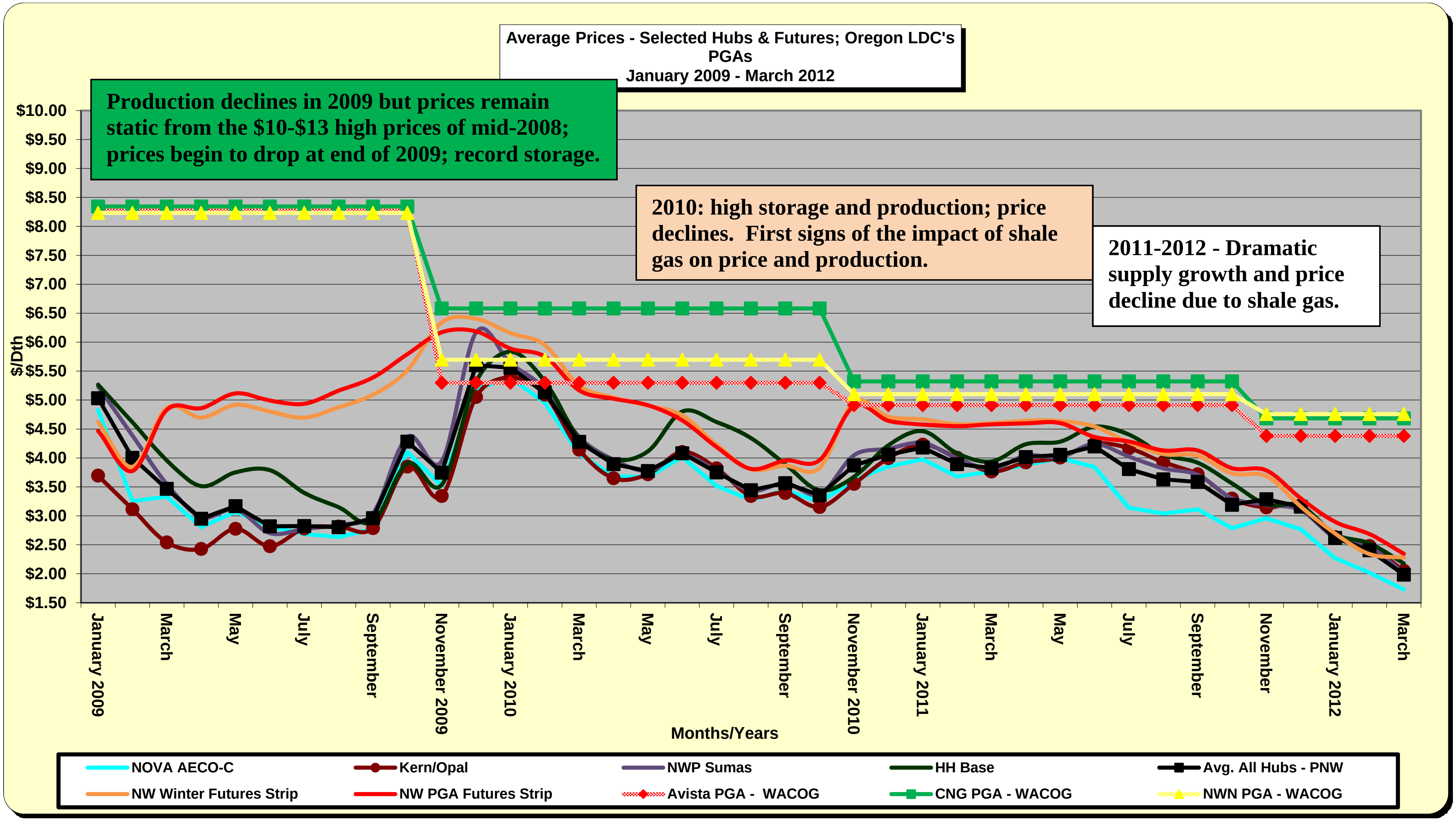

EC
EC
EC
B
40
33
EC
EC
THREE-MONTH OUTLOOK
PRECIPITATION PROBABILITY
0.5 MONTH LEAD
VALID MJJ 2012
MADE 19 APR 2012
EC MEANS EQUAL
CHANCES FOR A. N. B
A MEANS ABOVE
N MEANS NORMAL
B MEANS BELOW

Figure 3: Recent History of US Natural Gas Prices[1]

Since the end of 2009 prices have been falling consistently, due primarily to the expansion in the production of shale gas and the decline in consumption due to the economic recession and mild winters. By historical standards prices overall remain low (see Figure 4).



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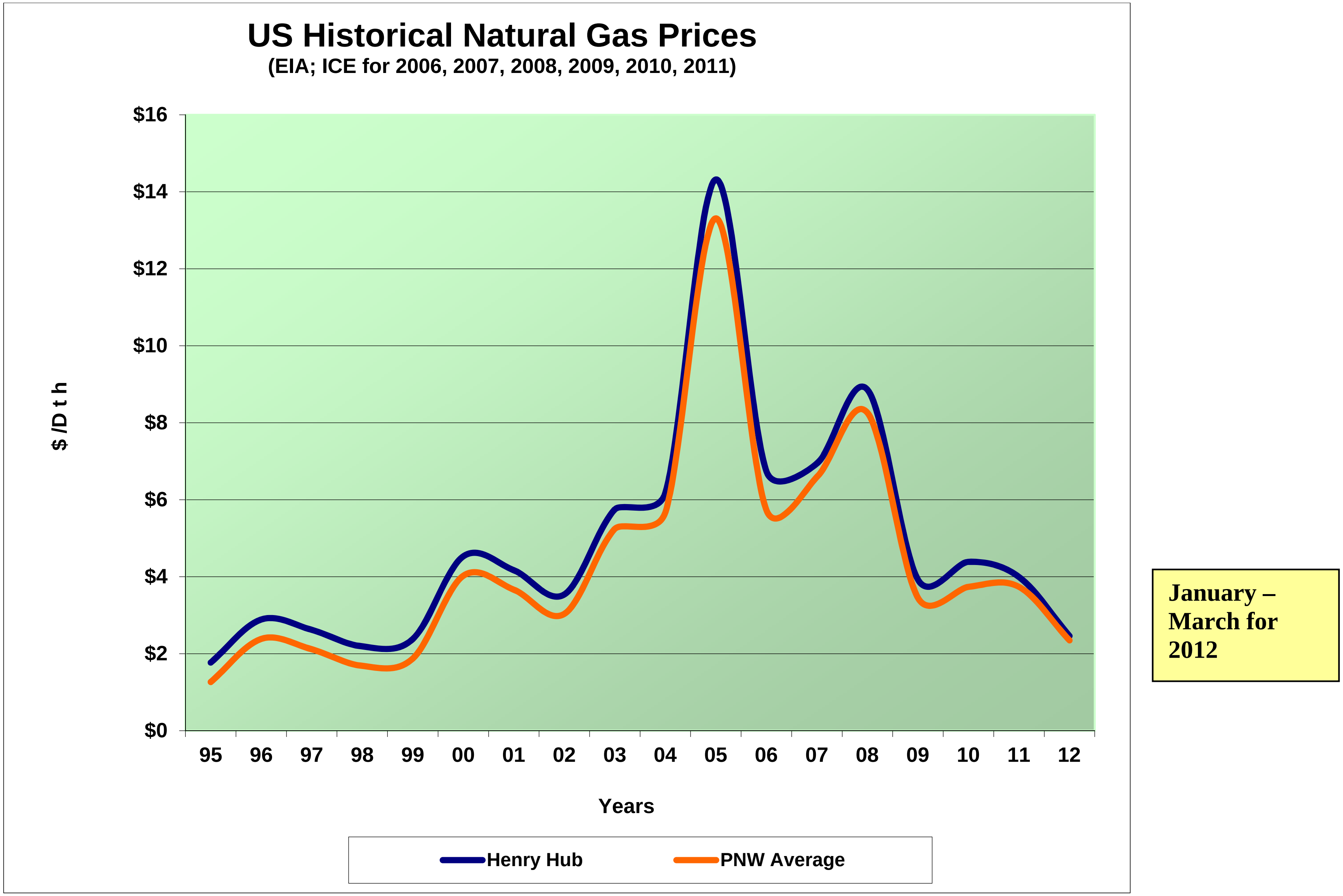
[1] Sources: Ken Zimmerman, with data from published index prices, EIA, and Wikipedia encyclopedia.

Figure 4: Historical US Natural Gas Prices[2]



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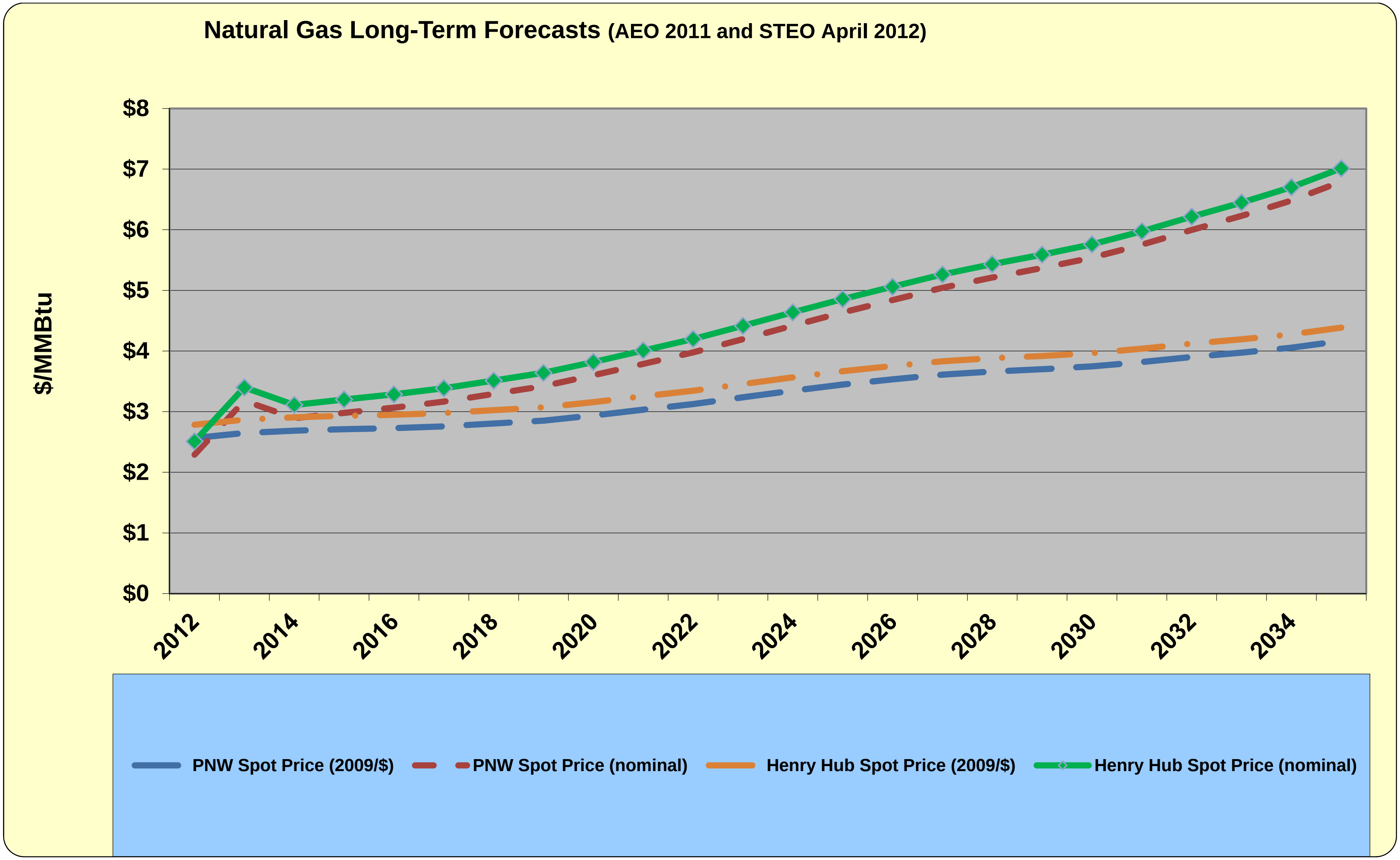
[2] Quite a ride for prices. And now they're back to where they were in 1999-2000. Through end of March 2012. This pattern represents an annual average growth rate in gas prices since 1998 of about 2% for the Pacific Northwest prices.

Figure 5: Forecasted US Natural Gas Prices, based on EIA AEO 2011 ($/MMBtu). [3]



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[3] I've adjusted EIA's natural gas forecasts by -40%/year for real price and nominal price.

Headlines for the Period

➢ Pacific Northwest

- Wind farms generated a record-breaking amount of power during March. The Bonneville Power Administration is hoping to avoid over-generation problems that happened last spring.
- Backers of Jordon Cove LNG terminal proposed for the Oregon Coast are not deterred by the withdrawal of federal approvals for the project. The Federal Energy Regulatory Commission (FERC) ruled April 16th that Jordan Cove could not rely on prior approvals of the terminal and pipeline as an LNG export terminal for making the construction of an export terminal instead. Jordan Cove project manager, Bob Braddock, says his group is already working on getting its export application ready. US DOE has already given its tentative go-ahead to the export terminal.
- Coos County has begun studying routes for a 16-mile section of pipeline that would funnel natural gas from Coos Bay to Bandon. The county awarded NW Natural a contract to find three routes and present them to the commissioners by August. The engineering firm will then design the pipeline. Construction would begin in 2014. The 4-inch pipeline is part of a project to bring natural gas from Roseburg to Coos County. The initial pipeline was built in the early 2000s, but the Bandon lateral was stalled during a contractual dispute between the construction company and the county.
- Pacific Gas & Electric has agreed to pay $70 million in restitution to San Bruno, Calif., for a 2010 pipeline explosion that killed eight people in the San Francisco suburb.

➢ USA

- Natural Gas Price
  - ✓ "We expect the record storage overhang will lead to a turbulent summer as unprecedented coal-to-gas switching will be required to avoid breaching storage capacity before next winter," wrote David Greely of Goldman Sachs. He sees prices hovering around $2.10 an MMBtu through the second and third quarters. Overall, the firm lowered its 2012 average price forecast to $2.40, from $3.10. But Greely sees some light at the end of the tunnel. He expects prices will shoot higher in 2013 amid slowing production and a return to more normal winter weather conditions next year. Prices could move back to $4 next year.
  - ✓ From the *Tulsa World*, April 11th, "The price of natural gas has fallen to its lowest level in more than a decade, a remarkable decline for a commodity that not long ago was believed to be in short supply. The country's supply of natural gas is growing so fast that analysts worry the country's underground storage facilities could reach their limits by fall. On Wednesday, the futures price of natural gas declined to $1.987 per 1,000 cubic feet, its lowest level since January 28, 2002, when the price hit $1.91. If the price falls to $1.75, it would be the lowest since March 23, 1999. Natural gas production has boomed across the

country as energy companies employ a new drilling technique to tap previously untouched reserves. The process has raised concerns about water safety, and has been temporarily banned in New York and New Jersey. But where it has been allowed, it has led to increases in drilling, job growth and production. The falling price of natural gas has been a boon to homes and businesses that use the fuel for heat and appliances, and for manufacturers that use it to power their factories and make chemicals, plastics and other materials. From October to March, households spent $868 on average on natural gas, a decline of 17 percent from last winter. Those savings have helped to relieve the burden of rising gasoline prices. Households spent $1,940 on gasoline from October to March, a 7 percent increase from the same period a year ago. There is so much natural gas being produced — and still in the ground — that drillers, policymakers, economists and natural gas customers are trying to figure out what to do with it."

- Supply and Demand
  - According to the *Wall Street Journal* of April 12th,

> Plummeting natural-gas prices are pushing U.S. industries into virgin terrain, even beginning to dislodge cheap Western coal from its once-untouchable perch as the nation's favorite fuel for power production. The natural-gas surplus has implications for a variety of industries. Energy companies that produce gas are seeing revenue shrink and are searching for more lucrative oil. Cheap gas is stealing power-generation markets from coal, spreading gloom across a mining industry that is being spurned by its most important customer. Railroads, whose single largest source of revenue is typically hauling coal, are hurting. The economics of building a nuclear plant, wind farm or solar-power installation look shakier than ever. The biggest winners from all this: electricity consumers. In February, Boston-based utility NSTAR told its business customers that it will cut their retail electricity rates 34% this spring, to 5.5 cents a kilowatt hour from 8.5 cents. In May, it expects to announce rate cuts for residential customers, too. In many parts of the U.S., cheap gas is pushing wholesale power prices down to two cents to four cents a kilowatt hour. In New England, for example, wholesale power prices were often in the three- or four-cent range in February, compared with six to eight cents on average that month from 2006 to 2011, according to the Energy Information Administration. Oklahoma Gas & Electric, a unit of OGE Energy Corp., OGE +0.84% has traditionally produced most of its power at two plants fired by coal from the Powder River Basin of Wyoming and Montana. But recently that has started to change, said John Wendling, manager of generation planning. The company's two most-efficient gas plants "are pushing coal out of the way and the customer is benefiting," Mr. Wendling said, adding that the utility expects to lower its electricity rates this summer for its customers in Arkansas and Oklahoma. Energy-industry analysts at Sanford C. Bernstein & Co. said utilities could boost power production from gas plants by 450 million megawatt hours this year, increasing natural-gas consumption by 3.3 trillion cubic feet a year. This equals 13.5% of total U.S. natural-gas consumption last year. To be sure, coal isn't going to be completely displaced; some coal-fired plants sit at crucial locations and are needed to keep

the electricity grid stable. Some utilities are contractually bound to take coal deliveries or face hefty penalties. Another wild card is the weather, which is the biggest single factor that determines utilities' consumption of coal and natural gas. High temperatures—and humming air conditioners—would drive utilities to run more power plants, burning more gas and more coal. That could prevent natural-gas storage from filling up by the late summer, some experts said. But others argue that storage is simply too full and too much gas is still being produced. In the face of a gas glut, it would make economic sense for production to decline—but that hasn't happened yet. Most new gas is coming from shale rocks, where companies are using a new combination of techniques to unlock vast amounts of gas and oil. In the past year, companies have scaled back their hunt for gas, but are still harvesting significant amounts as a byproduct of drilling for oil. Indeed, the U.S. has produced more gas, so far in 2012, than during the same period last year, according to industry consultant Bentek Energy. Some experts say electric utilities' growing appetite for inexpensive gas will prevent storage from filling up. "The power market will save the day," predicted Rusty Braziel, an industry consultant with RBN Energy and a former Texaco marketing executive in the mid-1990s, when gas prices last fell below $1.50 per million British thermal units. Southern Co., SO +0.11% for many years one of the largest burners of coal in the U.S., has taken the bait being dangled by low natural-gas prices. "We are in the transition in a big way" from coal to natural gas, says Tom Fanning, chief executive of Atlanta-based Southern. The company is building three gas-fired plants in Georgia as replacements for coal-fired units—and plans to do more coal-to-gas conversions. This summer, it expects to burn more gas than ever to take advantage of low prices. In 2008, when gas prices still were high, Southern got almost 70% of its electricity from coal. Today, it is getting less than half as much power from its coal fleet. Gas-fired plants now are responsible for 46% of its electricity, up from about 16% four years ago. Fuel switching is sending shudders through the coal industry because the power industry consumes more than 90% of all domestic coal. Eastern markets felt the effects of lower gas prices first, because eastern utilities mostly burn Appalachian coal, which is more costly, per ton, than coal from Wyoming's giant Powder River Basin, source of about half the nation's coal. But now, "the coal that was least likely to be displaced is being displaced," said Anthony Yuen, energy analyst for Citigroup Global Markets Inc. He thinks the trend will pick up if prices continue to fall.

- Policy Debates
  - ✓ The Obama administration said April 14th it is creating a high-level working group to coordinate federal oversight of natural gas production, amid industry complaints that excessive regulation could stymie a natural gas boom that has pushed prices to 10-year lows. In an executive order signed April 13th, President Barack Obama said the group was needed to make sure a host of federal agencies that oversee drilling work together. Obama said it is vital that the nation take full advantage of its natural gas

resources, while ensuring that public health and safety - including air and water quality - are not compromised.

- ✓ With Congressional inaction on a national energy policy, the balance of power has tipped to federal regulatory agencies, said Nick Akins, president and CEO of American Electric Power. It's complicating the future for consumers, states and electricity generating companies. Congress can't get anything done, so it's left to the administrative agencies to promulgate rules, and in some cases those rules are not realistic," said Akins, who spoke at a panel on energy transitions at Oklahoma City University's Meinders School of Business. It's going to take some time to move toward a different portfolio mix in the future. AEP is moving from predominantly a coal-fired generator to one that's more balanced. But Akins said timelines by the Environmental Protection Agency to deal with coal-plant emissions are much too aggressive. Installing scrubbers or decommissioning coal plants too fast will mean higher rates for utility customers and could jeopardize electricity reliability, he said.
- ✓ Several environmental groups are voicing their opinions about natural gas drilling on the heels of a West Virginia conference on the topic. The groups are gathering as an industry conference on the topic begins April 1st at the Greenbrier Resort. West Virginia Gov. Earl Ray Tomblin, U.S. Sen. Joe Manchin and others are attending the three-day "Marcellus and Utica Shale Conference and Expo." According to the Greenbrier website, the conference's main themes include the future of natural gas and leveraging its value, as well as navigating legislative rules. Environmental groups are designating April 1st as "Fossil Fool's Day." They say the development of natural gas pose dangers to the environment and people.

➢ World

- o Total world proved natural gas reserves, as of the end of 2010, were 187 trillion cubic meters (TCM; or 6609 trillion cubic feet - Tcf). That would last, at current production rates, 59 years. Reserves have grown about 2%/year. With production also growing, the reserve-to-production ratio has stayed within the range of 58 to 68 years since 1985. The four nations with the largest reserves are Russia (45 TCM), Iran (30 TCM), Qatar (25 TCM) and Turkmenistan (8 TCM). The US is not too far behind at 7.7 TCM. Over the last 20 years or so there has been a revolution in unconventional gas, with the US leading the way. Estimates of technically recoverable resources in the US range as high as roughly eight times reserves. There is little doubt that world reserves will rise substantially. Most of the discussion has been around two new sources. The first is the arctic, which the USGS estimates may contain about 1700 Tcf of technically recoverable, conventional, undiscovered reserves, with the largest share probably on Russian territory. The second is unconventional – most importantly shale – gas. There is little data to go on so far, but experts are guessing that unconventional sources could raise world reserves by 50-100%. The International Energy Agency has rather an outlier estimate that total recoverable gas is approximately 850 TCM.

- Not since the allies leveled Germany in World War II has Europe’s biggest economy undertaken a reconstruction of its energy market on this scale. Chancellor Angela Merkel is planning to build offshore wind farms that will cover an area six times the size of New York City and erect power lines that could stretch from London to Baghdad. The program will cost 200 billion euros ($263 billion), about 8 percent of the country’s gross domestic product in 2011, according to the DIW economic institute in Berlin. Germany aims to replace 17 nuclear reactors that supplied about a fifth of its electricity with renewables such as solar and wind. Merkel to succeed must experiment with untested systems and policies and overcome technical hurdles threatening the project, said Stephan Reimelt, chief executive officer of General Electric Co. (GE)’s energy unit in the country. “Germany is like a big energy laboratory,” Reimelt said in an interview. “The country has a political and societal consensus to drop nuclear power but lacks a clear technological solution.”
- Pampered by abundant subsidies Germany´s solar industry saw a massive growth during the past 10 years. However, recently two crucial factors came into play which led to a substantial shift. On the one hand, there was a discussion in Germany as to how much money should be pumped into renewable energies. Economic analyses revealed that more than EUR 100 billion have been directed towards renewables so far. With ever growing installed capacities this amount is bound to grow over the coming years, thus putting a substantial burden on electricity consumers who, in the end, are paying the bill. As a consequence and in order to keep subsidies under control feed-in tariffs have been cut drastically recently. On the other hand, German producers of solar modules are increasingly suffering from competitors, especially in China. This led to a slump in prices for PV modules (more than 70 % since 2009) which, in turn, increased the pressure on German companies. What is going to happen? Once the market forces have done their work, PV will continue its upward trend, though at a more moderate pace. But most importantly, the vast majority of PV modules will come from China, thus leaving not much room for production in Europe. What is bad news for the solar industry is, in turn, good news for the consumers and for investors who will see lower investment expenses as the prices for modules have fallen dramatically. PV as such is not to be blamed for the current problems. On the contrary, PV fills a useful niche in the power grid, but not more than that. However, what is to be blamed is a legal framework which created the illusion of a quasi risk-free economy where feed-in tariffs were guaranteed for 20 years and even paid for non-produced electricity in case of network problems caused by the renewables themselves. The price for this illusion was first to be paid by the consumers and now by the people losing their jobs in the companies going bankrupt. Photovoltaics has certainly a future in Germany as in other parts of Europe. However, its growth needs to be based on a sound economic environment. This process is now under way. It goes without saying that PV will always be a minor player in the field. Nevertheless, it has a role to play and maybe, on a smaller scale and by using smart storage technologies, it may develop into a key power source for local communities.

Historical Natural Gas Prices [4]

Table 1

Historical Prices

Spot Prices ($/MMBtu)	Thu, 5-Apr	Fri, 6-Apr	Mon, 9-Apr	Tue, 10-Apr	Wed, 11-Apr	Thu, 19-Apr	Fri, 20-Apr	Mon, 23-Apr	Tue, 24-Apr	Wed, 25-Apr
Henry Hub	$1.98	Holiday	$1.99	$1.99	$1.91	$1.85	$1.82	$1.89	$1.97	$1.99
New York	$2.19	Holiday	$2.18	$2.17	$2.09	$2.00	$1.96	$2.07	$2.17	$2.18
Chicago	$2.17	Holiday	$2.15	$2.06	$2.02	$2.00	$1.98	$2.01	$2.09	$2.11
AECO	$1.65	Holiday	$1.63	$1.61	$1.53	$1.48	$1.49	$1.51	$1.52	$1.52
Sumas	$2.03		$1.87	$1.81	$1.82	$1.78	$1.77	$1.75	$1.64	$1.74
Rockies	$1.92	Holiday	$1.79	$1.77	$1.73	$1.69	$1.72	$1.75	$1.78	$1.73
Cal. Comp. Avg,*	$2.26	Holiday	$2.24	$2.26	$2.23	$2.14	$2.06	$2.13	$2.22	$2.17
Futures ($/MMBtu)										
May Contract	$2.09	Holiday	$2.11	$2.03	$1.98	$1.91	$1.93	$2.01	$1.98	$2.07
June Contract	$2.20	Holiday	$2.22	$2.15	$2.11	$2.00	$2.02	$2.10	$2.06	$2.17

*Avg. of NGI's reported prices for: Malin, PG&E citygate, and Southern California Border Avg.

Source: NGI's Daily Gas Price Index

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[4] Most current data available at the time this report was prepared.

Forecasted Gas Prices – USA[5]

Table 2

Forecasted ($/MMBtu)	Three Month	One Year	Three Year	Avista 2012 WACOG	Cascade 2012 WACOG	NWN 2012 WACOG
AECO	$1.86	$2.44	$2.63	$4.38	$4.68	$4.76
Sumas	$2.11	$2.69	$2.88	$4.38	$4.68	$4.76
Rockies	$2.07	$2.65	$2.84	$4.38	$4.68	$4.76
CA Average	$2.50	$3.08	$3.27	$4.38	$4.68	$4.76
Henry Hub	$2.24	$2.82	$3.01	$4.38	$4.68	$4.76

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[5] Forecasts by Ken Zimmerman based on EIA and NGI data.

Selected Other Items of Interest

“Feedback is invited”

- Regulatory Reform
    - For decades, Administrations and Congresses have periodically raised the issue of regulatory reform. For the most part, however, reform efforts have been piecemeal and incomplete. Practically every President since Eisenhower has issued Executive Orders designed to make regulations more efficient, cost-effective, and based on a sound factual foundation. And in 1996, Congress even passed the Congressional Review Act—giving it the power to review and reject regulations that were found wanting. Just five years later, lawmakers also passed the Data Quality Act, which was intended to make sure that sound data and objective analyses are the basis of regulation. Neither the orders nor the acts have accomplished there intended purpose. In spite of past efforts, we remain an overregulated society because regulatory reform is only as good as its implementation. Rhetoric is no substitute for oversight and checks and balances that work. Over the past 30 years, the Code of Federal Regulations has increased 50%, growing to over 150,000 pages today. It seems obvious that it would be hard to make the case that we have 50% more regulatory problems than we had in 1980 or that no regulations have out lived their usefulness and should be rescinded. More attention is being paid to regulations today because the Obama Administration, especially its EPA, has acted as a regulatory machine on steroids. In 3 years, it has issued 194 major regulations—those with a cost of $100 million or more—compared with 141 in the first 3 years of the Bush Administration. The regulatory bureaucracy is non-partisan. It just keeps grinding on independent of whether a Republican or Democrat is in the White House. Some Presidents have tried to slow its assault with tough Executive Orders and a strong hand in OMB’s Office of Information and Regulatory Review (OIRA). But even then the impact has not been significant. Special interests and their supporters in Congress can make life tough on the Executive Branch. Each regulation has a rent seeking supporter, and regulatory reform just hasn’t been a sufficient priority to produce comprehensive reform of the Administrative Procedures Act. In January of last year, President Obama issued Executive Order 13563, aimed at streamlining the regulatory process and making it more effective. But from the response of EPA, you might conclude that his actions were taken with a wink and a nod. In spite of a very weak economy that could benefit from a lighter regulatory burden, EPA aggressively pursued an early rewrite of the ozone NAAQS which would have put most of the nation in non-attainment and brought major construction to a halt, has issued very stringent regulations on mercury, boilers, CAFE standards, and refineries. The refinery MACT comes at a time when U.S. refineries are shutting down because they can’t make a reasonable profit. And although, the major sources of air pollution are now stationery sources, EPA is planning a Tier III gasoline rule that will force gasoline sulfur levels close to zero on the basis of very shaky health and environmental benefits. This will further increase the price at the pump. Some might say that EPA is being criticized for simply doing its job. That line of argument might get some sympathy if Administrator Jackson had shown any understanding of the impact of an aggressive regulatory assault when the economy is in such poor shape. In some instances, regulations might be the result of statutory deadlines or court dictated deadlines. But there is a

range of options for compliance and it today’s economic circumstances, a light regulatory hand instead of a hammer would be more appropriate. Instead of employing balance and judgment in issuing regulations, EPA has regulated with myopic zeal. One example of regulatory overreach came to light in an appeals court decision last week that over turned EPA’s rejection of Texas’ program to meet national air quality standards. According to The Wall Street Journal, the court found that EPA “failed to identify a single provision of the Act that Texas had violated, let alone explain its reasons for reaching its conclusion.” The court went on to find that the “authorities” cited by the agency were internal memoranda and guidance documents. It is very troubling when an agency creates its own laws instead of implementing those passed by Congress. It is actions such as these that give credibility to claims of Constitutional erosion. Nothing useful is going to happen in an election year. It never does. But if the next Congress and President are serious about restoring robust economic growth and enabling the private sector to successfully compete in the global economy, regulatory reform should be part of a larger reform agenda. Regulatory overhaul can follow common sense principles and need not be radical in nature. First, agencies should be required to review over a five year period existing regulations, starting with the oldest, to determine if they are still necessary and meeting criteria of efficiency and effectiveness. The results should be posted on line to provide transparency. Major regulations that have been in existence for 10 years or more should candidates for being sunset or reissued if a review determines that the implementation cost was greater than 110% of the estimated cost at the time of implementation. New major regulations should be subjected to an independent review of their justification, cost-effectiveness, and compliance with the Data Control Act. And Congress should be provided a statement signed by the agency head certifying how the regulation will achieve Congressional intent and meet criteria of necessity, efficiency, and economic impact. Congress has an important role to play in being clearer about the objectives that are to be achieved and constraints that are to limit implementing regulations. Finally, regulatory reform legislation should contain look-back and sunset provisions for the implementing regulations. The objection that these kinds of requirements would be too burdensome is not convincing. Major regulations should not be easy to implement because their cumulative impact on society and business is significant, exceeding $1 trillion annually. We can do better and should.

~ William O'Keefe, Chief Executive Officer of the Marshall Institute, is President of Solutions Consulting, Inc. He has also served as Senior Vice President of Jellinek, Schwartz and Conolly, Inc., Executive Vice President and Chief Operating Officer of the American Petroleum Institute and Chief Administrative Officer of the Center for Naval Analyses. Mr. O'Keefe has held positions on the Board of Directors of the Kennedy Institute, the U.S. Energy Association and the Competitive Enterprise Institute and is Chairman Emeritus of the Global Climate Coalition.

- A polluted drainage ditch that once flowed with industrial waste from Lake Charles, La., petrochemical plants teems with overgrown, wild plants today. A light-rail line zips past the spot where a now-defunct Portland, Ore., gasoline station advertised in 1972 that it had run out of gas. A smoking Jersey City, N.J., dump piled with twisted, rusty metal has disappeared, along with the twin towers of the World Trade Center in lower Manhattan that were its backdrop. Forty years after the Environmental Protection Agency sent an army of nearly 100 photographers across the country to capture images at the dawn of environmental regulation. The Associated Press went back for Earth Day this year to see how things have changed. It is something the agency never got to do because the “Documerica” program, as it was called, died in 1978, the victim of budget cuts. AP photographers returned to more than a dozen of those locations in recent weeks, from Portland to Cleveland and Corpus Christi, Texas. Of the 20,000 photos in the archive, the AP selected those that focused on environmental issues, rather than the more general shots of everyday life in the 1970s. Gone are the many obvious signs of pollution — clouds of smoke billowing from industrial chimneys, raw sewage flowing into rivers, garbage strewn over beaches and roadsides — that heightened environmental awareness in the 1970s, and led to the first Earth Day and the EPA's creation in 1970. Such environmental consciousness caused Congress to pass almost unanimously some of the country's bedrock environmental laws in the years that followed. Today's pollution problems aren't as easy to see or to photograph. Some in industry and politics question whether environmental regulation has gone too far and whether the risks are worth addressing, given their costs. Republican presidential contender Mitt Romney has called for the firing of EPA chief Lisa Jackson, while GOP rival Newt Gingrich has said the EPA should be replaced altogether. Jackson has faced tough questioning on Capitol Hill so often the in past two years that a top Republican quipped that she needs her own parking spot. "To a certain extent, we are a victim of our own success," said William Ruckelshaus, who headed the EPA when it came into existence under Republican President Richard Nixon and was in charge during the “Documerica” project. "Right now, EPA is under sharp criticism partially because it is not as obvious to people that pollution problems exist and that we need to deal with them." Environmental laws that passed Congress so easily in Ruckelshaus' day are now at the center of a partisan dispute between Republicans and Democrats. Dozens of bills have been introduced to limit environmental protections that critics say will lead to job losses and economic harm, and there are those who question what the vast majority of scientists accept — that the burning of fossil fuels is causing global warming. In the 1970s, the first environmental regulations were just starting to take effect, with widespread support. Now, according to some officials in the oil and gas and electric utility industries, which are responsible for the bulk of emissions and would bear the greatest costs, the EPA has gone overboard with rules. For instance, “Documerica” photographers captured a wave of coal-fired power plants under construction. Republicans and the industry now say environmental regulations are partly to blame for shuttering some of the oldest and dirtiest coal plants. Jim DiPeso of ConservAmerica, a group that recently changed its name from Republicans for Environmental Protection, says the EPA is caught in the center of a perfect storm. "This time of greater cynicism about government, more economic anxiety and the fact that the problems are not immediately apparent, has created this political problem for EPA," he said. In an interview, Jackson said she believes that people in the United States still want to protect the environment. "There's a large gulf between the rhetoric inside the Beltway to do everything from cut back on EPA to get rid of the whole place, and what the American people would actually stand for," she said. "It's very easy to make rash statements without thinking about what that means to the health of everyday Americans." A 2010 Pew Research Center survey showed that 57 percent of those questioned held a favorable view of the EPA, compared with a 1997 poll that showed 69 percent with a positive view of the agency. A CNN/Opinion Research Corp. poll taken last year found that 71 percent of people surveyed said that the government should continue provide money to the EPA to enforce regulations to address global warming and other environmental issues. "We are not done. We still have challenges we have to face," Jackson said. The agency last year began a volunteer photography project called State of the Environment. More than 620 people have participated and submitted 1,800 photographs, but only a few are at the same sites at the 1970s project. Images always have spurred environmental consciousness. A 1980s satellite picture of the ozone hole helped lead to a ban on the chemicals in aerosol cans and refrigerants that were responsible. Underwater video of oil spewing into the Gulf of Mexico in 2010 opened the public's eyes to the gravity of the largest offshore oil spill in U.S. history. But a second “Documerica” project, with professional photographers, would be impossible today, given budget cuts facing the agency and the wariness of industry barring access by photographers. Lyntha Scott Eiler, 65, shot photographs for “Documerica” around her then-home in northern Arizona, as well as one of the early emissions testing sites for automobile exhaust in Hamilton County, Ohio. At the Navajo Generating Station in Arizona, Eiler got right down in a strip mine "where the shovels were." "They weren't afraid of the EPA, so it was, 'What else you do you want to get a photograph of,?" Eiler said. "You probably would have a hard time doing that today."

~ *ChemInsider Newsletter*, April 24, 2012

Chapter 2: Key Assumptions

SUMMARY OF KEY FINDINGS

Pacific Northwest population and energy costs are expected to increase over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.7 million by 2030. This 4.0 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older-age categories as the baby-boom generation reaches retirement age. While the total regional population is projected to increase by over 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity use. Some possible effects could include increased health care, more retirement and elder-care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, and electricity) is expected to be significantly higher than during the 1990s. Although prices have decreased significantly since the summer of 2008, current levels, especially for natural gas, are depressed by the effects of the recession. Nonconventional natural gas production has increased in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has been a recent development that continues to improve, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing these new supplies is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon-emission taxes or cap-and-trade policies are likely to raise energy costs further. Wholesale electricity prices are expected to increase from about $30 per megawatt-hour in 2010 to $74 per megawatt-hour by 2030 (2006$). These electricity prices reflect carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Higher electricity prices reduce demand, advance new sources of supply and efficiency, and make cost-effective more efficiency measures.

INTRODUCTION

The Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuel.

The power plan treats energy efficiency as a resource for meeting future demand. In order to understand and properly assess its potential, demand forecasts must be developed in great detail considering specific uses of electricity in various sectors. Such assessments require significant detail in their underlying economic assumptions; the number and types of buildings, their electrical equipment, and their current efficiency levels are all critical to accurately assessing potential efficiency improvements.

Most of the assumptions and forecasts for the demand forecast are also important for other parts of the power plan. For example, fuel prices affect not only electricity demand, but also the cost of electricity generation from natural gas, oil, and coal-fired power plants. Because of this, fuel price forecasts help determine the wholesale electricity price and the avoided cost of alternative resources when considering the cost-effectiveness of improved efficiency. In addition, sector-specific economic forecasts of building and appliance stocks, their expected growth over time, and their pattern of energy use over different seasons and times of the day are factors in determining efficiency potential and cost-effectiveness. Basic financial assumptions such as rates of inflation, the cost of capital for investments by various entities, equity-to-debt ratios, and discount rates are used throughout the planning analysis.

For many of these assumptions, there is significant uncertainty about the future. That uncertainty creates risk that is addressed in the Council's power plan. These risks and uncertainty include long-term trends, commodity and business cycles, seasonal variations, and short-term volatility.

ECONOMIC GROWTH

Demand for energy is driven by demand for services needed in homes and places of work. In the long-term, the region's economic growth is a key driver of demand. One general measure of the size of the regional economy is its population. As the regional population increases, the number of households increases, the number of jobs increases, and goods and services produced in the economy increase, all driving the need for energy. This is not to say there is a one-to-one relationship between growth in the economy and growth in demand. Other factors, such as energy prices, technology changes, and increased efficiency can all change the relationship between economic growth and energy use.

The residential demand forecast is driven by the number of homes and the amount and types of appliances they contain. Commercial sector demand is determined by square feet of buildings of various types, and industrial demand depends on projections of industrial output in several manufacturing sectors. The expected electricity use in aluminum smelters is forecast independently. A brief overview of the forecast assumptions for each of the key economic drivers of demand follows:

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected to slow to about 1.2 percent annually, resulting in a total regional population of 16.7 million by 2030.

Homes. The number of homes is a key driver of demand in the residential sector. Residential units (single family, multifamily, and manufactured homes) are forecast to grow at 1.4 percent annually from 2010-2030. The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

Appliances. In the residential sector, lifestyle choices affect demand. As more homes are linked to the Internet, and as the saturation rate for air conditioning and electronics increases, residential sector demand increases. Over 80 percent of all new homes in the region now have central air conditioning, and the growth rate in home electronics has been phenomenal--over 6 percent per year since 2000, and it is expected to continue growing at about 5 percent per year.

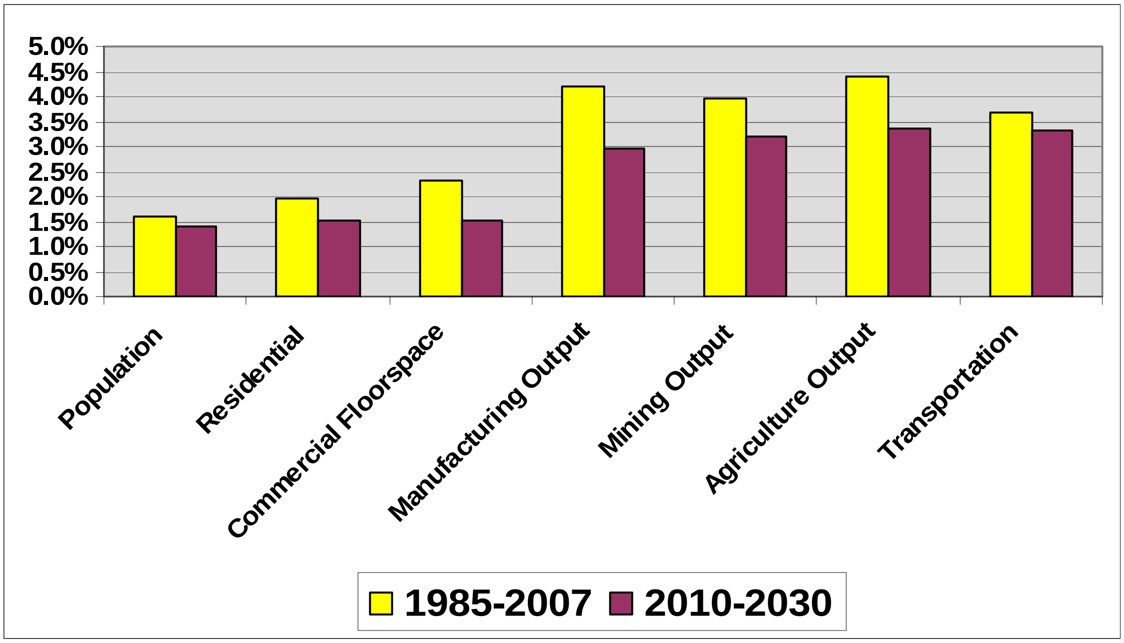
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.2 percent annually from 2010-2030. The current 2007 commercial building stock of 2.9 billion square feet is expected to grow to 3.9 billion square feet by 2030, or at a rate of about 40 million square feet per year. A growing portion of this commercial floor space is for elder-care facilities.

Industrial Output. The key driver of demand for the industrial and agricultural sectors is dollars of value added (a measure of output) in each industry. Industrial output is projected to grow at 3 percent per year, growing from $83 billion (2006 constant dollars) in 2007 to $149 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from $13 billion (2006 constant dollars) in 2007 to $25 billion by 2030.

Direct Service Industries. Demand for Bonneville's direct service industries (mainly aluminum smelting operations) is projected to be nearly constant, rising from 764 average megawatts in 2007 to 770 average megawatts in 2012, and then remaining constant from 2012 through 2030.

The main source of data for the economic drivers is HIS Global Insight's quarterly forecast of the national and regional economy and Global Insight's U.S. business demographic forecast. Third quarter 2009 data was used in developing the Council's Sixth Power Plan. The Council's financial assumptions, such as the inflation rate, are also drawn from the same economic forecast. Figure 2-1 shows both the historic and medium case growth rate assumed for the development of the Sixth Power Plan. In general, the medium forecast reflects a slowdown in key economic drivers compared to the last 20 years. The impact of the current recession was incorporated into the plan using Global Insight's long-term October 2009 forecast.

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

Three alternative scenarios are considered in the demand forecast. In the medium-case scenario, the key economic drivers project a long-term, healthy regional economy (albeit with a slower growth rate than in the recent past). In addition to the medium case, two alternative scenarios are considered: one representing a low-economic-growth scenario and the other a high-growth projection of the future. The low-case scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slowdown in labor productivity growth, and a high inflation rate. On the other hand, the high-case scenario assumes faster economic growth, stronger demand for energy, higher fossil fuel prices, sustained growth in labor productivity, and a lower inflation rate.

It is assumed in the medium, low, and high scenarios that climate change concerns and demand for cleaner fuel lead to a carbon tax, which pushes fuel prices to a higher trajectory. Table 2-1 summarizes the average growth rate for key inputs in each of the alternative scenarios.

Table 2-1: Historic, Medium-Case, and Alternative Scenarios for Growth Rates

Key Economic Drivers	1985-2007 (Actual)	2010-2030 (Low)	2010-2030 (Medium)	2010-2030 (High)
Population	1.60%	0.49%	1.20%	1.5%
Residential Units	1.90%	0.49%	1.40%	1.5%
Commercial Floor Space	2.30%	0.67%	1.20%	1.43%
Manufacturing Output $	4.10%	0.00%	1.70%	2.11%
Agriculture Output $	4.40%	3.0%	3.60%	4.2%
Light Vehicle Sales	-	2.52%	2.40%	3.05%
Inflation Rate	2.20%	2.70%	1.70%	1.50%
Average Annual Growth Rate in Price (2010-2030)*				
Oil Prices	1.70%	-1.00%	1.04%	2.30%
Natural Gas Prices	1.80%	0.90%	2.80%	3.50%
Coal Prices	-4.80%	-0.50%	0.50%	1.20%

* Fuel price assumptions are consistent with the Council's fuel price and electricity price forecast.

FUEL PRICES

The future prices of natural gas, coal, and oil have an important effect on the Council's power plan. As the Pacific Northwest's electricity system has diversified beyond hydropower, it has become more connected to national and global energy markets. Fuel price assumptions affect demand, choice of fuel, and the cost of electricity generation. The effect on demand is primarily through retail natural gas prices to consumers, but natural gas prices may also affect electricity consumption because of its effect on cost. Oil and coal are not used extensively by end users in the Pacific Northwest. Coal is, however, an important fuel for electricity generation; it affects the wholesale market price of electricity in some hours and the overall cost of electricity for utilities that rely on coal-fired generation.

The connection between fuel costs and electricity planning has been strengthened by changes in energy regulation and the development of active trading markets for energy commodities. Less regulation and mature commodity markets have also made the price of energy more volatile. The volatility of natural gas prices, in particular, is an important factor when considering the use of natural gas for electricity generation. Price volatility creates risks that the Council evaluates in developing a resource plan.

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was issued in 2004. Natural gas prices have collapsed since the summer of 2008. This reduction in price is partly due to natural supply-and-demand responses to a period of high prices, but also to a great extent is a result of the current recession and financial crisis.[1] The Council's forecast of natural gas prices assumes prices will rebound from recent recession-induced lows.

Long-term fuel price trends are uncertain, as reflected in a wide range of assumptions. The Council's power plan reflects three distinct types of uncertainty in natural gas prices: 1) uncertainty about long-term trends; 2) price excursions due to supply-and-demand imbalances that may occur for a number of years; and 3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. This section discusses only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis as discussed in Chapter 9.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case wellhead natural gas price increases to $9 by 2025 and increases to $10 by 2030. The Council's forecasts assume that rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely affect the economy. For the long-term trend analysis, the need to expand energy supplies, and its effect on prices, is considered the dominant factor. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for reduced demand are limited.

The low case assumes slow world economic growth that reduces the pressure on energy supplies. Wellhead natural gas prices in the low case fall to levels between $4 and $5 per million Btu; still double the prices during the 1990s. It is a future where world supplies of natural gas are made available through the aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices that provide an alternative to natural gas use. The low case would also be consistent with a scenario of rapid progress in renewable generating technologies, reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil- and natural gas-producing areas.

Many of the assumptions that lead to high or low fuel prices are independent of one another or have offsetting effects. Those conditions lead to the medium-fuel-price cases being considered more likely. Figures 2-2 through 2-4 illustrate the forecast ranges for natural gas, oil, and Powder River Basin (Wyoming) coal prices compared to historical prices. Tables 2-2 through 2-4 show the forecast values for selected years. Appendix A provides a detailed description of the fuel price forecasts.

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[1] The fuel price forecast used for the plan does not completely reflect the current recession and the recent collapse in commodity prices. Therefore, the near-term prices through 2012 are likely higher than the most likely range. These short-term differences are not expected to affect the Council's resource portfolio or planning results significantly, but will be modified for the final power plan.

Most of the cases show fuel prices increasing from their recent depressed levels in the early years of the forecast. Following this near-term recovery, longer-term trends in most of the cases show real fuel prices increasing gradually. All prices, even in the lowest cases, remain well above prices experienced during the 1990s.

The fuel-price-forecast ranges are both higher and broader than the Council's Fifth Power Plan, reflecting greater uncertainty about long-term trends. The smooth lines for the price forecasts should not be taken as an indication that future fuel prices will be stable. Price cycles and volatility will continue. These variations, and the risks they impose, are introduced into the Council's planning by the Resource Portfolio Model analysis.

Figure 2-2: U.S. Wellhead Natural Gas Prices: History and Forecast Range

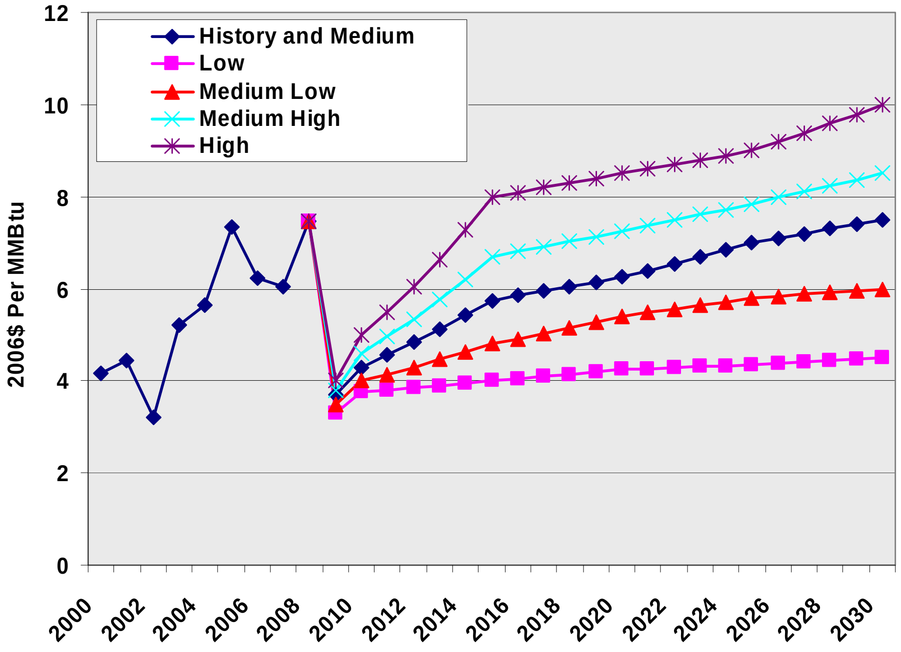


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

	Low	Medium Low	Medium	Medium High	High
2008			7.47		
2010	3.75	4.00	4.30	4.60	5.00
2015	4.00	4.80	5.75	6.70	8.00
2020	4.25	5.40	6.25	7.25	8.50
2025	4.35	5.80	7.00	7.85	9.00
2030	4.50	6.00	7.50	8.50	10.00
Growth Rates					
2007 - 15	-7.51%	-5.38%	-3.22%	-1.35%	0.86%
2007 - 30	-2.18%	-0.95%	0.02%	0.56%	1.22%

Figure 2-3: World Oil Prices: History and Forecast Range

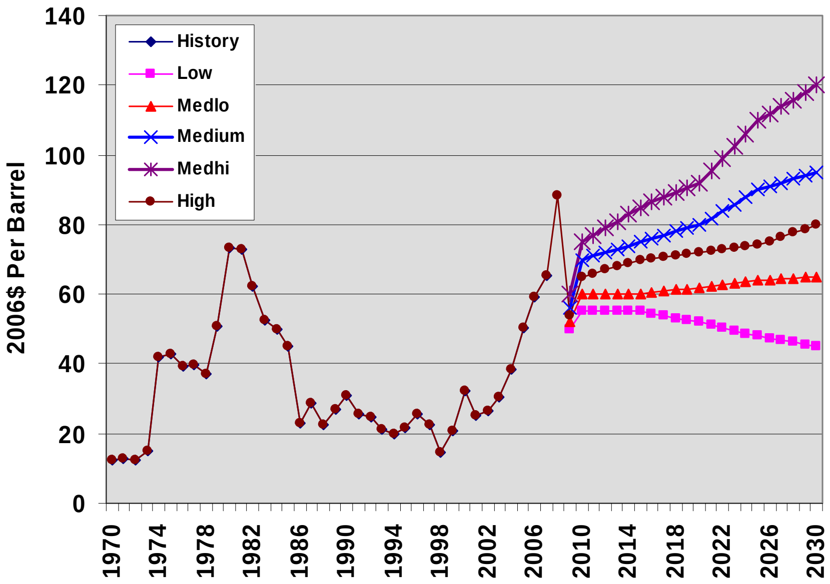


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007			65.29		
2008			88.42		
2010	55.00	60.00	65.00	70.00	75.00
2015	55.00	60.00	70.00	75.00	85.00
2020	52.00	62.00	72.00	80.00	92.00
2025	48.00	64.00	74.00	90.00	110.00
2030	45.00	65.00	80.00	95.00	120.00
Growth Rates					
2007 - 15	-2.12%	-1.05%	0.88%	1.75%	3.35%
2007 - 30	-1.60%	-0.02%	0.89%	1.64%	2.68%

Figure 2-4: Powder River Basin Minemouth Coal Prices: History and Forecast

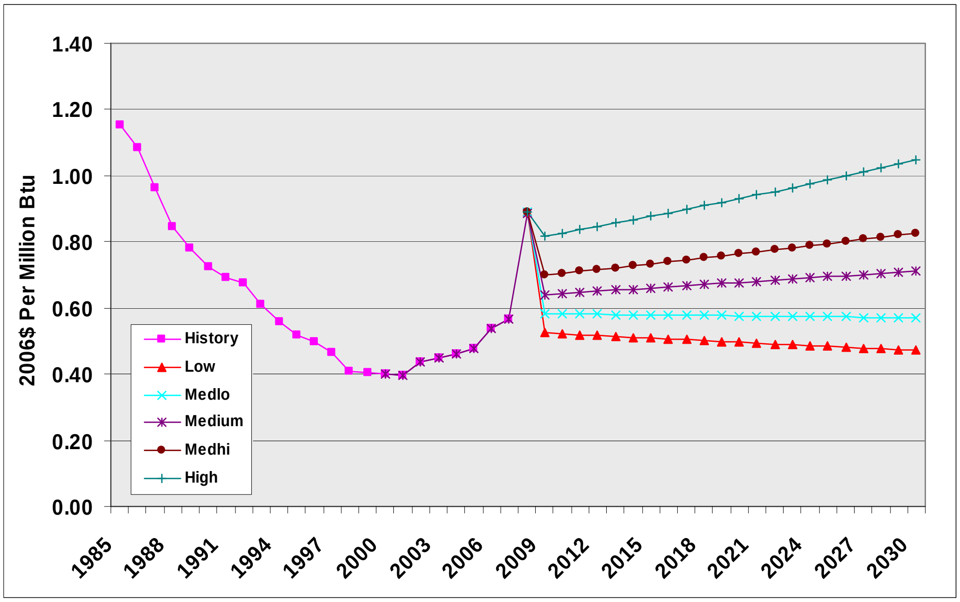


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

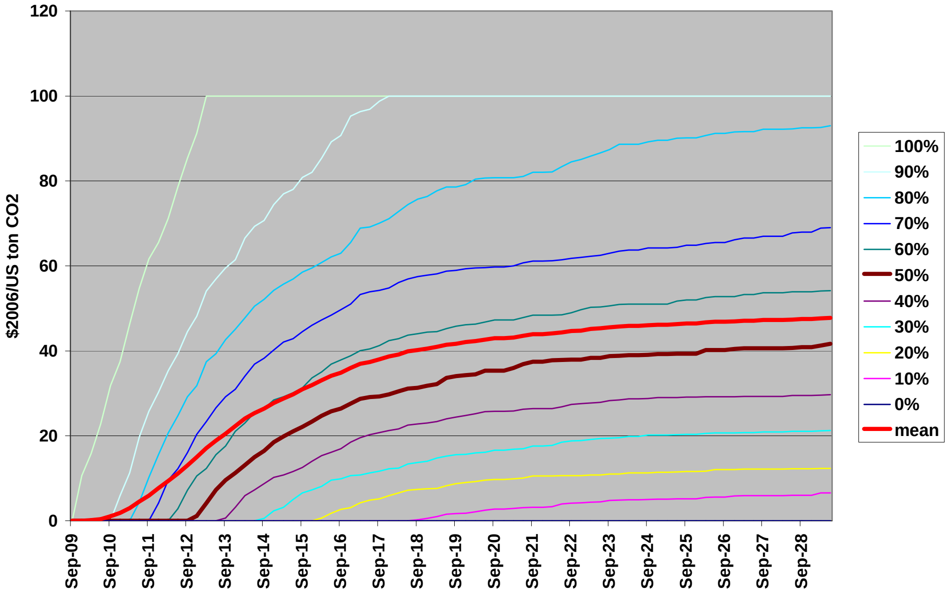
	Low	Medium Low	Medium	Medium High	High
2007	-	-	0.56	-	-
2010	0.52	0.58	0.64	0.70	0.83
2015	0.51	0.58	0.66	0.73	0.88
2020	0.50	0.58	0.68	0.76	0.93
2025	0.48	0.57	0.69	0.79	0.99
2030	0.47	0.57	0.71	0.83	1.05
Growth Rates					
2007-2015	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-2030	-0.78%	0.05%	1.01%	1.67%	2.73%

CARBON DIOXIDE PRICES

The risk of carbon-pricing policies is one of the key uncertainties addressed in the Council's Sixth Power Plan. Such policies have been proposed by the Western Climate Initiative and in proposed federal legislation. Whether, when, and at what level such policies might be implemented are all unknown at this time. Therefore, the plan treats these policies as a risk that should be considered in making electric resource choices made for the region.

The carbon risk scenario captures the carbon pricing risk by modeling both the adoption of a policy and the amount of the carbon price, or penalty, as random variables. The carbon price can be thought of as a carbon tax or the cost of a carbon-emission allowance under a cap-and-trade system. Once a carbon-pricing policy is implemented, the price is assumed to fall between $0 and $100 per ton of carbon emissions. The modeling approach is described in Chapter 9. Figure 2-5 shows a decile chart of the range of resulting carbon prices. The average of the carbon prices begins at zero and increases to above $40 by midway through the forecast period ending at $47 per ton in 2030.

Figure 2-5: Decile Chart of Carbon Prices Used in the Carbon Risk Analysis



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

The choice of the range of carbon prices to be considered was informed by research and review of the results of studies done by various organizations on the likely cost of carbon allowances that would result under various cap-and-trade policies. The Council commissioned a study by EcoSecurities Consulting Limited to review the literature on carbon-pricing studies and develop a range of likely prices under different policy scenarios. The range of estimates is very wide. Results depend on the study methodology, the carbon-reduction targets assumed, and the assumed scope and role of carbon-credit trading. However, the bulk of the estimates fell between $10 and $100 per ton of CO_2. Understanding that there is some chance that no carbon pricing policy will be agreed on, the Council used a range from $0 to $100 for its carbon-risk analysis.

In addition to this range of prices, a number of fixed-price levels and other price ranges were explored in the draft and final plan. The Council is not taking a position on carbon policy for the region by exploring various levels of carbon prices. The analysis is intended to provide information on what would be required to meet existing goals in some states, and to provide information to the region on possible actions to mitigate the risks of unknown future carbon-pricing policies. Chapters 10 and 11 discuss climate change analysis and issues further.

RENEWABLE PORTFOLIO STANDARD RESOURCE DEVELOPMENT

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the Western Electricity Coordinating Council region: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington[2]. In addition, British Columbia has adopted an energy plan with

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[2] Utah's *Energy Resource and Carbon Emission Reduction Initiative* adopted in 2008 has characteristics of a renewable portfolio standard, but mandates acquisition of qualifying resources only if cost-effective. Because

conservation and renewable-energy goals similar to an RPS. RPS laws are complex with great variation between states regarding target amounts, qualifying resources, resource "set-asides," existing resource qualification, in-state credits, price caps, and other provisions. State-by-state assumptions used for this forecast are described in Appendix D.

Mandatory development of low-variable-cost renewable resources can significantly affect wholesale power prices and the need for discretionary resources. A forecast of the types of renewable resources that may be developed and the success in achieving the targets is needed for the wholesale-power price forecast and the resource-portfolio analysis. The resulting estimate of need for new renewable energy to meet state RPS obligations is provided in Table 2-5.

Table 2-5: Estimated Committed and Forecast Incremental RPS Generating Resource Requirements (MWa)

	AZ	BC	CA (33%)	CO	MT	NM	NV	OR	WA
Committed	87	366	3954	454	65	111	273	465	520
Cumulative new (100% achievement of standards)									
2010	32	0	425	0	0	0	21	0	0
2011	77	0	1,068	0	0	0	63	0	0
2012	115	0	1,774	0	19	0	137	0	0
2013	157	0	2,416	0	24	112	277	0	0
2014	196	17	2,863	280	31	147	339	0	218
2015	240	85	3,329	368	37	184	452	0	367
2016	313	136	3,401	450	37	214	463	0	511
2017	390	185	3,477	537	37	243	496	0	662
2018	471	239	3,551	626	37	273	508	0	812
2019	555	296	3,602	718	37	304	524	0	958
2020	642	351	3,674	813	37	335	537	0	953
2021	733	406	3,745	836	37	341	551	0	941
2022	826	462	3,816	860	37	346	566	478	939
2023	925	520	3,885	885	37	353	580	538	939
2024	1,027	579	3,954	910	37	359	595	599	941
2025	1,134	638	4,026	935	38	366	610	662	944
2026	1,163	698	4,099	961	38	372	626	670	950
2027	1,192	758	4,171	987	39	379	641	677	956
2028	1,223	819	4,244	1,014	39	385	657	685	965
2029	1,254	882	4,318	1,041	40	392	672	697	977
Total	**1,341**	**1248**	**8,272**	**1,495**	**105**	**503**	**945**	**1,162**	**1,497**

Table 2-5 shows the estimated qualifying energy needed to fully achieve current renewable portfolio standards. Because of price caps and other limiting factors, the forecast used for this plan assumes 95 percent achievement of standards. All energy from potentially qualifying existing capacity is assumed to be credited. Energy-efficiency measures, in states where credited, are assumed to be employed to the extent allowed. The remaining generating resource obligations (i.e., 95 percent of the new energy of Table 2-6) will be met by a mix of new resources, determined by state-specific resource eligibility criteria, new resource availability, resource cost, RPS policies governing use of out-of-state resources, state-specific resource set-asides and special credit and other factors. The resource mix in the near-term was assumed to resemble the mix of recent qualifying resource development. Over the planning period,

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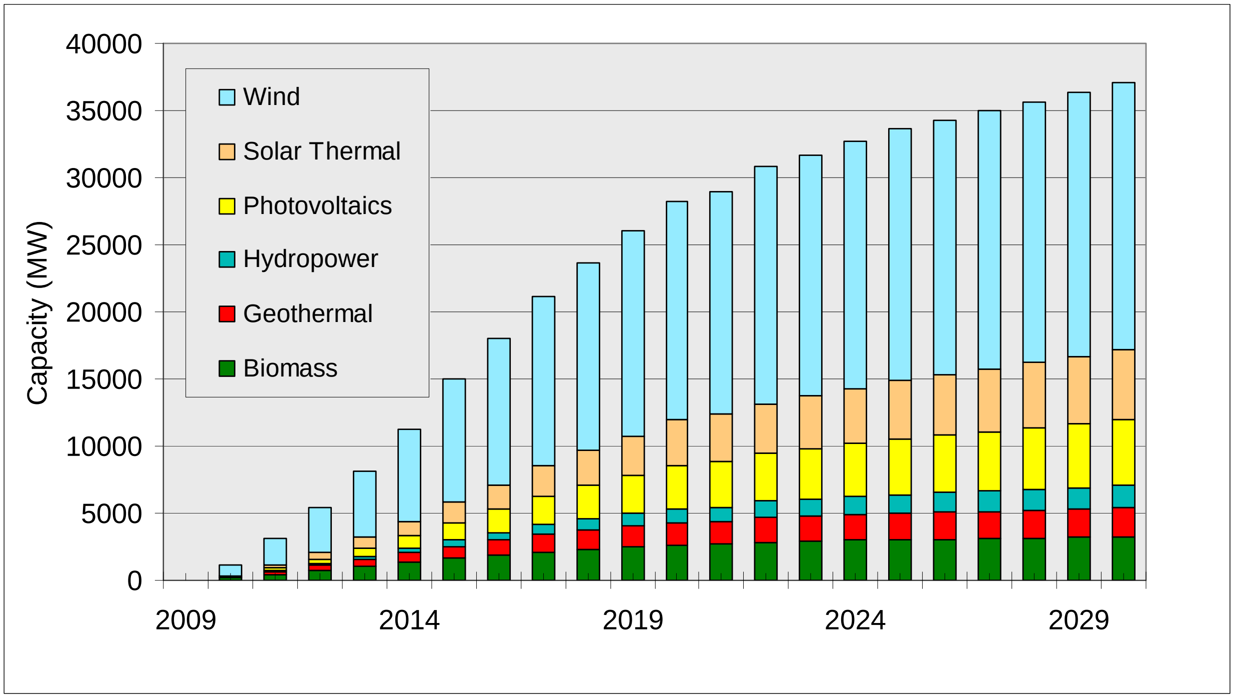
resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA$^{xmp®}$ Electricity Market Model used for the wholesale power price forecast, it was not necessary to separately forecast renewable resource development for Utah.

development is assumed to shift toward locally abundant, but relatively undeveloped resources such as solar thermal. Figure 2-6 illustrates the assumed incremental capacity additions needed to provide 95 percent of the cumulative energy requirements of Table 2-5.

To simplify the forecast, the Council assumed that all new resource requirements would be met in-state, although it is clear that states such as California, with substantial need for qualifying RPS resources, will secure much of its RPS needs from out-of-state sources.

Figure 2-6: Forecast RPS capacity by resource type



WHOLESALE ELECTRICITY PRICES

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices, representing the future price of electricity traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. The forecast establishes benchmark capacity and energy costs for conservation and generating resource assessments and serves as the equilibrium wholesale power prices for the Resource Portfolio Model. In addition, the forecast is used for the ProCost model to assess the cost-effectiveness of conservation measures. The Council's electricity price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans, and for other purposes.

An overview of the development of the wholesale electricity price forecast and a summary of the results are provided in this section. A complete description is provided in Appendix D.

The Council uses the AURORA$^{xmp®}$ Electricity Market Model[3] to forecast wholesale power prices. Electricity prices are based on the variable cost of the most expensive generating plant or

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[3] Supplied by EPIS, Inc. (www.epis.com)

increment of load curtailment needed to meet load for each hour of the forecast period. AURORA$^{xmp®}$, as configured by the Council, simulates plant dispatch in each of 16 load-resource zones making up the Western Electricity Coordinating Council (WECC) electric reliability area. The Northwest is defined as four of these zones: Western Oregon and Washington; Eastern Oregon and Washington, Northern Idaho and Western Montana; Southern Idaho; and Eastern Montana. The 16 zones are defined by transmission constraints and are each characterized by a forecast load (net of conservation), existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives, and a portfolio of new-resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses, and wheeling costs. The demand within a load-resource zone may be served by native generation, imports from other zones, or (rarely) load curtailment.

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide (CO_2) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. CO_2 allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO_2 costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO_2 costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. As described earlier in this chapter, state renewable portfolio standards are expected to force the development of large amounts of wind, solar, and other resources with low-variable costs, in excess of the growth in demand. This will force fossil-fueled generators with lower variable costs to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding-scenario cases were run. The base forecast assumes medium-case fuel prices and mean CO_2 prices. All forecast cases assume 95-percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are shown in Table 2-6.

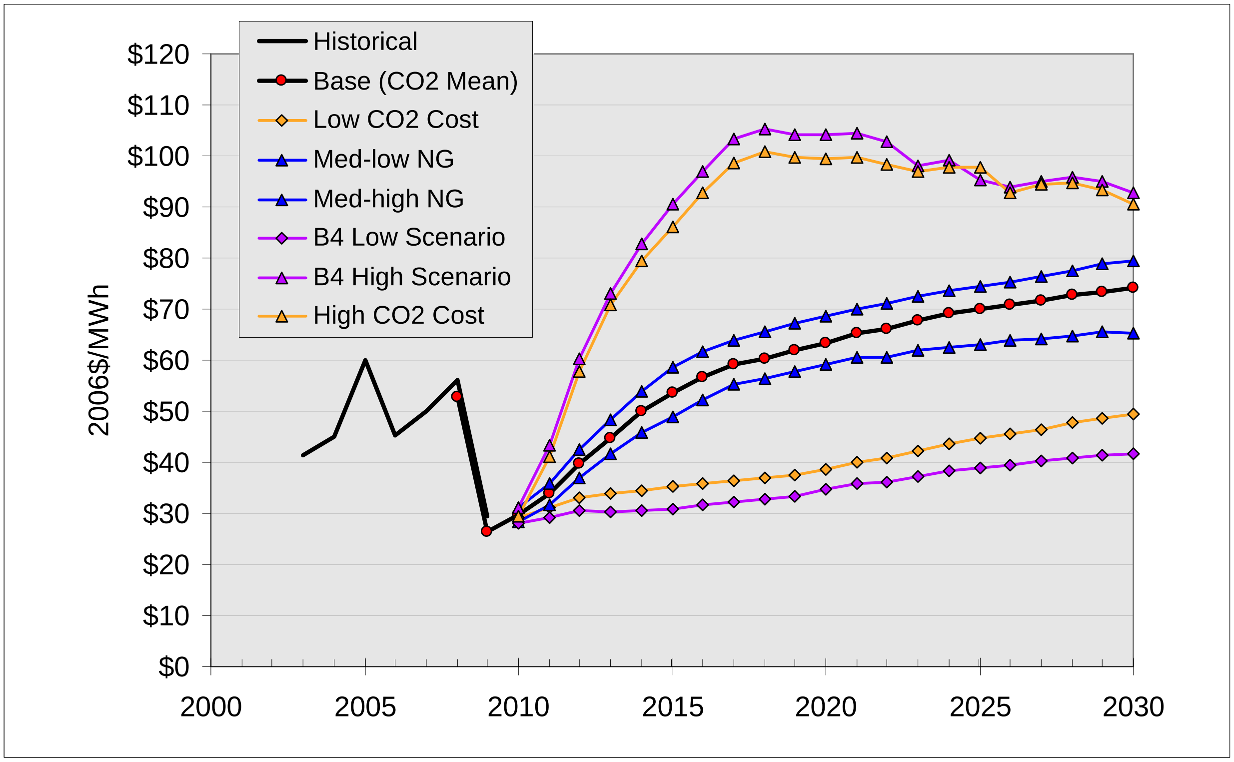
Table 2-6: Price Forecast Case Changing Assumptions

Case	Fuel Prices	CO_2 Cost
Base (mean CO_2)	Medium Case	Mean
Low CO_2 Cost	Medium Case	90% prob. of exceedance decile
High CO_2 Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM cases
Medium-High Natural Gas	Medium-high NG	Mean of RPM cases
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

For the base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $30 per megawatt-hour in 2010 to $74 per megawatt-hour in 2030 (in real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to $29 in 2009 with the collapse of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 base case forecast is $56 per megawatt-hour.

Figure 2-7 illustrates recent and forecast wholesale power prices for the various cases. Comparing the shape of the power price forecasts with the mean CO_2 price forecast of Figure 2-5 clearly demonstrates the significant effect of CO_2 costs on prices. This is particularly evident in the high CO_2 and high-scenario cases. In these cases, prices rise rapidly early in the planning period as CO_2 prices increase, then stabilize and decline as CO_2 prices reach a steady-state of $100/ton of CO_2 and additional low-carbon resources are deployed.

Figure 2-7: Historical and Forecast Annual Average Mid-Columbia Wholesale Power Prices



Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure 2-8 shows the monthly average heavy-load hours, all-hours, and light-load-hours prices for the base forecast. A flattening of prices during high-runoff, lower-load seasons, becoming evident in the mid-term of the planning period, is likely attributable to the increasing proportion of must-run resources with low variable costs.

The levelized 2010-29 forecast values and values for selected years are shown in Table 2-7. The full monthly price series are provided in Appendix D.

Figure 2-8: Monthly Average Base Case (Mean CO_2) Forecast of Mid-Columbia Wholesale Power Prices

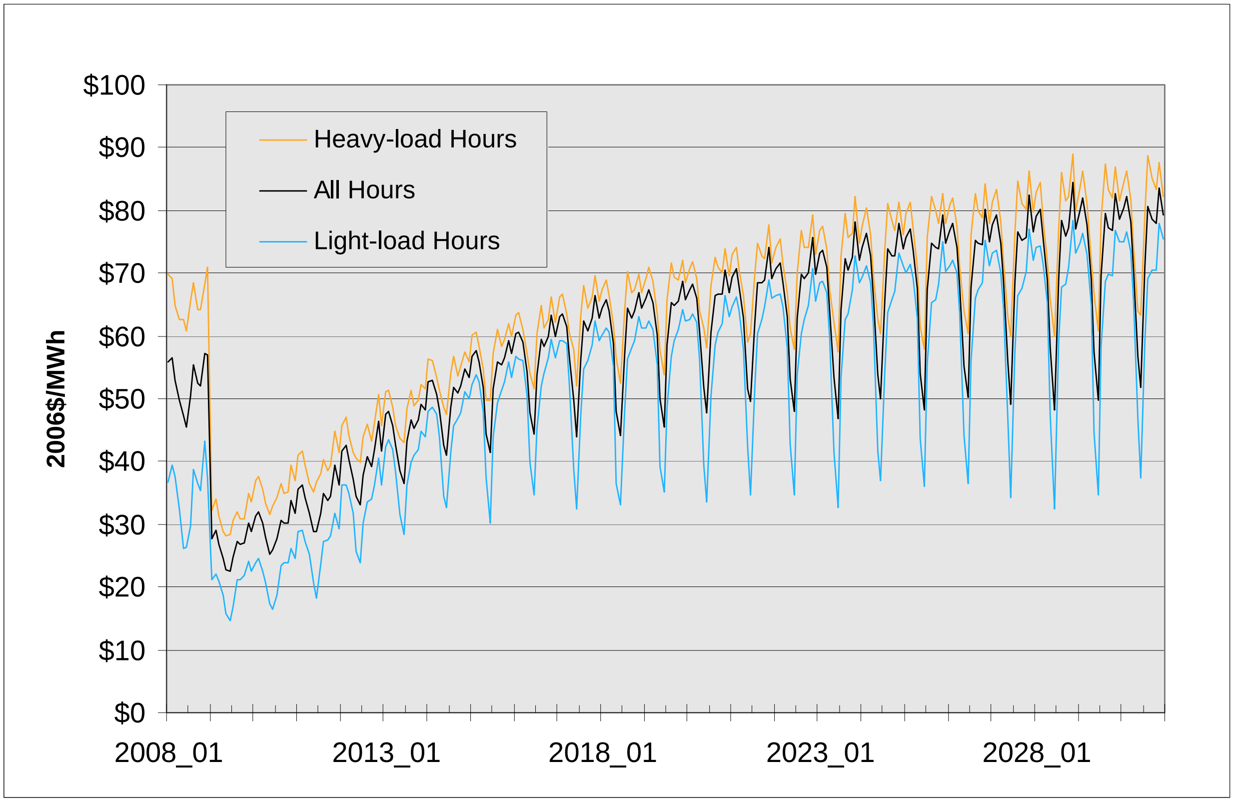


Table 2-7: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

	Base	Low-CO_2	High CO_2	Med-Low NG	Med-High NG	Low Scenario	High Scenario
2010	$30	$29	$29	$28	$31	$28	$31
2015	$54	$35	$86	$49	$59	$31	$90
2020	$63	$39	$99	$59	$69	$35	$104
2025	$70	$45	$98	$63	$74	$39	$95
2030	$74	$49	$91	$65	$79	$42	$93
Levelized (2010-29)	**$56**	**$38**	**$82**	**$51**	**$60**	**$34**	**$85**
Growth Rates							
2010-2029	4.4%	4.6%	2.6%	5.9%	4.3%	4.7%	2.0%

Forecast wholesale power prices have often been used to determine the avoided cost of new resources. Wholesale energy price forecasts, in general, must be used with caution in setting avoided costs because of capacity and risk considerations. However, this price forecast in particular is not a suitable stand-alone measure of avoided resource costs.[4] This is because the Northwest, with the exception of Southern Idaho, enters the planning period with an energy

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[4] Market price adders representing the risk mitigation and capacity value of specific resource types can be calculated. The resulting sum of energy market prices, capacity credit and risk mitigation credit represents the avoided cost of the resource in question. This is the approach taken in this plan to establish the value of energy efficiency measures.

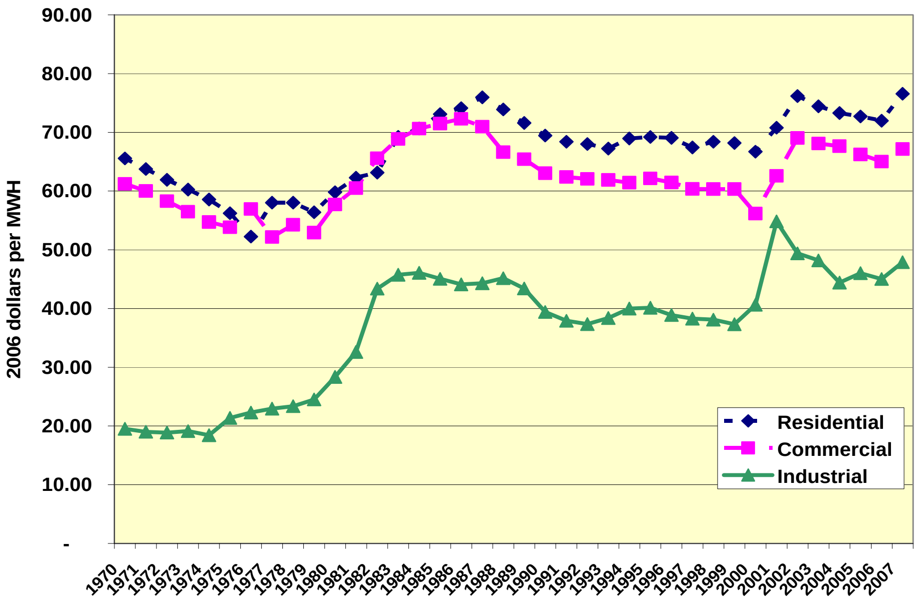
surplus, and remains so throughout the planning period because of the addition of resources to meet renewable-resource-portfolio requirements. Because of this continuing surplus, no discretionary (non-RPS) resources are added by the model and therefore the resulting energy prices do not reflect the avoided cost of any new resource. The actual avoided-resource costs for the three Northwest states with renewable portfolio standards are the costs of the renewable resources added to meet RPS requirements and any capacity additions needed to supply balancing reserves (balancing-reserve requirements are not tracked in the model). Southern Idaho is the exception. Here, about 570 megawatts of simple-cycle gas turbines are added during the planning period to maintain capacity reserves. Because this capacity only contributes incidental energy, even the energy price forecast for Southern Idaho does not represent the avoided cost of needed resources.

RETAIL ELECTRICITY PRICES

History

In the first half of the 1970s, consumers in the Northwest experienced declining electricity prices. However, by mid-1970 and into the 1980s, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In the latter half of the 1980s, electricity prices began a decade-long decline, in real (inflation-adjusted) terms. But in late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Since the sharp increase in 2000, electricity prices have stabilized, and even declined in inflation-adjusted prices. However, since 2006, another round of more moderate price increases has begun to be reflected in increases in fuel prices and other commodities. Figure 2-9 illustrates this price history.[5]

Figure 2-9: Average Retail Electricity Price by Sector (2006$/MWh)



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[5] Prices in Figure 2-7 are expressed in constant year 2006 dollars, as are many other tables and graphs throughout the plan.

Forecast of Retail Electricity Prices

Typically, the price of electricity for investor-owned utilities is determined through a regulatory-approval process, with utilities bringing a rate case to their regulatory authority and seeking approval of future rates. Future rates depend on the cost of serving electricity to customers and the level of sales. The approved rates should cover the variable *and* fixed-cost components of serving customers, plus a rate of return on invested capital. For customer-owned utilities, rates are set by elected boards to recover the costs of serving the electricity needs of their customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is a simplified approach, where fixed and variable costs of the power system are estimated for each period and then divided by the volume of sales of electricity. The annual growth rate in average revenue requirement derived from the least-risk plan was applied to sector-level electricity prices.

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-8 through 2-10. The annual real growth rate of electricity prices is expected to be about 1 percent per year for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, individual electric utility rates may be higher or lower than the figures presented here. Also, individual utilities may have significantly higher or lower rate increases than these average statewide figures would indicate.

Table 2-8: Price of Electricity for Residential Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
2005	75	68	65	84
2010	89	79	74	96
2015	101	90	83	109
2020	109	97	90	117
2030	108	96	89	116
Annual Growth				
1985-2000	-0.3%	0.0%	-0.3%	0.1%
2000-2007	2.9%	3.9%	0.3%	2.7%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-9: Price of Electricity for Commercial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
2005	67	65	56	77
2010	79	71	60	89
2015	89	80	67	101
2020	97	86	73	109
2030	93	83	70	104
Annual Growth				
1985-2000	-1.3%	-0.2%	-1.2%	-0.4%
2000-2007	3.2%	3.6%	-0.3%	3.5%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-10: Price of Electricity for Industrial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
2005	50	44	40	50
2010	51	55	45	60
2015	58	62	51	67
2020	63	67	55	73
2030	60	64	53	70
Annual Growth				
1985-2000	-1.3%	0.6%	-0.6%	0.7%
2000-2007	4.8%	3.2%	-0.1%	8.1%
2010-2030	1.0%	1.0%	1.0%	1.0%

UE 233 – CERTIFICATE OF SERVICE

I hereby certify that, on this 20th day of June, 2012, I served the foregoing **JUNE 20, 2012 TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket UE 233 upon each party listed in the UE 233 OPUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending one original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)
(HC denotes highly confidential)

(C denotes service of Confidential material authorized)

W **DON READING**
C 6070 HILL ROAD
HC BOISE ID 83703
dreading@mindspring.com

W **ERIC L OLSEN**
C 201 E CENTER ST
HC POCATELLAO ID 83201
elo@racinelaw.net

W **IDAHO POWER COMPANY**
C CHRISTA BEARRY
HC PO BOX 70
BOISE ID 83707-0070
cbearry@idahopower.com

W **IDAHO POWER COMPANY**
C LISA D. NORDSTROM
HC PO BOX 70
BOISE ID 83707-0070
lnordstrom@idahopower.com

W **PORTLAND GENERAL ELEC**
DOUGLAS C TINGEY
121 SW SALMON 1WTC13
PORTLAND OR 97204
doug.tingey@pgn.com

W **JOSHUA D JOHNSON**
C 101 S. CAPITOL BLVD., STE 300
HC BOISE ID 83702
jdj@racinelaw.net

W **MCDOWELL RACKNER & GIBSON**
C LISA F RACKNER
HC 419 SW 11TH AVE, STE 400
PORTLAND OR 97205
lisa@mcd-law.com

W **PORTLAND GENERAL ELEC**
RANDY DAHLGREN
121 SW SALMON ST - 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

W **DEPARTMENT OF JUSTICE**
C STEPHANIE S ANDRUS
HC 1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us

W **PUBLIC UTILITY COMMISSION**
C JUDY JOHNSON
HC PO BOX 2148
SALEM OR 97308-2148
judy.johnson@state.or.us

W **PUBLIC UTILITY COMMISSION**
C ERICK COLVILLE
HC PO BOX 2148
SALEM OR 97308-2148
erik.colville@state.or.us

W **RICHARDSON & O'LEARY**
C PETER J RICHARDSON
HC PO BOX 7218
BOISE ID 83707
peter@richardsonandoleary.com

W **DAVIDSON VAN CLEVE**
IRION A SANGER
333 SW TAYLOR - STE 400
PORTLAND OR 97204
ias@dvclaw.com

W **ESLER STEPHENS & BUCKLEY**
JOHN W STEPHENS
888 SW FIFTH AVE STE 700
PORTLAND OR 97204-2021
stephens@eslerstephens.com;
mec@eslerstephens.com

W **PACIFIC POWER**
R. BRYCE DALLEY
825 NE MULTNOMAH ST., STE 2000
PORTLAND OR 97232
bryce.dalley@pacificorp.com

W **PACIFICORP, DBA PACIFIC POWER**
OREGON DOCKETS
825 NE MULTNOMAH ST, STE 2000
PORTLAND OR 97232
oregondockets@pacificorp.com

W **RICHARDSON & O'LEARY PLLC**
C GREGORY M. ADAMS
HC PO BOX 7218
BOISE ID 83707
peter@richardsonandoleary.com

W **UTILITY NET.INC**
C ANTHONY J YANKEL
HC 29814 LAKE RD
BAY VILLIAGE OH 44140
tony@yankel.net

W **DAVIDSON VAN CLEVE PC**
MELINDA J DAVISON
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mjd@dvclaw.com; mail@dvclaw.com

W **NW ENERGY COALITION**
WENDY GERLITZ
1205 SE FLAVEL
PORTLAND OR 97202
wendy@nwenergy.org

W **PACIFIC POWER**
SARAH WALLANCE
825 NE MULTNOMAH ST., STE 1800
PORTLAND OR 97232
sarah.wallace@pacificorp.com

W **REGULATORY & COGENERATION SERVICES INC**
DONALD W SCHOENBECK
900 WASHINGTON ST STE 780
VANCOUVER WA 98660-3455
dws@r-c-s-inc.com

W **RENEWABLE NORTHWEST PROJECT**
MEGAN WALSETH DECKER
421 SW 6TH AVE #1125
PORTLAND OR 97204-1629
megan@rnp.org

Respectfully submitted,

Sommer Templet

Sommer Templet, OSB #105260
Staff Attorney
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
Portland, OR 97205
(503) 227-1984 phone
(503) 224-2596 fax
sommer@oregoncub.org