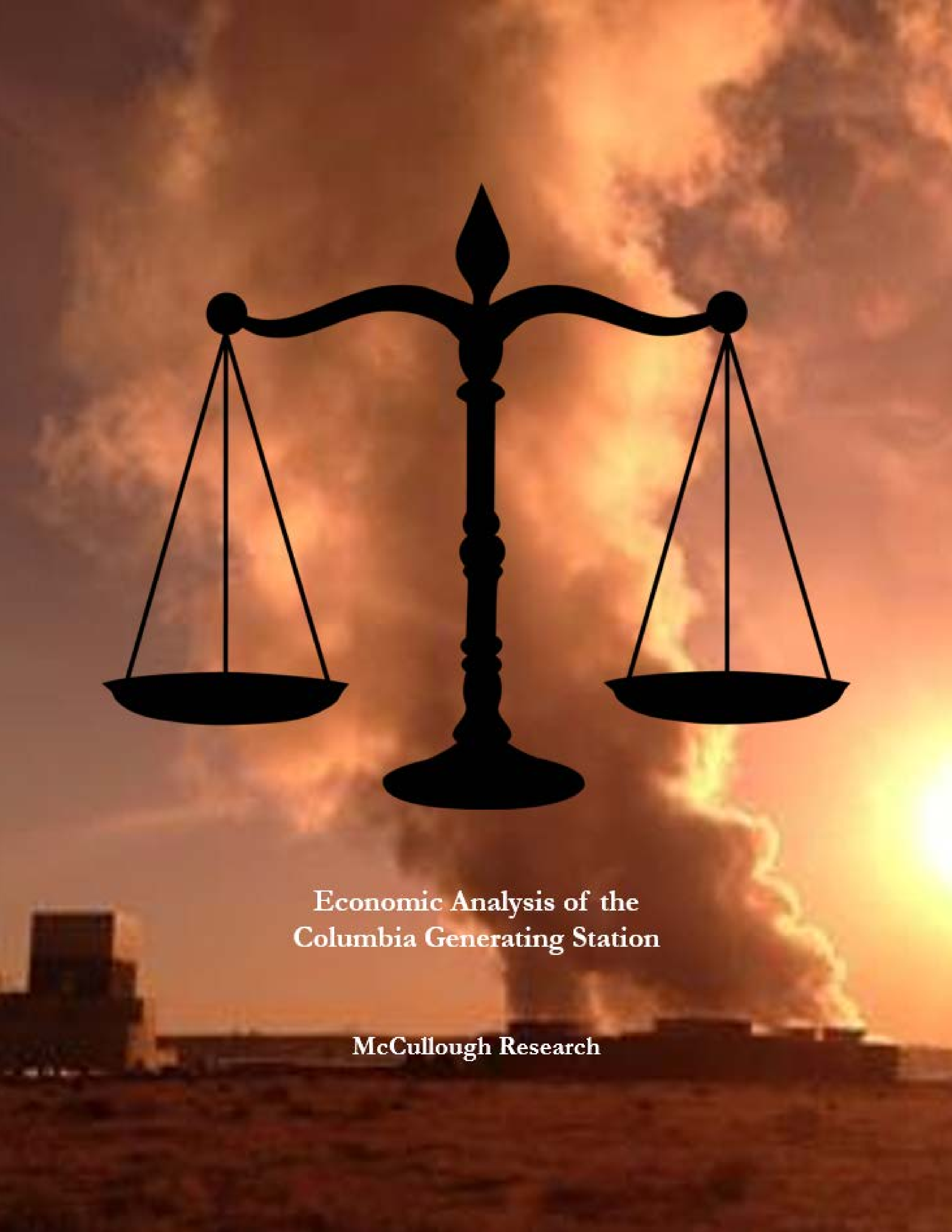

Economic Analysis of the Columbia Generating Station

McCullough Research

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RE: Economic Analysis of Columbia Generating Station (CGS)

The report on Columbia Generating Station's economics is attached below. I would like to thank you for the opportunity to return to a project I worked on in the 1980s. Energy Northwest (then the Washington Public Power Supply System) is a fascinating study with complex economics and a long and tangled history.

While I respect your concerns about nuclear power, you will find little on the risks of nuclear generation in this report. Our mandate was quite narrow – to carefully consider the economics of CGS and its possible replacement with other supplies. Our conclusion, bolstered by many interviews with the project's owners and operators, as well as with industry representatives throughout the region, is that CGS can be replaced at a significant cost savings to the region's ratepayers and utilities – approximately a $1.7 billion dollar saving. Our recommendation is that BPA issue a Request For Proposals (RFP) for alternatives and displace the unit within the current institutional framework.

The study has been unnecessarily complicated by a lack of transparency at Energy Northwest. Even the simplest requests have been delayed by months. In a number of cases, our request for materials already provided to the press has experienced a lengthy delay before response. We would like to thank Timothy Ford, the Washington State Assistant Attorney General for Government Accountability, and our liaison at BPA, Steven Weiss, for their help in working through these issues.

Sincerely,

Robert McCullough

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2 EXECUTIVE SUMMARY

In the mid-1990s, decreasing market prices – similar to the situation today – led to a sweeping evaluation of the role of Bonneville Power in the regional energy supply system. The governors of Oregon, Washington, Idaho, and Montana convened a blue ribbon panel to examine the facts and make recommendations. The Comprehensive Review conducted a year's worth of hearings and recommended significant changes. Among the results was a "Market Test" for the Columbia Generating Station (CGS) nuclear power plant that recommended closure if the plant cost more than market prices. The Market Test was adopted by the CEO of Energy Northwest (EN) and the Administrator of the Bonneville Power Administration (BPA), as well as endorsed by major elected officials like U.S. Senator Ron Wyden.

Carrying forward the Market Test from fifteen years ago, our study of the present day economics of CGS finds that it has failed the Market Test since 2009. We project that CGS will continue to cost more than market rates in years to come. It also poses physical and financial risks, has an antiquated ownership structure, and is ill-suited to Mid-Columbia area generation operations.

Nevertheless, we are not proposing CGS's immediate termination simply on the basis of price forecasts. Instead, we are recommending the issuance of a Request For Proposals (RFP) to see if the unit can be replaced with long-term options that are less costly, less risky, and better fitted to regional needs. If the RFP provides cost savings for BPA and its customers, CGS would commence decommissioning at the end of its current refueling cycle in 2015.

The plant's original name, "WNP-2," referenced that it was the second nuclear station constructed and operated by the Washington Public Power Supply System (WPPSS). The first, the Hanford N-Reactor, was a multi-purpose reactor that was used both for producing plutonium for nuclear weapons and steam for electric generation.

After WNP-2's construction commenced, WPPSS decided to treat the N-Reactor as a separate category. The follow on nuclear stations, WNP-1, WNP-3, WNP-4, and WNP-5, were named in numerical order to make a consistent set of unit names.[1] The N-Reactor was shut down for safety upgrades in 1987, and never resumed operation, reflecting concerns about the Chernobyl incident.[2] In 1999, WPPSS changed its name to Energy Northwest,

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[1] Miller, Gary K. *Energy Northwest: A History of the Washington Public Power Supply System.* Xlibris, 2001. Print. Page 181.

[2] Geranios, Nicholas K. *N Reactor Closure Is Permanent, Energy Secretary Says. Seattletimes.com.* The Seattle Times, 15 Aug. 1991. Web. 04 Nov. 2013. <http://community.seattletimes.nwsource.com/archive/?date=19910815>.

and in 2000 WNP-2 was renamed the Columbia Generating Station, although many industry insiders today still refer to it as "WPPSS 2" or "WNP-2." [3]

Different names have been used for the WNP-2 plant in different contexts, and we have chosen to use the name "CGS" throughout this report as a compromise between the current name "Columbia Generating Station" and the more adversarial "WNP-2".

In the Pacific Northwest, wholesale electric prices have been low over the past few years – so low in fact, that off-peak prices have actually fallen below zero on approximately 15% of days over the last two years. Adjusted for inflation, wholesale electric prices last year were at their lowest point in history.

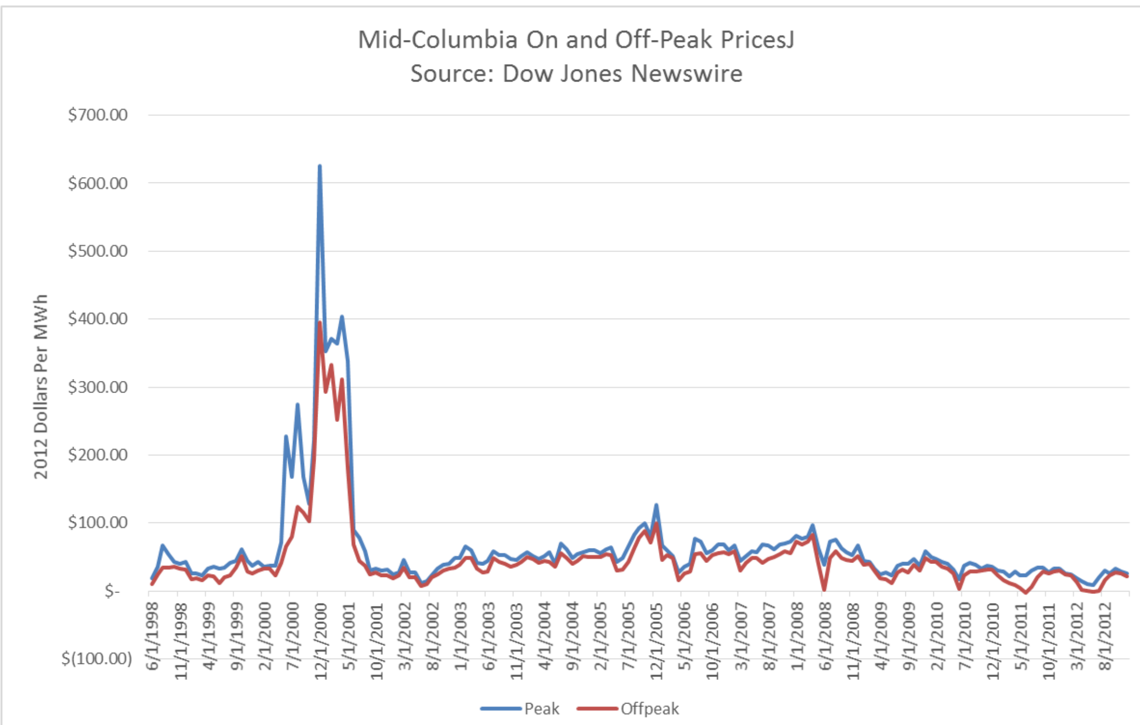

Figure 1

[3] BPA, for example, uses both WNP-2 and CGS interchangeably in many cases.

While wholesale power costs have fallen over the past five years, the operating costs of the Columbia Generating Station have continued to increase:

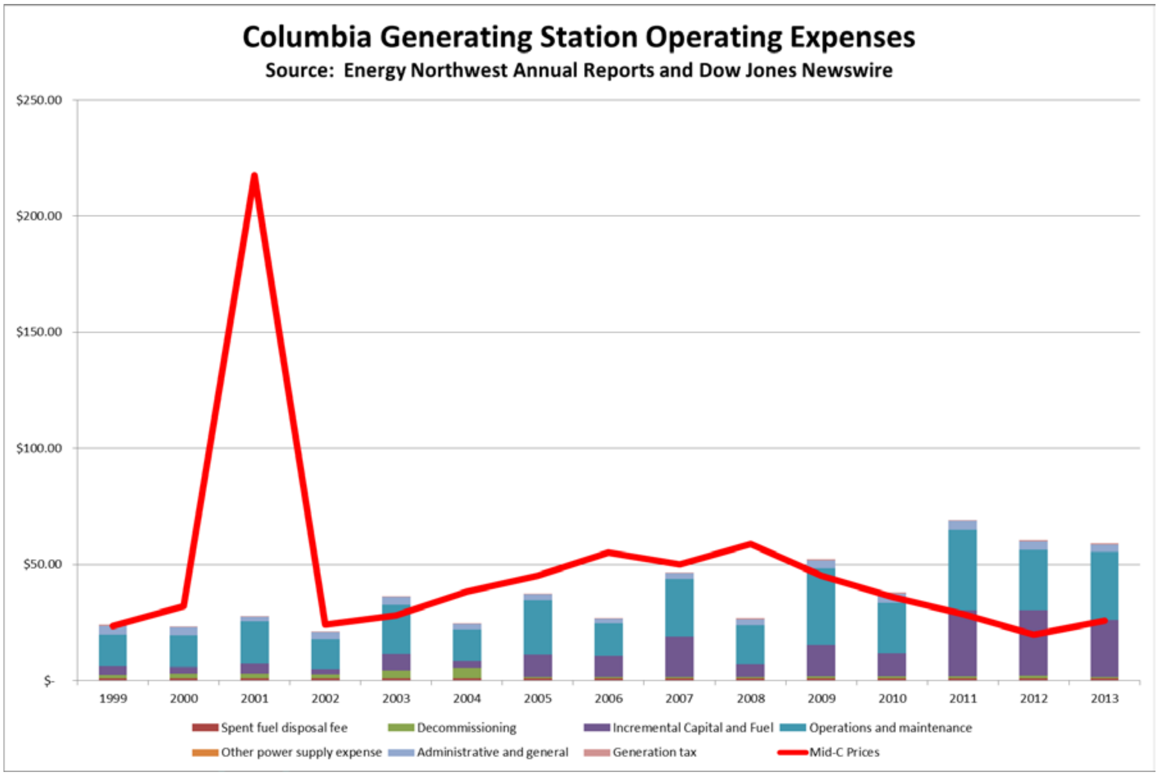

Figure 2

Several energy companies have indicated that competitive pressures have contributed to early closure and decommissioning of nuclear plants. Dominion Resources' Kewaunee Power Station (Kewaunee), Southern California Edison's San Onofre Nuclear Generating Stations, Units 2 and 3, and Duke Energy's Crystal River Unit 3 Nuclear Power Plant (Crystal River) have prematurely closed, and Entergy's Vermont Yankee nuclear plant announced it would close in 2014, turning these plants into long term decommissioning liabilities. Exelon, the largest owner of nuclear plants in the country, has said that "[Exelon] Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license."[4]

[4] Exelon. *United States Securities and Exchange Commission Form 10-K.* Washington, D.C.: United States Securities and Exchange Commission, 6 Feb. 2009. PDF. Page 46.

This sentiment was repeatedly recently when the CEO of Exelon was quoted as saying:

> "We think the nuclear assets are very valuable," Mr. Crane said. "We know how to run them better than anybody else. But at the end of the day, if we're not compensated for them we'll just have to shut them down."[5]

Recent reports indicate that decommissioning costs are rising by 8-9% per year, driven by the cost of burying lightly contaminated steel and concrete.[6] Moreover, the formula used by the Nuclear Regulatory Commission (NRC) to estimate decommissioning costs is considered to be the minimum cost of decommissioning. Actual decommissioning costs from plants undergoing closure are much higher. According to Energy Northwest, the decommissioning cost estimate for CGS is $454.6 million. Dominion estimates that decommissioning will cost nearly $1 billion for the recently closed, and much smaller, Kewaunee boiling water reactor.[7]

CGS is significantly more expensive than other nuclear plants because it is an older, stand-alone plant with an overly complex management structure. An obsolete financing structure from the 1960s called "net billing" – an arrangement discussed in more detail in Section 3.2 – bears much of the blame for high costs and a poor reliability history at the plant.

Section 4.3 summarizes a detailed review of CGS's historical and forecasted costs. Sources on comparative costs include industry surveys like that from the Nuclear Energy Institute (NEI), data from the Federal Energy Regulatory Commission (FERC), and other sources.

The following table summarizes operating costs filed at FERC for plants from 2006 through 2012. CGS has the highest cost, followed closely by the thirteen year older unit in Minnesota, Monticello.

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[5] Daniels, Steve. *What's Stronger than Nuclear Power? Falling Electricity Prices.* Crain's Chicago Business. 18 Nov. 2013.Web. 3 Dec. 2013.
[6] UBS Investment Research. *Nuclear Decommissioning Discussion with the NRC Staff: Conference Call Transcript.* Nrc.gov. 9 Apr. 2013. Web. 20 Sept. 2013. Page 6. <http://pbadupws.nrc.gov/docs/ML1312/ML13128A305.pdf>
[7] Dominion Energy. *2012 Decommissioning Cost Analysis of the Document Kewaunee Nuclear Power Plant SAFSTOR Methodology*. 26 Feb. 2013. Page 6.

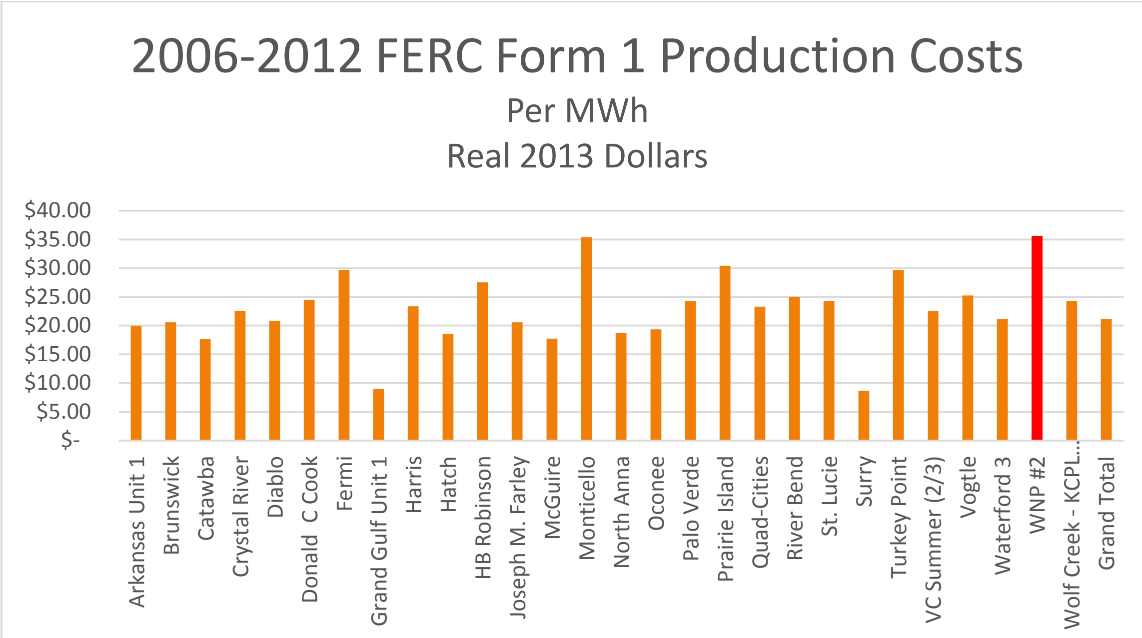


Figure 3

Simply put, CGS's costs are the responsibility of BPA, and in return, BPA receives the output of CGS.[8] Day to day management is in the hands of Energy Northwest. The history of this arrangement is rife with miscommunication and conflict between the two parties.

The cash out of pocket costs of CGS are now roughly twice the wholesale price on the Mid-Columbia market in 2012. The most recent budget estimates from Energy Northwest indicate that out of pocket costs for fiscal year 2014 will be $39.48/MWh.[9] Comparable forward prices at the Mid-Columbia market hub are $32.09/MWh.[10]

Our forecast of future CGS and market costs gives us an estimate of the possible future benefits of replacing CGS. Seattle City Light's Energy 1990 report put the role of a forecast very well:

> A forecast is not the same thing as a prediction. A prediction implies that we think we know what will happen at some time in the future. People who make forecasts do not regard themselves as prophets, nor are they necessarily

[8] CGS's costs were originally paid directly by the participating utilities who then "netted" the cost from their payments to BPA – hence the word "net" in "net billing". This was simplified in 2006 to allow direct billing of the participating utilities CGS's costs to Bonneville.

[9] Energy Northwest. *Fiscal Year 2014 Columbia Generating Station Annual Operating Budget.* 16 May 2013. Pdf. Page 5.

[10] Argus Media. *Argus US Electricity*. 28 Oct. 2013. Page 9. <https://www.argusmedia.com/Power/Argus-US-Electricity>

> pleased with the prospects they are forecasting. In essence, they are telling us the probable consequences of present assumptions and present trends. If we do not like the consequences, we can work to change the assumptions and trends.[11]

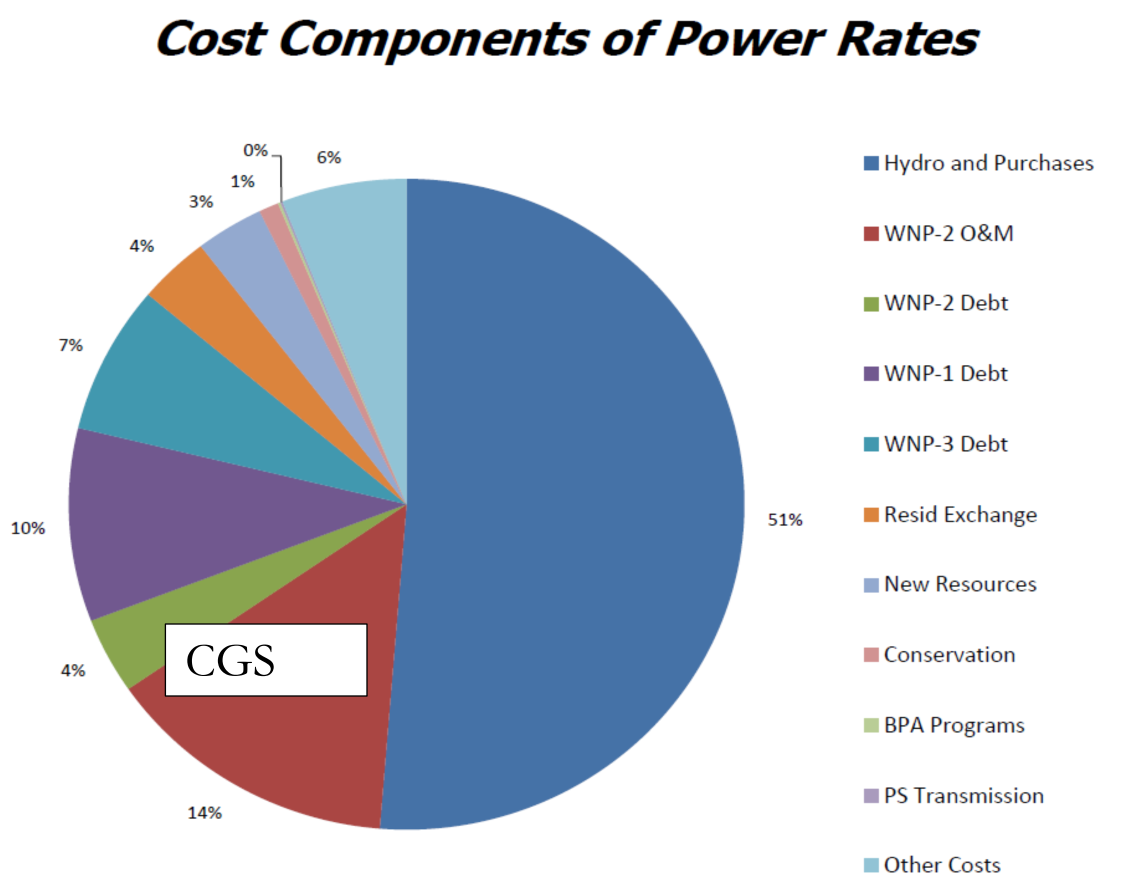
Our forecast of the regional benefits of displacing CGS at the end of its current refueling cycle until the end of its expected lifetime is $1,724,141,555 in today's dollars. The calculation of the benefits is explained in Section 5.11.

Problems and Opportunities:

- CGS institutional structure is a continuing challenge for BPA.
  - Management without ownership
  - Unmanageable "Project Consultant" arbitration
- Stand-alone plant
- Located in the center of over-generation and far from load
- For the past five years Mid-Columbia prices have been lower than "avoided costs" at CGS; this appears to be the case for many years to come.

Energy Northwest's nuclear projects have created a sizable cost burden for the region, consisting of 35% of the cost component for power rates: 17% consists of debt service for unfinished nuclear plants and 18% consists of CGS debt and O&M costs.[12]

[11] Seattle City Light. *Energy 1990 Initial Report Volume 1*. 27 Feb. 2976. Page 3-1.
[12] O&M stands for Operations and Maintenance.



[13]

Figure 4

In a perfect world, the 18% of costs attributable to CGS could be avoided. In the real world this is not the case. Existing debt costs are "sunk" and must be borne by BPA whether the plant operates or not. A variety of other costs are avoidable, however. O&M costs are largely avoidable, as are the increasing capital requirements of an aging plant. In addition, early closure of CGS will avoid the rapid escalation of decommissioning costs and exposure for future spent fuel storage.

[13] Bliven, Ray. *July 2013 Quarterly Business Review*. BPA. 30 Jul. 2013. Web. 27 Sept. 2013. Page 44. <http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2013FinancialOverviewDocuments/2013 3rd Qtr Package.pdf>.

2.1 RECOMMENDATIONS

- ***Aside from the inherent dangers embedded in nuclear power, the economics of CGS no longer makes sense. The plant should be "displaced."***

Displacement is a term of art in electricity operations in which a more expensive plant is "displaced" by less expensive market opportunities. CGS is already displaced, on occasion, by wind and hydroelectric generation by changing the timing of refueling. At current prices, CGS can be displaced by market purchases in the long term.

Displacement also provides an opportunity to reduce carbon exposure. Although CGS is often described as being "carbon free," CGS's fuel has been supplied by, and will continue to be supplied by for some years to come, one of the least environmentally friendly enrichment facilities in the industry. The phrase "carbon free" unfortunately has actually meant "carbon elsewhere" for CGS operations.[14]

- ***The Bonneville Power Administration should ask suppliers for firm bids to displace CGS.***

CGS's location is disadvantageous due to the ready supplies of renewable resources in its immediate vicinity. This is an opportunity to contract for an alternative supply that is less costly, more dependable, less risky, and poses fewer environmental hazards.

The Mid-Columbia market is both deep and liquid. Many suppliers are available, and a variety of transactions occurs every day. The displacement transaction or transactions would use modern power contracts that would avoid the problems in the existing antiquated 1971 Project Agreement, and would favor counterparties with substantial credit support.

- ***The displacement power should be purchased by Energy Northwest and supplied to BPA under the existing contract.***

Pacific Northwest cost allocation issues are often settled in contentious proceedings with complex dueling mathematical models. While this report does, in fact, model West Coast prices for the next thirty years as part of its review of CGS displacement, it does not attempt to model the Bonneville rate case.

Displacement and supply under the existing contract focuses squarely on the least cost solution for upcoming years. The reduction in costs from displacement would not require reworking of existing cost allocations in the BPA rate case since a similar quantity of energy

[14] Section 4.6.7 of this report goes into detail on the operations of the now defunct 1950s facility that has been supplying CGS's fuel with substantial carbon impacts. The facility also contributed the majority of CFC-114 (Freon) release for the United States.

would be delivered by the same entity, Energy Northwest, to the same customer. The only difference would be a reduction in the cost of the energy, along with a reduction in financial and operating risk.

- ***Energy Northwest should handle employment transitions by a combination of training and employing workers in plant decommissioning and a variety of additional strategies***

A solid local economy in the Tri-Cities and plans for additional industrial development, combined with educational institutions capable of retraining workers, make the adjustment of closing the CGS more manageable than it would be in some other communities. We would recommend Energy Northwest adopt DECON, rather than SAFSTOR, in order to maximize local employment during the decommissioning transition.[15] In addition, we recommend that decommissioning be handled directly by Energy Northwest and not turned over to an outside contractor. This mirrors the successful decommissioning record at Trojan and Rancho Seco.

As TransAlta has pledged to do in transitioning workers at the Centralia coal plant, it may make sense for Energy Northwest to set aside additional monies for retraining and employing workers in new energy enterprises.

2.2 THE BOTTOM LINE

If the recommendations above had been in place in Fiscal Year (FY) 2013, enormous savings would have taken place in the twelve months from July 1, 2012 through June 30, 2013.

Energy Northwest's Fiscal Year 2013 Annual report indicates that BPA paid $418,939,000 for CGS during this period (not including interest on outstanding bonds which is "sunk").[16] If BPA had purchased the same energy from the Mid-Columbia market at Dow Jones daily on-peak and off-peak prices, it would have paid $218,515,000.[17]

In sum, BPA paid $418,939,000 for $218,515,000 worth of energy. The difference, $200,424,000, would have had the impact of reducing BPA's rates by 10.67%. This

[15] The NRC's decommissioning studies indicate that DECON will be less costly than SAFSTOR.
[16] Energy Northwest. *Energy Northwest 2013 Annual Report*. 2013. Page 50.
[17] The Dow Jones company publishes daily prices at the Mid-Columbia power market based on a detailed survey of transactions submitted by market participants. Their reports are widely used and reported in the industry. A discussion of the index and its calculation is summarized in a Dow Jones publication entitled "Dow Jones Mid-Columbia Electricity Price Indexes[SM]" at http://www.djindexes.com/mdsidx/downloads/brochure_info/Dow_Jones_Mid-Columbia_Electricity_Price_Indexes_Overview.pdf".

calculation comes from BPA's July 2013 Quarterly Business Review, page 43, which explained that the $169,000,000 increase in costs was leading to a 9.0% rate increase.[18] The rate reduction, applied to BPA's Preference Firm rate, would have lowered BPA's wholesale rate by $3.37/MWh.

The U.S. Energy Information Administration (EIA) reports residential loads by utility on an annual basis.[19] The following table shows the per residential customer impact for twenty utilities in Oregon and Washington:

Utility	MWh/Customer	$/Customer	Total Impact
Puget Sound Energy Inc	11.30	$38.05	$36,602,088.67
Portland General Electric Co	10.37	$34.94	$25,274,273.86
PacifiCorp (Oregon)	11.41	$38.42	$18,203,155.15
Snohomish County PUD No 1	11.95	$33.12	$9,789,707.21
PUD No 1 of Clark County - (WA)	13.61	$32.07	$5,459,180.51
PacifiCorp (Washington)	15.32	$51.58	$5,375,422.40
City of Seattle - (WA)	8.68	$12.79	$4,637,093.51
City of Tacoma - (WA)	12.56	$27.77	$4,197,921.42
Avista Corp	11.52	$38.78	$4,131,141.13
City of Eugene - (OR)	11.83	$32.14	$2,559,318.95
PUD No 1 of Cowlitz County	17.49	$52.96	$2,284,577.03
PUD No 1 of Benton County	16.44	$44.72	$1,817,519.40
PUD No 1 of Grays Harbor County	14.36	$46.20	$1,601,164.86
Central Lincoln People's Ut Dt	13.24	$44.57	$1,459,501.49
PUD No 1 of Clallam County	16.43	$51.85	$1,409,512.82
PUD No 1 of Lewis County	17.78	$53.75	$1,381,819.79
PUD No 3 of Mason County	14.20	$44.81	$1,344,425.39
Peninsula Light Company	15.54	$44.70	$1,217,177.68
PUD No 1 of Chelan County	21.14	$11.48	$413,966.53
Inland Power & Light Company	17.17	$54.62	$85,267.43

Figure 5

This estimate is approximate since the actual impact of BPA's wholesale rates is determined differently for each utility based on the percentage of dependence on BPA and the specific

[18] Bliven, Ray. *July 2013 Quarterly Business Review.* BPA, 30-July-2013. Web. 27 Sept. 2013. Page 43. <http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2013FinancialOverviewDocuments/2013 3rd Qtr Package.pdf>.

[19] Energy Information Administration. *2012 Utility Bundled Retail Sales- Residential.* Eia.gov. EIA, Nov. 2013. Web. 02 Dec. 2013. <www.eia.gov/electricity/sales_revenue_price/pdf/table6.pdf >.

types of BPA purchases. It is also incomplete, since it does not consider the savings from avoiding Energy Northwest's significant plant repairs in FY 2013.

The bottom line is that the savings to the region are significant enough that residential customers could have saved as much as $50 apiece if more economical wholesale power had been used to meet the region's needs.

3 THE HISTORICAL ROOTS OF NUCLEAR GENERATION IN THE PACIFIC NORTHWEST

During the 1950s, many political leaders and market observers began to worry that Pacific Northwest hydro-electric generation could not accommodate projected increases in demand for electricity. These fears were compounded by the 1957 release of the Army Corps of Engineers "308" Review Report which argued that all feasible hydroelectric dams would be built by 1975 and that, based on forecasts of rising electricity demand, these dams would be insufficient in satisfying the future electrical needs of the Pacific Northwest.[20] The fear of a future energy shortage resulted in rising support for thermal energy production, primarily in the form of nuclear power plants.

After 1957, several important figures and organizations began pushing for the addition of nuclear power as a means to guarantee sufficient electrical generation in the Pacific Northwest. One of the more influential organizations in this movement was the Washington Public Power Supply System (WPPSS), which was created in 1957 by Seattle City Light and sixteen other utilities.[21,22] WPPSS Managing Director Owen Hurd gained the support for nuclear power from BPA Administrator David Black, and by 1962, BPA authorized WPPSS to begin construction on the 800-megawatt Hanford Generating Project at Hanford, Washington.[23] The N-Reactor was a dual-purpose reactor whose primary mission was the production of plutonium for the US nuclear weapons arsenal.[24]

The success of the initial nuclear project encouraged expansion of the WPPSS nuclear program. Eventually, WPPSS planned a total of five additional nuclear stations – three of which were financed through an innovative mechanism known as "net billing."

[20] Harrison, John. *Hydrothermal Power Plan.* Northwest Power and Conservation Council, 19 Mar. 2012. Web. 12 Sept. 2013. <http://www.nwcouncil.org/history/hydrothermal>.
[21] Wilma, David. *Washington Public Power Supply System (WPPSS).* HistoryLink.org, 10 Jul. 2003. Web. 1 Apr. 2013. <http://www.historylink.org/index.cfm?DisplayPage=output.cfm&File_Id=5482>
[22] Miller, Gary K. *Energy Northwest: A History of the Washington Public Power Supply System.* Page 12.
[23] Harrison, *Hydrothermal Power Plan,* Page 2.
[24] Tollefson, Gene. *BPA and the Struggle for Power at Cost.* Portland, OR: Bonneville Power Administration, 1987. Print. Page 330.

3.1 NET BILLING

There is some mystery concerning the origin of the financing approach called "net billing." BPA's history cites expansion of transmission to rural electrical cooperatives in Oregon and Washington in the late 1940s:

> To build a line down into a remote part of Oregon, to Bonneville standards, was economically infeasible, so we had some sessions with REA [Rural Electrification Administration] and they designed a very low cost 69 kilovolt transmission line. Bonneville leased it and the REA loaned the money to the co-op. We net-billed it, meaning that their monthly power bill was reduced equivalent to the payments due for interest and amortization and O&M on the line. They got a net bill. [25]

As BPA began developing plans to expand thermal generation in the Pacific Northwest, it faced legal and financial obstacles. First, federal law prohibited Bonneville from building its own power plants. Proposals were introduced in Congress to revise this prohibition in 1951 and 1958, but were fiercely opposed by investor owned utilities in the Pacific Northwest because they feared competition from the federal government. [26,27] By 1968, Bernard Goldhammer, BPA's Director of Power Management, recommended that Bonneville adopt net billing to avoid these legal problems.[28]

In this iteration of net billing, BPA's customers would build a series of thermal plants, including three of the Washington Public Power Supply System's five nuclear plants, to accommodate increasing electricity demand.[29] The output of a net billed plant was supplied to BPA, then sold back to customers at BPA rates. The cost of the plants would be credited against the participants' electric bills at BPA.[30] BPA would then treat this deficit in billings as an expense to be funneled through their intricate accounting system to arrive at rates to customers. In exchange for receiving the output of the plants, BPA would build transmission lines and back the bonds issued by WPPSS to fund the construction costs of these new thermal plants.[31]

[25] Ibid. Page 281.
[26] Ibid. Page 290.
[27] Harrison, *Hydrothermal Power Plan,*
[28] Pope, Daniel. *Nuclear Implosions: The Rise and Fall of the Washington Public Power Supply System*. New York: Cambridge UP, 2008. Page 55.
[29] Preference customers consisted of the 104 publicly owned utilities who purchased shares in the thermal plants.
[30] US. Department of the Army. General Accounting Office. *Pacific Northwest Hydro-thermal Power Program, a Regional Approach to Meeting Electric Power Requirements*. Gao.gov. Web. 20 Sept. 2013. Page ii. <http://archive.gao.gov/f0202/094223.pdf>.
[31] Miller, Gary K, *Energy Northwest: A History of the Washington Public Power Supply System,* Page 155.

The common name for this mechanism is "sleeving." A sleeve is when one party to a transaction lacks standing to participate. Another entity steps in to provide the standing for a consideration. In this case, BPA lacked authority to build thermal plants and asked WPPSS to "sleeve" the transaction. The most common sleeve is familiar to any parent whose college age child wants to buy a car. The undergraduate lacks standing – has not yet established a credit history – so the parent buys the car. The student pays the interest and principal to the parent and receives use of the car.

Three constraints existed in the net billing procedure. First, net billing was limited to the total BPA bill to the member utility. Second, BPA was not allowed to increase its rates solely to have adequate revenues to acquire power through net billing. Third, thermal power acquired on a long-term basis was to be from the publicly-owned portions of thermal plants to meet the needs of preference customers and industries, as well as BPA's short-term commitments to the region's investor owned utilities.

There appeared to be benefits to this arrangement. WPPSS would enjoy a strong credit rating and low interest rates by having the bonds backed by BPA.[32] Preference customers gained access to the thermal energy, at what they thought would be low rates, without having to finance the construction of the plants on their own.[33]

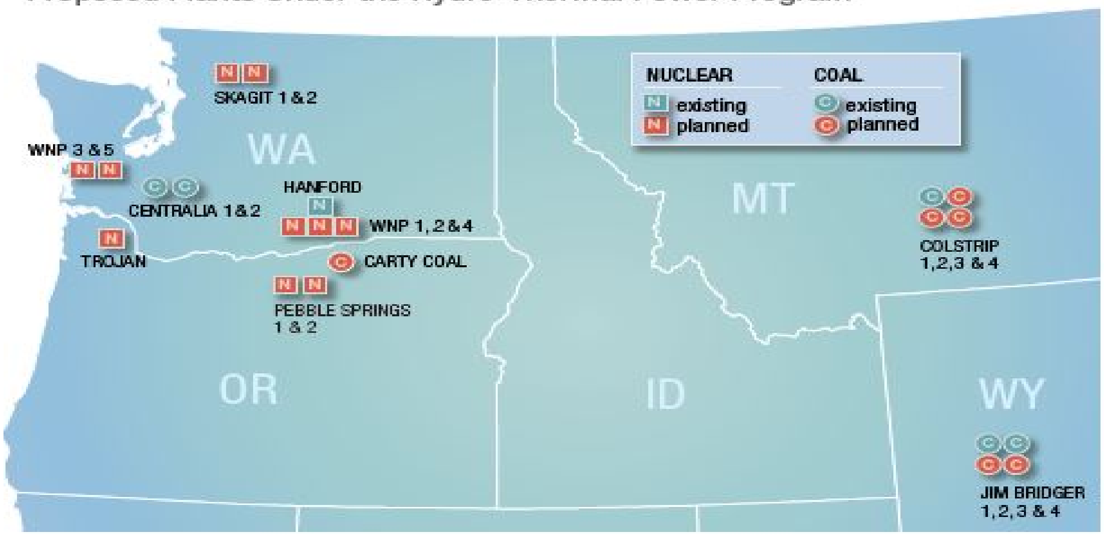
3.2 HYDRO-THERMAL POWER PLAN

With a legal framework established, BPA developed an ambitious plan to construct new hydroelectric dams and thermal power plants throughout the Pacific Northwest. By 1968, the Joint Power Planning Council – a group composed of Bonneville Power Administration, investor owned utilities, and publicly owned utilities – proposed a $15 billion construction program called the Hydro-Thermal Power Program (HTPP).[34,35]

This new plan initially called for 20 nuclear or coal plants. Phase I was comprised of three nuclear plants in Washington, the Trojan nuclear plant in Oregon, and two coal plants.[36] Phase II consisted of six nuclear and two coal units.

[32] Harrison, *Hydrothermal Power Plan.*
[33] Pope, *Nuclear Implosions,* Page 56-7.
[34] Tollefson, *BPA and the Struggle for Power at Cost,* Page 351.
[35] Ibid. Page 353.
[36] Ibid. Page 354.

Proposed Plants Under the Hydro-Thermal Power Program



In the early 1970s, Northwest utilities planned up to 10 nuclear plants in the Hydro-Thermal Power Program. Only two were finished: Portland General Electric's Trojan nuclear plant and the Washington Public Power Supply System's WNP-2, now known as the Columbia Generating Station. Many of the coal plants planned by regional utilities were completed and still operate. [37]

Figure 6

BPA was unable to acquire any of the output from Phase II through net billing due to regulatory and financial obstacles.[38, 39]

The Hydro-Thermal Plan faced massive cost overruns, construction delays, shifting public opinion, legal challenges, and changing regulations that prohibited future net billing arrangements. Of the ten nuclear plants envisaged in this ambitious program, only two – Trojan and CGS – were completed.

[37] Bonneville Power Administration. *Power of the River: The Continuing Legacy of the Bonneville Power Administration in the Pacific Northwest.* Government Printing Office, 2012. Bpa.gov. Web. 26 Sept. 2013. Page 7. <http://www.bpa.gov/news/pubs/GeneralPublications/Book-Power-of-the-River-BPA-History-Book.pdf>.
[38] Tollefson, *BPA and the Struggle for Power at Cost,* Page 353-4.
[39] Ibid. Page 360.

Plant	Phase	% Private Ownership	% Public Ownership	Fuel	MW	Commerical Operation	Original projected opening date	Sponsor	Complete?	Location
Trojan	1	70%	30%	N	1130	Dec-75		PGE	Yes	Rainier, OR
Centralia 1	1	72%	28%	C	700	Aug-71	Sep-71	PP&L & WWP	Yes	Centralia, WA
Centralia 2	1	72%	28%	C	700	Aug-71	Sep-72	PP&L & WWP	Yes	Centralia, WA
Colstrip 1	1	100%		C	330	Nov-75		TNPCo & PP&L	Yes	Colstrip, MT
Colstrip 2	1	100%		C	330	Aug-76		TNPCo & PP&L	Yes	Colstrip, MT
Jim Bridger 1	1	100%		C	500	Nov-74		PP&L & IPCo	Yes	Rock Springs, WY
Jim Bridger 2	1	100%		C	500	Dec-75	5/1/1976	PP&L & IPCo	Yes	Rock Springs, WY
Jim Bridger 3	1	100%		C	500	Sep-76		PP&L & IPCo	Yes	Rock Springs, WY
Pebble Springs 1	1	85%	15%	N	1260	N/A		PGE	No	Arlington, OR
WNP 1	1		100%	N	1250	N/A	4/1/1980	WPPSS	No	Hanford, WA
WNP 2	1		100%	N	1100	Mar-84	Apr-77	WPPSS	Yes	Hanford, WA
WNP 3	1	30%	70%	N	1240	N/A	1/1/1982	WPPSS	No	Satsop, WA
WNP 4	2		100%	N	1250	N/A		WPPSS	No	Hanford, WA
WNP 5	2	10%	90%	N	1240	N/A		WPPSS	No	Satsop, WA
Boardman (Carty)	2	90%	100%	C	530	Aug-80	Oct-78	PGE	Yes	Boardman, OR
Pebble Springs 2	2	85%	15%	N	1260	N/A		PGE	No	Arlington, OR
Colstrip 3	2	100%		C	700	1984		TNPCo & PP&L	Yes	Colstrip, MT
Colstrip 4	2	100%		C	700	1986		TNPCo & PP&L	Yes	Colstrip, MT
Jim Bridger 4	2	100%		C	500	Dec-79		PP&L & IPCo	Yes	Rock Springs, WY
Skagit 1	2	100%		N	1288	N/A		PSPL	No	Sedro-Woolley, WA
Skagit 2	2	100%		N	1288	N/A		PSPL	No	Sedro-Woolley, WA

Figure 7

The original plan projected that CGS would cost $394 million and be completed by 1977. Instead, CGS was not completed until 1984 with a cost overrun of $2 billion. [40,41,42,43]

3.3 COST OVERRUNS AND CONSTRUCTION DELAYS

In 1974, after 36 years selling power at one third of a cent per kilowatt-hour, Bonneville was forced to raise rates by 27.5%. This outraged consumers who had been told that nuclear power was inexpensive.[44] This was the first of many rate increases to follow.

Cost and delays for the HTPP nuclear plants continued to escalate. It became apparent to many in the Interior Department that Bonneville was not providing proper oversight to WPPSS. Bonneville responded to Interior Department pressure by commissioning a report which would recommend methods to reduce the cost and time needed to finish WPPSS' nuclear plants. On January 5, 1979, this report concluded that there was, in fact, a lack of proper administration within WPPSS. Specifically, it lacked "effective checks and

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[40] Ibid. Page 354.
[41] Ibid. Page 398.
[42] Black, Charlie. *Historical Context of Power Plan Provisions of the Northwest Power Act.* Memorandum to Power Committee. 30 July 2013. MS. Portland, OR.
[43] The cost overrun was much greater if calculated correctly. BPA paid $1.391 billion in cash towards completion; if this and interest on this had been accrued to the date of Commercial Operation, would have been more like $4 billion over. See Actual Cost of Power from WPPSS #2. See WNP2 through 2012 spreadsheet. –Jim Lazar. 20 Mar 2012.
[44] Ibid. Page 360.

balances."[45] In addition, the report predicted that the three phase one nuclear plants would increase in cost from $1.6 billion to $4 billion.[46]

The initial cost estimate for the five WPPSS nuclear plants was $5 billion in 1975. By 1981, actual construction costs had skyrocketed to $24 billion. These increases resulted in controversial BPA rate increases in 1981, 1982, and 1983.[47] By the time CGS finally entered service on September 22, 1984, the Project was seven years behind schedule and $2 billion over budget.[48] In 1981, WNP-4 and WNP-5 halted construction. Construction halted on WNP-1 in 1982 and WNP-3 in 1983. The courts held that the local utilities did not have to pay for the construction costs of WNP-4 and WNP-5, resulting in the largest municipal bond default, at that time, in US history. The costs of the unfinished WNP-1 and 70% of WNP-3 plant were net billed into Bonneville's costs and are still being paid for by Northwest ratepayers.[49]

3.4 CHANGING REGULATIONS AND LEGAL PROBLEMS

In 1972, the Treasury changed its regulations, effectively prohibiting future net billing activity.[50] Under the 1972 regulations, public agencies would no longer be considered tax exempt if more than 25 percent of the output of a generating unit was used by a private company. This effectively eliminated net billing as a financing mechanism for new plants since BPA's sales to Pacific Northwest industries and investor owned utilities were greater than 25%.

In 1975 the Sierra Club and Natural Resources Defense Council filed a lawsuit against Bonneville under the National Environmental Policy Act of 1969. The District Court ruling held that Bonneville must complete an environmental impact statement, detailing its thermal constructions and power sales in the region. This statement took five years to complete, as regional utilities became increasingly frustrated with the lack of progress.[51,52]

[45] Tollefson, *BPA and the Struggle for Power at Cost*, Page 368-9.
[46] Ibid. Page 369.
[47] Harrison, *Hydrothermal Power Plan*, Page 14.
[48] Tollefson, *BPA and the Struggle for Power at Cost*, 1987, Page 398.
[49] Ibid, Pages 392-7.
[50] Pope, *Nuclear Implosions*, Page 73.
[51] Tollefson, *BPA and the Struggle for Power at Cost*. Page 362.
[52] Pope, *Nuclear Implosions,* Page 87-8.

3.5 SHIFTING PUBLIC OPINION

Public opinion shifted away from the Hydro-Thermal Program as costs began to appear in customer rates. A growing environmental movement began to oppose nuclear energy.[53] Alternative scenarios to avoiding shortages were investigated in which a greater reliance on energy conservation was envisioned. In 1976, an influential study authorized by the Seattle City Council, called Energy 1990, made the case that consumers could conserve energy, reducing the need for new power plants. If prices increased this would then reduce demand, without the need for spending large amounts of additional money on new power plants.[54]

The Energy 1990 study, as well as changes to the net billing procedure, resulted in a Seattle City Council vote on July 12, 1976 to block Seattle's municipal utility from participating in WPPSS's fourth and fifth nuclear plants, marking an early instance of participating utilities losing confidence in the WPPSS project.[55,56]

3.6 CONSTRUCTION SCREECHES TO A HALT

By January 1982, deeply in debt and behind schedule, and not backstopped by Bonneville through net billing, the WPPSS board terminated construction on nuclear plants WNP-4 and WNP-5.[57] In March of that year, WPPSS completed a confidential termination cost study for the remaining plants under construction.[58] The report was kept confidential, but several weeks later, Peter Johnson, the administrator for the BPA, pressured the WPPSS board to slow or halt work on one of the net billed plants, recommending that WNP-1 should be halted for two to five years. In a meeting on April 29 1982, the Board voted to comply. The Board felt that it had no choice but to acquiesce to BPA's wishes, one member even going so far as to say they were a "virtual hostage" to BPA's pressure.[59]

The decision to mothball WNP-1 was motivated by both the state of the project and its ownership structure. CGS was over 75% complete, while projects WNP-1 and WNP-3 were 60% and 50% complete, respectively. Between these two less complete facilities, WNP-1 was entirely owned by the WPPSS, while only 70% of WNP-3 was owned by WPPSS. The

[53] Tollefson, *BPA and the Struggle for Power at Cost*, Page 360.
[54] Harrison, *Hydrothermal Power Plan,* Page 10.
[55] Wilma, David, *Washington Public Power Supply System (WPPSS),* Page 2.
[56] Tollefson, *BPA and the Struggle for Power at Cost*, Page 360.
[57] Myers, Elaine and Myers, David. *Lessons from WPPSS*. Governance. Autumn 1984. Web. 3 Dec. 2013. Page 28. <http://www.context.org/iclib/ic07/myers/>.
[58] United States Securities and Exchange Commission. Division of Enforcement. *Staff Report on the Investigation in the Matter of Transactions in Washington Public Power Supply System Securities.* 1998. Web. 20 Sept. 2013. Page 160. <http://3197d6d14b5f19f2f440-5e13d29c4c016cf96cbbfd197c579b45.r81.cf1.rackcdn.com/collection/papers/1980/1988_0901_SEC_WPPSS.pdf>.
[59] Pope, Daniel, *Nuclear Implosions*, Page 178-80.

remaining 30% of WNP-3 was owned by four investor-owned utilities. Each said that it would "vigorously resist any such efforts" to stop construction or terminate the project.[60]

Mothballing WNP-1 was not enough to save WNP-3. Wall Street was lukewarm on further bond sales, and this sentiment echoed in the May 17th downgrade of WPPSS bond rating by Moody's from AA to A1.[61] Standard & Poor's bond rating remained AA, and in January of 1983, another $981 million in bonds was planned to cover additional budget overruns. This latest round of bond sales was more than double the initial total cost projection for a single plant. Even this strategy would only have provided enough cash for the project to continue through June of that year. With funds running out, increasing fear on Wall Street of a potential default, and challenges to the legality of net billing coming from Oregon, WPPSS was considering other potential avenues for finding financing to finish the project.

In the spring of 1983, BPA was facing its own $350 million budget shortfall, which prompted Peter Johnson to write a letter to Carl Halvorson at WPPSS, stating that without revisions to the current financial plan, work would have to stop on WNP-3. The following day Standard & Poor's suspended bond ratings on the net billed projects based on the concern that WPPSS could not avoid filing Chapter IX bankruptcy.[62] As it turned out, this was a reasonable and prudent course of action, as WPPSS defaulted on WNP-4 and WNP-5 bonds in August of the same year. Out of options, the WPPSS Board voted to mothball WNP-3 for an indefinite period on May 27, 1983.[63]

WNP-1 and WNP-3 stayed in limbo for another decade. The continuing postponement finally reached a conclusion on May 13, 1994, when the WPPSS Board, in a 9-to-4, vote passed a resolution officially terminating WNP-1 and 3. The termination resolution contained an agreement to preserve the plants until January 13, 1995, or until a date mutually agreed upon by Bonneville and WPPSS. This delay allowed WPPSS to explore potential opportunities to repurpose the plants or to sell them to an outside investor.[64]

The Trojan nuclear plant, majority owned by Portland General Electric, came online in 1975 as part of Phase 1 and was closed in 1993 after concerns about the repair of failing steam generators and a major leak, resulting in increasing criticism from the NRC.[65, 66] Of the

[60] Ibid, Page 179.
[61] Ibid, Page 181.
[62] Chapter IX bankruptcies are those intended to protect public agencies from their creditors during reorganization.
[63] Ibid. Page 195.
[64] Walters, Dennis. *WPPSS Board Finally Agrees to Put Power Units 1 and 3 out of Their Misery*. *American Banker*. 16 Mar. 1994. Web. 12 Sept. 2013. <http://www.americanbanker.com/issues/159_16/-37619-1.html>.
[65] Koberstein, Paul. *Trojan: PGE's Nuclear Gamble*. Willamette Week. 9 Mar. 2005. Web. 12 Sept. 2013. <http://www.wweek.com/portland/article-4174-1975.html>.
[66] Harrison, *Hydrothermal Power Plan*.

original ten nuclear plants in Bonneville's Hydro-Thermal Plan, the only other one completed was, of course, CGS, which began commercial operation in December 1984.

The massive delays and cost overruns suffered by the Hydro-Thermal Plan occurred for several reasons. First, the net billing management structure did not reward timeliness or prudent economic practices since BPA was responsible for funding, while WPPSS was responsible for managing the construction of the five nuclear plants. This arrangement gave WPPSS very little incentive to contain costs. BPA's official history notes that:

> Hodel, in a newspaper interview, said their attitude was that "although BPA was in there, we were only in there as a convenience in their eyes. They clearly felt that the Supply System was their vehicle and we should not be over-injecting the federal government into their affairs".[67]

Another challenge was that many of the WPPSS managers and architects had little or no experience with the construction of large nuclear plants. Frequent adjustments to the plant design were made to account for mistakes made due to inexperience and poor coordination.[68]

3.7 BOND DEFAULTS AND LITIGATION

WPPSS defaulted on $2.25 billion worth of bonds issued by the BPA used to finance their nuclear construction.[69,70] In 1983, Time Magazine reported on the WPPSS blunder:

> D-Day finally arrived last week for the Washington Public Power Supply System. D for default. D for debacle. With its coffers almost empty, WPPSS or Whoops, as everyone now calls the agency, formally declared that it could not repay $2.25 billion in bonds used to finance partial construction of two now abandoned nuclear power plants in Washington State. It is by far the largest municipal bond default in U.S. history, and the damage is incalculable. [71,72,73]

[67] Tollefson, *BPA and the Struggle for Power at Cost,* page 360.
[68] Pope, Daniel, *Nuclear Implosions*, Chapter 4.
[69] Tollefson, *BPA and the Struggle for Power at Cost*, 1987, page 398.
[70] Doolittle, Theodore M. *Sec Says It Won`t Pursue WPPSS Action*. Chicago Tribune. 23 Sept. 1988. Web. 12 Sept. 2013. <http://articles.chicagotribune.com/1988-09-23/business/8802010563_1_sec-action-municipal-bond-sec-spokesman>.
[71] The acronym WPPSS - pronounced "whoops" - came to represent how *not* to run a public works project.
[72] Wilma, David. "Washington Public Power Supply System (WPPSS)." 10 July 2003.
[73] Alexander, Charles P. "*Whoops! A $2 Billion Blunder: Washington Public Power Supply System*. TIME 8 Aug. 1983: Web. 12 Aug. 2013.

The Securities and Exchange Commission eventually ruled in 1988 that no "enforcement action" would be pursued but that WPPSS had concealed information about increasing costs and delay.[74] Subsequently many bondholders filed suit against the utilities which comprised WPPSS. Most of these suits were settled out of court.[75]

3.8 RENAMING WPPSS AND CGS

In 1999, the Washington Public Power Supply System attempted to distance itself from its 'whoops' past and rebrand itself as a new and improved organization. WPPSS was renamed Energy Northwest.

> We are not fleeing from our past. Rather, we are running toward our future. Five years ago our journey almost ended prematurely. Plant 2, our sole operating nuclear generating station, was over-staffed, over-priced, and under-productive. The cost of power was too high, at 3.34 cents per kWh, to be competitive. The plant was unreliable, worker radiation exposure was too high, and our staff was wasting far too much time trying to keep the plant running, rather than operating it reliably. We were faced with a clear choice: cut costs and increase reliability, or terminate the plant.[76]

By 2000, Energy Northwest declared that the future had arrived and proceeded to change the name of Washington Nuclear Plant No. 2 (CGS), eliminating the word 'nuclear' from its name entirely:

> Heralding the region's renewed focus on energy was a name change for our commercial nuclear power plant. CGS is now the Columbia Generating Station – an appropriate name for a plant that is a valued complement to the region's hydroelectric resources.[77]

3.9 COMPETITION COMES TO THE PACIFIC NORTHWEST

In the 1980s, a number of Pacific Northwest utilities – both public and private – began trading wholesale electricity at market prices. This was a profound change in the industry. The result, the Western States Power Pool (WSPP), is the largest power market in the world, both geographically and in terms of total transactions. A brief history of the WSPP can be found on their web site:

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[74] Doolittle, Theodore M. *Sec Says It Won`t Pursue WPPSS Action*. Chicago Tribune.
[75] AP. *SEC to Take No Action in WPPSS Case : Says Enforcement Is Not Necessary Due to Suit in Bond Default*. Los Angeles Times 22 Sept. 1988: Web. 12 Sept. 2013. <http://articles.latimes.com/1988-09-22/news/mn-3505_1_wppss-bond>.
[76] Energy Northwest. *Energy Northwest 1999 Annual Report*, Page 4.
[77] Energy Northwest. *Energy Northwest 2000 Annual Report,* Page 5.

> The Western Systems Power Pool (WSPP) began as an agreement among a group of utilities in the western states. The agreement, which was filed with the Federal Energy Regulatory Commission by Pacific Gas and Electric Company on behalf of the group, established a multi-state bulk power marketing experiment. The agreement was meant to test whether broader pricing flexibility for coordination and transmission services would promote increased efficiency, competition, and coordination.
>
> The WSPP began operations in 1987 first as an experiment allowed by the Federal Energy Regulatory Commission (FERC) and then beginning in 1991 as a more permanent entity. Its initial purpose was to allow sales of power for short-term transactions to take place with a maximum of flexibility and minimum of regulatory filings and to test market efficiency and competition.[78]

Unlike California's deeply flawed experiments with competition, the WSPP is a completely transparent open outcry market. Prices are set by negotiation between market participants without the intervention of a central bureaucracy. Not surprisingly, the market has attracted many buyers and many sellers. Prices outside of the complex administered market in California have historically been significantly lower than California's.

A variety of "hubs" – agreed upon market locations – developed in the 1980s and have continued to today. The two major hubs in the Pacific Northwest are Mid-Columbia (Mid-C), with delivery at the dams at the bend of the Columbia River near the Tri-Cities, and the California Oregon Border (COB).

Mid-C has strong transmission links both east and west. It is also home to a number of thermal plants – primarily natural gas fueled – and is a preferred location for wind projects. In recent years the growth of generation in the area has often outpaced the ability of the transmission system to carry energy to loads along the I-5 corridor. When this happens, prices fall to zero and, in many cases, below zero.

The Market Test referenced above has been significantly affected by the market changes at Mid-C as generation alternatives have rapidly expanded and prices have fallen.

Any market participant – utilities, industries, marketers, and generators – can simply pick up the phone and make electricity transactions for hours, days, months, or years to come. Prices are reported all over the world in a variety of media, ranging from real time prices on the web to summaries of forward prices for electricity reported in industry newsletters.

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78 Western Systems Power Pool. *History of WSPP*. WSPP. Web. 03 Dec. 2013. <http://www.wspp.org/about_history.php>.

While the competitive power market at Mid-C is a boon for consumers, it also poses a severe challenge to aging power plants like CGS and Centralia which are high cost producers in an increasingly competitive industry.

3.10 REPEATING HISTORY

The history of net billing and the Hydro Thermal Program was generally one of failure. The complex financing structure bears much of the blame. The model of divided management – plant construction and operation at Energy Northwest and cost control and recovery at BPA – has proven to be a very poor approach to achieving reliability and cost effectiveness.

CGS's history after reaching commercial operation has been rocky. Reliability has been poor, although significantly improved over the last few years. Costs have continued to escalate, and evidence indicates that the operational costs at CGS will be higher than market for many years to come.

The cycle of deferred plant investment that caused major operating problems in the last decade began a new round this spring when replacement of CGS's turbines was eliminated from the current 10 Year plan by "reflowing" them to FY 2025.[79]

Each of these issues will be addressed in the following section.

4 REVIEW OF THE WASHINGTON NUCLEAR PROJECT NUMBER 2 (WNP-2 OR CGS)

The WPPSS-2 plant, also known as WNP-2 and, more recently, the Columbia Generating Station, is a geographically isolated nuclear plant located near Richland, Washington about 160 miles southeast of Seattle on the US Department of Energy's Hanford Nuclear Reservation. It is also in the center of renewable over-generation, far from load, and almost a thousand miles from the nearest commercial nuclear plant.

[79] Ridge, Brent. *Columbia Fiscal Year 2014 and Long-range Plan.* 16 June 2013. Page 10.

Figure 8

CGS's origin was highly controversial. The Washington Public Power Supply System had committed to an ambitious program of plant construction with five nuclear plants under construction at once. Although the "Supply System" had a good track record in previous projects, the sheer scale of their construction program soon overwhelmed their management systems.

The eventual collapse of the other Supply System projects occurred in an atmosphere of public controversy. The last two plants – WNP-4 and WNP-5 – occasioned a default on bonds massive in scale.

The plant has had a rocky operating history in its first two decades. Like most U.S. nuclear stations, operations have improved over time. It has, however, experienced unplanned shutdowns or "SCRAMS" such as during the last decade when replacement of aging equipment had been delayed sufficiently to lead to operating problems.

The site on the Hanford Nuclear Reservation has been leased from the U.S. Department of Energy for a term of 50 years commencing July 1, 1972, with options to extend the lease for two consecutive ten-year periods.[80]

CGS is a GE designed Boiling Water Reactor (BWR) with a Mark II containment structure and a Westinghouse turbine generator. The NRC has licensed the plant at 3,486 thermal megawatts (MWt). Energy Northwest reports its electric capacity at 1,170 (MWe), although this capacity rating has not been fully accepted at BPA.[81,82,83]

Replacement of aging equipment is increasing capital requirements over time.

Most United States nuclear stations are Pressurized Water Reactors (PWRs). The accident at Fukushima Dai-ichi has focused substantial attention on U.S. BWRs, and safety improvements are now underway.[84]

4.1 TECHNOLOGY AND OPERATIONS

Since the onset of problems at Fukushima, there is substantial concern for the safety of Boiling Water Reactors.

The Nuclear Regulatory Commission has ordered hardened vent retrofits for all BWR Mark I and Mark II containment structures due to their limited containment volume.[85] Proposed retrofits for CGS are discussed below in the section on the Fukushima Dai-ichi accident.

The Nuclear Regulatory Commission's monograph on Reactor Concepts for BWR units provides the following graphic and explanation:

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[80] Energy Facility Site Evaluation Council. *EFSEC Nuclear Projects*. Efsec.wa.gov, 14 Nov. 2012. Web. 22 Nov. 2013. <http://www.efsec.wa.gov/nuclearproj.shtml>.

[81] Nuclear Regulatory Commission. *Columbia Generating Station*. Nrc.gov. 24 Sept. 2013. Web. 26 Sept. 2013. <http://www.nrc.gov/info-finder/reactor/wash2.html>.

[82] Energy Northwest. *Columbia Generating Station*. Energy-northwest.com. Web. 17 Oct. 2013. <http://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/default.aspx>.

[83] Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study Technical Appendix, Volume 1: Energy Analysis*. Oct. 2012. Web. 17 Oct. 2013. <https://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf>. Page 172.

[84] Nuclear Regulatory Commission. *Japan Lessons Learned*. Nrc.gov. 10 Jan. 2013. Web. 18 Sept. 2013. < http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard.html >.

[85] Nuclear Regulatory Commission. *Issuance of Order To Modify Licenses With Regard To Reliable Hardened Containment Vents*. By Eric Leeds. 12 Mar. 2012. Web. 13 Sept. 2013. <http://pbadupws.nrc.gov/docs/ML1205/ML12054A694.pdf>.

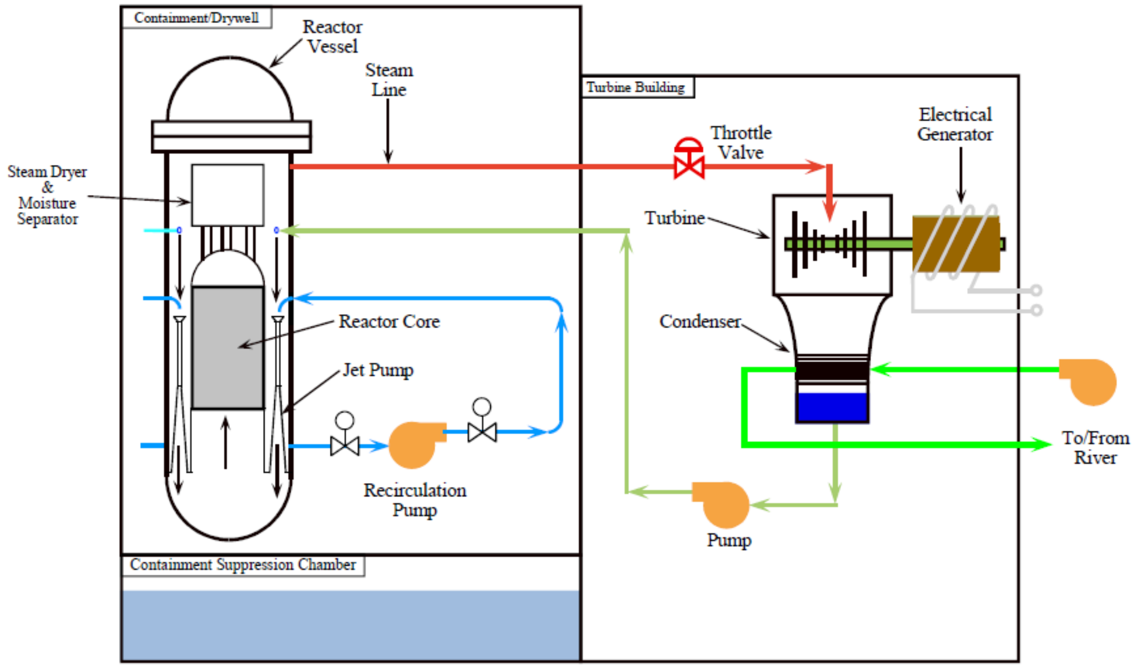

Figure 9

> Inside the boiling water reactor (BWR) vessel, a steam water mixture is produced when very pure water (reactor coolant) moves upward through the core absorbing heat. The major difference in the operation of a BWR from other nuclear systems is the steam void formation in the core. The steam-water mixture leaves the top of the core and enters the two stages of moisture separation, where water droplets are removed before the steam is allowed to enter the steam line. The steam line, in turn, directs the steam to the main turbine causing it to turn the turbine and the attached electrical generator. The unused steam is exhausted to the condenser where it is condensed into water. The resulting water is pumped out of the condenser with a series of pumps and back to the reactor vessel. The recirculation pumps and jet pumps allow the operator to vary coolant flow through the core and change reactor power.[86]

The NRC monograph also summarizes the Mark II containment structure:

> The Mark II primary containment consists of a steel dome head and either a post-tensioned concrete wall or reinforced concrete wall standing on a base mat of reinforced concrete. The inner surface of the containment is lined

[86] Nuclear Regulatory Commission. *Reactor Concepts Manual Boiled Water Reactor Systems*. Web. 9 Sept. 2013. <http://www.nrc.gov/reading-rm/basic-ref/teachers/03.pdf> page 3-2.

> with a steel plate that acts as a leak-tight membrane. The containment wall also serves as a support for the floor slabs of the reactor building (secondary containment) and the refueling pools.
>
> The Mark II design is an over-under configuration. The drywell, in the form of a frustum of a cone or a truncated cone, is located directly above the suppression pool. The suppression chamber is cylindrical and separated from the drywell by a reinforced concrete slab. The drywell is topped by an elliptical steel dome called a drywell head. The drywell inerted atmosphere is vented into the suppression chamber through a series of downcomer pipes penetrating and supported by the drywell floor.[87]

CGS has had a troubled operating history with poor operations in its early years. Its operations, like those of most US reactors, were also affected by a difficult annual refueling cycle which reduced output significantly. As discussed below, one continuing problem involved the condenser, which was constructed using a standard but less expensive industry technology (Admiralty Brass tubes) that has later proven to be problematic.

One way to evaluate the relative position of CGS in the industry is to compare the number of NRC "Events" against the rest of the industry. The NRC defines LERs as:

> Licensee Event Reports (LERs) - detailed reports submitted to NRC within 60 days of a plant abnormality in accordance with 10 CFR 50.73. These reports contain root causes and corrective actions undertaken by licensees. Some plant abnormalities that are not of a significant nature are reported only through LERs.[88]

The NRC's LER database is available to compare CGS against other U.S. nuclear stations.

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[87] Ibid. Pages 3-15.

[88] Nuclear Regulatory Commission. *Events Assessment.* Nrc.gov. 1 July 2013. Web. 26 Sept. 2013. <http://www.nrc.gov/about-nrc/regulatory/event-assess.html>.

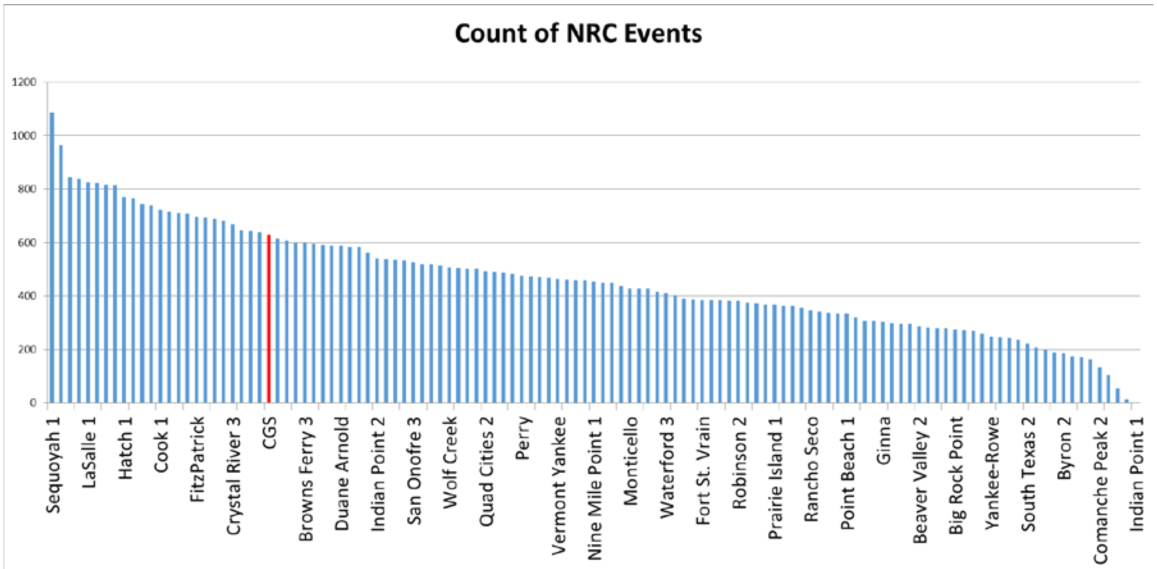

Figure 10

Overall, CGS has issued more than the average – 629 events – compared to the industry average of 460, but within one standard deviation of the mean. In the chart above, CGS has issued more reports than 80% of the plants in the NRC database.

Over time, the number of events reported to the NRC has fallen. The decrease has followed the industry pattern of declining plant problems over time:

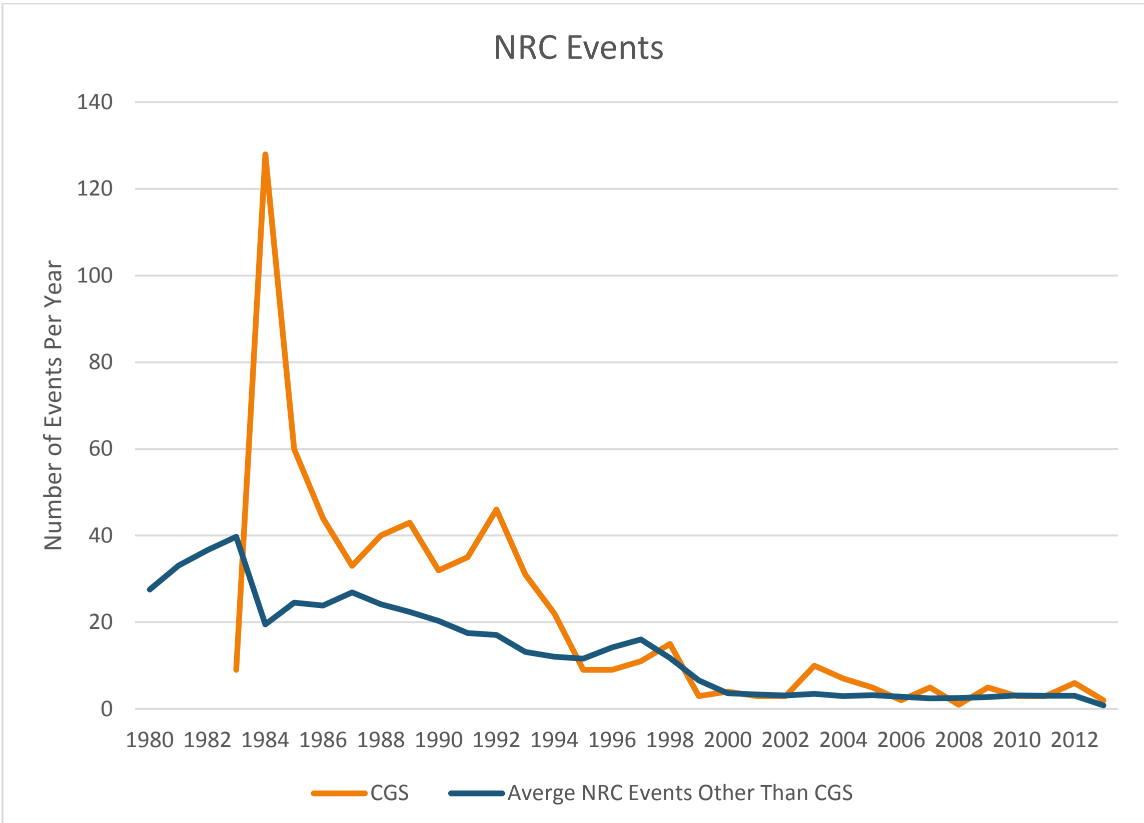

Figure 11

The analysis of NRC events roughly mirrors the evolution of generation at CGS:

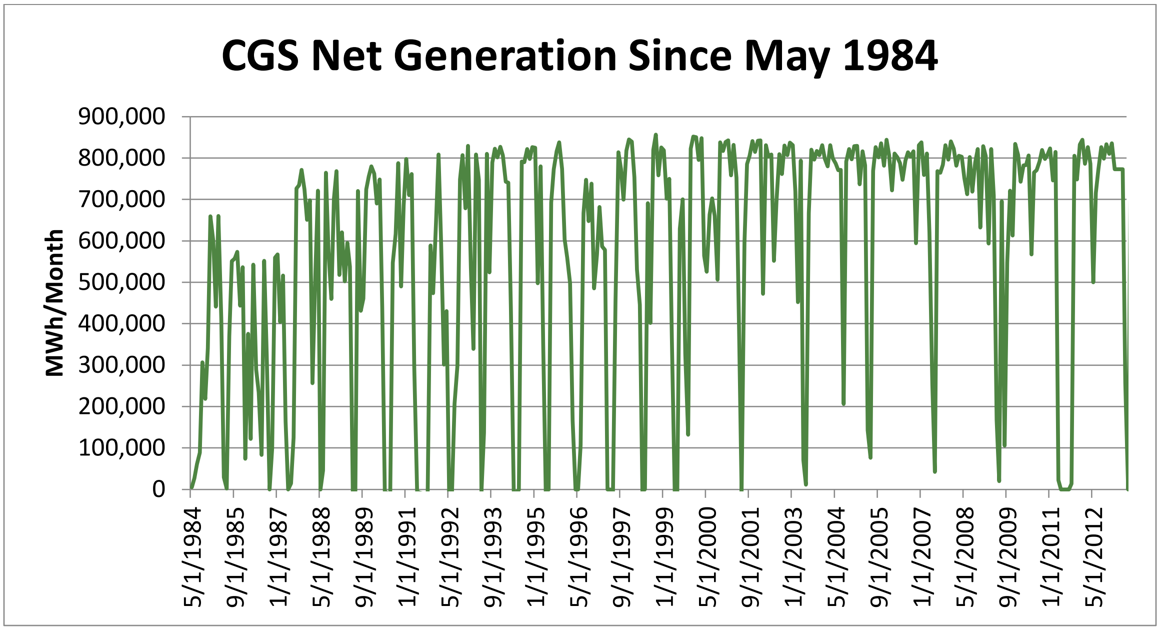

Figure 12

CGS operations in 2009 were especially poor. The plant was placed on the NRC watch list after a series of SCRAMS:

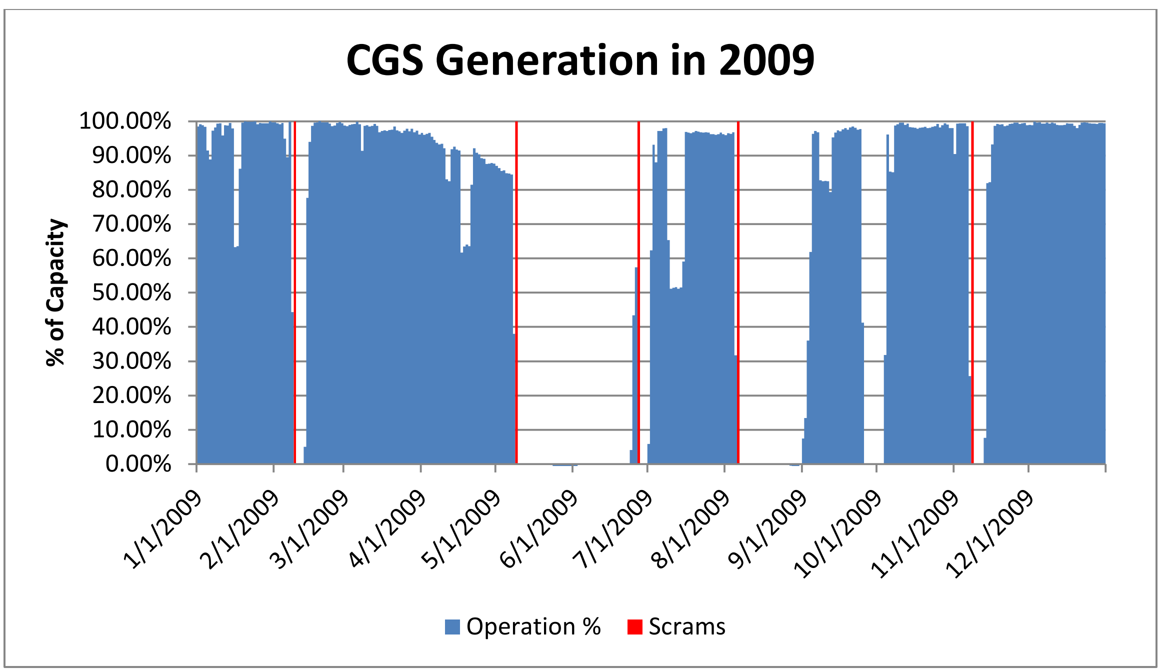

Figure 13

The lengthy outage in 2011 reflected the long delayed replacement of the condenser.

Energy Northwest provides a forecast of future generation in its ten year plans. These forecasts are of limited relevance since they do not drive either capital investment or O&M in later years. Bonneville could use these forecasts, but has chosen to use their own – considerably lower – values. The "bible" of BPA long term forecasts is the annual "White Book."[89] The Technical Appendix, Volume 1: Energy Analysis provides detailed monthly analysis for CGS from 2014 through 2023.[90]

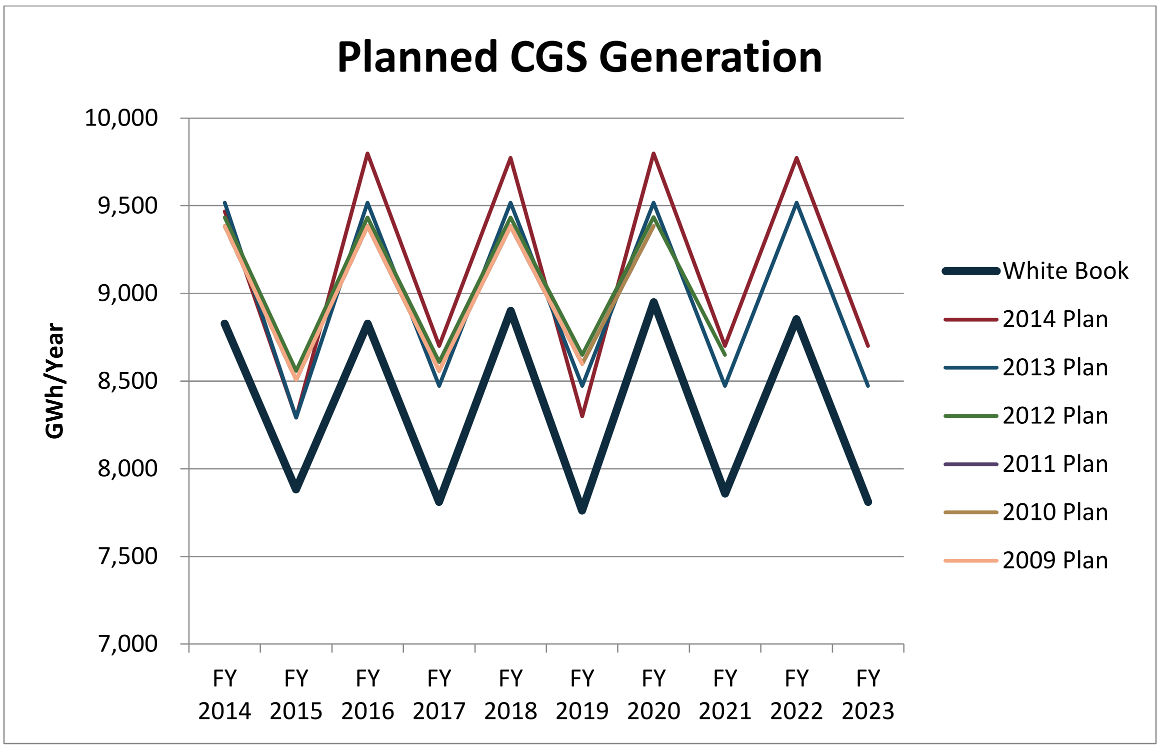

Figure 14

The values in the 2014 plan are 9.4% higher than those in the 2012 White Book.

A component of the difference is the assumed availability factor of CGS. The CGS Long Range Plan assumes 1% unplanned outages and 2% planned outages in addition to the refueling cycle outage.[91] Comparable data from the North American Electric Reliability

[89] Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study*. 8 Feb. 2013. Web. 13 Sept. 2013. <http://www.bpa.gov/power/pgp/whitebook/2012/WhiteBook2012_SummaryDocument_Final.pdf>.
[90] Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study. Technical Appendix. Volume 1: Energy Analysis*. 2012. Web. 13 Sept. 2013. <http://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf >.
[91] Energy Northwest, *Fiscal Year 2014 Columbia Generating Station Long Range Plan*. 16 May 2013.

Corporation's GADS data (EFOR) is 2.87%.[92,93] Data for nuclear plants internationally is even more pessimistic with forced outage rates for BWRs over 600 megawatts at 4.6%.[94]

BPA staff commented on the aggressive Energy Northwest forecasts last year:

> At this time we do not see strong enough performance from CGS [CGS], especially given the outages this year, to justify increasing CGS [CGS] generation in the T1SFCO [Tier 1 System Firm Critical Output]study above the current 1030-aMW PNCA planning number.[95]

Analysis of hourly data from October 1, 2009 through July 15, 2012, eliminating the refueling and repair outage from May through September 2011, indicates average output of only 7,459 MWh – considerably less than both the Bonneville White Book and Energy Northwest forecasts for CGS:

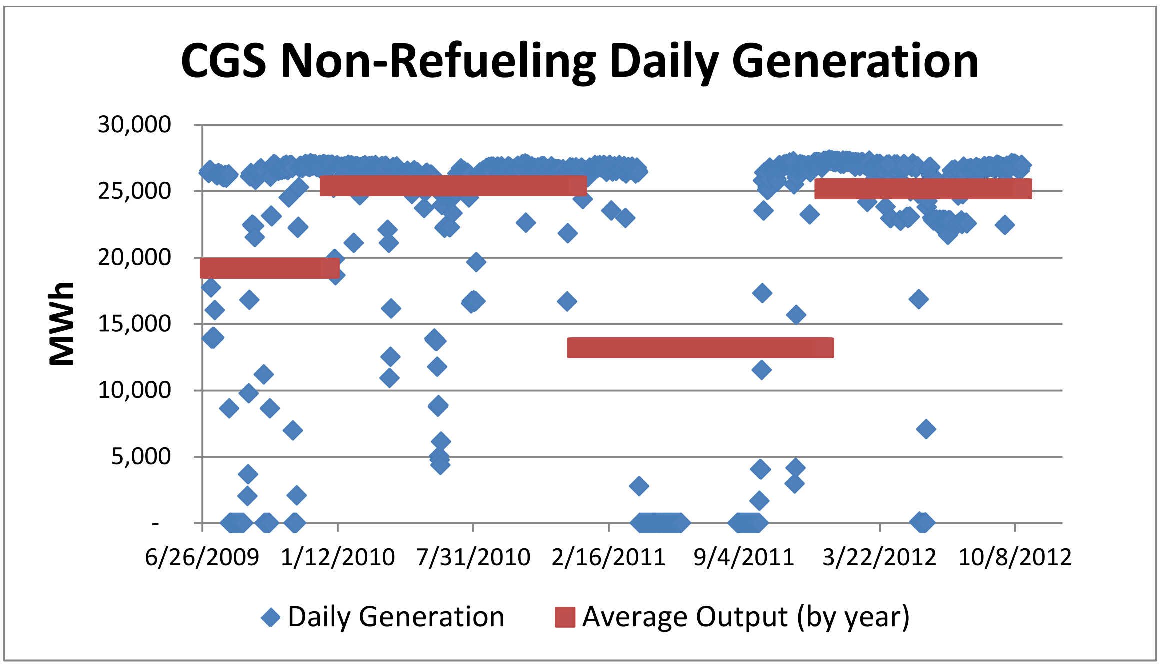

Figure 15

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[92] North American Electric Reliability Corporation. *2007-2011 Generating Unit Statistical Brochure - All Units Reporting*. North American Electric Reliability Corporation, 21 Aug. 2013. Web. 20 Sept. 2013. <http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx>.

[93] NERC, EFOR for BWR units over 1,000 megawatts.

[94] International Atomic Energy Agency. Vienna: IAEA, 2013. Reference Data Ser. No. 2. *Nuclear Power Reactors in the World*. Iaea.org, 2013. Web. 13 Sept. 2013. Page 57. <http://www-pub.iaea.org/MTCD/Publications/PDF/rds2-33_web.pdf>.

[95] Bonneville Power Administration. *Proc. of RHWM Process Workshop, Rates Hearing Room*. 9 Aug. 2012. Page 11.

Overall, the newest ten year plan expects average generation in future years to be approximately 19% higher than that experienced by the plant in recent years.[96]

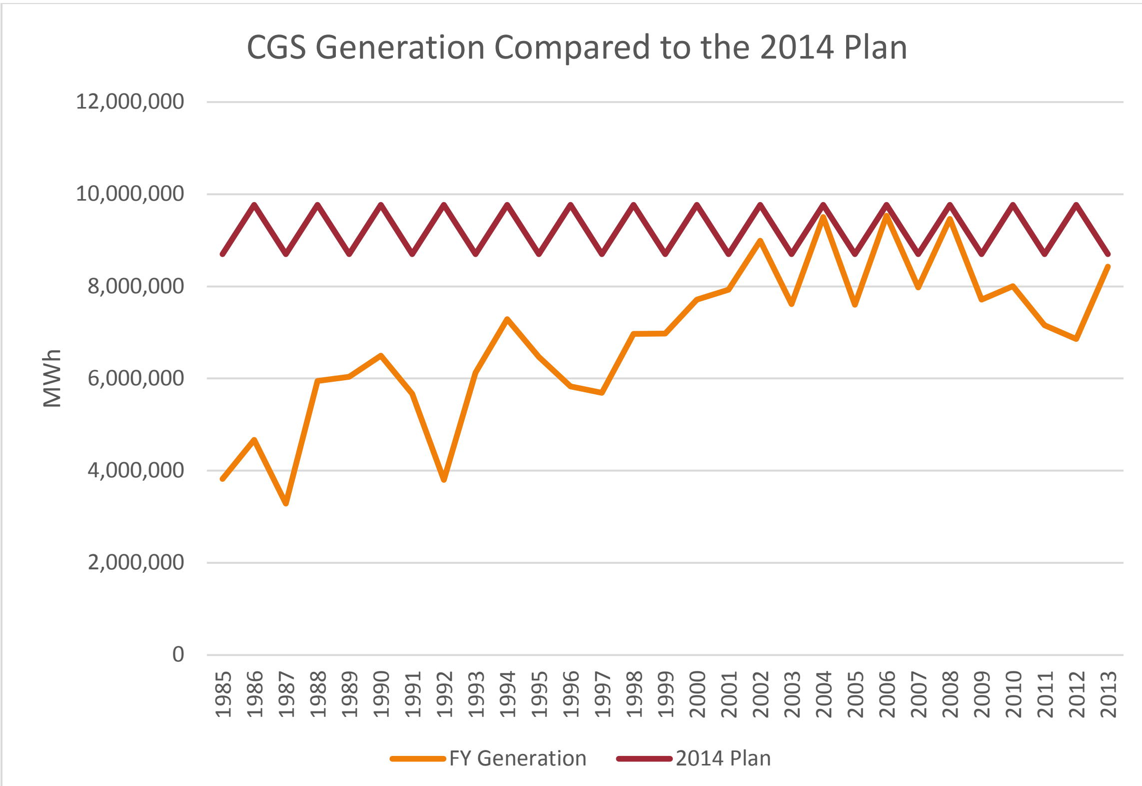


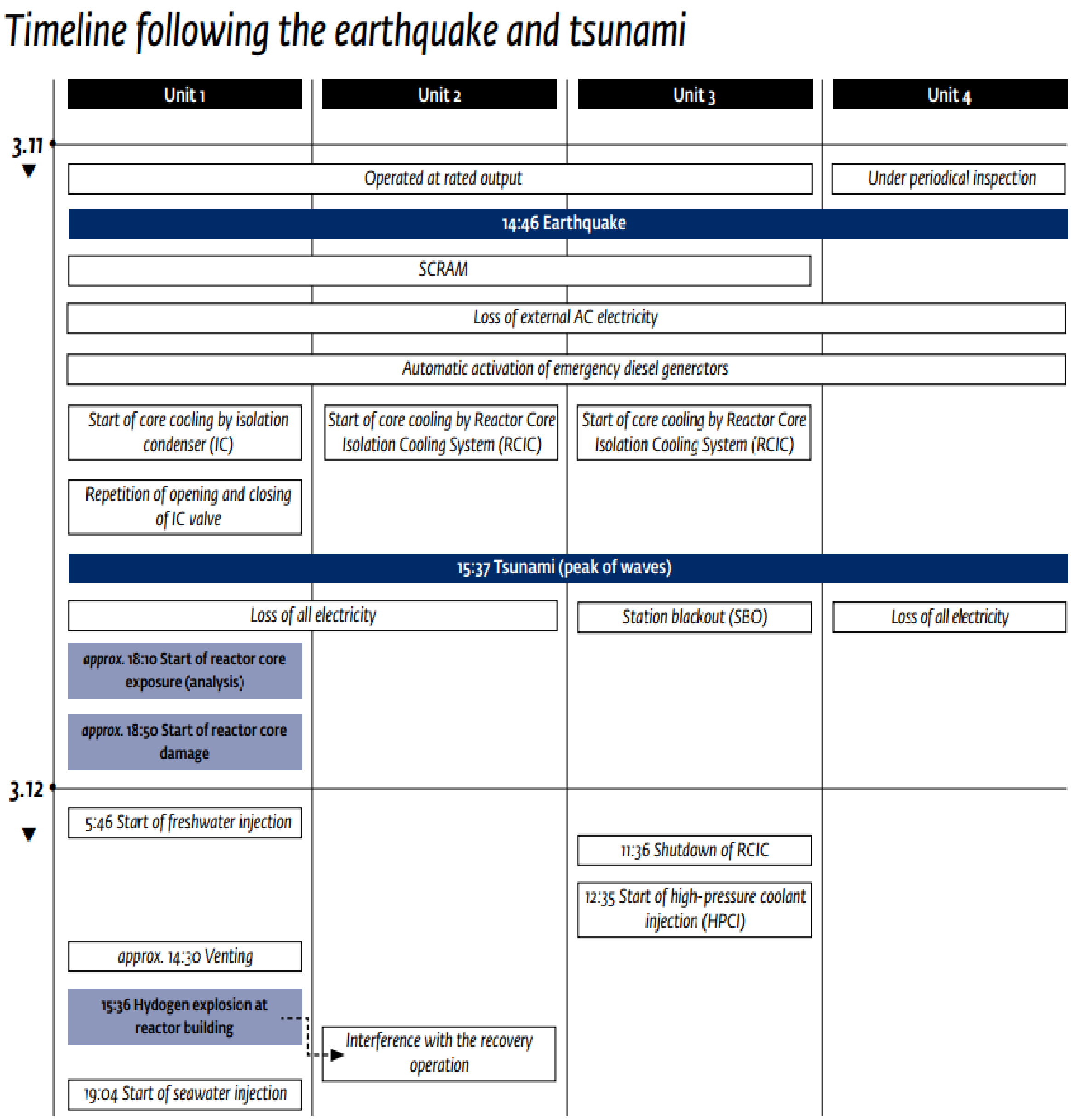
Figure 16

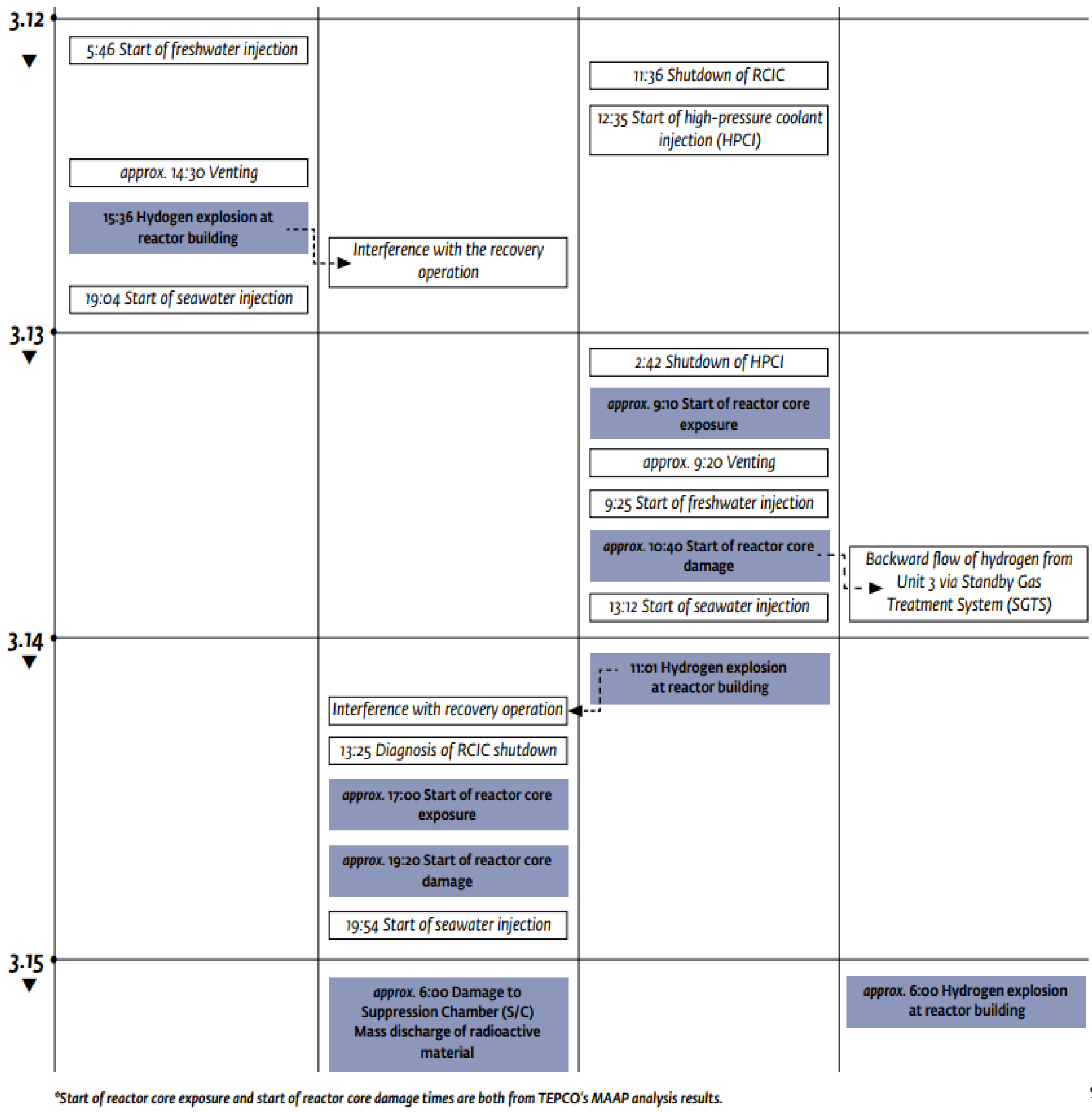
This seems optimistic for an aging plant, although not impossible.

4.1.1 Fukushima Dai-ichi Accident and Policy Responses

At 2.46 P.M, on March 11, 2011, an earthquake and, 49 minutes later, a tidal wave hit the Fukushima Dai-ichi nuclear station on the east coast of Japan.[97] The official report on the accident contains a very useful summary of the cascading failures at the plant:

[96] Energy Northwest. *Fiscal Year 2014 Columbia Generating Station Long Range Plan*. Page 2.
[97] The prefecture is "Fukushima" which is a governmental subdivision of Japan. The plant's name is "Fukushima Dai-ichi".


Timeline following the earthquake and tsunami
Unit 1
Unit 2
Unit 3
Unit 4
3.11
Operated at rated output
Under periodical inspection
14:46 Earthquake
SCRAM
Loss of external AC electricity
Automatic activation of emergency diesel generators
Start of core cooling by isolation condenser (IC)
Start of core cooling by Reactor Core Isolation Cooling System (RCIC)
Start of core cooling by Reactor Core Isolation Cooling System (RCIC)
Repetition of opening and closing of IC valve
15:37 Tsunami (peak of waves)
Loss of all electricity
Station blackout (SBO)
Loss of all electricity
approx. 18:10 Start of reactor core exposure (analysis)
approx. 18:50 Start of reactor core damage
3.12
5:46 Start of freshwater injection
11:36 Shutdown of RCIC
12:35 Start of high-pressure coolant injection (HPCI)
approx. 14:30 Venting
15:36 Hydrogen explosion at reactor building
Interference with the recovery operation
19:04 Start of seawater injection



[98]

Figure 17

While Fukushima Dai-ichi possessed multiple safeguards, the combination of the earthquake and tidal wave eliminated almost all backup electricity to the station. In the absence of electricity, cooling systems at the units were inoperable, and temperatures rose quickly inside the containment vessels. Hydrogen explosions occurred at Units 1, 3 and 4, and it is believed that the containment vessel was damaged in Unit 2.[99]

[98] National Diet of Japan. *The Official Report of The Fukushima Nuclear Accident Independent Investigation Commission.* 2012. Web. 13 Sept. 2013. Page 13. <http://www.nirs.org/fukushima/naiic_report.pdf>
[99] Ibid. Page 12-14.

In the U.S., much of the policy response to the accident has focused on venting gases before an explosion can occur.[100,101] The NRC's conclusions on venting overpressure in the reactor vessel have led to a change in hardened vent regulations for BWRs:

> Information available at the time of this report indicates that, during the days following the Fukushima Dai-ichi prolonged SBO event, primary containment (drywell) pressure in Units 1, 2, and 3 substantially exceeded the design pressure for the containments. The operators attempted to vent containment, but they were significantly challenged operating the wetwell (suppression pool) vents because of complications from the prolonged SBO. Units 1, 2, 3, and 4 use the Mark I containment design; however, because Mark II containment designs are only slightly larger in volume than Mark I containment designs, it can reasonably be concluded that a Mark II under similar circumstances would have suffered similar consequences.
>
> The process at Fukushima Dai-ichi Units 1, 2, 3, and 4 for venting the wetwell involves opening one ac-powered motor-operated valve to permit air pressure to open air-operated valves in the vent line, and then opening another ac-powered motor-operated valve in line with the air-operated valves, permitting containment pressure to impact a rupture disk designed to open if containment pressure is significantly above design pressure. If all of these actions are successful, the containment would vent directly to the plant stack, and containment integrity could be reestablished by closing either the in-line ac-powered motor-operated valve or the air-operated valves. In a prolonged SBO situation, these actions would not be possible from the control room because of the loss of ac power and the depletion of the batteries providing dc control power for the valves. It is unclear whether the operators were ever successful in venting the containment in Unit 1, 2, or 3. The operators' inability to vent the containments complicated their ability to cool the reactor core, challenged the containment function, and likely resulted in the leakage of hydrogen gas into the reactor building, precipitating significant explosions in Units 1, 3, and 4.[102]

CGS has budgeted over $60 million over the next six years to address NRC concerns. Since the problems at Fukushima continue to plague Japan, it is reasonable to expect further NRC instructions and future expenditures at a later date.

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[100] NRC, *Compliance with Order EA-12-050, Reliable Hardened Containment Vents*, August 29, 2012. Web. September 23, 2013. < http://pbadupws.nrc.gov/docs/ML1222/ML12229A475.pdf >.

[101] Nuclear Regulatory Commission. *Recommendations for Enhancing Reactor Safety in the 21st Century*. Nrc.gov. 12 July 2011. Web. 27 Sept. 2013. Pages 41-42.

[102] Nuclear Regulatory Commission. *Recommendations for Enhancing Reactor Safety in the 21st Century*. Nrc.gov. 12 July 2011. Web. 27 Sept. 2013. Pages 41-42. <http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf>.

	2013 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Item Description (Final FY 14 Updated 5/2/13 LP Years)	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24
Capital Costs											
PRC Capital Projects	$ 54,246	$ 55,420	$ 34,443	$ 53,095	$ 29,517	$ 48,982	$ 24,807	$ 27,625	$ 16,450	$ 27,318	$ 33,889
Moveable Capital & Downtown Capital Projects	$ 1,281	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507
Facilities Capital Projects	$ 500	$ 530	$ 535	$ 565	$ 565	$ 565	$ 565	$ 565	$ 565	$ 565	$ 565
Information Technology Capital Projects	$ 9,276	$ 8,235	$ 9,996	$ 8,288	$ 10,206	$ 9,286	$ 10,550	$ 9,887	$ 9,595	$ 9,701	$ 9,771
Admin / General (A&G)	$ 13,470	$ 14,920	$ 12,668	$ 16,229	$ 12,302	$ 14,379	$ 8,617	$ 9,294	$ 6,859	$ 9,043	$ 9,416
Capital Risk Reserve	$ 4,000	$ 8,000	$ 4,000	$ 6,000	$ 4,000	$ 6,000	$ 4,000	$ 4,110	$ 4,000	$ 4,000	$ 4,000
Fukushima Impacts	$ 18,080	$ 9,900	$ 16,710	$ 13,940							
Management Discretion-Special Projects**	$ -	$ 5,250	$ 30,400	$ 29,894	$ 28,546	$ 8,300	$ 3,100	$ 3,100	$ 3,100	$ 3,100	$ 5,801
Subtotal Capital Costs	**$ 100,853**	**$ 103,762**	**$ 110,259**	**$ 129,518**	**$ 86,643**	**$ 89,019**	**$ 53,146**	**$ 56,088**	**$ 42,076**	**$ 55,234**	**$ 64,949**
Escalation on Capital (3.5%)		**$ 3,632**	**$ 7,853**	**$ 14,081**	**$ 12,782**	**$ 16,708**	**$ 11,760**	**$ 14,848**	**$ 12,905**	**$ 19,619**	**$ 26,668**
Total Capital Costs (includes escalation)	**$ 100,853**	**$ 107,394**	**$ 118,112**	**$ 143,599**	**$ 99,425**	**$ 105,727**	**$ 64,906**	**$ 70,936**	**$ 54,981**	**$ 74,853**	**$ 91,617**

Key Assumption/Qualifications
Escalation Rate = 3.5% starting FY 15
R24 Refuel Duration 55 Days due to N1/N2 Replacement
* Recover 30 MWe from Instrument Fouling beginning FY 16
** Includes Fukushima Filter Requirement Risk
Generation assumes 1% unplanned / 2.5% planned loss in FY 14. Beyond FY 14 assumption is 1% unplanned / 2% planned loss.

103

Figure 18

In March of this year, the NRC announced that it was directing its staff to consider filters on the newly required hardened vents as part of their response to Fukushima and to develop a final rule on filtering by March 2017.[104] It should be noted that in the key assumptions reproduced above, CGS management has also included a provision reflecting the NRC's possible decision.

4.2 Governance and Ownership

Ownership generally means legal title with exclusive rights. By this definition, CGS's actual owners are difficult, if not impossible, to identify. The problem is sufficiently complex that the Energy Northwest board retained outside counsel to address the problem in 2007.[105] A very significant part of the report prepared by the outside counsel was a summary of the conflict between Energy Northwest and BPA concerning the replacement of the condenser at the nuclear plant.[106]

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103 Energy Northwest. *Fiscal Year 2014 Columbia Generating Station Long Range Plan. Energy-northwest.com.* 16 May 2013. Web. 27 Sept. 2013. Page 2.<http://www.energy-northwest.com/whoweare/finance/Documents/2014 Annual Budget Docs/Final 2014 Columbia Long Range Plan.pdf>.
104 Nuclear Regulatory Commission. Office of Public Affairs. *NRC to Enhance Post-Fukushima Vent Requirements, Broaden Analysis of Filtering Strategies.* Nrc.gov. 19 Mar. 2013. Web. 1 Oct. 2013. < http://pbadupws.nrc.gov/docs/ML1307/ML13078A415.pdf>.
105 Redman, Eric. *The BPA-Energy Northwest Relationship in the Context of Columbia Generating Station Operating and Capital Budgets, A Report to the Executive Board of Energy Northwest Pursuant to Executive Board Resolution No. 1462.* March 2007. Pdf.
106 Ibid. Appendix C.

The governance question was so serious at the time that the conflict may have actually endangered the safe operation of CGS. This conflict is addressed in the section below entitled "A Case Study: Management Failure in the Replacement of CGS/CGS's Steam Condenser."

The legal framework of CGS is comprised of only three documents: the net billing agreements, the project agreement, and the direct pay agreement.[107]

BPA proposed net billing for CGS at the start of the Hydro-Thermal Power Program. This allowed financing through Energy Northwest (then named WPPSS) and resulted in "participation" of ninety two utilities. Participant shares in CGS vary tremendously from Snohomish PUD at 15.363% to the City of Minidoka .005%. Twenty-one of the "participants" are also members of Energy Northwest, comprising 61.502% of the plant.[108] Six members of Energy Northwest are not participants in CGS – Asotin County PUD, Chelan County PUD, Grant County PUD, Jefferson County PUD, Pend Oreille County PUD, and Tacoma Public Utilities.

BPA's rates and operations are subject to review by the Public Power Council (PPC) and other public power organizations, which consist of different sets of public utilities than either the Energy Northwest members or the CGS participants, although there is a high degree of overlap in membership:

[107] Energy Northwest. *Minutes of the Energy Northwest Regular Executive Board April 24-25, 2013*. Web. 13 Sept. 2013.
[108] Energy Northwest. *Energy Northwest Columbia Generating Station Electric Revenue Bonds, Series 2012-D A~D Series 2012-E (Taxable)*. 15 Aug. 2012. Pdf. Appendix F.

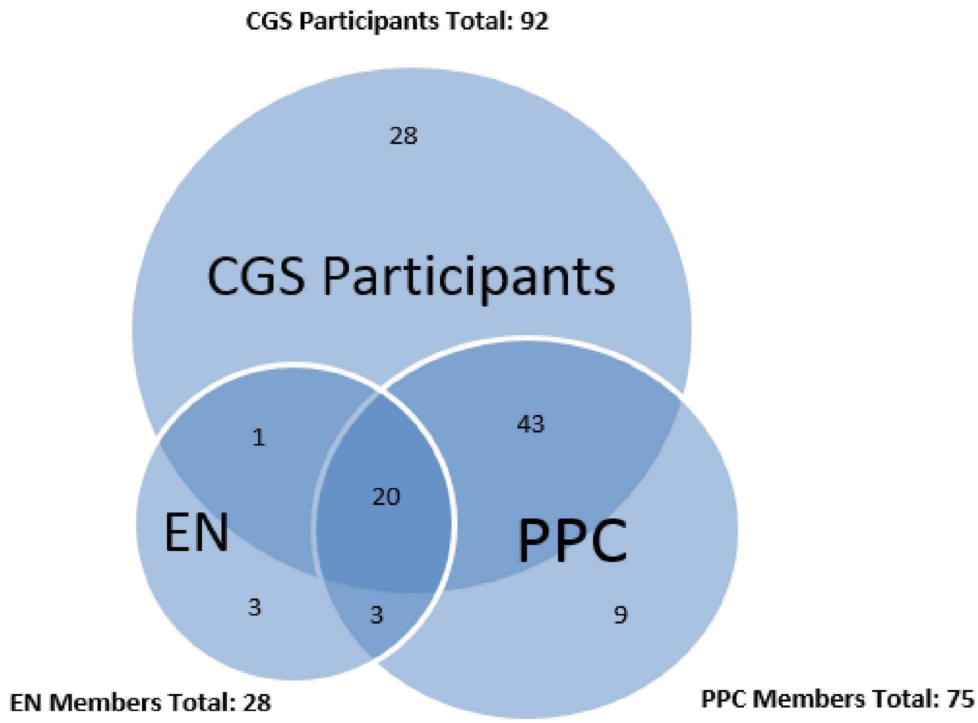

Figure 19

This arrangement is complicated enough that Energy Northwest's executive committee can approve plant investments that the Public Power Council can oppose – even though the same utilities are represented in both organizations. Information flows very poorly through this process. As the 2007 Redman Report amply demonstrates, this has had serious impacts on decisions.[109]

The 1971 Project Agreement provides a framework between the BPA and Energy Northwest. Under the Agreement, Bonneville Power Administration acquires the entire generation capability of CGS. Section 10 provides for arbitration by a "Project Consultant" in cases where BPA fails to approve activities at CGS.[110] The participants also have a say in the activities at CGS through the Participants' Review Board under the Net Billing

[109] Redman, Eric. *The BPA-Energy Northwest Relationship in the Context of Columbia Generating Station Operating and Capital Budgets. 2007.* Appendix C.
[110] Washington Public Power Supply System Nuclear Project No. 2
Agreement executed by the United States of America Department of the Interior
Acting by and through the Bonneville Power Administrator and Washington Public Power Supply System, January 4, 1971, Page 16.

Agreements.[111] Under Section 8 of the CGS Project Agreement, a disagreement between the project participants and Energy Northwest can also trigger arbitration by the Project Consultant.

The Project Agreement's arbitration procedure is unwieldy. Unlike most arbitration clauses, Section 10 of the Agreement specifies the selection of a single Project Consultant – agreed to by both parties – who then will decide conflicts based on "Prudent Utility Practice."[112] If the parties cannot agree on the Project Consultant, the selection process goes to the Chief Judge of the United States District Court for the Western District of Washington.[113]

The definition of Prudent Utility Practice is particularly significant:

> (k) "Prudent Utility Practice" at a particular time means any of the practices, methods, and acts engaged in or approved by a significant proportion of the electrical utility industry prior to such time, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice shall apply not only to functional parts of the Project but also to appropriate structures, landscaping, painting, signs, lighting, and other facilities and public relations programs reasonably designed to promote public enjoyment, understanding and acceptance of the Project and to other activities relating to the statutory responsibilities and duties of Supply System. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts. **In evaluating whether any act or proposal conforms to Prudent Utility Practice, the parties and any Project Consultant shall take into account the objective to integrate the entire Project Capability with the hydroelectric resources of the Federal Columbia River Power System and to achieve optimum utilization of the resources of that system taken as a whole, and to achieve efficient and economical operation of that system.**[114] (Emphasis supplied)

The last sentence opens the arbitration to consideration of CGS as part of the Bonneville Power Administration control area, but the reference to the Federal Columbia River Power System (FCRPS) would appear to limit the review to the federal hydro-electric projects.

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[111] Ibid. page 24.
[112] Ibid. Page 16.
[113] Ibid. Page 17.
[114] Ibid. Pages 5-6.

Since the major integration problem is with wind – not covered by the standard definition of FCRPS – it is unclear what issues the Project Consultant can address in his review.

Operation of CGS is entrusted to the Energy Northwest Executive Board which is partially elected from the members of Energy Northwest and partially nominated by the Governor of Washington.

If the process stopped there, it would be complex enough. Unfortunately, it is not so simple. BPA's rate and program reviews are subject to the advocacy of the Public Power Council, as well as other stakeholders in regional arenas. The PPC also represents a set of public agencies – seventy five currently – that represents a subset of both the participants and the members of Energy Northwest, as well as utilities that are neither CGS participants nor members of Energy Northwest.

This means that a large number of different public power groups – each slightly different in composition -- has a hand in the operations of the plant. It is not unfair to say that this is a committee designed by a committee.

Decision making in this context can be convoluted and contradictory. Friction between BPA and Energy Northwest has been a constant throughout the history of the project. A statement by the Energy Northwest general counsel indicates that these cumbersome arbitration procedures have never been initiated:

> Mr. Dutton stated the project consultant clause is included in both the PA [Participants Agreement] and the NBA [Net Billing Agreement] but is something that has never been used.[115]

A case in point is the complex budgetary dance that occurred this spring. Energy Northwest presented a Budget and 10 Year Plan to BPA. BPA brought the plan to the Public Power Council for review, where the plan was significantly changed – even though eleven members of Energy Northwest have seats on the Public Power Council's Executive Committee.

At the beginning of April, 2013, Energy Northwest provided its ten year capital plan to BPA.[116] This was summarized in a March 6, 2013 presentation by Jim Gaston of Energy Northwest.[117] The plan envisaged an 80% increase in capital expenditures from the estimated amount in the previously adopted ten year plan.[118] Overall, Energy Northwest forecasted

[115] Energy Northwest. *Minutes of the Energy Northwest Regular Executive Board.* 24-25 April, 2013. Page 5.
[116] Energy Northwest. *Fiscal Year 2014 Columbia Generating Station Long Range Plan.* 16 May 2013.
[117] Energy Northwest. *Long Range Plan Columbia Generating Station.* 6 Mar. 2013.
[118] Ibid. Page 28.

$572 million over the next decade. This value is extremely significant given provisions in the 1971 Project Agreement.[119]

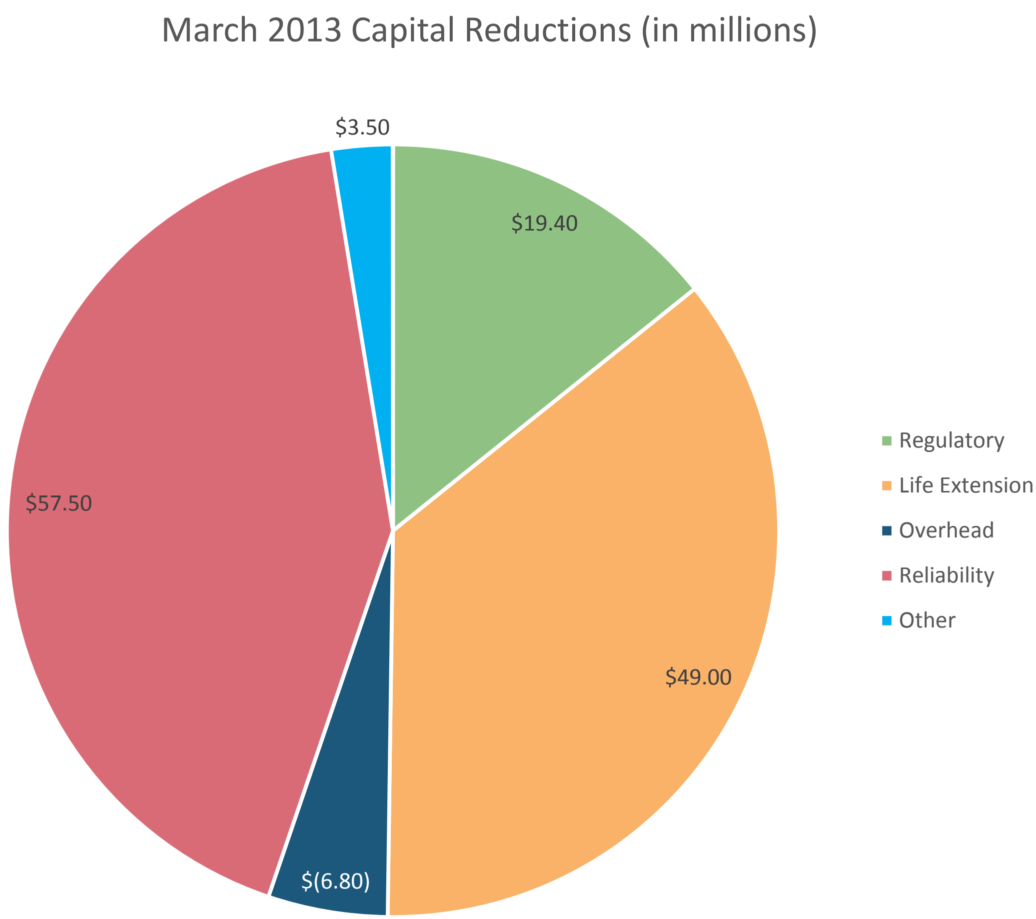

Figure 20

Capital items cut in the reliability area were Control Rod Drive Repair/Refurbishment, Pump & Motor Program, Reactor Feedwater Turbine Refurbishment, Normal Transformers Replacement, and Replacement of SOLA Type 39 Regulating Transformers. The "Overhead" section of the chart in blue represents $6.8 million in additions to the budget.

The life extension reductions were highly significant since these investments are required to continue operating the plant as existing equipment lives beyond its operating lifetime.[120]

[119] Energy Northwest. *Columbia Fiscal Year 2014 and Long-range Plan Update.* 24 Apr. 2013, Page 5.

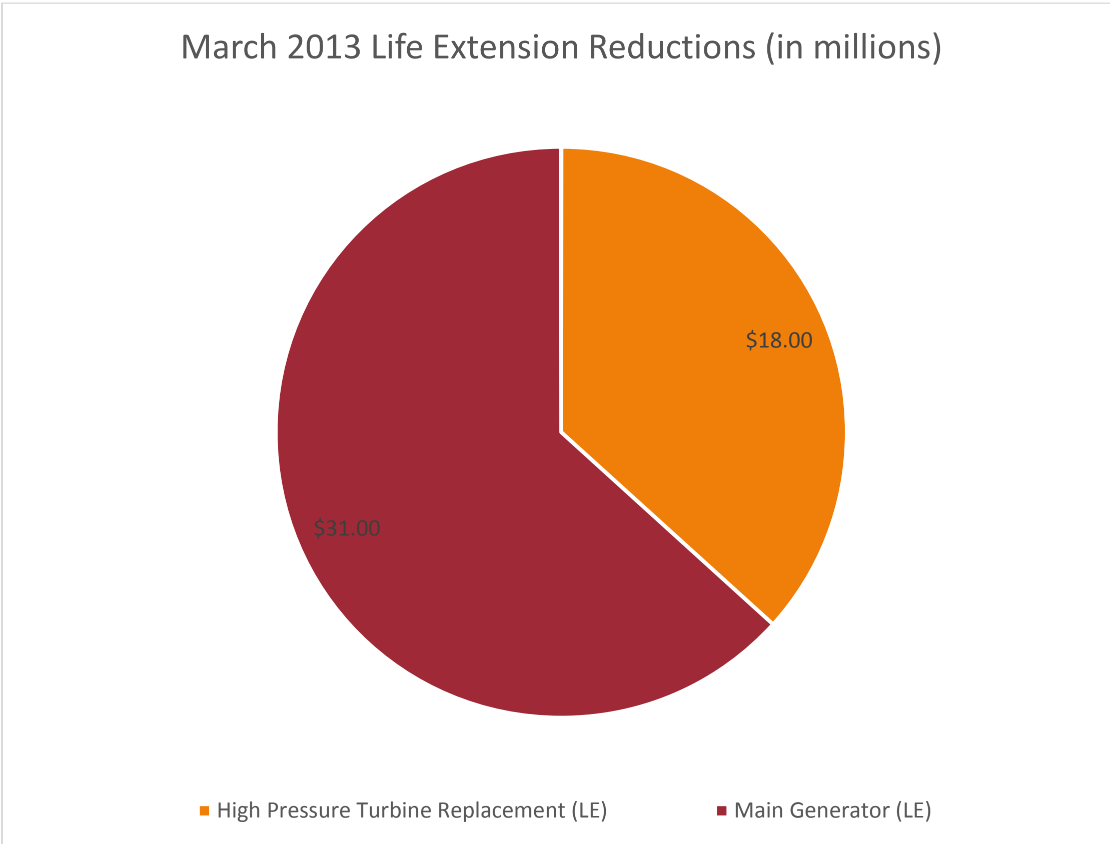

Figure 21

To a degree, the dramatic changes in just two weeks were more cosmetic than actual since ten year plans have often seen major changes. It is reasonable to expect that replacement of turbines and generators will actually occur during the next ten years, even if these replacements have been dropped from this official ten year plan.

The significance of this example is that control over CGS budgets – even critical components – is often implemented in a relatively informal manner. This underscores the general perception that "ownership" may be difficult to identify.

The Project Agreement addresses the termination of CGS in Section 15:

> 15. <u>End of the Project</u>. The Project shall terminate and Supply System shall cause the Project to be salvaged, discontinued, decommissioned, and

[120] Energy Northwest. *Fiscal Year 2014 Budget and Long-Range Plan*, 16 May 2013, Page 3.

> disposed of or sold in whole or in part to the highest bidder(s) or disposed of in such other manner as the parties may agree when
>
> (a) Supply System determines it is unable to construct, operate, or proceed as owner of the Project due to licensing, financing, or operating conditions or other causes which are beyond its control.
>
> (b) the parties determine the Project is not capable of producing energy consistent with Prudent Utility Practice or, if the parties disagree, the Project Consultant so determines, or
>
> (c) the Administrator directs end of Project as provided in section 11(a).
>
> The date of termination shall be the earliest of the date of the determination under subsections (a) or (b) above or the date of direction under subsection (c) above.[121]

Section 11(a) referenced in Section 15(c) states:

> 11. Replacements, Repair and Capital Additions.
>
> (a) After the Date of Commercial Operation Supply System shall submit its plan, including but not limited to a financing plan, and budget of expenditures to the Administrator for each replacement, repair, or betterment relating thereto, or capital addition required by governmental agencies, each as related to the Project and having a cost, as estimated by Supply System, in excess of $3,000,000; **provided, however, if the estimated cost of any such replacement, repair, or betterment relating thereto, or capital addition required by governmental agencies, exceeds 20 percent of the then depreciated value of the Project, the Administrator may direct that Supply System end the Project in accordance with section 15.** If the parties cannot agree upon such estimated costs, such estimated costs shall be referred to and determined by the Project Consultant. If the Administrator does not so direct within 90 days from the date such estimated cost has been so agreed upon or determined, Supply System shall proceed with its plan and budget of expenditures for such replacement, repair, or betterment relating thereto, or capital addition required by such governmental agency. Each such

[121] Department of the Interior. *Washington Public Power Supply System Nuclear Project No. 2 Agreement*. January 4, 1971, Page 22.

> plan and budget or updated or revised budget relating thereto shall be submitted to the Administrator and shall become effective at the time and in the manner provided in section 6(a).[122] (Emphasis supplied)

The 2012 Annual Report sets the Net Utility Plant value as $1,424 billion.[123] This would appear to be the best match with the definition of "Project" in the Project Agreement which references Exhibit A to the agreement.[124]

The plain reading of the contract would indicate that the Administrator could take the capital budget adopted by the Energy Northwest board, $472.5 million, and divide by Net Utility Plant, $1,424 million, to calculate a value, 33.2%, which is higher than the 20% limit set in 11(a).

That said, such an interpretation could be disputed. The language is hardly operational. We would normally view most of the items identified by the capital project list as "required" by the NRC – especially those listed as "Regulatory," "Life Extension," and "Reliability." Nevertheless, it is certainly arguable that "required" could instead be interpreted as narrowly as requiring a specific order. In that case, it is possible that only the Fukushima upgrades are "required."[125,126]

It should be noted that this provision would not appear to be at risk of arbitration by the Project Consultant, since Energy Northwest's own capital estimates would be accepted by the BPA administrator.

In conclusion, CGS's ownership is difficult to determine in the normal meaning of the term, with three different parties – Energy Northwest, BPA, and the CGS participants – able to force an unwieldy binding arbitration of everyday operating decisions. Operational decisions are usually made in a diffuse political fashion, or as the General Counsel of Energy Northwest noted earlier this year:

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122 Ibid. Page 19.

123 Energy Northwest. *2012 Energy Northwest Annual Report*. Page 42.

124 Department of the Interior. *Washington Public Power Supply System Nuclear Project No. 2 Agreement*. 4 Jan. 1971. Page 5.

125 The word "required" is not defined in the agreement, nor is it used in such a way to avoid conflicting interpretations. It should be noted that Section 7(a) clearly is meant to use the word in its normal context:

> 7. Operation and Maintenance of the Project.
>
> (a) Supply System shall operate and maintain the Project in accordance with Prudent Utility Practice and so as to meet the requirements of the Atomic Energy Commission, and other government agencies having jurisdiction.

126 Ibid. Page 13.

> The parties have not strictly followed the procedures set forth in Section 8 and have instead implemented the section differently than originally contemplated.[127]

It appears, however, that the BPA Administrator can force closure of CGS, given the level of capital budgets in years to come.

4.2.1 Cost and Operational Arrangements Outside of the 1971 Project Agreement

BPA and Energy Northwest have implemented a number of cost and operational agreements over the years. Two arrangements are of specific importance to our analysis – the 1998 Market Test cited above and the 1999 Memorandum of Agreement.

The remaining arrangements are largely innocuous. The 1980 Memorandum of Agreement simply set out the working procedures for the two parties that would normally be delineated in a more modern contract than the 1971 Project Agreement.[128] Likewise the 2001 Plan to Strengthen Working Relationship Related to the Contract Management of Columbia Generating Station is mainly concerned with liaison responsibilities.[129]

There is some evidence that additional arrangements – without the benefit of contracts – have also occurred over the years. Our review of the board minutes found references to payments that were apparently so informal that they were never written down – a very unusual arrangement where millions of dollars are concerned:

> Mr. Smith reported that the incentive fee program for Energy Northwest began a few years ago with a handshake agreement between Randy Hardy, former Bonneville Administrator, and J. V. Parish, Chief Executive Officer.[130]

The Market Test was the result of an extensive process that lasted from 1996 through 2000. In 1996, the four northwestern governors convened a Comprehensive Review of the Northwest Energy System under the auspices of the Northwest Power and Conservation Council.[131] The steering committee was comprised of:

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127 Energy Northwest. *Regular Executive Board Meeting*. 24-25 April 2013, Page 5.
128 Contract BE-MS79-80BP90148. *Memorandum of Understanding*. 25 Apr. 1980.
129 Energy Northwest and BPA. *Plan to Strengthen Working Relationship Related to the Contract Management of Columbia Generating Station*. 14 Nov. 2001.
130 Energy Northwest. *Report of the Operations and Construction Committee Meeting*. 15 Dec. 1999. Page 3.
131 The Northwest Power and Conservation Council was established in 1979 as a result of the passage of the Pacific Northwest Planning and Conservation Act. Its role is to provide a plan for the region and to protect the environment.

Chuck Collins	Chair
Al Alexanderson	PGE
Rick Applegate	Trout Unlimited
Ken Canon	Industrial Customers of the Northwest
Jim Davis	Douglas County Public Utility District
Bill Drummond	Western Montana Generation and Transmission
Jason Eisdorfer	Citizens Utility Board of Oregon
Bob Gannon	Montana Power Company
K.C. Golden	Consultant
Chuck Hedemark	Intermountain Gas Company
Sharon Nelson	WUTC
John Saven	Full Requirements Group
Rachel Shimshak	Renewable Northwest Project
Brett Wilcox	Northwest Aluminum
Gary Zarker	Seattle City Light.[132]

The Comprehensive Review comprised an extensive set of meetings throughout the region of the steering committee and a number of sub-committees. There were four primary sub-committees:

COMPETITION & CUSTOMER CHOICE WORKGROUP

Al Alexanderson, Portland General Electric
Ken Canon, Industrial Customers of Northwest Utilities
Terry Morlan, Manager, Demand Forecasting

CONSERVATION, RENEWABLES & PUBLIC PURPOSES WORKGROUP

Rachel Shimshak, Renewable Northwest Project
Jim Davis, Douglas County Public Utility District
Tom Bikman, Manager, Conservation Resources

FEDERAL POWER MARKETING WORKGROUP

John Saven, Northwest Requirement Utilities
Bob Gannon, Montana Power Company
Wally Gibson, Manager, System Analysis & Generation

TRANSMISSION WORKGROUP

[132] Regional Planning Council. *Organizational Binder of the Comprehensive Review*. Jan. 1996. Page 1.

K.C. Golden, Consultant
Bill Drummond, Western Montana Electric Generating & Transmission
Ken Corum, Staff Economist, Demand Forecasting[133]

A central issue in the Comprehensive Review was the debt associated with WNP-1, CGS, and WNP-3. A lesser, although critical issue, was the operating costs associated with CGS. The summary of the first Oregon public meeting notes:

> Bonneville: [Jeff] Shields suggests BPA should stay as a wholesaler. But, if BPA supports no public purposes it should vanish. Suggests direct access to federal power for residential customers rather than the exchange. [Steve] Weiss says the big issue is WPPSS debt. Suggests charging customers for part, cut costs, kill subsidies, close CGS and maybe hang the rest on transmission. [Fergus] Pilon suggests fish subsidy should be paid by taxpayers.[134]

The Northwest Conservation Act Coalition (NCAC) took a strong position on CGS. They issued a position paper early in the proceeding recommending closure if the plant could not match market rates.[135]

By July 11, 1996, the chair of the Federal Power Marketing Subgroup characterized this position as a "third model."[136]

The final report of the Comprehensive Review did not address CGS costs directly. Instead, the Comprehensive Review handed the responsibility of implementation to the Bonneville Cost Review Committee:

Charles Collins:	Former Chair of the Comprehensive Review
Robert J. Lane:	President of West One Bancorp (Retired)
Curtis Bostick:	Personal investment manager
Rosemary Mattick:	Vice President of Weyerhaeuser Company
William Vittitoe:	President of Washington Energy (Retired)
Sue Hickey:	BPA
Jim Curtis:	BPA
Todd Maddock:	Planning Council (Idaho)
John Etchart:	Planning Council (Montana)
Mike Kreidler:	Planning Council (Washington)

[133] Ibid. Pages 42-43.
[134] Comprehensive Review. *Oregon Comprehensive Review Meeting Summary, Public Meeting #1, February 12, 1996, Salem, Oregon.*
[135] Steven Weiss. *NCAC'S FEDERAL POWER MARKETING PROPOSAL FOR THE COMPREHENSIVE REVIEW*. 18 Apr. 1996, Page 1.
[136] Comprehensive Review. *Comprehensive Energy Review Steering Committee*. 11 July 1996.

Joyce Cohen: Planning Council (Oregon).[137]

When the Bonneville Cost Review released its final recommendations, CGS was directly addressed:

> Recommendation #7:
>
> WNP-2 [CGS]: Aggressive cost management, flexible response to market conditions
> Baseline:
>
> $172.5 million/year operating expenses (2002-06 annual average)
> - $127.8 million/yr. - O&M Expenses
> - $ 33.8 million/yr. - Nuclear Fuel
> - $ 4.8 million/yr. – Capital
> - $ 6.1 million/yr. - Other
>
> $153.8 million/yr. Revenues (878 aMW @ 20 mills/kWh)
>
> Recommended Improvement in Annual Net Operating Revenues:
> About $19 million/year (2002-06 annual average)
>
> Recommendation:
>
> The overriding intent of the Committee's recommendations regarding WNP-2 is to ensure, insofar as possible, that the operations of the plant not be insulated from the discipline of the marketplace. In order to accomplish this, the Management Committee recommends:
>
> 1. Subject WNP-2 to a market test biennially: annual revenues at market price recover annual operating costs, accounting for hydro firming value provided by the plant.
>
> 2. Implement a strategy that combines aggressive cost management with a flexible response to market conditions and unforeseen costs.
>
> 3. In Bonneville's subscription process and 1998 Rate Case, determine how to allocate the plant's costs in rates and market a portion of the FBS [Federal Base System] equivalent to the plant's expected output priced in a manner that ensures the recovery of the plant's operating costs and allows a lower price for the rest of the FBS, unless legal or other issues prevent doing so.

[137] Northwest Power Planning Council. *Congressional Update*. 22 Aug. 1997

> 4. To the extent that plant revenues exceed operating expenses, use a portion of the resulting net operating revenues first to build up the decommissioning fund to improve future financial flexibility.
>
> 5. Re-evaluate plant termination in the event that operating costs are projected to exceed revenues achievable at market prices by more than the termination costs (i.e., terminate if termination is more economical than continued operation, taking into consideration hydro-firming value of the plant and termination costs).[138]

Numerous parties, ranging from public power representatives to environmental groups, commented favorably on the recommendations in public hearings.[139,140] Important figures in Congress also commented. In his February 23, 1998 letter to the Cost Review Committee, Senator Ron Wyden commented:

> I support the recommendation to subject the Washington Nuclear Power Unit - 2 (WNP-2) to a market price test to see if the troubled nuclear plant can survive in the competitive marketplace. Bonneville needs to determine whether the high costs of WNP-2 would make the plant noncompetitive if it were marketed separately from the rest of the federal hydro system. This recommendation should give Bonneville the information to decide if WNP-2 can face the competition and to take the necessary steps to shut the plant down if it cannot.[141]

A complementary process, Issues '98, was conducted at Bonneville. The May 2000 final revenue requirement study summarizes the process clearly:

> In June 1998, BPA began a public involvement process entitled Issues '98. Issues '98 was designed to provide the region an overview and context for major policy issues surrounding BPA's future, including cost management. In addition to taking written comment, three public meetings were held within the region to provide an opportunity for the public to participate. BPA notified process participants that Issues '98 was their opportunity to comment on BPA's proposed implementation plan of the Cost Review recommendations. At the conclusion of the Issues '98 process, BPA completed and released the "Cost Review Implementation Plan." This

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[138] Cost Review of the Federal Columbia River Power System. *Management Committee Recommendations*. 10 Mar. 1998.
[139] Cost Review of the Federal Columbia River Power System. *Public Comment Meeting*. 9 Feb. 1998.
[140] Cost Review of the Federal Columbia River Power System. *Public Comment Meeting*. 11 Feb. 1998.
[141] Wyden, Ron. *Letter from U.S. Senator Wyden to Cost Review Management Committee*. 23 Feb. 1998. Page 2.

> document, published in October 1998, summarized the 13 recommendations of the Cost Review, the implementation plan, and relevant customer comments.[142]

BPA formally adopted the conclusions of the Comprehensive Review and the follow-on Cost Review in its 2002 multi-year rate case.[143]

The design of the Market Test was prospective, calculated on a biennial basis, and compared market prices with adjusted CGS costs.[144] The Market Test started by using California Power Exchange data which was replaced in 2000 by a weighted average of the Dow Jones indices at the California Oregon Border and Mid-Columbia.[145,146]

Various documents describe the costs to be included in the test slightly differently. The most complete example is contained in the draft Executive Board Report on Nuclear Programs in 2002:

Fiscal Year	Production Cost*	Power Worth
1999	$158,000,000	$174,000,000
2000	175,600,000	265,650,000
2001	199,500,000	1,597,246,000
2002	196,000,000	218,098,000
Total	**$729,100,000**	**$2,255,661,000**

*Does not include interest and decommissioning costs. Interest cost ranged from $132 million to $110 million during the four-year period. Decommission contributions for the same time period range from $5 million to $6 million. [147]

The production cost values in this table from Energy Northwest's 1999 Annual Report closely approximate removing depreciation and amortization from operating expenses and adding incremental capital:

---

142 Bonneville Power Administration. *2002 Final Power Rate Proposal Revenue Requirement Study*. May 2000, Page 16.

143 An extensive discussion of the Comprehensive Review and the Cost Review are contained in the 2002 BPA Rate case in both the Revenue Requirements Study (WP-02-FS-BPA-02, Appendix A) and the Record of Decision (WP-02-A-02, Section 5.3.1). The materials are too extensive to reproduce here, but the conclusion is that the 2002 BPA Rate Case correctly implemented the Comprehensive Review and Cost Review recommendations.

144 Management Committee. *Cost Review of the Federal Columbia River Power System Management Committee Recommendations*. 10 Mar. 1998. Page 27.

145 Energy Northwest. *Draft Executive Board Report on Nuclear Programs*. 20 Sep. 2002. Appendix A.

146 Energy Northwest. *Report of Energy Northwest Operations and Construction Committee Meeting*. 25 Apr. 2001. Page 2.

147 Energy Northwest. *Draft Executive Board Report on Nuclear Programs*. 20 Sep. 2002. Appendix A.

OPERATING EXPENSES	(thousands)
Nuclear fuel	23,978
Spent fuel disposal fee	6,613
Decommissioning	10,299
Depreciation and amortization	105,212
Power production and transmission	
Operations and maintenance	95,354
Other power supply expense	
Administrative and general	27,437
Generation tax	2,442
TOTAL OPERATING EXPENSES	271,335
DEDUCTIONS	
Nuclear fuel	-23,978
Depreciation and amortization	-105,212
Decommissioning	-10,299
ADDITIONS	
Incremental capital	25,279
MARKET TEST	157,125

[148]

This closely matches the $158 million in Energy Northwest's calculations. Overall, the costs to be included were marginal or avoidable. Accounting costs – like depreciation – were not included; nor were the sunk capital costs.

Curiously, in spite of BPA's endorsement of the Market Test and subsequent discussions of the Market Test in Energy Northwest materials, BPA actually undertook a completely different arrangement to manage CGS costs and operations in 1999. This was the November 17, 1999 Memorandum of Agreement between Bonneville Power Administration and Energy Northwest (1999 MOA).[149] There was little discussion of this arrangement in the region, and it went unmentioned in the press.

The basic theme of the 1999 MOA was to pay a bonus to Energy Northwest for costs and operations compared to a data set developed by an industry group, the Electric Utility Cost Group (EUCG). If CGS operations reached fifty percent or above of the performance of

[148] Energy Northwest. *1999 Annual Report*. Pages 17-18.
[149] *Contract No. 00GS-75016*. *Memorandum of Agreement Between Bonneville Power Administration and Energy Northwest*. 17 Nov. 1999.

EUCG plants, a bonus ranging up to $7 million per year would be payable for "the creation of new business opportunities which are intended to reduce Project 2's cost of power."[150]

Amounts paid to Energy Northwest under this agreement are unclear. The following payments reflect cursory references from a variety of sources:

FY 2000	$1,600,000[151]
FY 2001	$1,100,000
FY 2002	$5,900,000[152]
FY 2003	Cancelled[153]

Since the cancellation of the 1999 Memorandum of Agreement, BPA has conducted a number of additional external reviews. These reviews have been sponsored by BPA alone and have lacked the clout of the 1996-1999 reviews, which were sponsored by the congressional delegation and the Pacific Northwest governors.

4.2.2 A Case Study: Management Failure in the Replacement of CGS's Steam Condenser

In October 2009, after nearly a decade of disputes with Energy Northwest over the operation of the CGS nuclear plant, a BPA report stated:

> The plant has not met these projections. Continuing equipment problems and unexpected outages have combined to keep CGS in the bottom quartile of nuclear plants. CGS performance scores have declined substantially since the increased investments began and in August reached their lowest point in more than a decade. Although the plant's safety record is solid, CGS performance now ranks very close to the bottom of all nuclear plants. EN executives have agreed that CGS performance in recent years has not met their expectations and that operations must improve. There is a substantial need for evaluation, new commitment and direction at CGS.[154]

Throughout the last decade, Energy Northwest proposed, and then was dissuaded from, replacement of the steam condensers at CGS on many occasions. The long delayed replacement of this critical system posed both economic and safety issues for the Pacific

150 Ibid. Page 4.
151 Energy Northwest. *Summary Report or the Audit, Legal, and Finance Committee Meeting.* 24 Aug. 2000. Page 20.
152 Energy Northwest. *2002 Energy Northwest Annual Report.* 2002. Page 22.
153 Energy Northwest. *2003 Energy Northwest Annual Report.* 2003. Page 31.
154 Bonneville Power Administration. *EXECUTIVE SUMMARY: Columbia Generating Station Performance.* October 2009, Page 2.

Northwest. The delay was in large degree due to a management failure – an inability of Energy Northwest and BPA to communicate and expedite a major operating decision.

The situation was exacerbated by a lack of public transparency, as neither agency communicated with the public or their constituents about the steam condensers. In fact, our review of electronic news archives, industry newsletters, and other sources only revealed two articles in Clearing Up and the single workshop call by Washington State Senator Rockefeller in 2010. In marked contrast to the Pacific Northwest tradition of transparency, little recorded discussion took place outside of closed doors.

The problem with the steam condenser was described in detail in an Energy Northwest White Paper in 2006.[155]

The White Paper starts with a brief description of the equipment:

> The main condenser is a key component in the closed-loop system that transfers energy from the reactor to the turbine, in support of creating electricity. The condenser's primary function is to take steam exhaust from the main turbine and return it to a liquid form. The liquid, called condensate, is highly purified water. The condensate is preheated and pumped back to the reactor pressure vessel where energy in the form of heat is added to convert the condensate back into steam.[156]

[155] Oxenford, Scott. *Columbia Generating Station Main Condenser*. White Paper. VP Technical Services, June 1, 2006.
[156] Ibid. Page 1.

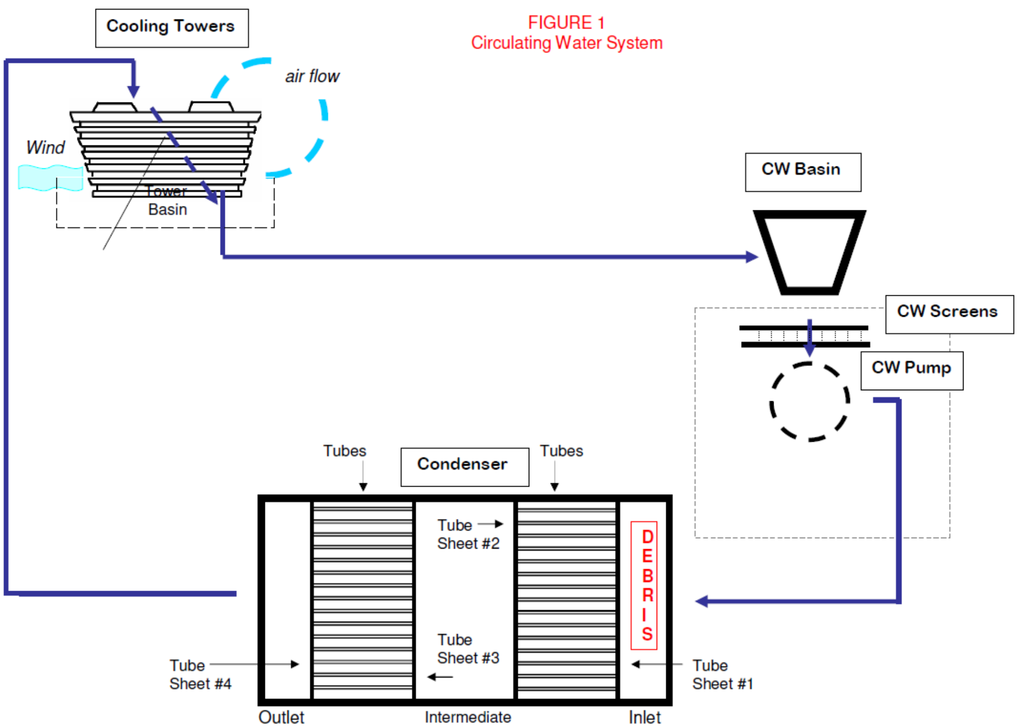

Figure 22

The root cause of the problem had been the use of "Admiralty Brass" for the condenser tubes:

> Admiralty Brass Material
>
> Columbia's condenser tubes, like many original condensers, were fabricated from admiralty brass. Admiralty brass is made primarily of copper, with the second largest constituent being nickel. It was selected for its excellent heat transfer efficiency and inexpensive cost relative to other suitable materials.
>
> Susceptibility to Mechanical Wear
>
> Admiralty brass is more susceptible to damage than the other contemporary condenser materials like stainless steel and titanium. For example, plastic tie wraps have caused leaks in our condenser when they became lodged at the inlet end of condenser tubes and, moved by water flow, wore holes in the soft metal tubes. Titanium is approximately 6.5 times harder and stainless steel is about 3 times harder, making them less susceptible to debris induced damage.

> Likewise, steam leakage from exhaust lines into the condenser has been known to wear through tubes, leading to rapid increases in condenser leakage and prompt shutdown of the plant to protect primary system chemistry.
>
> Copper and Fuel
>
> Even slow wear of the soft condenser tube material adds copper to the condensate. Columbia demineralizers are not designed for mechanical filtration, the best method for removal of copper. Based on that and the lack of deep bed demineralizers, Columbia is classified as a 'high copper plant'.[157]

The purpose of the white paper and its later addendum was to put forward the case for replacement of the condenser. The major concerns were:

1. Condenser leaks require a reduction in output to 60% during repair;
2. Violations of water chemistry limits may require additional output reductions or shutdowns; and,
3. Copper in the water may degrade fuel elements.

The addendum attempted to estimate the monetary impacts over a single twelve month period. The estimate for June 2005 through May 2006 was:

Tube plugging:	\$1,400,000[158]
Replacement power:	\$4,000,000[159]
Chemical decontamination:	\$1,700,000[160]

The basic facts of the Energy Northwest White Paper largely recapitulate materials previously provided to the Nuclear Regulatory Commission staff in 2002.[161]

BPA and Energy Northwest files indicate that the replacement of the condenser was proposed repeatedly in the last decade.[162]

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157 Ibid. Page 3.
158 Oxenford, Scott. *Columbia Generating Station Main Condenser, Addendum 1*. VP Technical Services, June 1, 2006 Page 2.
159 Ibid. Page 2.
160 Ibid. Page 4.
161 Humphreys, Mike, Rx/Fuels Engineering Manager. *Columbia Generating Station Fuel Corrosion Investigation Status Report Presentation to NRC Region IV Personnel*. 24 May 2002.
162 See, for example:

> *Draft Energy Northwest Executive Board White Paper*. 20 Sep. 2002. Page 3.
> *Energy Northwest Executive Board Review of Nuclear Program*. 23 Jan. 2003. Page 11.

Bonneville's response was tepid at best. In the Closeout Report of the 2006 Program Review, the text read:

> The forecast by EN for the FY07-FY09 rate period includes place-holder funding of $35 million to replace the main condenser at CGS. EN acknowledged that the plan, design, and cost estimate for the condenser replacement has not yet been fully developed. BPA is not currently comfortable with justification for this project yet and will continue to work with EN to explore the need for condenser replacement and reasonable alternatives, and we will make a final determination in the final PFR II report regarding the inclusion of replacement condenser costs in the power final rate proposal. BPA customers expressed interest in receiving a follow-up report on EN's plan in regard to condenser replacement, and EN and BPA intend to provide this follow up.[163]

As a simple engineering issue, this conclusion is somewhat surprising. Other Boiling Water Reactors with similar Admiralty Brass condensers had already implemented solutions or planned to do so in the future.[164]

The relationship between Energy Northwest and BPA had declined to such a degree that in the following year, Energy Northwest's executive board commissioned outside counsel for solutions:

Bonneville Power Administration Power Business Line FY 2002 Generation Audited Accumulated Net Revenues for Financial-Based Cost Recovery Adjustment Clause (FB CRAC)," Feb. 2003. Page 2.
BPA Rate Case Announcement Letter. 7 Feb. 2003. Page 2.
Power Function Review Columbia Generating Station/Energy Northwest Technical Workshop. 15 Mar. 2005. Page 5.
Clearing Up, 6 Feb. 2006. Page 15.
Columbia Generating Station Long Range Plan. 10 Feb. 10, 2006. Page 4.
The BPA-Energy Northwest Relationship in the Context of Columbia Generating Station Operating and Capital Budgets. 2007. Page 1.

163 Bonneville Power Administration, *Bonneville Power Administration Date Power Function Review II Draft Closeout Report.* April 4, 2006, Page 6.

164 W. Scott Oxenford, VP Technical Services. *Columbia Generating Station Main Condenser, Addendum 1.* June 2006, Page 6.

> EXECUTIVE BOARD RESOLUTION NO. 1462
>
> A RESOLUTION AUTHORIZING A REVIEW OF THE LEGAL AND OPERATING RELATIONSHIPS OF ENERGY NORTHWEST AND THE BONNEVILLE POWER ADMINISTRATION
>
> IT IS HEREBY RESOLVED that the Executive Board authorizes the engagement of independent counsel to review on a limited basis all contractual agreements, operative documents, regulatory requirements and enabling legislation with regard to the respective rights and obligations of the Bonneville Power Administration and Energy Northwest in authorizing Columbia Generating Station operating and capital budgets. This review will not only identify the respective rights and obligations of the parties, but will also identify apparent conflicts. **Said independent counsel will be requested to focus on the events and actions of the parties over the past several years concerning proposed capital spending for a new main condenser as a case in point**.[165] (Emphasis supplied)

Appendix C of the independent counsel report directly addresses the deteriorating relationship between the two agencies. In sum, the two agencies drifted into conflict over the condenser through a series of misunderstandings which blocked the flow of information and, eventually, resulted in a perception that a "deal" between the agencies had been breached.[166]

Delays in addressing the condenser issue (as well as other repairs) created conditions that threatened plant reliability. Energy Northwest intermittently chooses to release its ratings from the Institute of Nuclear Power Operations (INPO), a nonprofit industry-funded organization which inspects US nuclear plants every two years.[167,168]

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165 Eric Redman, *The BPA-Energy Northwest Relationship in the Context of Columbia Generating Station Operating and Capital Budgets.* March 2007, Appendix A.
166 Ibid. Appendix C, Page 5.
167 See, for example, BPA Power Business Line Sounding Board Meeting, February 11, 2004, Page 3.
168 Cary, Annette. *Energy Northwest Nuclear Plant Scores Low in Reliability.* Tri-City Herald. 2 Nov. 2010. <http://www.tri-cityherald.com/2010/11/02/1233869/energy-northwest-nuclear-plant.html>.

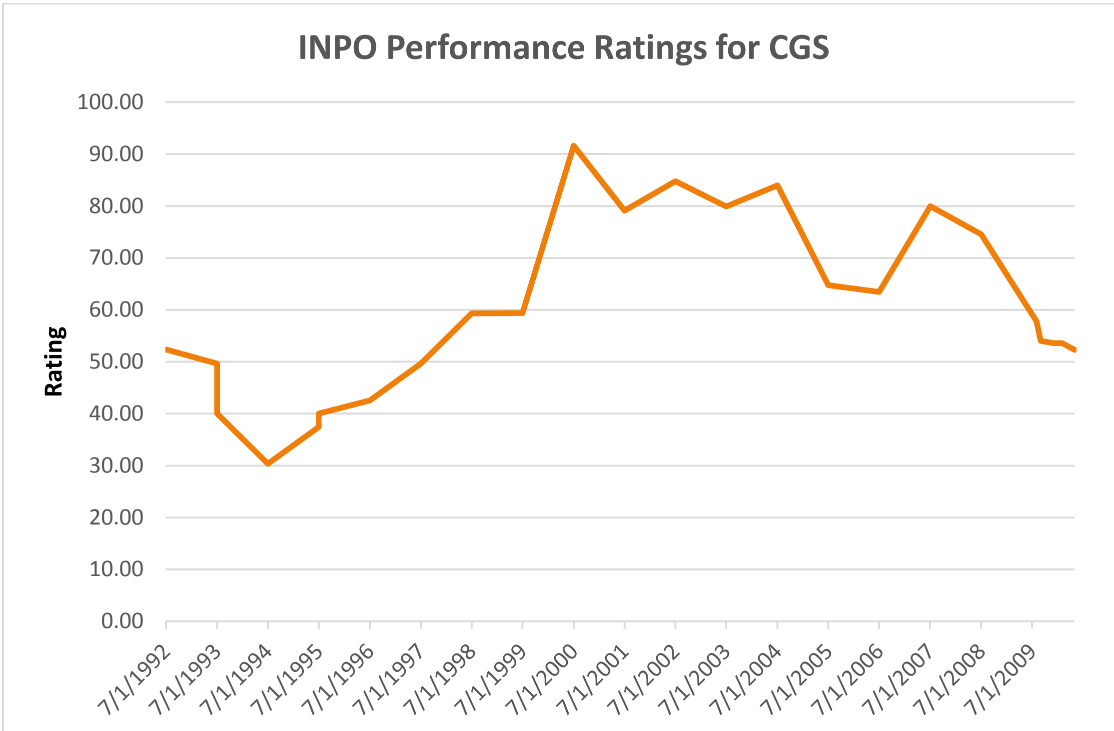

Figure 23

The dramatic improvement in the 1990s reflected a series of equipment upgrades and improvement in training. As noted above, the period from 1996 through 1999 was also the period when the plants faced closure as part of the Comprehensive Review. After 2000, capital budgets were tight.

The dramatic decline in 2009 reflected a series of five scrams. Several scrams were related to the condenser; others, in particular a fire on June 27, 2009, may have involved operator error.[169] The series of problems placed CGS on the NRC's watch list.

In August of 2009, Energy Northwest distributed another study, this time by an outside consultant, that argued strenuously for the condenser replacement:

> The capital budgets for Columbia from 2005-2006 (and at least five years before this period) were a little low and possibly too low to sustain reliable performance. The capital budgets were in the top quartile (i.e. low) in 2005 and 2006. In 2007, higher capital budgets were approved to deal with persistent reliability issues.

[169] *Columbia Generating Station, Docket No. 50-397 Licensee Event Report No. 2009-003-01*. March 16, 2010.

> Poor reliability, while it can be caused by underfunding, is just as often caused by other factors such as inadequate prioritization, human errors and improper planning. There is ample evidence in the industry that more money, by itself, does not guarantee improved performance.
>
> Anticipating performance over the next two years, Columbia's cost of power will increase until they complete a lengthy outage in 2011 to replace their condenser and then decrease to above average levels in future years.[170]

In 2009 BPA conducted a searching review of CGS operations and management. The dialogue between Energy Northwest and BPA had changed from collaboration to criticism. On October 22, 2009, BPA's administrator summarized BPA's draft report on CGS at an Energy Northwest board meeting:

> Mr. Wright provided a background and brief history of money spent on equipment, improvements made in the plant and the decline of performance since those investments in the plant were made. He reviewed the following BPA recommendations:
>
> - New leadership: New CEO should focus singularly on improving plant safety, reliability and generation output at a reasonable cost.
> - Vigilant, focused Executive Board: The Executive Board should focus on strengthening Columbia's performance, ahead of pursuing other strategic opportunities including new generation development.
> - Addition of nuclear experience to the Executive Board: the Executive Board should consider the addition of an individual with nuclear experience/expertise to the Board.
> - Strengthen BPA partnership: BPA encourages the Executive Board to endorse the overarching principle BPA proposed in 2007 as a foundation for a cooperative and constructive partnership between the agencies.
> - Performance improvement initiative: BPA endorses Energy Northwest's new Pride in Performance initiative and its goals; however, BPA believes that Energy Northwest should clearly outline steps to ensure that this positive action proves more successful than similar previous efforts.
> - Dedicated nuclear oversight: BPA strongly supports the Executive Board's consideration of creating a committee focused on oversight of Columbia. BPA proposes that the CNSRB [Corporate Nuclear

[170] David Oatley. *Columbia Generating Station's Performance 2005-2009*. August 20, 2009.

> Safety Review Board] report to and provide input to this new committee.[171,172]

The conflict had now reached such proportions that BPA issued a report criticizing plant operations and making a number of recommendations:

> In a Jan. 28 letter to [State Senator] Rockefeller, [Energy Northwest Chairman] Morrison offered his "personal opinion about the relationship" between ENW and BPA. He said ENW is responsible to the NRC, "no matter who finances the plant." He related that the Institute of Nuclear Power Operations (INPO) "dislikes the separation between operation/responsibility and net billing," adding that according to INPO, "this separation often leads to what we have seen at Columbia this past decade: fluctuating investments in plant upkeep followed by fluctuating plant performance and reliability."
>
> Morrison also said ENW has accepted all six recommendations BPA has made, including a new CEO; placing CGS performance ahead of other pursuits such as new generation; creating a board committee to focus on performance; and bringing more nuclear experience to the board. He noted BPA has been added to the screening committee for finalists in Energy Northwest's search for a new CEO.[173]

In our interviews with Energy Northwest board members and industry representatives, the term "personality conflict" was used to describe the relationship between Energy Northwest's CEO and the Bonneville Administrator. Over the following few years, all but one of the senior executives at CGS were replaced.

Bonneville's chief executive, Steve Wright, may have had an incentive program at BPA that might have explained the extended battle with Vic Parrish and the largely inexplicable decade long delay in the replacement of the steam condenser. In 2009, Steve Wright was quoted as saying:

> Mr. Wright shared a brief history of trying to create alignment three years ago with the Columbia Generating Station (Columbia) performance indicators and the cost of power to be used as a basis for incentive compensation for both BPA and Energy Northwest. Mr. Wright, Mr. Steve Oliver and Mr.

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[171] Energy Northwest. *Minutes of the Energy Northwest Special Board of Directors' Meeting*. October 22, 2009, Pages 8-9.
[172] Wright, Steve. *Letter to Larry Kenny*. 5 Oct. 2009. Page 1.
[173] Ben Tansey. *Morrison Promises to Reconsider BPA's 'Overarching Principle' for CGS*. Clearing Up. February 8, 2010, Page 16.

> Andy Rapacz have written into their performance contracts incentive pay based on the agreed upon Columbia performance indicators and cost of power. Mr. Wright indicated he was surprised when he learned Mr. Vic Parrish, current CEO of Energy Northwest, was not using the agreed upon performance indicators as a basis for his at risk compensation. Mr. Wright stated BPA is committed to supporting Columbia. As such, he felt the incentive portion of the CEO contract should be as much in alignment with the BPA executives' incentives as possible.[174]

On November 21, 2013, BPA responded to our FOIA request regarding these incentive contracts, reporting that it could not provide Steve Wright's contract without first getting Department of Energy approval. Severely redacted portions of the contracts for Steve Oliver and Andy Rapacz were provided, however.[175] A similar summary of the incentive contract for Paul Norman also identified incentive language for CGS.[176]

Although the evidence is fragmentary, it appears that the "agreed upon performance indicators" were the cost of the plant, a performance indicator, and the quarterly capacity factor.

If this is correct, it might explain the nine year disconnection between CGS's safety concerns and a desire to maximize very short term measurements of cost-effectiveness. Compromises with safety – like the delay of the replacement of the condenser -- might well have served to increase the remuneration of responsible BPA officials.

One sign of the lack of good communication between the agencies is a long-standing dispute about whether the Energy Northwest board would adopt an "overarching principle" presented to them by the Bonneville Administrator in 2007 that:

> BPA and ENW are committed to long-term, safe, reliable operation of CGS accomplished at the lowest reasonable cost necessary to achieve those objectives. It is also our objective to integrate CGS with the Federal Columbia River Power System and to achieve optimum utilization of the

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174 Energy Northwest. *Minutes of the Special Meeting of the Ad Hoc Search Committee of the Executive Board.* 19 Feb. 2010.

175 Munroe, Christina. Final response to FOIA #BPA-2014-00132-F. 21 Sept. 2013. Page 1:

> Mr. Wright's performance contract is a product of the Department of Energy (DOE) as he was a senior SES employee. BPA has transferred your request for Mr. Wright's performance contract element and the one performance contract found in response to your request to DOE for their determination and release.

176 Norman, Paul. *FY 08 Performance Contract Elements Summary*. 11 Sep. 2008.

> resources of that system taken as a whole and to achieve efficient and economical operation of that system.[177]

It is difficult to see how such a resolution would affect the procedures and standards set out in the 1971 agreement. The inability of the two parties to agree on overarching goals and principles in managing the nuclear plant is troubling.

The condenser was finally replaced during the refueling outage in 2011, after years of debate and delay.

Although it is tempting to try to attribute blame to specific participants, the root cause was the lack of a recognized procedure to resolve conflicts in the 1971 Project Agreement. Conflict between different objectives – cost and reliability, in this case – is a natural part of a power purchase agreement. The 1971 project agreement has a very limited ability to address conflict – the selection of a single arbitrator to moderate disputes is presumably deemed unworkable, has clearly never worked, and has never been used.

As Energy Northwest's outside counsel stated in 2007:

> In practice, BPA has never disapproved a CGS Annual Budget or budget item. Thus, BPA's one significant contractual power (at least the contractual power relevant here) has never been used. In interviews, BPA officials made clear that they would regard as a "breakdown" any situation that required BPA to resort to formal disapproval. For a dispute to reach this stage would be inconsistent with the type of ENW relationship BPA officials say they want. It would trigger a review process they consider - rightly or wrongly - to be tilted against them, and, even if not tilted against them, to be expensive, perhaps slow, and potentially poisoned by the parties' loss of control to their respective lawyers. Perhaps most important, BPA officials believe that any disagreement serious enough to force dispute resolution by the Project Consultant would probably strike BPA as too serious to be left to an uncertain outcome, which is inherent in the Project Consultant process. BPA doesn't feel it can take the chance of what it would consider a truly bad outcome on anything that is truly worth fighting about.[178]

In sum, the existing contract between the two agencies has not worked well. In this case study, the replacement of a failing plant component was delayed by a decade through conflict and lack of communication. Since a similar issue was broached this spring – the

[177] Bonneville Power Administration. *FY 2010-2011 Power and Transmission Program Levels Final Report*, Bonneville Power Administration Integrated Program Review. November 14, 2008, Page 19.
[178] Eric Redman, *The BPA-Energy Northwest Relationship in the Context of Columbia Generating Station Operating and Capital Budgets*. Page 8.

postponement of the steam turbine replacement – this would appear to be a continuing problem at CGS.[179]

4.3 COSTS

CGS comprises 93.4% of Energy Northwest's annual budget.[180] Compared to the majority of US nuclear power plants, CGS has relatively little regulatory and financial reporting. The primary sources for information on the plant are the Energy Northwest annual reports, board presentations, submissions to Bonneville, and the bond prospectus. Accessing public information through Energy Northwest is an arduous process where even documents prepared and previously distributed to the press can takes months to be delivered.[181]

This review has relied upon the annual reports since 1984, a variety of board handouts and studies, BPA materials from the program review and rate cases, bond prospectuses, budget documents, ten year strategic plans, and ten year fuel plans. Many of these documents are not easily obtained. Energy Northwest's web site is neither complete nor dependable. The current Energy Northwest website includes partial materials for the past five years and has a history of incomplete links and missing documents.[182]

4.3.1 Historical Costs

Energy Northwest's annual reports are idiosyncratic – they are not readily compared to documents from other nuclear stations. In part this is due to a decision to not state its operating costs in the standard format used by the Federal Energy Regulatory Commission.[183] While CGS is not regulated by FERC, the 1971 Project Agreement specifies that it must keep its books consistent with FERC's standard system of accounts.[184]

Energy Northwest summarizes its operating costs in each annual report in several ways. The first two, "Cost of Power" and "Operating Cost," are not defined in the annual report. They appear to be terms unique to Energy Northwest. By checking the annual report carefully, it

179 Mark Reed, Asset Manager/Controller. *Fiscal Year 2014 Budget and Long Range Plan*, *Columbia Generating Station.* March 6, 2013, Page 30.
180 Energy Northwest, *2012 Energy Northwest Annual Report*, Page 44.
181 See the section on transparency, below.
182 <http://www.energy-northwest.com>
183 Federal Energy Regulatory Commission. *FERC FINANCIAL REPORT FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report*. Web. <http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf>. Page 402.
184 Department of the Interior. *Washington Public Power Supply System Nuclear Project No. 2 Agreement*. January 4, 1971, Section 6(c).

is logical to conclude that "Operating Cost" equals "Operating Expenses" plus "Operating Income/Loss."[185]

The materials that Energy Northwest provides to Nucleonics Weekly, an industry publication, allow a crosswalk – something like a "Rosetta Stone" or translator – to be created that reflects the differences between Energy Northwest definitions and those used by FERC:

Energy Northwest Income Statement		FERC Form 1 Page 402		
Title	Value	Row	Item	Value
Net Generation, Exclusive of Plant Use - KWh	6,983,739,430	12	Net Generation, Exclusive of Plant Use - KWh	6,983,739,430
		19	Production Expenses: Oper, Supv, & Engr	15,090,646
Nuclear fuel	35,393,000	20	Fuel	41,952,779
Spent fuel disposal fee	6,560,000			
Operations and maintenance	177,468,000	21	Coolants and Water (Nuclear Plants Only)	2,599,885
		22	Steam Expenses	36,068,965
		23	Steam From Other Sources	
		24	Steam Transferred (Cr)	
		25	Electric Expenses	
		26	Misc Steam (or Nuclear) Power Expenses	46,946,155
		27	Rents	
		28	Allowances	
		29	Maintenance Supervision and Engineering	11,797,965
		30	Maintenance of Structures	
		31	Maintenance of Boiler (or reactor) Plant	
		32	Maintenance of Electric Plant	
		33	Maintenance of Misc Steam (or Nuclear) Plant	64,963,468
Total Production Expenses	219,421,000	34	Total Production Expenses	219,419,863
		35	Expenses per Net KWh	0.031
Decommissioning	7,433,000			
Depreciation and amortization	74,440,000			
Other power supply expense				
Administrative & general	26,876,000			
Generation tax	3,239,000			
Total operating expenses	331,409,000			
Operating Income (Loss)	66,472,000			
Total Operating Costs	397,881,000			
Cost of Power (Total Operating Expenses/kWh)	0.047			

Figure 24

The bottom line, in FERC's Form 1, page 402 can be found at line 34. Energy Northwest's accounting actually matches FERC's and follows the 1971 Project Agreement language.

Energy Northwest's "Cost of Power" calculation is not a FERC accounting concept, but follows logically from the addition of fixed cost items not reported on page 402. If Energy Northwest filed a FERC Form 1, these would be reported in more detail on other pages.

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185 Energy Northwest. *2012 Energy Northwest Annual Report*, page 34 ("Total Operating Costs") and Page 44, ("Operating Revenues").

To summarize, Energy Northwest's Income Statement is consistent with FERC's traditional reporting, but uses unique definitions that can be misleading without careful review.

There is some question whether Energy Northwest's Administrative & General cost should be reported as operating costs. The comparable nuclear plants in the industry are part of integrated utilities or large scale independent power producers. The other nuclear plants' share of A&G expenses in our study is relatively small. In the case of Energy Northwest, the A&G costs are treated as a cost of the unit and described as an operating cost. Operations other than CGS are minimal, so it is logical to include these as plant operational costs – consistent with Energy Northwest's definitions, but different than FERC's accounting treatment. This is the approach we have taken in the following comparisons between CGS and the Form 1 data for other nuclear units.

Seven years of "Large Plant Steam-Electric Generating Plant Statistics" cost data for nuclear plants were compiled from the Federal Energy Regulatory Commission (FERC) Form No. 1, which is a comprehensive operational and financial report submitted by major utilities for financial audits and rate regulation.

Operations and Maintenance costs – omitting depreciation, revenue taxes, and decommissioning costs – provide a good start for an understanding of CGS's relative costs:

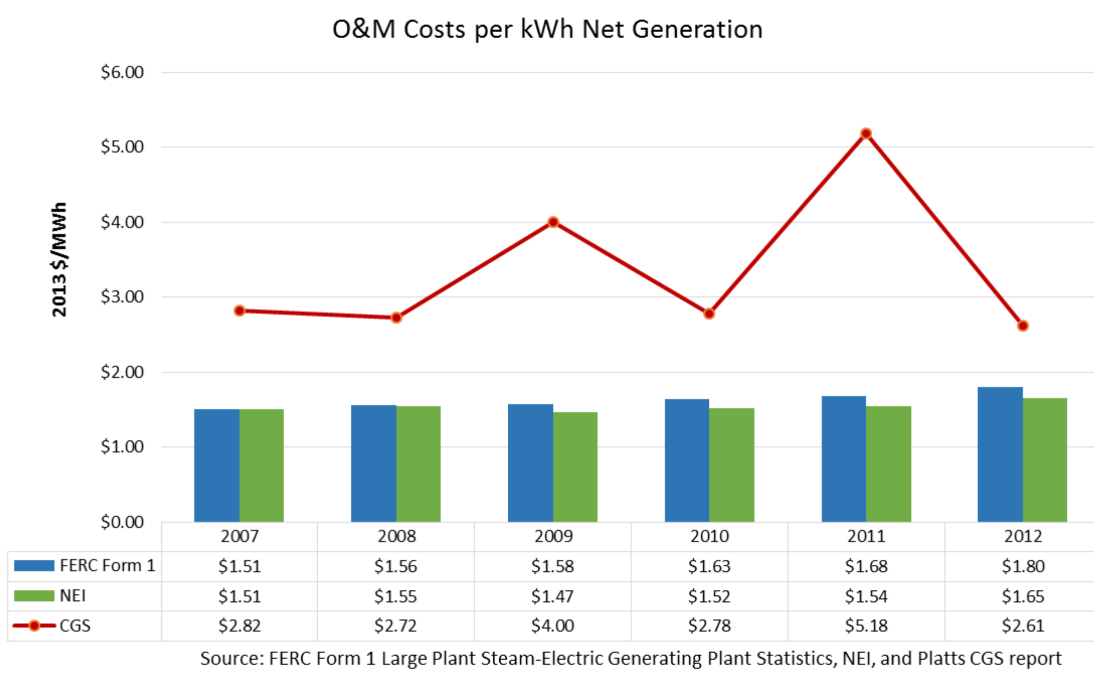


Figure 25

An important component of the high O&M costs is the number of employees at CGS. On an employees per gigawatt-hour (GWh) basis, CGS stands out from other plants in our FERC Form 1 database:

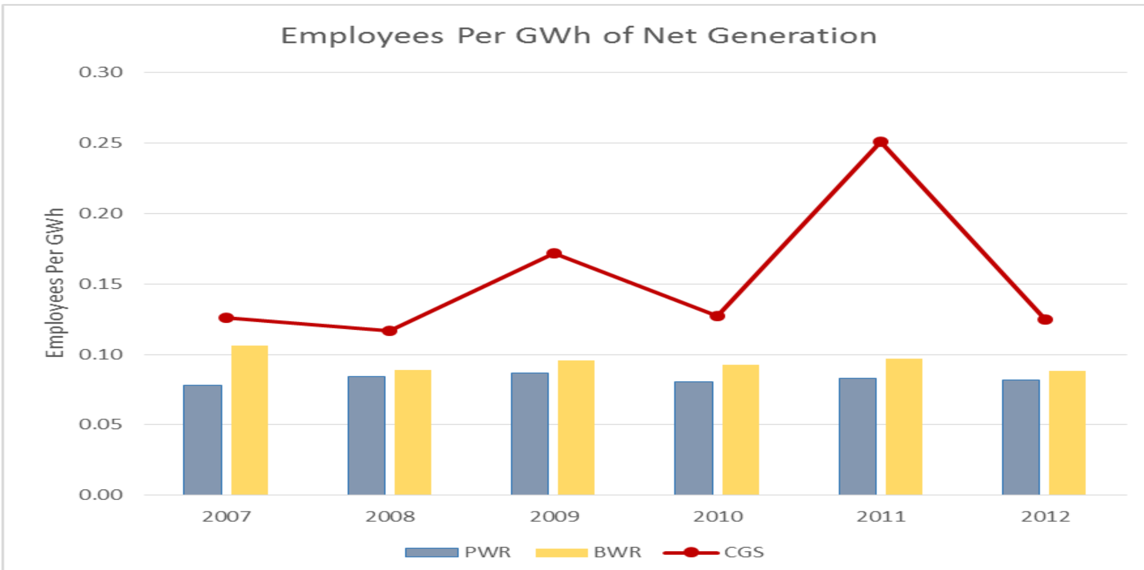


Figure 26

The one area where CGS has tended to perform well is fuel costs:

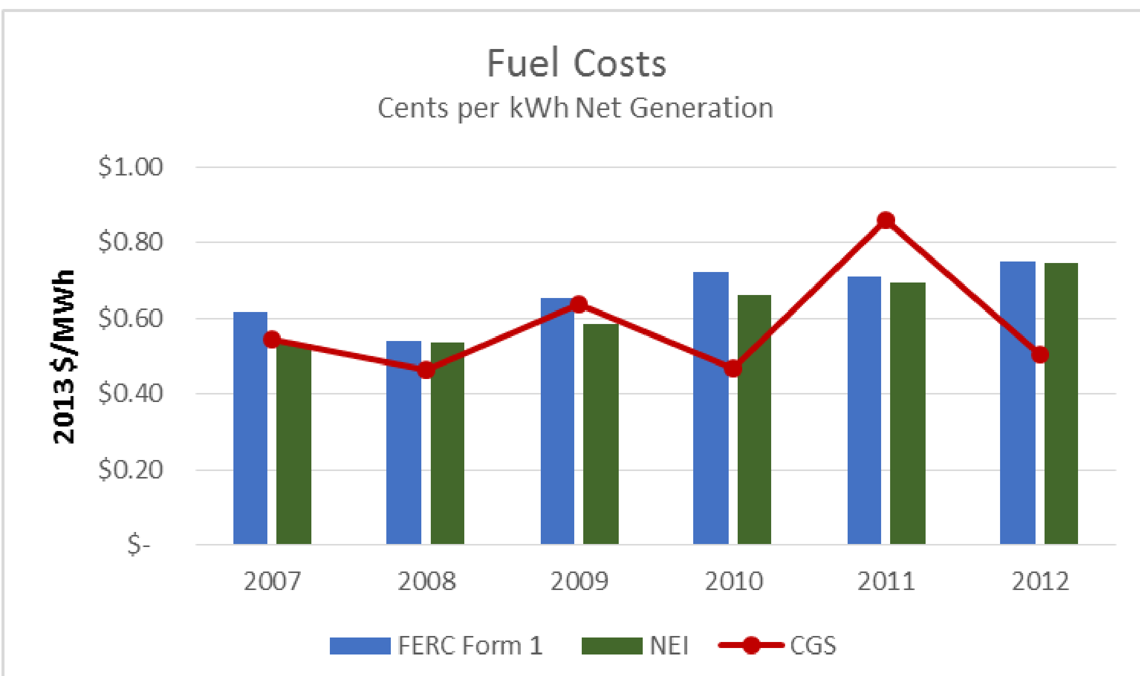


Figure 27

Overall, compared to twenty-eight other U.S. nuclear stations' Form 1 submissions, CGS appears considerably more expensive:

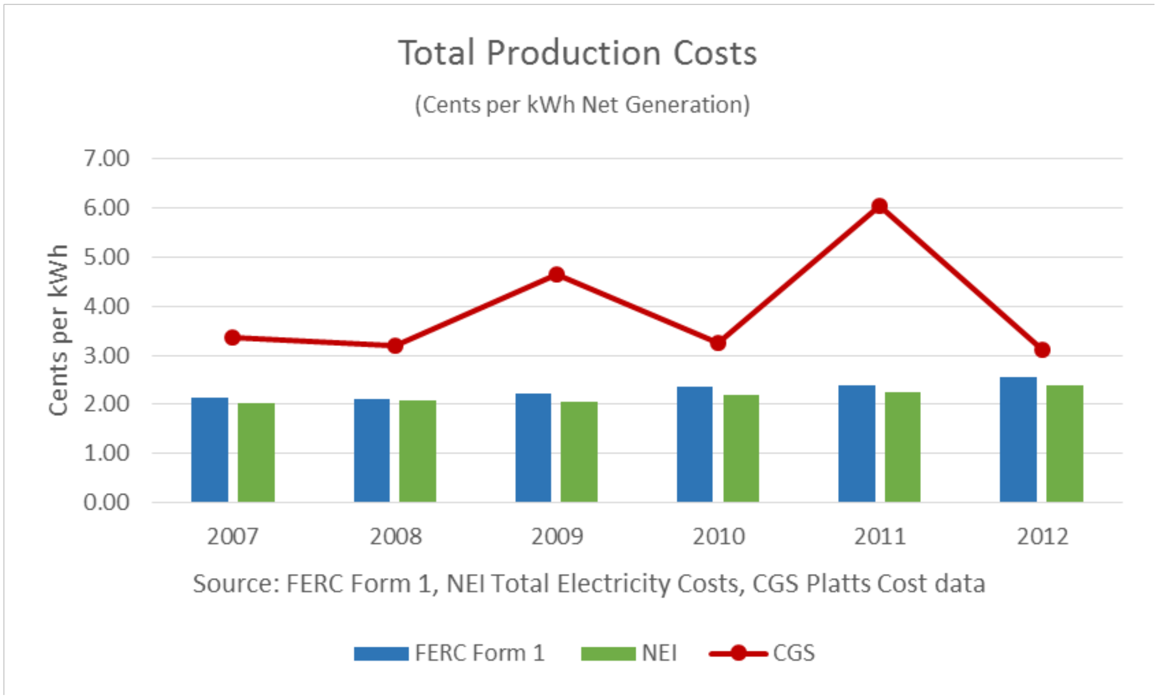
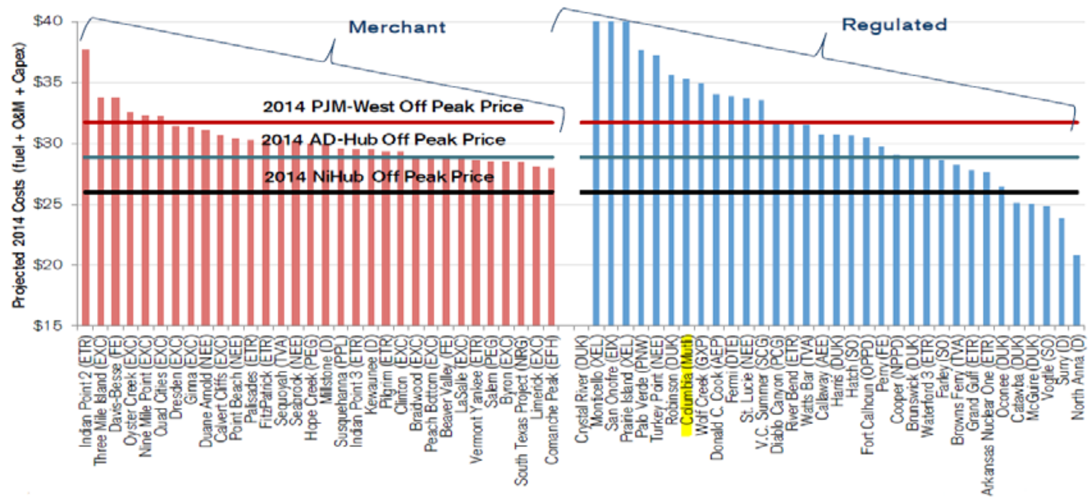


Figure 28

This spring, Credit Suisse came to a similar conclusion, placing CGS as the eighth most expensive "regulated" unit. Since this report was issued, CGS's ranking would be sixth, since two of the more expensive units have closed.



[186]

Figure 29

The explanation appears to involve the complex ownership of CGS. When we asked BPA for details on CGS's cost submissions, we received the following response:

> **Information requested:**
> Energy Northwest's CGS's operating and maintenance costs for the years 1992 to 2012.
>
> Enclosed are two reports from 1992 and 1993 where the maintenance costs are supplied. Our staff, Ms. Dana Sandlin, the Authorizing Official for this request, reports that the format for financial reports provided to BPA from Energy NW changed after 1993. In the new format the maintenance costs were no longer broken out. Therefore, for the years 1994 to 2012 we have no responsive records.[187]

The lack of information is even more pronounced on forecasted costs.

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[186] Credit Suisse. *Nuclear… The Middle Age Dilemma? Facing Declining Performance, Higher Costs, Inevitable Mortality.* 19 Feb. 2013. Page 10.

[187] Bonneville Power Administration. *FOIA #BPA-2013-01065-F.* June 18, 2013.

4.3.2 Forecasted Costs

Under the Project Agreement, Energy Northwest provides BPA with both a budget for the current year and forecasts for upcoming years.[188] The official "Fuel Plan" has not been publicized for some years. The last public reference we were able to find on the Fuel Plan is for FY 2007.[189]

Although not required in the Project Agreement, Energy Northwest has provided a series of reports entitled "Long Range Plan" or some variant.

These plans are often detailed, but appear to have little resemblance to actual events. The FY 2007 plan, for example, bears little resemblance to the FY 2007 through FY 2012 actual costs:

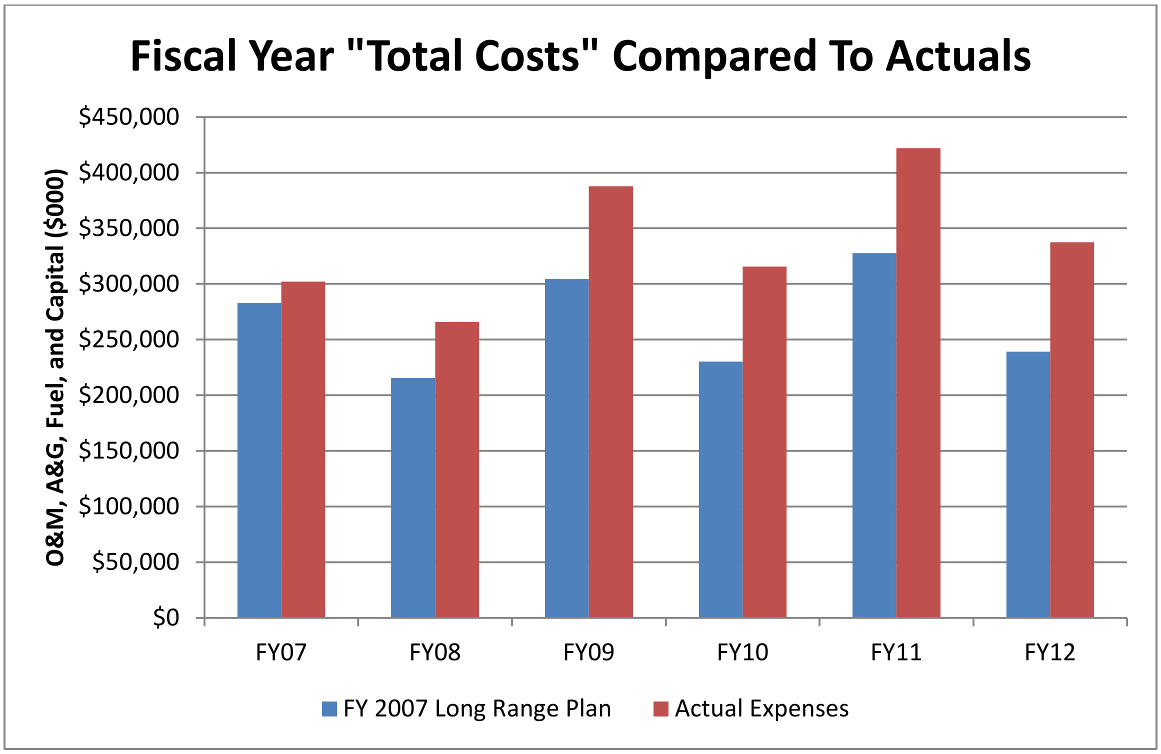

Figure 30

This chart compares CGS's "Total Costs (Industry Basis)" values, with the actuals taken from Energy Northwest's annual reports. "Total Costs (Industry Basis)" includes operating costs, administrative and general costs, and incremental capital costs.

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188 Department of the Interior. *Washington Public Power Supply System Nuclear Project No. 2 Agreement*. Pages 14-15.
189 Ferek, Lisa L. *FY 2007 Fuel Management Plan*, Energy Northwest. 26 Apr. 2006.

The corresponding "Cost of Power" calculations are even less accurate:

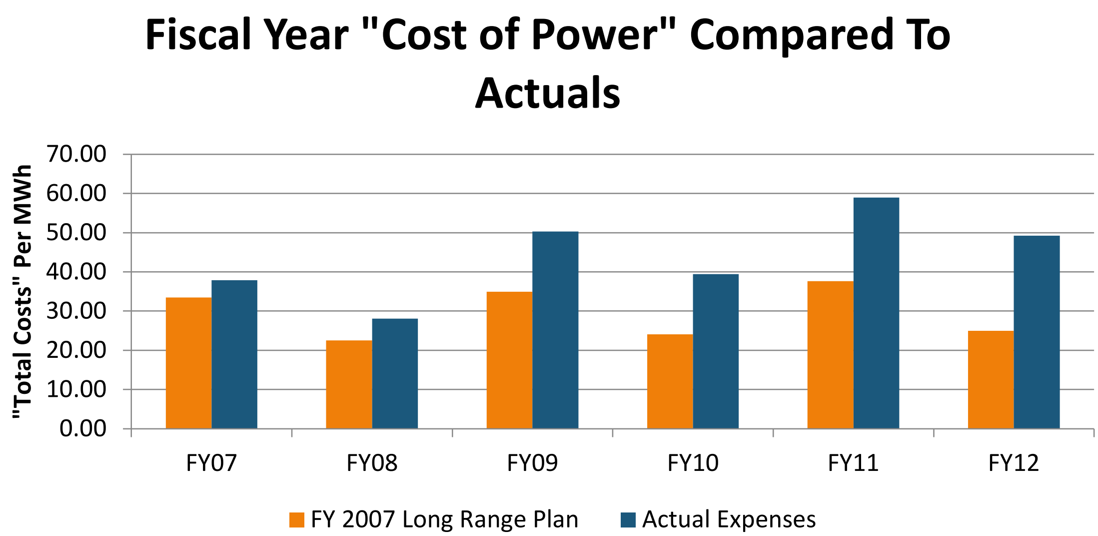

Figure 31

Costs since FY 2000 have increased 5.3% above inflation:

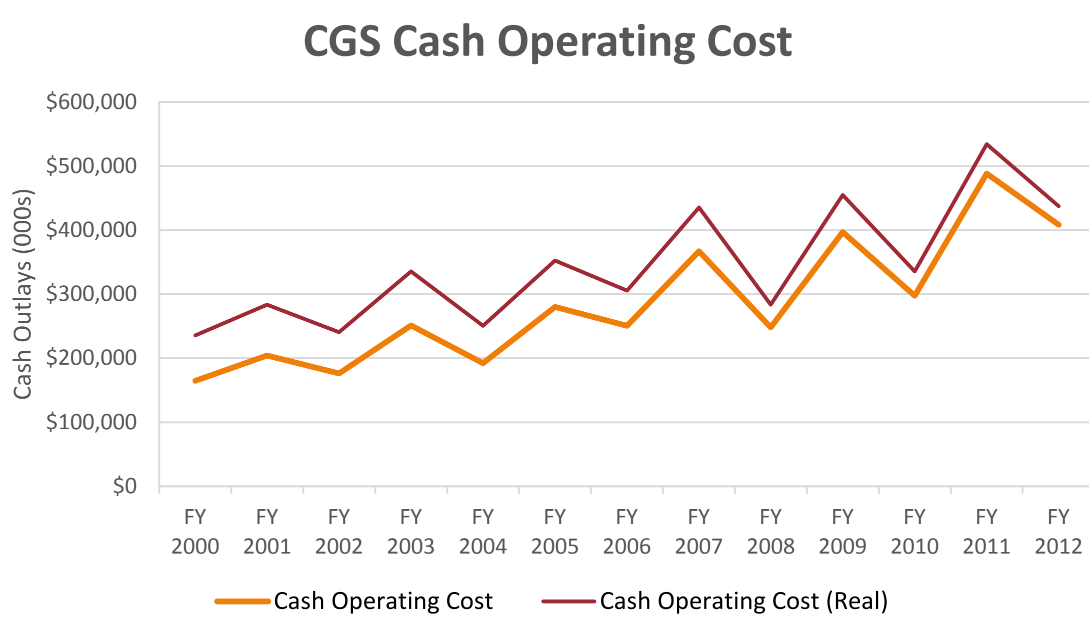

Figure 32

The current Long Range Plan also assumes no increase in real costs in most categories from FY 2014 through FY 2023.[190] In part this is due to "stage dressing" adjustments such as moving the replacement of turbines and generators out of the current ten year period.

The deferral of the turbine alone moved $54.5 million to "FY 25," immediately after the current 10 year period. This was one of many such deferrals listed in a document entitled 'LRP Adjustments Following BPA Meeting on March 6, 2013 in Portland.'[191]

LRP Adjustments Following BPA Meeting on March 6, 2013 in Portland

AR Number	Description	Previous Schedule in Fiscal Years	New Schedule	Notes / Action	Risks
Capital Projects					
186055	SOLA regulating transformers for DGs	14/15/16/17	14 / 15	Removed $428K in 16/17 for Modification	Reverse engineering is being performed. The $428k was a placeholder in case the reverse engineering failed.
261654	Byron Mods Final Solution	14/15	14/15	Corrected dollars in FY 14/15 (add $3.07M in FY 15)	None
5733	RCIC Hydrogen Accumulation	14/15/16/17	14/16/17/18/19	Rescheduled. Pushed $1.3M into 3rd BPA rate period	Operate 2 additional years under administrative bridging strategy while a more effective/efficient permanent solution is investigated for CGS
16962	Feedwater Heater Level Controllers	18/19/20/21	25	Removed $3.3M from 10 Year Period into FY 25	
10434	Normal transformers N1 and N2	20/21/22/23/24	18/19	Combined N1/N2 in same years. Saved $1.8M in LRP	FY 19 is a 55 day outage, due to the scope of work to remove N1/N2 there is less risk to outage critical path to perform the work.
268869	MT-ELEV-NE/RB Reactor Building Elevator	16/17	18/19	Rescheduled. Pushed $843K into 3rd BPA rate period	
3174	CFD Precoat Pump	18/19/20	19/10	Rescheduled. Pushed $136K into 3rd BPA rate period	
224656	Emergency Chillers	17/18/19	22/23/24	Rescheduled. Pushed $3.75M beyond 3rd BPA rate period	
4825	Moisture Separator Reheaters	22/23	22/23	Leave As Is - Risk is too high to move	
7564	Service Building HVAC	22	25	Removed $178K from 10 Year Period into FY 25	Drawing Backlog Cleanup
2783	RHR-FCV-64A/B/C	21/22/23	25	Removed $791K from 10 Year Period into FY 25	
11509	ASD units on Circ water fan motors	21/22/23	25	Removed $4.47M from 10 Year Period into FY 25	Megawatt Gain Deferral
9664	Differential Protection on distribution transformers	16/17/18	16/17/18	Leave-as-is - Risk is too high to move	
23773	Deactivate portion of the PASS system	14/15/16/17	25	Removed $2.6M from 10 Year Period into FY 25	Loss of radiation and maintenance labor reduction until implementation. Delay results in 600 additional MR and $350,000 additional maintenance.
9248	Supplemental Fuel Pool Cooling	21/22/23	25	Removed $9.8M from 10 Year Period into FY 25	Megawatt Gain Deferral, Outage duration reduction deferral.
AR TBD	Replace High Pressure Turbine	19/20/21	25	Removed $19.8M from 10 Year Period into FY 25	Megawatt Gain Deferral
AR TBD	ISFSI Security Rule	16/17/18	17/18	Use current location. Implement Security Head reduction.	Will require up to 40 additonal security officers if implemented at current ISFSI location. Details are considered safeguards information.
6523	Generator Stator Rewind	16/17/18/19	25	Removed $54.5M from 10 Year Period into FY 25	Megawatt Gain Deferral
AR TBD	Wired / Wireless backbone	15/16/17	15/16/17/18/19	Rescheduled. Pushed $1M into 3rd BPA rate period	
7185	Chemical Decon (R25 - RHR and FPC)	21	25	Removed $8.7M from 10 Year Period into FY 25	

Figure 33

[190] Economists use the term "real" to describe dollar amounts that have been adjusted for inflation. The corresponding term "nominal" means the actual price tag the consumer pays in a store.
[191] Energy Northwest. *LRP Adjustments Following BPA Meeting on March 6, 2013 in Portland.* Undated.

In sum, the March meeting between BPA and Energy Northwest moved $105.14 million (in real terms) out of sight by placing it in the year following the plan. A variety of other investments were "reflowed" to later periods.

It is tempting to describe this as deceptive. Staff presentations to the board on this adjustment repeat frequently, "Long-range Plan will continue to be revisited each year."[192,193]

The final outcome of the March adjustments had little public discussion outside Energy Northwest and BPA. All in all, 92.5% of the capital expenses addressed above were moved out of the planning period, and the result was characterized as a cost reduction.[194]

A new cost reduction measure – moving O&M costs to a capital expense – accentuates the "house-keeping" nature of the Long Range Plans. In recent Energy Northwest documents, the plan to capitalize 10% of O&M has been mentioned a number of times.

> The result is an increase to the capital budget in FY14 that carries throughout the 10-year long range plan timeframe. At the same time operations and maintenance budgets have been reduced. The bottom line is reduced Energy Northwest estimates that contribute into the Bonneville Rate Cases over the next 10 years.[195]

This leads to some curious arithmetic operations. One example is the "reduction" in personnel by reclassifying them as "capital."

[192] Ridge, Brent. *Columbia Fiscal Year 2014 and Long-range Plan.* 16 June 2013. Page 10.
[193] Ridge, Brent. *Columbia Fiscal Year 2014 and Long-range Plan Update.* 24 Apr. 2013. Page 18.
[194] Ibid. Page 5.
[195] Reed, Mark. *Fiscal Year 2014 Budget and Long Range Plan CGS.* 6 Mar. 2013. Page 4.

Table 4
Summary of Full Time Equivalent (FTE) Positions*

Description	FY 2014 Budget	FY 2013 Budget	Variance
FTE Positions Supporting Operations and Maintenance (1)	984	1,088	(104)
FTE Positions Supporting Capital Projects	164	60	104
Total	**1,148**	**1,148**	**-**

*** Includes allocation of Corporate Full Time Equivalent Positions.**
(1) Includes Environmental & Cal Lab support (20 Full Time Equivalent Postions in FY 2014 and 19 Full Time Equivalent Postions in FY 2013). [196]

Figure 34

There is as little logic in viewing the financing of current expense as a cost saving measure as there is in taking out a mortgage to pay everyday living expenses. The bottom line is exactly the same – only the timing of payment changes. And, depending on interest costs, the ultimate burden on consumers may actually increase.

The economics of this approach only makes sense if the borrowing at Energy Northwest is at a lower rate than that of the public power entities who eventually purchase the electricity from BPA. If this is so, then the Federal Government, through BPA's loan guarantee for CGS, is effectively loaning money to its customers. Unfortunately, no effort has been made to show that using BPA's guarantee to bulk up borrowing at Energy Northwest is really in the interest of BPA's customers – nor has any serious discussion been opened to see if this is an option they prefer.

In terms of our analysis, this is of no importance, since the proposed closure of CGS would allow the region to avoid the full set of current and capital items regardless of how they are capitalized.

In conclusion, CGS appears to be a relatively expensive plant compared to other U.S. units. Costs have been increasing rapidly compared to inflation. The Long Range Plan documents have traditionally been inaccurate forecasts and are difficult to apply to real world budgetary decisions.

[196] Energy Northwest. *Fiscal Year 2014 CGS Annual Operating Budget*. May 16, 2013. Page 8.

4.3.3 Bond Repayment

Under the 1971 Project Agreement, payment of interest and principal on CGS bonds is guaranteed by BPA. The strength of this guarantee has been tested by the cancellation of CGS's sister plants WNP-1 and WNP-3. Thus the large existing financing costs of CGS are "sunk" and have no impact on this study.

4.4 Transparency

The West Coast currently has six functioning commercial nuclear reactors, including the two Diablo Canyon units in California, and the three Palo Verde units in Arizona. CGS is the least transparent of the six in many, if not most, areas.

1. CGS is the only West Coast unit not subject to an annual FERC FORM 1 filing. This means that "apples to apples" comparisons of operating costs between CGS and the industry are difficult and time consuming.

2. CGS is not subject to state level regulation of operations, costs, and fueling. This stands in stark contrast to the California Nuclear Decommissioning Cost Triennial Proceeding and other standard regulatory reviews.

3. Evidence indicates that Energy Northwest is sparing in the data it shares with the Bonneville Power Administration.[197]

4. The Energy Northwest website, potentially a window into its operations and finances, reports data infrequently and inconsistently.[198]

5. Requests for public records from Energy Northwest often face extensive delays and are frequently unresponsive.

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[197] Information requested:

> "Energy Northwest's CGS's operating and maintenance costs for the years 1992 to 2012."
>
> Response: "Enclosed are two reports from 1992 and 1993 where the maintenance costs are supplied. Our staff, Ms. Dana Sandlin, the Authorizing Official for this request, reports that the format for financial reports provided to BPA from Energy NW changed after 1993. In the new format the maintenance cost were no longer broken out. Therefore, for the years 1994 to 2012 we have no responsive records."

[198] For example, the CGS fuel plan has not been posted on Energy Northwest's web site since 2008.

In the course of conducting the research for this report, we submitted 35 public document requests to Energy Northwest. The average promised response was 71 days and average actual response time was 37 days.

Request Sent	PRR No.	Request Subject	Proposed Response Date	Estimated Days	Actual Response Date	Actual Days
2/6/2013	2013-06	Contracts as follows: #335903, #335900, #335901	4/19/2013	72	3/12/2013	34
4/10/2013	2013-13	Request for annual reports	8/8/2013	120	Canceled - obtained through other sources	
4/22/2013	2013-14	The most recent versions of the Energy Northwest Budget and Strategic Plan	None given		5/3/2013	11
4/24/2013	2013-17	The Columbia Generating Station Value Study and working papers from board meeting on 4/24/2013.	8/9/2013	107	8/15/2013	113
5/1/2013	2013-21	CGS Fund Status Reports from 1990-2003	8/9/2013	100	5/31/2013	30
5/15/2013	2013-22	FERC-compatible CGS O&M costs	8/1/2013	78	7/18/2013	64
5/30/2013	2013-26	Minutes from all board meetings during May 1994.	9/4/2013	97	7/18/2013	49
5/30/2013	2013-27	Minutes from all board meetings during April 1982.	9/4/2013	97	7/18/2013	49
5/31/2013	2013-23	The WPPSS Joint Operating Agreement	9/4/2013	96	7/11/2013	41
7/1/2013	2013-30	Strategic Plan ratified at most recent board meeting	9/2/2013	63	7/18/2013	17
7/24/2013	2013-32	Workpapers for the CGS Value Study.	8/15/2013	22	8/15/2013	22
7/24/2013	2013-33	Fuel management plans for CGS submitted to the Bonneville Power Administrator from 2007 to present	9/12/2013	50	9/4/2013	42
8/8/2013	2013-36	Eric Redman's report from the April 2013 Executive Board meeting	8/26/2013	18	8/26/2013	18
8/8/2013	2013-37	All board minutes for 2013	8/26/2013	18	8/26/2013	18
8/8/2013	2013-38	Workpapers for the March 6, 2013 budget/plan presentation	11/15/2013	99	10/30/2013	83
8/8/2013	2013-39	Workpapers for carbon calculations in Columbia Generating Station value Study	11/15/2013	99	None found	
8/8/2013	2013-40	Workpapers for the March 18, 2013 budget/plan presentation	11/15/2013	99	10/30/2013	83

8/8/2013	2013-42	WNP-1 completion feasibility study	11/15/2013	99	10/4/2013	57
8/8/2013	2013-43	WNP-2 alternatives for sale or management study	9/20/2013	43	9/9/2013	32
8/30/2013	2013-44	Board minutes since 2006	10/10/2013	41	9/11/2013	12
8/30/2013	2013-45	October 2009 BPA report documenting WNP-2 performance issues and EN CEO expectations	10/10/2013	41	9/24/2013	25
9/13/2013	2013-47	BPA's response to the Redman Report provided to Public Power Council (PPC) in February of 2008.	10/24/2013	41	9/24/2013	11
9/16/2013	2013-49	Hourly generation for 2000-present	11/22/2013	67	10/4/2013	18
9/16/2013	2013-50	EN's letter to Steve Wright in response to the 2009 draft BPA white paper and attached report	11/22/2013	67	10/16/2013	30
9/20/2013	2013-51	Documents pertaining to the implementation of the 1998 "Market Test" as set out in the Cost Review Panel Conclusion.	12/23/2013	94	None found	
9/20/2013	2013-52	WPPSS board minutes for 1999-2000 and 2004-2005	10/24/2013	34	10/4/2013	14
9/27/2013	2013-53	The November 2001 "Plan to Strengthen Working Relationship" adopted and signed by BPA and ENW	12/12/2013	76	10/30/2013	33
9/27/2013	2013-54	1980 Memorandum of Understanding between Energy Northwest and BPA	12/12/2013	76	10/30/2013	33
10/3/2013	2013-55	1999 Memorandum of Agreement	12/19/2013	77	10/30/2013	27
10/11/2013	2013-56	The letter from Jeff Shields in 1999 regarding the misuse of public funds for the Memorandum of Agreement between BPA and Energy Northwest. Also requested: BPA's point-by-point defense of the MOA in response to the	12/20/2013	70	11/7/2013	27
11/13/2013	2013-63	Long Range Plans for 2003 - 2006	1/10/2014	58		

Figure 35

A number of these requests received responses that were anomalous:

- An estimated 120 days for Energy Northwest's annual reports was 119 days longer than that required for our staff to accumulate a full set from the Washington State Library.
- 90 days for the CGS Value Study, which had been distributed to the press at the April board meeting, and 113 days for the Value Study workpapers
- 64 days for FERC compatible O&M data which turned out to be a one page summary provided to an industry journal on an ongoing basis

As discussed above, the history of the plant over the past decade has not been transparent. The decade long battle over the condenser replacement was largely held in the "back rooms" of Energy Northwest and BPA. The similar, but equally troubling, debate over replacement of CGS's turbines has started in a very similar fashion.

Possibly most troubling, both BPA and Energy Northwest have been unable to find any materials on the Market Test for the continued operation of CGS.[199]

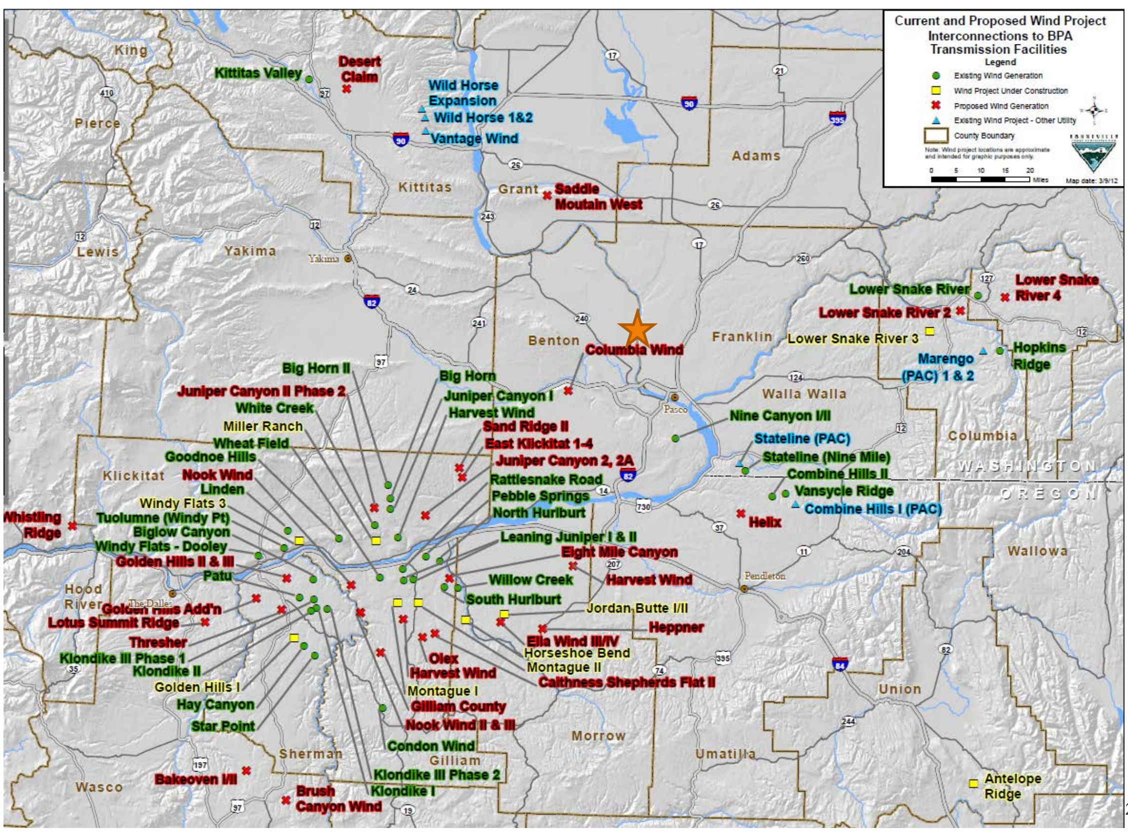
[199] Glica, Alex. *Public Records Request 2013-51*. Message to Rose Anderson. 13 Nov. 2013. E-mail.

Our FOIA request for Steve Wright's CGS incentives has also been deflected with the doubtful explanation that the contract has been sent to the Department of Energy which may, or may not, have deposited it in their long term archives.

Overall, CGS is significantly less transparent than other West Coast nuclear units.

4.5 ECONOMIC DISPATCH

Volatility of power prices at the Mid-Columbia trading hub has increased as massive increases of wind power have added non-schedulable intermittent generation to the area. In BPA's chart showing wind generation, CGS lies near the center of these rapidly increasing resources:



[200]

Figure 36

[200] Bonneville Power Administration. *Current and Proposed Wind Project Interconnections to BPA Transmission Facilities.* bpa.gov. 9 Mar. 2012. Web. 15 Nov. 2013. <http://www.bpa.gov/transmission/Projects/wind-projects/Documents/BPA_wind_map_2012.pdf>

CGS is denoted by the star near Pasco, Washington.

Our analysis of future power prices using the EPIS Aurora model is summarized in Section 5.6. With the approaching increases in renewables mandated by legislators in Oregon, Washington, and California, we can expect additional wind resources in years to come.

A central concern about integrating wind with traditional baseload resources concerns their ability to conduct economic dispatch. As a general rule, nuclear stations are poor candidates for economic dispatch.

Energy Northwest has expressed concerns over economic dispatch of CGS over the years:

> More difficult to quantify is the resulting wear-and-tear on plant equipment and increased risk of human error. In 1996, variable speed drives for the reactor recirculation pumps were installed to reduce the stress on the piping, valves and pumps. Even so, each time power is reduced, additional wear is placed on steam plant components when they are operated in off-normal conditions. Also, each power change, depending on the level of change, introduces opportunities for operator errors.[201]

Economic dispatch has been a frequent discussion at Energy Northwest Executive Board Meetings in recent years.[202] In March 2013 Bradley Sawatzke summarized the long term parameters for economic dispatch:

- 100 percent power steady state
- →85 percent power and hold steady – 72 hour notice with one to two hours recovery time to full power
- → 85 percent power daily load cycling – 72 hours prior notice with one to two hours recovery time to full power
- → 65 percent power and hold steady – seven working days prior notice with eight to 12 hours recovery time to full power
- → 45 to 50 percent power – seven working days prior notice with 12 to 24 hours recovery time to full power
- Forced shutdown – 10 working days prior notice for forced outage completion [203]

Not surprisingly, these protocols are inconsistent with the operation of wind. Overall, economic dispatch at CGS appears to be extremely low – especially in recent high water years:

[201] Energy Northwest. *Energy Northwest Executive Board Review of Nuclear Program*, January 23, 2003, Page D-2.
[202] See, for example, the minutes for Board meetings on February, May, June, July, and October in 2010, January, March, October, and December, and April, June. July, and August in 2012.
[203] Energy Northwest. *Special Budget Review Meeting of the Executive Board and Participants Review Board.* March 26, 2013. Page 6.

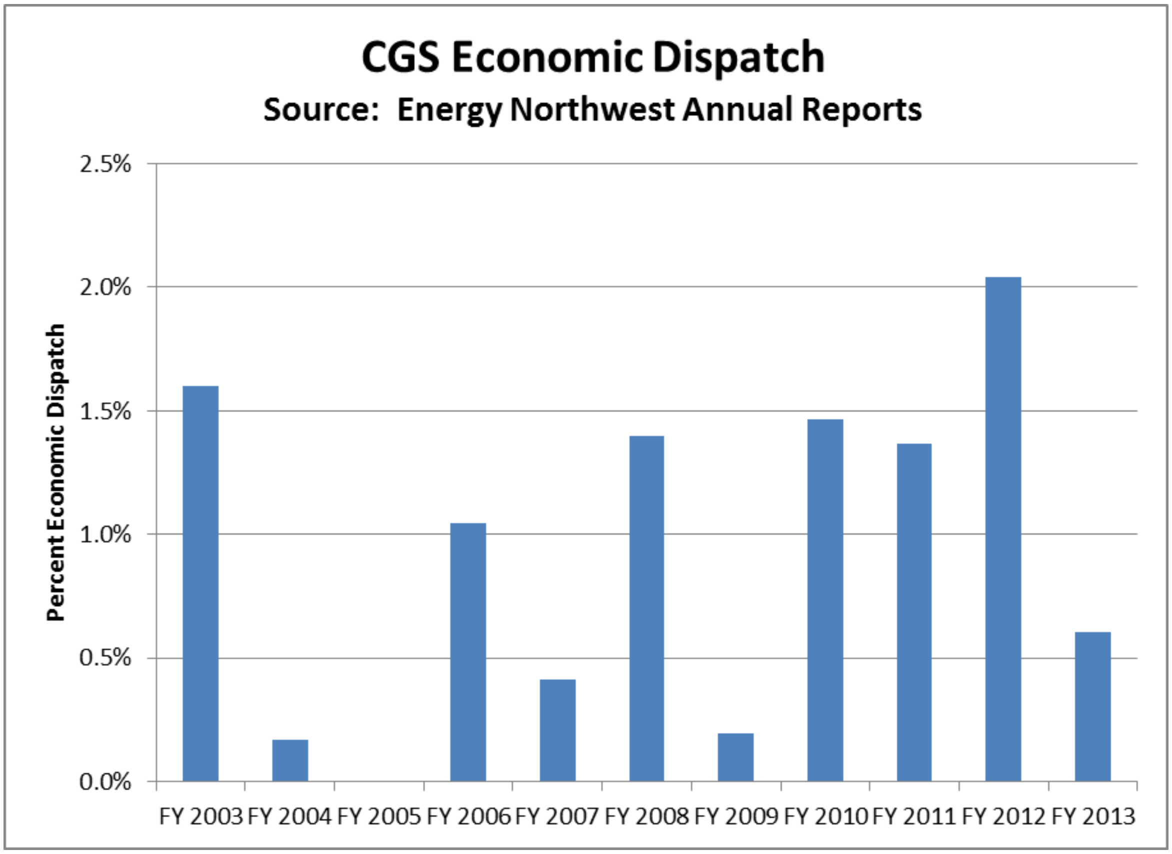


Figure 37

The vertical axis shows the percentage of CGS generation reduced due to requests from BPA each year.

The April 2013 Minutes of the Energy Northwest Regular Executive Board note that economic dispatch is not mentioned in the Net Billing Agreement or the Project Agreement.[204]

The question would seem to have been more than adequately addressed in the Net Billing Agreements, however. Section 8 states:

> 8. Scheduling. Prior to 4 p.m. on each work day beginning on the day preceding the Date of Commercial Operation (work day meaning a day which the Administrator and Supply System observe as a regular work day) the Administrator shall notify Supply System of the amounts of energy from the Participant's Share he will require for each hour of the following day or days; provided, however, that the Administrator may during any hour request

[204] Energy Northwest. *Minutes of the Energy Northwest Regular Executive Board*. April 24-25, 2013. Page 4.

> delivery of other amounts of such energy. Supply System's dispatcher, within the capability of the Participant's Share and in accordance with Prudent Utility Practice, shall schedule for delivery to the Administrator at the point of delivery specified in section 11 for each hour in the term hereof the amounts of energy so requested by the Administrator.[205]

In conclusion, CGS has not been a good candidate for load following in the past, nor does it appear that this is a good role for CGS in the foreseeable future.

4.6 NUCLEAR FUEL CYCLE

CGS relied on traditional nuclear fuel suppliers until 2006 when it began to experiment with the enrichment of tailings supplied by the U.S. Department of Energy and processed to commercial levels at the Paducah enrichment facility in Paducah, Kentucky.[206]

This relationship with Paducah culminated in a massive transaction from May 2012 through May 2013, where Energy Northwest paid over $700 million as part of a complicated – largely political – transaction to produce a 31 year supply of Separation Work Units (SWUs), largely for resale to the Tennessee Valley Authority (TVA).[207]

The prudence of this transaction goes beyond the scope of this report, but it has a bearing on a frequent claim by Energy Northwest Public Affairs Staff that CGS has no carbon emissions.[208] Unfortunately, this claim conflicts sharply with the facts. The Paducah facility is located in Kentucky, where coal is the marginal fuel source used to supply the plant. The Paducah plant is also the nation's largest source of CFC-114 – colloquially known as "Freon."[209]

The fuel for CGS involves five stages of processing before use. These are:

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[205] Department of the Interior. Bonneville Power Administrator. *WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PROJECT NO. 3 AGREEMENT*. September 25, 1973, Section 8, Page 16.

[206] Platts. *BPA to Test Use of Depleted Uranium as Commercial Reactor Fuel.* Platts Commodity News, July 6, 2005.

[207] Beattie, Jeff. *Fate Of Top DOE Nominee Tied To USEC Aid Proposal.* Energy Daily, April 12, 2012.

[208] See, for example:

> Columbia began delivering power to the region in 1984. Since then it has provided billions of dollars worth of electricity while emitting virtually no greenhouse gases or carbon emissions commonly associated with natural gas, coal and other fossil fuel powered plants.

Energy Northwest. *Columbia Generating Station.* Energy-Northwest.com. Web. 17 Sept. 2013. <http://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/default.aspx>.

[209] Nuclear Regulatory Commission. *UNITED STATES ENRICHMENT CORPORATION FINANCIAL REVIEW*. 24 Aug. 2000. Page 15.

1. Mining – commercial ore
2. Refining – refining to Yellow Cake
3. Conversion – production of Uranium Hexafluoride
4. Enrichment – production of 3% to 5% U-235
5. Fuel Fabrication – UO_2 fuel rods

The following chart and discussion are directly taken from the U.S. Department of Energy's summary of the process of developing fuel for nuclear power reactors.[210] We have updated the discussion in some cases to bring it up to date, citing the closure of the Paducah enrichment facility this spring for example.

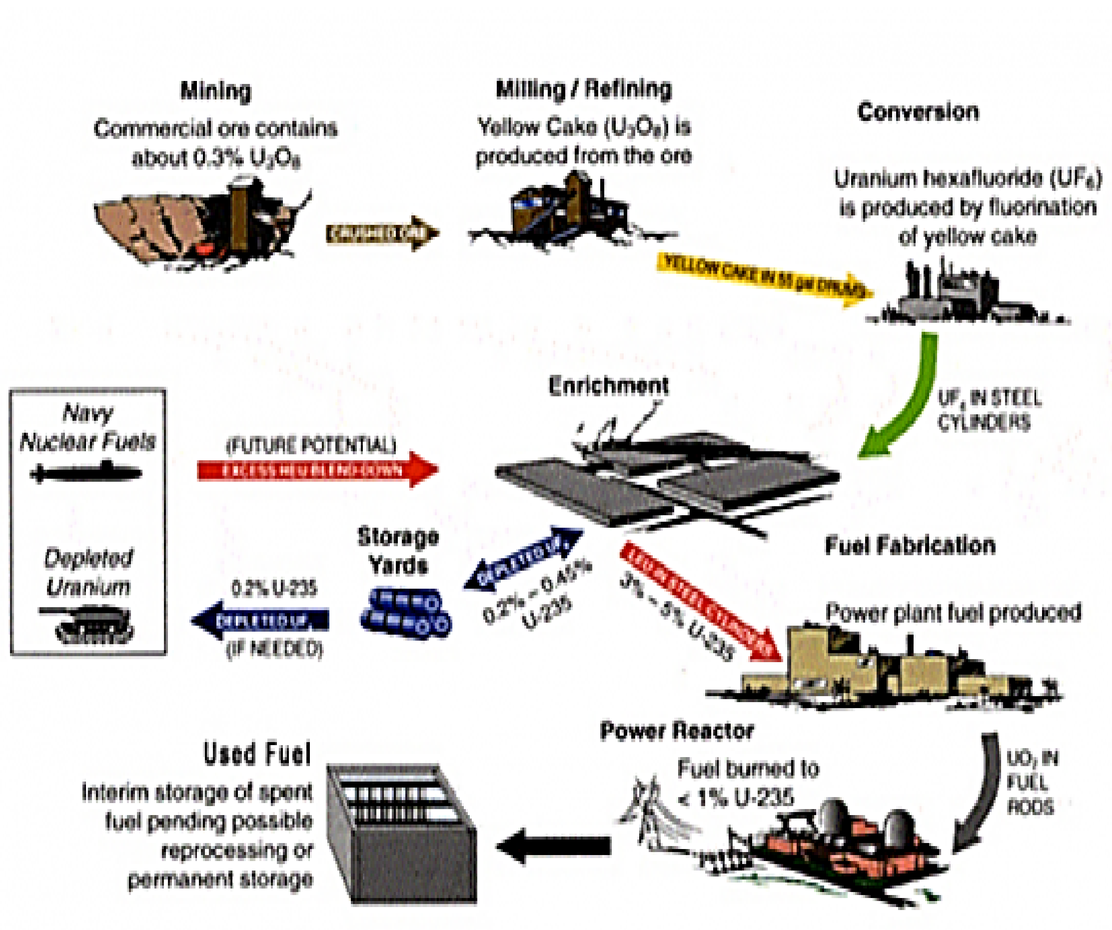

Figure 38

[210] United States Department of Energy. *Nuclear Fuel Cycle.* Energy.gov. Web. 04 Nov. 2013. <http://energy.gov/ne/nuclear-fuel-cycle>.

4.6.1 Uranium Mining

Both "conventional" open pit, underground mining, and in situ techniques are used to recover uranium ore. In general, open pit mining is used where deposits are close to the surface and underground mining is used for deeper deposits. Open pit mining involves a large pit where stripping out and removal of much overburden (overlying rock) is required. Underground mines have relatively small surface disturbance and the quantity of material that must be removed to access the ore is considerably less than in the case of an open pit mine. Special precautions, consisting primarily of increased ventilation, are required in underground mines to protect against airborne radon exposure. An increasing proportion of the world's uranium now comes from in situ recovery (ISR), where oxygenated groundwater is circulated through a very porous orebody to dissolve the uranium oxide before it's pumped to the surface treatment plant where it is recovered. ISR may be with slightly acid or with alkaline solutions to keep the uranium in solution. The uranium oxide is then recovered from the solution as in a conventional mill. In ISR mining that removal of the uranium minerals requires little major ground disturbance and is less operator/personnel intense compared to conventional mines.

4.6.2 Uranium Milling and Processing

Uranium oxide concentrate (often known as "yellowcake") is produced from naturally occurring uranium minerals through milling uranium ore extracted through conventional mining or processing uranium-bearing solution from ISR operations. Most mining facilities include a mill, although where mines are close together, one mill may process the ore from several mines. Milling produces a uranium oxide concentrate which is shipped from the mill. In the milling process, uranium is extracted from the crushed and ground-up ore by leaching, in which either a strong acid or a strong alkaline solution is used to dissolve the uranium oxide. The uranium oxide is then precipitated and removed from the solution. After drying and usually heating, it is packed in drums as a concentrate, sometimes referred to as "yellowcake".

The remainder of the ore, nearly all the rock material, becomes tailings, which are emplaced in engineered facilities near the mine (often in a mined-out pit). Tailings are isolated from the environment because they contain long-lived radioactive materials in low concentrations and toxic materials such as heavy metals. The tailings are placed into a pond in the ground on top of a plastic liner to prevent leakage. The waste is then covered with a layer of soil and then water. In ISR facilities, uranium is concentrated and extracted from solutions into uranium oxide concentrate at a processing plant. As in conventional mining, one processing facility may serve a number of ISR operations. For more information on uranium production, go to the U.S. Energy Information Administration website: http://www.eia.gov/nuclear/

4.6.3 Conversion

For most types of reactors, the concentration of the fissile 235U isotope in natural uranium must be enriched typically to between 3 percent and 5 percent. Natural uranium oxide from mines and processing plants is chemically converted into uranium hexafluoride (UF6), a compound which when heated forms a gas that can be fed into enrichment plants. Honeywell International Incorporated operates the only uranium conversion facility in the U.S. in Metropolis, Illinois.

4.6.4 Enrichment

The enrichment process separates gaseous uranium hexafluoride into two streams, one being enriched to the required level known as low-enriched uranium (LEU); the other stream is progressively depleted in 235U and is called "tails", or simply depleted uranium. There are two types of enrichment technologies in large-scale commercial use, each of which uses uranium hexafluoride gas as feed: gaseous diffusion and gas centrifuge. These processes both use the physical properties of molecules, specifically the 1 percent mass difference between the two uranium isotopes, to separate them. A third technology that can be used to enrich uranium is called laser enrichment. This technology has not been utilized at the commercial level as of today.

4.6.4.1 **Gaseous Diffusion**

The gas diffusion process involves forcing uranium hexafluoride gas under pressure through a series of porous membranes or diaphragms. As U-235 molecules are lighter than the U-238 molecules they move faster and have a slightly better chance of passing through the pores in the membrane. The UF6 which diffuses through the membrane is thus slightly enriched, while the gas which did not pass through is depleted in U-235.

This process is repeated many times in a series of diffusion stages called a cascade. Each stage consists of a compressor, a diffuser and a heat exchanger to remove the heat of compression. The enriched UF6 product is withdrawn from one end of the cascade and the depleted UF6 is removed at the other end. The gas must be processed through some 1,400 stages to obtain a product with a concentration of 3 to 5 percent U-235.

The gaseous diffusion process was first developed in 1943 on a large scale at the U.S. Department of Energy plant in Oak Ridge, Tennessee. Two additional uranium enrichment plants were subsequently constructed in Paducah, Kentucky, and Portsmouth, Ohio. The Ohio plant ceased operation in 2001. USEC Inc. operated the only remaining gaseous diffusion plant, Paducah, until its closure this spring.

Paducah has a long history of controversy. The old equipment was inefficient and costs were high. Paducah was also significant as the United States' largest source of CFC-114 because of its national security exemption from international agreements signed in 1987 banning ozone depleting chemicals.

In recent years, CGS has purchased enrichment services from Paducah and for the last year has been, effectively, its only customer.

4.6.4.2 Gas Centrifuge

The gas centrifuge, like the diffusion process, uses UF6 gas as its feed and makes use of the slight difference in mass between 235U and 238U. The gas is fed into a series of vacuum tubes rotated at very high speeds to obtain efficient separation of the two isotopes. The slightly heavier 238U isotope is concentrated closer to the cylinder wall with the lighter 235U increasing toward the center of the cylinder where it can be drawn off. Although the capacity of a single centrifuge is much smaller than that of a single diffusion stage, its separative capability is significantly greater. In the centrifuge process, the number of stages may only be 10 to 20, instead of a thousand or more for diffusion. Centrifuge stages are arranged in parallel into cascades. The gas centrifuge technology consumes only about five percent as much electricity as the gaseous diffusion technology to produce a given amount of product.

Three companies, Areva Enrichment Services (AES), a wholly owned subsidiary of AREVA; Louisiana Enrichment Services (LES), a wholly owned subsidiary of URENCO, Ltd.; and USEC have received licenses from the NRC to build and operate uranium enrichment facilities in the United States using centrifuge technology. The NRC issued a license in 2004 to USEC to construct a test and demonstration facility known as the Lead Cascade at the Piketon, Ohio site, and a separate license in 2007 to construct and operate the full-scale American Centrifuge Plant. In June 2006, the NRC issued a license to LES to construct and operate the National Enrichment Facility in Lea County, New Mexico. The National Enrichment Facility is currently operating. A third gas centrifuge plant is being planned by AES as the Eagle Rock Enrichment Facility near Idaho Falls, Idaho.

4.6.4.3 Fuel Fabrication

Reactor fuel is generally in the form of ceramic pellets. These are formed from pressed uranium oxide (UO_2) which is sintered (baked) at a high temperature (over 2550°F). The pellets are then encased in metal tubes to form fuel rods, which are arranged into a fuel assembly ready for introduction into a reactor. The dimensions of the fuel pellets and other components of the fuel assembly are precisely controlled to ensure consistency in the characteristics of the fuel. Nuclear fuel assemblies are specifically designed for particular types of reactors and are made to quality assurance specifications. The most common reactor, the pressurized-water reactor (PWR), contain between 150-200 fuel assemblies whereas the boiling-water reactor, like the CGS, which is the second most common reactor contain between 370-800 fuel assemblies.

In a fuel fabrication plant great care is taken with the size and shape of processing vessels to avoid criticality (a limited chain reaction releasing radiation). With low-enriched fuel criticality is most unlikely, but in plants handling special fuels for research reactors, this is a vital consideration. There are currently three fuel fabrication plants in the U.S.: 1) AREVA Inc. in Richland, Washington, 2) Global Nuclear Fuel-Americas, LLC in Wilmington, North Carolina, and 3) Westinghouse Electric Company, LLC in Columbia, South Carolina.[211]

4.6.5 Uranium Tails Pilot Project

Since 2005, an important component in CGS's fuel supply has been the enrichment of tailings at USEC's Paducah, Kentucky facility.[212]

The U.S. Department of Energy has a vast stockpile of depleted uranium. These tailings can be enriched to commercial levels by returning them to an enrichment facility. In the case of the United States Enrichment Company's Paducah facility, tailings with an average assay of .44% were enriched to bring their assay to 4.4% nuclear fuel.

> Energy Northwest provided the following history and final results of the project through 2007:
>
> - An Action Memorandum was brought to the Executive Board in December 2004 stating that the pilot project would process 8,534 metric tons of DUF6 into between 1,820 and 1,957 metric tons of UF6 with an assay equivalent to natural uranium.
> - Combined estimated pilot project cost was $85 to $88 million to produce between 1,820 and 1,957 metric tons of UF6.
> - The current market value of $62 per KgU of UF6 was between $112 and $123 million or a savings of between $27 and $35 million.
> - The final savings value would be calculated at the end of the pilot project.
> - UTPP produced 1,939 metric tons of natural equivalent UF6.
> - UTPP cost was $94.6 million plus UTPP taxable bonds cost of $31.4 million equaled a total cost of $126 million.
> - November 2006 average spot market price for UF6 was $177.68 per KgU.
> - Spot market value of the UF6 produced by the UTPP was $344.7 million; Energy Northwest paid $126 million.

[211] United States Department of Energy, *Nuclear Fuel Cycle*.
[212] Ferek, Lisa L. *FY 2007 Fuel Management Plan*, Energy Northwest. April 26, 2006. Page 11.

- Increased loan revenue and bond interest for FY07 is $7.8 million; no credit is taken for any additional loan revenue from UTPP uranium.
- Final cost savings value is calculated to be $226.5 million.[213]

4.6.6 Depleted Uranium Enrichment Program

In May 2012, Energy Northwest, TVA, the Department of Energy, and USEC commenced a major expansion of the tails enrichment program in order to keep the Paducah facility open until May 2013.[214]

The agreement involved Energy Northwest purchasing approximately 31 years of uranium enrichment from USEC in return for $700 million.[215,216] Approximately seven eighths of the enrichment units plus a block of uranium has been sold to TVA over the next decade.[217]

The uranium enrichment transaction at Paducah involves the Tennessee Valley Authority, the US Enrichment Corporation, and the US DOE. As part of the transaction, the US DOE provided uranium tailings to Energy Northwest. Energy Northwest had the uranium tailing enriched at USEC's plant in Paducah, Kentucky that is located next to the US DOE's uranium tailings storage facility. USEC delivered enriched uranium on a biweekly basis and the enriched uranium was stored at the US DOE's site. Energy Northwest expects to retain roughly one eighth and sell seven eighths of the enriched uranium and separative work units (SWU) to TVA, starting in 2015. Energy Northwest expected the uranium enrichment program would provide significant cost savings compared to its forecasted fuel costs and compared to current market prices.

The complicated fuel transaction with the United States Enrichment Corporation is only relevant to our study if it requires continued operation of Energy Northwest's plant. Our reading of the complex contracts is that it does not. The Paducah contracts do not commit Energy Northwest to continued plant operations.

213 Energy Northwest. *Minutes of Energy Northwest Regular Executive Board Meeting.* December 14, 2006, Page 13.
214 Energy Northwest. *2012 Uranium Enrichment Program.* April 26, 2012.
215 Ferek, Lisa L. *FY 2007 Fuel Management Plan*, Energy Northwest. April 26, 2006. Page 14.
216 *AGREEMENT between ENERGY NORTHWEST and UNITED STATES ENRICHMENT CORPORATION, USEC CONTRACT NO. EC-SC01-12UE03133, ENERGY NORTHWEST CONTRACT NO. 335900, Article 3.1.*
217 *ENRICHED PRODUCT AND UF6 SUPPLY AGREEMENT between TENNESSEE VALLEY AUTHORITY and ENERGY NORTHWEST, EN CONTRACT NUMBER 335901, TVA CONTRACT NUMBER 6140, Sections 3.1b and 5.1b.*

4.6.7 Emissions

Energy Northwest has frequently claimed in recent years that the CGS is carbon free. An even more doubtful claim is that CGS has prevented millions of tons of carbon from entering the atmosphere.[218,219]

The reality is completely different. Energy Northwest has chosen a particularly energy intensive supplier of enrichment services in a state that is highly dependent on coal. Moreover, Energy Northwest's role in the 2012 Depleted Uranium Enrichment Program has caused an enormous one-time release of carbon and CFC-114 into the atmosphere.

Paducah's use of gaseous diffusion made it one of the most expensive enrichment facilities in the world. The use of tailings apparently also contributed to a low level of energy efficiency during the contract period. The following chart shows Paducah energy efficiencies – kilowatt-hours per Separation Work Unit over time:

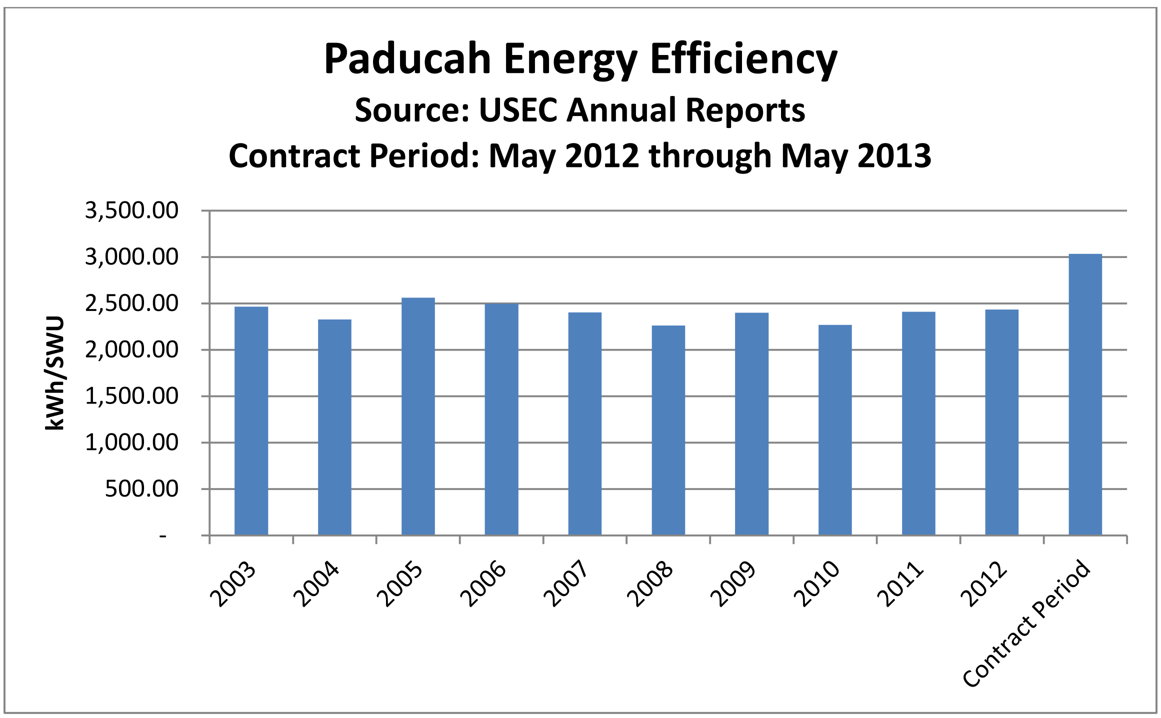

Figure 39

[218]Again, in one year, the electricity from CGS prevented 7.9 million metric tons of greenhouse gases from entering the atmosphere. Source: Nuclear Energy Institute.

[219] Energy Northwest. *Environmental Commitment*. Energy-northwest.com. Web. 17 Sept. 2013. <http://www.energy-northwest.com/whoweare/environmentalcommitment/Pages/default.aspx>.

A standard tool for estimating the carbon impact of the nuclear fuel cycle can be found at http://www.wise-uranium.org/nfce.html. This tool allows the insertion of site specific values for energy intensity, carbon release from electric generation, and other factors. Each of the five stages in the nuclear fuel cycle is separately calculated. Not surprisingly, the enrichment stage is the most important.

Emissions per kilowatt-hour for Kentucky were taken from the Environmental Protection Agency's eGrid database.[220]

The kWh per SWU is taken from the USEC 2012 Annual Report. Plant generation is entered as the average generation over the two year refueling cycle.

The results are shown below:

	Energy Consumption			CO_2 Emission		
	Fossil Fuel		Electricity	from fossil fuel	from electricity	Total
	[TJ]	= [GWh_{th}]	[GWh_e]	[t]	[t]	[t]
Mining	80.97479	22.49300	0.533200	5992.135	548.1297	6540.265
Milling	96.09540	26.69317	3.700568	7111.059	3804.184	10915.24
Conversion	540.2658	150.0738	5.558103	39979.67	5713.730	45693.40
Enrichment	85.82793	23.84109	379.1671	6351.267	389783.7	396135.0
Fuel Fabrication	69.58425	19.32896	7.729014	5149.234	7945.427	13094.66
Total	872.7482	242.4301	396.6879	64583.37	407795.2	472378.6

Figure 40

An average year of operations at CGS released 472,378 metric tons of CO2 into the atmosphere.

Paducah's technology has been superseded in almost all respects. Not the least of the changes is that it still used CFC-114, a banned ozone-depleting gas.[221] EPA reports indicate

[220] Environmental Protection Agency. *EGRID*. Epa.gov. Web. 17 Sept. 2013. <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.

[221] CFC-114 was banned in the Montreal Protocol. The Montreal Protocol was signed by the United States in 1987.

that in 2012 68.6% of CFC-114 release in the U.S. occurred at Paducah.[222] CFC-114, known to most of us as Freon, was used for cooling at the facility. In addition to its atmospheric ozone-depleting qualities, CFC-114 is a far greater greenhouse gas polluter than CO-2 – between 8,040 and 10,000 times greater – according to the Intergovernmental Panel on Climate Change.[223]

The reported release, 184,195 pounds, adjusted by the lowest of the relative impact ratios from the IPCC, would add a carbon equivalent impact of 672,708 tonnes.[224] This value, of course, would correspond to the entire facility in 2012. CGS's own annual requirements – 128,000 SWUs would be 2.56% of total production for 2012, making the additional carbon equivalent impact an additional 44,265 tonnes. In sum, CGS's own carbon impact in 2012 totaled 489,759 tonnes.

The 2012 Uranium Enrichment Program produced 4,000,000 SWU's – 31.25 times CGS's annual requirements. The full impact of the decision to sign this specific contract, factoring 489,759 tonnes released annually by 31.25, added a total of 15,299,373 tonnes of carbon and carbon equivalent gases to the atmosphere.

By comparison, in 2012, the average dispatchable natural gas fired generation unit in Washington State operated only 12.8% of the time. The remainder of the generation was provided by plentiful wind and hydroelectric generation. To meet the same capacity loads as CGS, the natural gas fired generation in Washington would have required 9,619,924 MMBTU of natural gas with a carbon emission of only 510,537 tonnes.[225,226,227] In addition to the carbon footprint outlined above, the inability of CGS to be displaced when zero carbon alternatives are plentiful puts it at a severe environmental disadvantage.

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222 Environmental Protection Agency. *Pollution Prevention.* Epa.gov. Web. 18 Sept. 2013. <http://iaspub.epa.gov/enviro/P2_EF_Query.p2_report?FacilityId=42001PDCHGHOBBS&ChemicalId=000076142&ReportingYear=2001&DocCtrlNum=>.

223 Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.) *Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, 2007 Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Web. 3 Oct. 2013. <http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html>.

224 A metric ton is 2204.6 pounds. It is commonly represented by the term "tonne" as opposed to the more common tern, "ton", which represents 2,000 pounds.

225 The total MMBTUs used in Washington state for generation are available at http://www.eia.gov/electricity/data/eia923/. Total capacity from this source is 4,155.9 megawatts. MMBTUs to meet an 1,170 megawatt load were 9,619,924 with a carbon content of 117 pounds per MMBTU. The source for pounds per MMBTU is http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

226 Energy Information Administration. *Frequently Asked Questions.* Eia.gov. 4 Mar. 2013. Web. 3 Dec. 2013. <http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11>

227 Energy Information Administration. *Form EIA-923 detailed data*. Eia.gov. Web. 3 Dec. 2013. <http://www.eia.gov/electricity/data/eia923/>.

Paducah closed this spring due to falling enrichment prices and unwillingness at the U.S. Department of Energy to provide additional support for programs like the 2012 Uranium Enrichment Program. Future enrichment will be met by more efficient facilities. These facilities will produce significantly less carbon and no CFC-114.

The downside of the 2012 Uranium Enrichment Program is that Energy Northwest has locked itself in to a high carbon fuel supply for some years to come – both for itself and TVA. The carbon and Freon have been released and cannot be recalled. Under no circumstances, however, can Energy Northwest be viewed as emissions free.

4.7 CGS LIFE EXPECTANCY

The difference between the relicensing of hydroelectric facilities at the Federal Energy Regulatory Commission and the relicensing of nuclear facilities at the Nuclear Regulatory Commission was raised in a number of our interviews.

Hydroelectric relicensing addresses a wide variety of prospective economic, environmental, and engineering issues. A successful relicensing carries with it a high probability of the operation of the plant through the life of the new license. A license from the Nuclear Regulatory Commission, on the other hand, represents permission to continue operating the plant, but carries no overall assurance of continued operation.

A recent New York Times article noted:

> When the Nuclear Regulatory Commission began routinely authorizing reactors to run 20 years beyond their initial 40-year licenses, people in the electricity business began thinking that 60 was the new 40. But after the last few weeks, 40 is looking old again, at least in reactor years, with implications for the power plants still running, and for several new ones being built.[228]

Recent examples include the Kewaunee Power Station owned and operated by Dominion, the San Onofre Nuclear Generating Station owned by Southern California Edison, San Diego Gas & Electric, and the City of Riverside, and Duke Energy's Crystal River 3 Nuclear Power Plant.

[228] Wald, Matthew L. *Nuclear Plants, Old and Uncompetitive, Are Closing Earlier Than Expected.* New York Times. 14 Jan. 2013. Web. 18 Sept. 2013. <http://www.nytimes.com/2013/06/15/business/energy-environment/aging-nuclear-plants-are-closing-but-for-economic-reasons.html>

4.7.1 Kewaunee Nuclear Plant

The Kewaunee Nuclear Plant is a 556 MW Pressurized Light Water Reactor (PWR) located in Carlton, Wisconsin. On May 7, 2013, the plant was permanently closed entirely for economic reasons.

The plant began operations in June 1974 and was originally owned by Wisconsin Public Service Corp (WPS) and Wisconsin Power and Light, a subsidiary of Alliant Energy. Dominion Energy purchased the plant for $192 million in 2005. As part of the deal, WPS and Alliant agreed to purchase power at a fixed rate from Kewaunee through 2013 when the plant's license expires. Kewaunee received a new license on December 21, 2011 allowing operation unit December 21, 2033.[229]

Dominion experienced operational, maintenance, and strategic difficulties at the Kewaunee plant. For a month in 2011, a link that provides radiation data to control room operators was broken at the Kewaunee plant.[230] Dominion was also fined $70,000 by the NRC for falsifying records and failing to conduct fire drills. Dominion planned to acquire more reactors in the Midwest to benefit from economies of scale since it is not as profitable to operate a stand-alone nuclear plant without other assets in the vicinity.[231] The plant struggled in the face of low natural gas prices, high fixed costs, and expensive repairs which made it difficult to compete.

The company spent over a year trying to sell the plant, but no buyer emerged. Even though the license was renewed through 2033, the company announced that the plant did not improve shareholder value or support its objectives to provide a return on invested capital, so they decided to close its doors at its scheduled refueling in May of 2013.[232, 233, 234] Dominion spokesman Mike Kanz cited plummeting electricity prices on the wholesale regional power market and the inability to acquire more reactors in the Midwest to benefit from economies of scale. In addition, Kewaunee's power purchase agreements were ending

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229 Nuclear Regulatory Commission. *Kewaunee Power Station.* NRC.gov. 2 Aug. 2013. Web. 18 Sept. 2013. <http://www.nrc.gov/info-finder/reactor/kewa.html>.

230 Nuclear Regulatory Commission. http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/reactors/k.html

231 Wald, Matthew L. New York Times. "Aging and Expensive, Reactors Face Mothballs." New York Times. 23 Oct. 2012. Web. 19 Sept. 2013 <http://www.nytimes.com/2012/10/24/business/energy-environment/economics-forcing-some-nuclear-plants-into-retirement.html?_r=1&>

232 Dominion. *Midwest ISO Concludes That Closing Of Kewaunee Power Station Will Not Affect Regional Electric Reliability. Dom.mediaroom.com*. 19 Feb. 2013. Web 3 Dec. 2013. <http://dom.mediaroom.com/2013-02-19-Midwest-ISO-Concludes-That-Closing-Of-Kewaunee-Power-Station-Will-Not-Affect-Regional-Electric-Reliability>.

233 Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Jsonline.com. Milwaukee Wisconsin Journal Sentinel. <http://www.jsonline.com/business/kewaunee-nuclear-power-plant-shutdown-cost-is-nearly-1-billion-lr9j5fg-203912611.html>.

234 Wald, Matthew, *Aging and Expensive, Reactors Face Mothballs.*

at a time when Wisconsin utilities shunned high priced nuclear energy in favor of low priced natural gas. [235]

The Midwest Independent System Operator (MISO) determined that grid reliability would not be affected as a result of the Kewaunee nuclear plant closing. In a letter to Dominion, MISO wrote that "After being reviewed for power system reliability impacts, the retirement of Kewaunee would not result in violations of applicable reliability criteria. Therefore, Kewaunee may retire immediately." [236] Once the fuel has been removed from the reactor, the license will no longer authorize operating the plant. The license remains in effect until the company completes decommissioning and the NRC sends notification of license termination.

All of the spent fuel that has been used since 1974 is located on site, with only a very small amount moved to dry cask storage. Dominion will spend an estimated $340 million upfront for the disposal of spent fuel, which is presumably to be reimbursed by the federal government when it establishes a high-level waste repository.[237,238] Currently, eight dry casks storage modules are on site, with the potential to hold an additional 32 storage modules. The contents of the spent fuel pool will be transferred to dry cask storage by the end of 2019. [239,240]

Dominion selected the SAFSTOR decommissioning approach. Once the plant is shut down and defueled, the facility is stabilized and maintained in a safe storage state. At the end of the storage period, the facility is dismantled and decontaminated to a level that permits license termination. Fuel is removed from the reactor vessel and stored in the spent fuel pool for around seven years. At that point, the spent fuel will be transferred to the onsite

[235] Content, Thomas. *Community vents over timeline for nuclear plant decommissioning.* Jsonline.com. Milwaukee Wisconsin Journal Sentinel. 25 Apr. 2013. Web. 3 Dec. 2013. <http://www.jsonline.com/business/community-vents-over-timeline-for-nuclear-plant-decommissioning-q99n7mg-204769391.html>

[236] Dominion. *Midwest ISO Concludes That Closing Of Kewaunee Power Station Will Not Affect Regional Electric Reliability.*

[237] Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Milwaukee Wisconsin Journal Sentinel, 20 Apr. 2013

[238] Ibid.

[239] Ryman, Richard. *Kewaunee nuclear plant VP talks about shutdown. Greenbaypressgazette.com.* Green Bay Press Gazette. 29 Apr, 2013. Web. 3 May 2013. <http://www.greenbaypressgazette.com/article/20130428/GPG03/304280308/Kewaunee-nuclear-plant-VP-talks-about-shutdown>.

[240] Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Milwaukee Wisconsin Journal Sentinel, 20 Apr. 2013

Independent Spent Fuel Storage Installation (ISFSI) until the DOE locates a permanent repository.[241]

Detailed decommissioning costs for Kewanee are located on page 90 of the "Kewaunee Post Shutdown Decommissioning Activities Report".[242] The following chart provides a summary of the projected $920 million of decommissioning costs:

Kewaunee Power Station Schedule and Costs of Decommissioning (2012 dollars)				
Description	**Start**	**End**	**Years**	**Cost**
A. License Termination				
SAFSTOR Planning, Preparations, and Deactivation	7/1/2013	11/30/2014	1.41	$99,274,000
SAFSTOR Preparation, Delay During Wet Fuel Storage	11/30/2014	7/1/2020	5.58	$25,105,000
Completion of SAFSTOR Preparations	7/1/2020	12/28/2020	0.49	$15,899,000
Dormancy With Dry Storage	12/28/2020	10/19/2050	29.8	$51,910,000
Dormancy Only	10/19/2050	4/17/2067	16.49	$28,550,000
Decommissioning Planning During Dormancy	4/17/2067	6/22/2069	2.18	$42,755,000
Dismantlement Site Modifications and Preparations	6/22/2069	5/24/2070	0.91	$64,972,000
Systems Removal	5/24/2070	10/26/2071	1.42	$153,318,000
Site Decontamination	10/26/2071	8/29/2072	0.84	$61,058,000
			59.12	**$542,841,000**
B. Spent Fuel				
Spent Fuel Planning, Cooling and Transfer to Dry Storage	7/1/2013	7/1/2020	7	$175,227,000
Dry Storage During Completion SAFSTOR Preparations	7/1/2020	12/28/2020	0.49	$2,665,000
Dry Storage During Dormancy	12/28/2020	10/19/2050	29.8	$161,714,000
ISIFI Demolition	10/19/2050	7/31/2073	0.33	$2,622,000
			37.62	$342,228,000
B. Greenfield				
Clean Building Demolition	8/29/2072	7/31/2073	0.91	$30,827,000
Site Restoration	7/31/2073	12/4/2073	0.34	$3,976,000
			1.25	$34,803,000
SCENARIO TOTAL				**$919,872,000**

Figure 41

Source: Kewaunee Power Station Post-Shutdown Decommissioning Activities Report[243]

241 Dominion Energy. *Kewaunee Power Station, Post Shutdown Decommissioning Report*. 26 Feb. 2013. Web. 3 Dec. 2013. <http://pbadupws.nrc.gov/docs/ML1306/ML13063A248.pdf>.
242 Ibid.
243 Nuclear Regulatory Commission. "Kewaunee Power Station Post-Shutdown Decommissioning Activities Report." Nrc.gov, 26 Feb. 2013. Web. <http://pbadupws.nrc.gov/docs/ML1306/ML13063A248.pdf >

4.7.2 San Onofre Nuclear Generating Station (SONGS)

The San Onofre Nuclear Generating Station (SONGS) was a three unit pressurized water reactor located on the Pacific Plate of the active San Andreas Fault line in San Diego County.[244] Unit 1 was operational for 25 years before it was decommissioned in 1992. Units 2 and 3 became operational in 1983 and 1984 respectively. Southern California Edison (SCE) holds a 78% ownership stake, Sempra Energy's San Diego Gas & Electric holds 20%, and the City of Riverside has the remaining stake.[245]

SCE completed a $671 million steam generation replacement project in 2011 for Units 2 and 3. During a routine refueling outage in January 2012, SCE operators found a small leak in the steam generator tube in Unit 3 which allowed radioactive steam to mix with the steam going outside the containment building to the generators.[246] Both units were shut down for inspection and substantial degradation of the newly installed tubes was discovered.[247] By July 2012, the NRC said "the plant will not be permitted to restart until the licensee has developed a plan to prevent further steam generator tube degradation and the NRC independently verifies that it can be operated safely."[248]

The alternatives SCE examined included closing the plant and either buying replacement power on the market or building replacement generation. The conclusion reached was that a cross-over point was reached where operating Unit 2 no longer cost less than the alternatives.[249]

On June 7, 2013, SCE announced that units 2 and 3 of SONGS would be prematurely retired. Ted Craver, Southern California Edison's chairman and chief executive officer, said that instead of "continu[ing] to spend approximately $30 million a month to keep the plant

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244 Gerhardt, Tina. *San Onofre Nuclear Generating Station to Remain Shuttered*. *Washingtonmonthly.com*. Washington Monthly. 23 Jul. 2012. Web. 3 Dec 2013. <http://www.washingtonmonthly.com/ten-miles-square/2012/07/san_onofre_nuclear_generating038760.php>

245 O'Grady, Eileen. *Grid looking at extended San Onofre nuclear outage.* Uk.reuters.com. Reuters. 21 Mar. 2012. Web. 3 Dec 2013. <http://uk.reuters.com/article/2012/03/21/utilities-california-sanonofre-idUKL1E8ELSYE20120321>.

246 Spotts, Pete. *California nuclear plant to shut: a case of unforgiving nuclear economics.* Csmonitor.com. Christian Science Monitor. 7 Jun. 2013. Web. 3 Dec. 2013. <http://www.csmonitor.com/Environment/2013/0607/California-nuclear-plant-to-shut-a-case-of-unforgiving-nuclear-economics>

247 O'Grady, Eileen. *Grid looking at extended San Onofre nuclear outage.*

248 Gerhardt, Tina. *San Onofre Nuclear Generating Station to Remain Shuttered.*

249 Craver, Ted. *Prepared Remarks of Ted Craver Chairman and Chief Executive Officer, Edison International EIX SONGS Update Conference Call.* Edison.com. Edison International. 7 Jun. 2013. Web. 3 Dec. 2013. <http://www.edison.com/files/EIX SONGS Update Call CEO Prepared Remarks 6-7-2013.pdf>

ready for restart, and prolong the uncertainty surrounding the plant, we have decided to no longer seek to restart SONGS.[250]

Over the next year, the plant's workforce will be cut from 1,500 to about 400 — who will be charged with securing the plant during the potentially decades-long decommissioning process. Daniel Dominguez, business manager for Utility Workers Union of America Local 246, said the employees were disappointed but will now focus on keeping the facility safely shut down: "We're all professionals," he said. "It's unfortunate the plant was shut down, but it is what it is."[251]

4.7.3 Crystal River 3

On February 5, Duke Energy announced plans to retire Crystal River Unit 3 in Florida. This was shortly after Duke had acquired Progress Energy, which owned Crystal River. Crystal River Unit 3 was licensed to operate through 2016, and an application to extend the operating life of the unit to 2036 was under review by the NRC. Crystal River Unit 3 was shut down in September 2009 to refuel and to replace its steam generators. During the shutdown, workers discovered damage to the concrete wall of the containment building, and additional damage occurred during subsequent repairs in 2011. Although a 2012 report indicated that the damage could be repaired and the plant restored to service, the uncertainty surrounding the cost and timing of repairs ultimately led Duke Energy to retire Crystal River Unit 3.[252]

The company and its insurance carrier, Nuclear Electric Insurance Limited (NEIL), have reached a resolution of the company's coverage claims through a mediation process. Under the terms of the mediator's proposal, NEIL will pay an additional $530 million. Along with the $305 million NEIL has already paid, customers will receive $835 million in insurance proceeds. This will be the largest claim payout in the history of NEIL.[253]

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[250] Ibid.

[251] Sewell, Abby and Anh Do. *San Onofre closure generates mixed feelings*. Latimes.com. Los Angeles Times. 23 Jun. 2013. Web. 3 Dec. 2013. <http://articles.latimes.com/2013/jun/23/local/la-me-adv-nuclear-neighbors-20130624-1>.

[252] Energy Information Administration. *Lower power prices and high repair costs drive nuclear retirements.* Eia.gov. 2 Jul. 2013. Web. 3 Dec. 2013. <http://www.eia.gov/todayinenergy/detail.cfm?id=11931>.

[253] Duke Energy. *Crystal River Nuclear Plant to be retired; company evaluating sites for potential new gas-fueled generation*, Duke-energy.com. 5 Feb. 2013. Web. 3 Dec 2013. <http://www.duke-energy.com/news/releases/2013020501.asp>

Duke has not yet filed its Post-Shutdown Decommissioning Activities Report (PSDAR), but their second quarter report indicates a write down of an additional $295 million over current decommissioning funds.[254]

4.7.4 West Coast Plants

Nuclear plants on the West Coast – Arizona, California, Oregon and Washington – have faced a significantly more adverse environment than the industry elsewhere in the United States. As of the date of this report 60% of commercial nuclear plants have closed in our region.[255]

The West Coast has commissioned fifteen nuclear power stations since 1963. Nine units have closed – Vallecitos Nuclear Center, Sodium Reactor Experiment, Humboldt Bay, the Hanford N-Reactor, Rancho Seco, Trojan, and the three San Onofre units. The major risk to a nuclear plant has been aging and economics. None of the major units were closed due to accidents. San Onofre and Trojan was closed because of the economics of repair, not an accident, per se.

4.7.4.1 *Humboldt Bay Nuclear Power Plant*

The Humboldt Bay Nuclear Power Plant (HBPP) was a 63 MWe GE boiling water reactor, owned by Pacific Gas and Electric Company that operated from August 1963 to July 1976 just south of Eureka, California. It was one of the first BWR's built and was less than one-tenth the size of later reactors.

According to a summary by the Nuclear Regulatory Commission (NRC), on July 2, 1976, Humboldt Bay Power Plant Unit 3 was shut down for annual refueling and seismic modifications, and it never reopened. In 1983, an economic analysis indicated that restarting the unit would probably not be cost-effective, and PG&E announced that it would decommission the unit. In 1985, the NRC changed the license status to possess-but-not-operate, and the plant was placed into SAFSTOR.

SAFSTOR decommissioning is a method in which radioactive components of the nuclear plant are maintained in storage awaiting decontamination to levels that permit license termination at a later date.

[254] Duke Energy. *Duke Energy posts second quarter 2013 results*. August 7, 2013. Page 3.
[255] Vallecitos Nuclear Center, Sodium Reactor Experiment, Humboldt Bay Nuclear Power Plant, Rancho Seco Nuclear Generating Station, Trojan Nuclear Power Plant, N-Reactor, San Onofre Nuclear Generating 1, 2, and 3 are closed. Diablo Canyon, CGS, and Palo Verde 1, 2, and 3 are operating.

In December 2003, PG&E submitted a license application for a dry-cask Independent Spent Fuel Storage Installation (ISFSI) at Humboldt Bay. A license for the ISFSI was issued in November of 2005. The transfer of spent fuel to the ISFSI was completed in December 2008. PG&E proceeded with limited decontamination and dismantlement of HBPP Unit 3 decommissioning commenced.

In 2010 the construction of a new power generation facility on site was completed. Radiological surveys of the area of the new plants were performed by the licensee. The NRC, with staff from ORISE, performed confirmatory surveys prior to construction. The licensee has begun decontamination and dismantlement of the non-nuclear Units 1 and 2 as well as the nuclear Unit 3. The estimated date for full closure is December 31, 2015.[256]

4.7.4.1 *Hanford N-Reactor*

The Hanford N Reactor was the only reactor of its kind – a dual purpose reactor that produced plutonium for nuclear weapons and generated electricity. President Kennedy visited Hanford in 1963 to break ground on the electricity generating component of the facility.

By the late 1960s, Hanford entered a period of decline in plutonium production operations as a result of a diminished need for plutonium and shifting national defense plans. All of the single-purpose plutonium production reactors were closed except the N Reactor, which remained open to research nuclear power a source of alternative energy.

The N Reactor was shut down for routine maintenance in 1987 but never restarted. Over 1 million gallons of contaminated water left in its storage basin have since been removed for treatment and disposal. Approximately 1/3 of Hanford's irradiated fuel segments left behind have also been moved to a Canister Storage Building awaiting a national repository.

4.7.4.2 *Trojan*

The Trojan Nuclear Plant was a 1,130 MW pressurized water reactor operated by Portland General Electric near Rainier, Oregon. The plant was licensed by the Atomic Energy Commission for forty years and began operating in 1976, yet the plant was plagued with

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[256] Nuclear Regulatory Commission. *Humboldt Bay.* Nrc.gov. 20 Nov. 2013. Web. 3 Dec. 2013. <http://www.nrc.gov/info-finder/decommissioning/power-reactor/humboldt-bay-nuclear-power-plant-unit-3.html>.

problems from the beginning and closed in 1993 after less than seventeen years in operation.[257]

In 1972, *the Wall Street Journal* reported that the U.S. Geological Survey had found a "concealed fault" running through the Columbia River next to the plant site. John Gofman, a former Atomic Energy Commission scientist, compared Trojan to "locating 2,500 atomic bombs worth of radiation in Portland's back yard."[258]

By 1977, it was discovered that the containment building walls were missing critical reinforcing rods and was not in compliance with the Uniform Building Code. Betchel, the contractor for Trojan, attempted an engineering patch which ultimately weakened the building, and the company was sued by PGE. PGE President Robert Short testified that 'This is the worst mistake we have ever seen in a construction project of this size." A 1981 review by the engineering consulting firm Preece/Goudie noted that given "the magnitude of the earthquake loads and the importance of the structure, it was the grossest kind of error."

Microscopic cracks were found during an annual refueling and maintenance shutdown in 1991. The outage was supposed to last 45 days, but ended up lasting over a year. PGE requested and received a temporary waiver authorizing Trojan to start up with unrepaired flaws in 428 tubes.

In 1992, a review by Schlissel Engineering Associates found that replacing Trojan's four steam generators would cost between $145 million and $215 million ($1993) and require a four month outage. The report found that the lifetime capacity factor for the plant was a lackluster 52% while finding no evidence to support PGE's claim from their Least Cost Plan which projected that Trojan would achieve a 71% capacity factor.[259]

Several statewide ballot measures were aimed at closing the Trojan nuclear plant. In 1980, Measure 7 was approved by voters, which placed a moratorium on the licensing of any new nuclear power plants in Oregon, though this was measure aimed at the Pebble Springs nuclear plants under construction and not at Trojan. In 1986, Measure 14 would have closed Trojan unless there was either a permanent spent fuel disposal site or a declaration of

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257 Nipper, Gregory. *Progress and economy: the clash of values over Oregon's Trojan Nuclear Plant*. Dissertations and Theses Portland State University. 1 Jan. 2005. Web. <http://pdxscholar.library.pdx.edu/cgi/viewcontent.cgi?article=1248&context=open_access_etds>.

258 Koberstein, Paul. *Trojan: PGE's Nuclear Gamble.* WWeek.com. Willamette Week. 9 Mar. 2005. Web. 3 Dec. 2013. <http://www.wweek.com/portland/article-4174-1975.html>.

259 "Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs". Schlissel Engineering Associates, July 15, 1992

emergency by the state legislature.[260] By 1992, the following two measures were presented to voters:

> MEASURE 5: Closes Trojan until Nuclear Waste, Cost, Earthquake, Health Standards Met
>
> Summary: Enacts new law. Suspends electric power generation at Trojan plant. Provides that no Oregon nuclear power plant, including Trojan, shall generate electricity unless the Energy Facility Siting Council finds, after a hearing: a permanent radioactive waste repository has been federally licensed and is accepting waste; the plant is then cost-effective, the plant can withstand major earthquakes without harming the public; and released radiation does not harm the public. If legislature declares electric power emergency and refers the question, voters may suspend or repeal this law.
>
> MEASURE 6: Bans Trojan Power Operation
>
> Summary: Act requires independent study of earthquake risk at, near Trojan site, plant's ability to withstand earthquake. Unless the Siting Council finds Trojan plant can withstand possible earthquake without harm to life, property, natural resources, plant must cease operation. Operator must pay for, cooperate with studies. Bans Trojan operation 30 days after Act takes effect until federal permanent waste storage site available or on-site storage does not exceed plant's annual production. Plant closing costs not includable in rates. Citizens may intervene in rulemaking, contested case proceedings.

PGE fought back with a $5 million campaign, and both measures to close Trojan failed on the November ballot.[261]

Two leaks accelerated the closure of Trojan. The first came one week after the election when Trojan's steam generator tubes burst with a major leak and the plant was shut down. The second leak came in the form of a small batch of NRC memos that were released by Robert D. Pollard, a former NRC reactor engineer. The memos suggested that the NRC waiver was based on the assumption that cracks would show detectable leaks before they rupture, which would allow time for a quick shutdown.[262] Pollard said the plant had "a high likelihood of an accident occurring with severe consequences to the public."

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[260] City Club of Portland. *City Club Report Ballot Measures 5 and 6 Closure of Trojan Nuclear Report.* Pdxcityclub.org. 16 Oct. 1992. Web. 3 Dec. 2013. <http://pdxcityclub.org/sites/default/files/reports/Measure5_6_1992.pdf
261 The Oregon Encyclopedia. "Trojan Nuclear Power Plant." Web. <http://www.oregonencyclopedia.org/entry/view/trojan_nuclear_power_plant/>.
[262] Associated Press. *Trojan documents reveal dissent.* News.google.com. The Bulletin. 20 Dec. 1992. Web. 3 Dec. 2013.

Trojan was finally closed in 1993, but PGE tried to recoup $550 million from ratepayers to reimburse them for profits lost because the plant closed early. Court decisions found that the charge was illegal, so PGE pushed the legislature to pass House Bill 3220 which allowed regulated utilities to "charge rates high enough to give the utilities profits on retired plant and property no longer providing service, including plants that have stopped working". Ballot Measure 90 was a veto referendum brought before the voters in the November 2000 election regarding HB 3220. The measure failed with 88% of the voters against cost recovery, so the House Bill did not take effect.[263,264]

4.7.4.1 *Rancho Seco*

The Rancho Seco Nuclear plant was a 913 MW pressurized water reactor, owned and operated by the Sacramento Municipal Utility District (SMUD) located southeast of Sacramento in Herald, CA. Rancho Seco began commercial operation in 1975 and was closed in 1989.

During the tenure of operation the plant suffered more than 100 emergency shutdowns, including a 27 month outage.[265] Two severe violations occurring in 1985, a rapid temperature drop in the reactor and a release of liquid waste containing radioactive materials, led to Rancho Seco being named as one of the ten U.S. "problem plants" by the NRC.[266]

Sacramentans for Safe Energy (SAFE) formed in 1986 and succeeded in obtaining 50,000 signatures to put forth a ballot initiative in order to close Rancho Seco. After a lengthy legal and political battle Rancho Seco was taken offline on June 7th, 1989, the day after Measure K was approved by 53% of voters.

The Board of Directors of SMUD approved "incremental decommissioning" for Rancho Seco in 1997 using the SAFSTOR method. All spent fuel assemblies were placed in the on-site dry storage ISFSI by 2002.[267] Total decommissioning costs have been estimated at

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<http://news.google.com/newspapers?nid=1243&dat=19921220&id=_5VTAAAAIBAJ&sjid=I4cDAAAAIBAJ&pg=6932,2639637>

263 Ballotpedia.org. "Oregon Authorizes Rates Giving Utilities Return On Investments In Retired Property, Ballot Measure 90 (2000)." Web. <http://ballotpedia.org/wiki/index.php/Oregon_Authorizes_Rates_Giving_Utilities_Return_On_Investments_In_Retired_Property,_Ballot_Measure_90_(2000)>

264 Koberstein, Paul. *Trojan: PGE's Nuclear Gamble.*

265 Sabey, Andrew. "Sacramento Turns Out Rancho Seco". *Environs.law.ucdavis.edu*, Web. 22 Nov. 2013. <http://environs.law.ucdavis.edu/issues/13/2/articles/sabey.pdf> Page 15.

266 Geissinger, Steve. *Cooling Accident at Rancho Seco Chills Nuclear Power Industry. Latimes.com*, Web. 22 Nov. 2013. <http://articles.latimes.com/1986-08-31/local/me-15083_1_rancho-seco-nuclear>

267 Nuclear Regulatory Commission. *Rancho Seco Nuclear Generating Station. Nrc.gov*, Web. 22 Nov.2013.

$517.1 million with all waste materials remaining in storage until a "suitable disposal facility" is found.[268]

4.7.5 Mark Cooper's Renaissance in Reverse Report on Aging Nuclear Reactors

In July of 2013 Dr. Mark Cooper of the Vermont Law School Institute for Energy and the Environment released a report on the Economics of nuclear energy titled, "Renaissance in Reverse: Competition Pushes Aging U.S. Nuclear Reactors to the Brink of Economic Abandonment." His report shows that four recent early retirements of US nuclear plants, although received with shock by the nuclear industry, are suggestive of a broad array of economic and operational problems for nuclear energy in the US. Dr. Cooper predicts more early retirements and argues that "Economic reality has slammed the door on nuclear power."[269,270]

Dr. Cooper lists eleven risk factors that contribute to early retirement in nuclear reactors but states that the main purpose of the report is to alert policy makers to the economics of nuclear power and demonstrate that "Policy efforts to resist fundamental economic reality of nuclear power will be costly, ineffective and counterproductive." [271] The report concludes that nuclear economics have always been marginal, and that nuclear plants are not competitive at any stage of their lifecycle.

The report's primary findings are summarized in Exhibit ES-1. The following table, updated for CGS and Vermont Yankee, identifies a number of at risk nuclear units:

<http://www.nrc.gov/info-finder/decommissioning/power-reactor/rancho-seco-nuclear-generating-station.html>

[268] SMUD. 2011 *Decommissioning Cost Estimate. Nrc.gov*, Web. 22 Nov. 2013. <http://pbadupws.nrc.gov/docs/ML1217/ML12179A224.pdf> Page 1.

[269] Cooper, Mark. *Renaissance in Reverse: Competition Pushes Aging U.S. Nuclear Reactors to the Brink of Economic Abandonment.* Institute for Energy and the Environment, Vermont Law School, July 18, 2013. Page iii - iv.

[270] Ibid, Page 39.

[271] Ibid, Page 40.

Reactor	Economic Factors							Operational Factors			Safety Issues	
	Cost	Small	Old	Stand Alone	Merchant	20yr w/o Ext	25yr w/ Ext.	Broken	Reliability	Long Term Outage	Multiple Safety Issues	Fukushima Retrofit
RETIRED, 2013												
Kewaunee	X	X	X	X	X						X	
Crystal River	X		O					X		O	X	
San Onofre					X	X		X		O	X	
Vt. Yankee	X	X	X		X		O					X
AT RISK												
CGS	X			X							X	X
Ft. Calhoun	X	X	X	X			O	X		O	X	
Oyster Creek	X	X	X	X	X		O			X		X
Ginna	X	X	X		X		O				X	
Point Beach	X	X	X		X		O					
Perry	X	X		X	X	X					X	
Susquehanna	X			X	X				X			X
Davis-Besse	X		O	X	X		O		X	X	X	
Nine Mile Point	X		X		X		O			X	X	X
Quad Cities	X			X	X		O					X
Dresden	X		X		X		O					X
Millstone	X		O	X	X		O				X	
Pilgrim	X	X	X		X	X	O			X	X	X
Clinton	X			X	X	X						
South Texas	X			X	X	X				X		
Commanche Peak	X			X	X	X						
Three Mile Island	X		X	X	X		O			X		
Palisades	X		X		X		O			X	X	
Fitzpatrick	X		O	X	X		O			X		X
Sequoyah	X				X	X				X		
Hope Creek	X			X	X							X
Seabrook	X				X	X			X			
Indian Point	X		X		X		O			X		
Duane	X		O		X		O				X	X

	Cost	Small	Old	Stand Alone	Merchant	20yr w/o Ext	25yr w/ Ext.	Broken	Reliability	Long Term Outage	Multiple Safety Issues	Fukushima Retrofit
Calvert Cliff	X		O		X		O			X	X	
Browns Ferry			X				O		X	X	X	
Monticello	X	X	X			X	O				X	
Prairie Island	X	X	X				O				X	
Turkey Point	X	X	X			X	O			X	X	
Robinson	X		X			X						
Wolf Creek	X			X					X		X	
Fermi	X		X	X		X				X		
Diablo	X			X		X					X	
Cooper	X		X	X			O				X	
Callaway	X			X		X					X	
Cook	X		O				O		X		X	
LaSalle	X				X	X						X
Limerick	X				X	X						X

Long term outage: X = past, O = current

Old: X = 1974 or earlier commissioning, O = commissioned 1975-1979 [272]
Figure 42

4.7.5.1 Cost/Age

Advocates of nuclear energy argue that new plants can be built at relatively low cost and that reactors will operate at high capacity for extended periods of time with low marginal costs. Recent early retirement decisions call into question these assumptions. The fleet is aging, and non-fuel O&M costs of nuclear plants are rising as a result. [273] Statistically, load factor for older plants is 4% lower than in newer plants, representing an important loss of revenue in tight economic times.[274] As margins shrink they become less able to cover the weighty fixed costs of nuclear units, and as reactors age, they become farther out of touch with modern safety standards, requiring costly retrofits. [275]

A 2013 UBS analysis described the economic difficulties for aging reactors. "Despite substantially lower fuel costs than coal plants, fixed costs are approximately 4-5x times

[272] Cooper, *Renaissance in Reverse,* Pages 24-5.
[273] Ibid, Page 5.
[274] Cooper, *Renaissance in Reverse,* Page 14.
[275] Ibid, Page 5.

higher than coal plants of comparable size and may be higher for single-unit plants." … "We believe 2013 will be another challenging year for merchant nuclear operators, as NRC requirements for Fukushima-related investments become clearer in the face of substantially reduced gas prices. While the true variable cost of dispatching a nuclear plant remains exceptionally low (and as such will continue to dispatch at most hours of the day no matter what the gas price), the underlying issue is that margins garnered during dispatch are no longer able to sustain the exceptionally high fixed cost structures of operating these units."[276] [277]

4.7.5.2 Small/Stand-alone

Small stand-alone units isolated geographically and organizationally are more vulnerable to economic pressures because they are less able to benefit from economies of scale or spread costs out over larger capacity and output. While some plants choose to outsource management to a more experienced party, this does not necessarily mean a decrease in costs for the nuclear plant. The management service provider may in fact capture the financial benefits of scale integration and experience rather than the owner. [278]

4.7.5.3 Merchant

Merchant plants are thought to face more immediate risk than regulated reactors because economic pressures directly affect their competitiveness. Decreasing prices in electricity markets are a powerful indicator to policy makers responsible for decisions about retiring regulated plants.

Cooper explains that regulators are supposed to emulate the market in decision-making,

> Those who fail to do so are allowing the utilities to act imprudently, in violation of public utility law. The fact that markets across the country are yielding similar economic results is strong evidence about the true economics of nuclear power in today's electricity market in the U.S. today. This should influence regulatory decisions. [279]

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[276] Ibid, Page 6.
[277] Dumoulin-Smith, Julien, and Jim Von Riesemann. *In Search of Washington's Latest Realities (DC Fieldtrip Takeaways).* UBS Investment Research (2013): Nrc.gov. 20 Feb. 2013. Web. 21 Oct. 2013. <http://pbadupws.nrc.gov/docs/ML1312/ML13128A302.pdf>.
[278] Cooper, *Renaissance in Reverse,* Page 17.
[279] Ibid, Page 11.

He finds that three dozen reactors in the US that have significant economic issues and could easily be retired early, and that although the market will operate faster for merchant reactors, economic pressures are so intense that regulators are being forced to take action as well.

4.7.5.4 **License Extension**

Although a short license is on the list of risk factors for early retirement, a long license is not a guarantee of long life. The Kewaunee plant had just had its license extended for 20 years, but closed for purely economic reasons. The same proved to be true for Vermont Yankee, which had also had its license extended. [280]

4.7.5.5 **Broken/Reliability/Long Term Outage**

The US Energy Information Administration has recently noted that in the current market, aging reactors in need of significant repair may not warrant the investment. Mechanical and safety related problems are among the factors considered likely to push an at-risk reactor over the line into early retirement.
As reactors age, they are more likely to experience outages. Outages can be caused by needed repairs, retrofits, or recovery of broken components, and the average cost of an outage in 2005 dollars was more than $1.5 billion. When reactors are offline, the owners must replace the power. This causes problems when demand for power increases, pushing up the market clearing price. Moody's reports that currently the low price of natural gas is masking the seriousness of this problem. Cooper reports on a study by David Lochbaum which finds that, since the start of the commercial industry, more than one quarter of all US reactors have had an outage of one year or more. [281] [282]

4.7.5.6 **Safety/Fukushima Retrofit**

Safety retrofits are another factor that can easily push at-risk reactors over the edge. Fukushima retrofits specifically will be a significant expense for many plants.

A 2013 UBS report said,

> Among our greatest concerns for the US nuclear portfolio into 2013 is the risk of greater Fukushima-related costs. While expectations around the need of hardened vents differ, we see cost risks of up to $30-40 Mn/per unit under a worst case

[280] Nuclear Regulatory Commission. *Vermont Yankee Nuclear Power Station - License Renewal Application*. Nrc.gov, Web. 21 Oct. 2013. <http://www.nrc.gov/reactors/operating/licensing/renewal/applications/vermont-yankee.html>.
[281] Lochbaum, David. *Walking a Nuclear Tightrope Unlearned Lessons of Year-plus Reactor Outages*. Cambridge: UCS Publications, 2006. Ucsusa.org. Web. 21 Oct. 2013.
<http://www.ucsusa.org/assets/documents/nuclear_power/nuclear_tightrope_report-highres.pdf>. Page 17.
[282] Cooper, *Renaissance in Reverse*, Page 28.

> scenario; while other estimates suggest costs range in the $15 Mn ballpark. Notably, PPL ests. [in Pennsylvania] Fukushima-related costs of $50-60 Mn, excluding vents for its 1.6 GW Susquehanna unit.[283]

A detailed discussion of the Fukushima Dai-ichi accident is addressed in Section 4.1.1 of this report.

4.7.5.7 Renewables/Low Natural Gas Prices

While nuclear construction costs and cost-estimates are rising, market prices are falling and renewable alternatives are becoming cheaper thanks to technological innovation, economies of scale, and learning by doing. Whether or not the US adopts carbon emission policies, there are numerous energy sources available to meet electricity demand at a lower cost than nuclear, and other low-carbon energy sources would stand to benefit as much or more than nuclear energy under climate policy. Solar prices are expected to continue decreasing and investment in energy efficiency is expected to increase, decreasing demand growth.

Most reasonable analysts have reached consensus that the price of natural gas can be expected to remain low for a significant time. This among other lower-cost sources of energy are adding pressure to the already shaky economics of nuclear power. [284]

4.7.5.8 Demand

"Energy efficiency," Cooper points out, "is the cheapest, cleanest and fastest energy source available today – it is significantly less expensive than nuclear and involves no safety issues, waste disposal problems and lengthy construction delays." [285] In the time frame relevant for retirement decisions, nuclear is unlikely to become competitive with low carbon alternatives and natural gas prices are likely to remain low.[286]

4.7.6 Statistical Analysis of Plant Life Expectancy

There is an optimistic impression in some quarters that the granting of an additional NRC license assures that the plant will operate for another thirty years – until 2043. Of the five units currently commencing decommissioning, Kewaunee and Vermont Yankee were recently relicensed. The San Onofre and Crystal River 3 units had commenced, but not completed, relicensing as of their closure.

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[283] Dumoulin-Smith, Julien. *In Search of Washington's Latest Realities,* Page 1.
[284] Cooper, *Renaissance in Reverse,* Pages 33-5.
[285] Cooper, Mark. *Why Nuclear Reactor Loan Guarantees Are Now More Imprudent Than Ever.* Yubanet.com, 14 Feb. 2011. Web. 21 Oct. 2013. <http://yubanet.com/opinions/Mark-Cooper-Why-Nuclear-Reactor-Loan-Guarantees-Are-Now-More-Imprudent-Than-Ever.php>.
[286] Cooper. *Renaissance in Reverse.* Page iii.

There are three readily available data sets for analysis of expected nuclear plant life expectancy:

1. World wide data from the IEA;
2. U.S./Canadian data from the NRC and the Canadian Nuclear Safety Commission; and,
3. West Coast data from the NRC.

Even a cursory review indicates that the conclusions drawn from the U.S./Canadian and world data sets give very different results than West Coast data.

The following chart shows the relationship between average plant life and the percentage of decommissioned units:

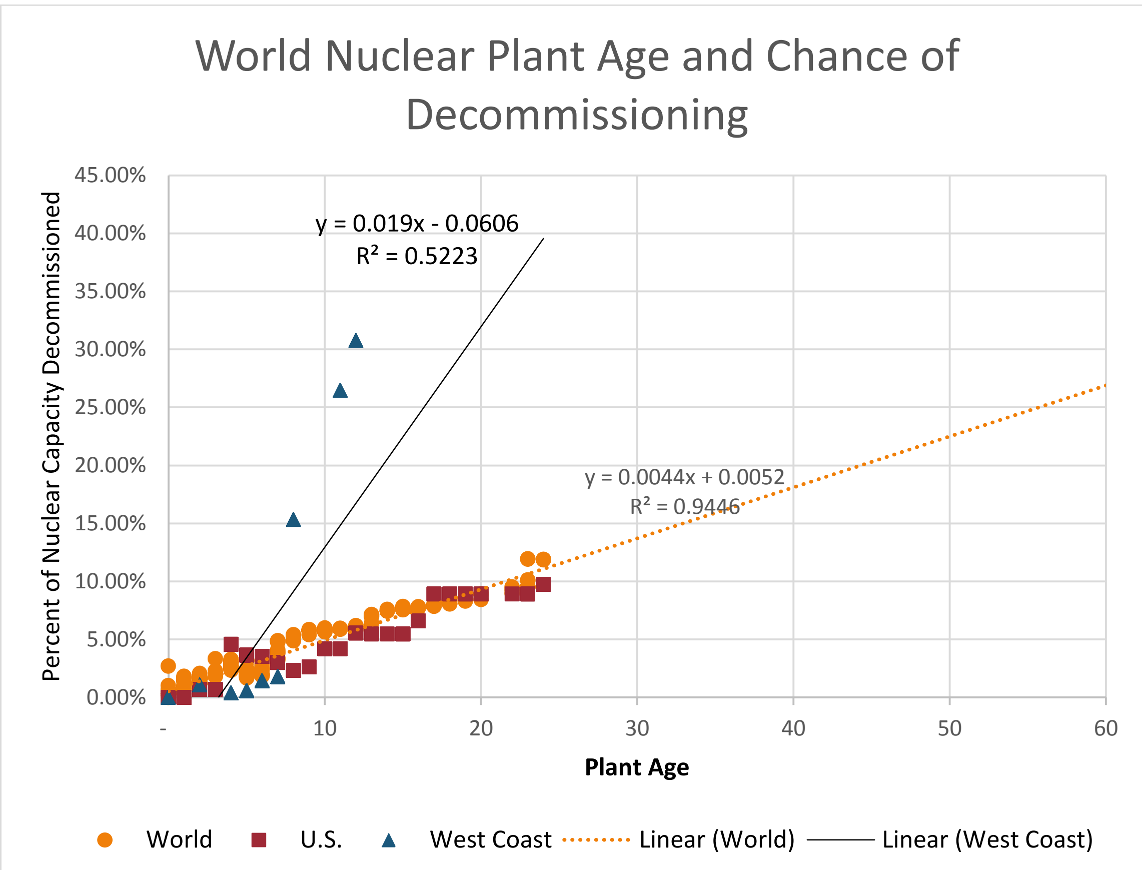

Figure 43

This analysis indicates that for plants outside of the West Coast of the U.S. the chance of closure is .4% per year. The West Coast analysis is very different – almost 2% per annum.

4.7.7 CGS Life Expectancy

Human life expectancy analyses often start with a simple tool called a "life table":

Table VI. Life table for the total population: United States, 2008

Age (years)	Probability of dying between ages x and $x+n$ $_nq_x$	Number surviving to age x l_x	Number dying between ages x and $x+n$ $_nd_x$	Person-years lived between ages x and $x+n$ $_nL_x$	Total number of person-years lived above age x T_x	Expectation of life at age x e_x
0–1	0.006593	100,000	659	99,425	7,812,389	78.1
1–4	0.001132	99,341	112	397,092	7,712,964	77.6
5–9	0.000623	99,228	62	495,972	7,315,872	73.7
10–14	0.000779	99,167	77	495,692	6,819,900	68.8
15–19	0.002875	99,089	285	494,821	6,324,208	63.8
20–24	0.004689	98,804	463	492,902	5,829,387	59.0
25–29	0.004861	98,341	478	490,514	5,336,485	54.3
30–34	0.005466	97,863	535	488,017	4,845,971	49.5
35–39	0.007077	97,328	689	485,012	4,357,954	44.8
40–44	0.010733	96,639	1,037	480,795	3,872,942	40.1
45–49	0.016773	95,602	1,604	474,262	3,392,147	35.5
50–54	0.025150	93,999	2,364	464,410	2,917,885	31.0
55–59	0.035784	91,635	3,279	450,415	2,453,475	26.8
60–64	0.052463	88,356	4,635	430,823	2,003,060	22.7
65–69	0.078443	83,720	6,567	403,086	1,572,237	18.8
70–74	0.118559	77,153	9,147	364,140	1,169,152	15.2
75–79	0.182982	68,006	12,444	310,338	805,011	11.8
80–84	0.283728	55,562	15,764	239,561	494,673	8.9
85–89	0.438470	39,797	17,450	155,294	255,112	6.4
90–94	0.628469	22,347	14,045	74,038	99,818	4.5
95–99	0.797603	8,303	6,622	22,048	25,780	3.1
100 and over	1.000000	1,680	1,680	3,732	3,732	2.2

SOURCE: CDC/NCHS, National Vital Statistics System.

Figure 44

[287]

The primary input to a human life table is the probability of dying in a given year or set of years. In this case, for example, the chance of death in the early sixties is 5.2%. The primary output is the life expectancy in the leftmost column. The corresponding value for early 60s is 22.7 years.

No such simple solution exists for nuclear plants. From the discussion above, it is clear that there is substantial evidence that nuclear plants do not have an infinite lifetime. There is no readily established methodology to estimate what the expected life expectancy of a nuclear plant will be.

The same life table model can be applied to nuclear plants since we have data on the probability of closure at different plant ages.

Of the fifteen commercial nuclear reactors built on the West Coast, only six are now in operation – Diablo Canyon 1 and 2, Palo Verde 1, 2, and 3 and CGS.

[287] Arias, Elizabeth. *United States Life Tables, 2008*. Rep. no. 3. Vol. 61. National Vital Statistics System, 2012. Cdc.gov. Web. 21 Oct. 2013. <http://www.cdc.gov/nchs/data/nvsr/nvsr61/nvsr61_03.pdf>. Page 63.

A standard life table analysis of West Coast nuclear plants is reproduced below:

Age (years)	Probability of plant closure between ages x and x + n	Number surviving to age x	Number plant closure between ages x and x + n	Plant-years lived between ages x and x + n	Total number of Plant-years lived above age x	Expectation of life at age x
x	n qx	lx	n dx	n Lx	Tx	ex
1-5	0.0%	15.0	0.0	15.0	485.6	32.4
6-10	13.3%	15.0	2.0	29.0	410.6	27.4
11-15	15.4%	13.0	2.0	41.0	340.6	26.2
16-20	9.1%	11.0	1.0	51.5	280.6	25.5
21-25	10.0%	10.0	1.0	61.0	228.1	22.8
26-30	11.1%	9.0	1.0	69.5	180.6	20.1
31-35	25.0%	8.0	2.0	76.5	138.1	17.3
36-40	12.0%	6.0	0.7	82.1	103.1	17.2
41-45	12.0%	5.3	0.6	87.1	74.9	14.2
46-50	12.0%	4.6	0.6	91.5	50.1	10.8
51-55	12.0%	4.1	0.5	95.3	28.2	6.9
56-60	12.0%	3.6	3.6	98.7	9.0	2.5

Figure 45

The closure of San Onofre 2 and 3 this year gives a closure rate of 25% for the 31-35 age cohort. This raises a serious analytical problem. Is the high risk of plant closure on the West Coast going to continue or will the rate of closure fall back to the historical average of 12.0% for a future five year period? This assumes that risk of closure for the next five years – and following periods – are approximately half of current levels. While possible, this seems unlikely given current political and economic trends.

The table above assumes that recent closures were unusual. The alternative assumption, at least equally likely, is that plant closures are more likely with increasing age.

If so, a reasonable assumption is that the chance of plant closure will continue at current levels until the end of the analysis. Assuming that plant mortality risk for the next five years (and following years) is more intuitive since we would expect risk to increase over time:

	Probability of plant closure between ages x and x + n	Number surviving to age x	Number plant closure between ages x and x + n	Plant-years lived between ages x and x + n	Total number of Plant-years lived above age x	Expectation of life at age x
	n qx	lx	n dx	n Lx	Tx	ex
1-5	0.0%	13.0	0.0	13.0	397.8	30.6
6-10	13.3%	13.0	1.7	25.1	332.8	25.6
11-15	15.4%	11.3	1.7	35.5	272.2	24.2
16-20	9.1%	9.5	0.9	44.6	220.2	23.1
21-25	10.0%	8.7	0.9	52.9	174.7	20.2
26-30	11.1%	7.8	0.9	60.2	133.5	17.1
31-35	25.0%	6.9	1.7	66.3	96.7	13.9
36-40	25.0%	5.2	1.3	70.9	66.3	12.8
41-45	25.0%	3.9	1.0	74.3	43.6	11.2
46-50	25.0%	2.9	0.7	76.8	26.5	9.1
51-55	25.0%	2.2	0.5	78.7	13.7	6.3
56-60	25.0%	1.6	1.6	80.2	4.1	2.5

Figure 46

A likely range for the life expectancy of CGS would lie between these two levels – 17.1 years to 20.2 years. Overall, based upon the trends listed in this section, it seems unlikely that CGS will continue operating for another thirty years.

4.8 CGS Decommissioning Cost Escalation

The current state of decommissioning nuclear stations in the United States can best be described as discouraging. Thirty one years after the passage of the Nuclear Waste Policy Act of 1982 the U.S. still has not started on a long term waste repository. Many plants – including CGS – have a severely underfunded decommissioning fund. The Nuclear Regulatory Commission's approach is one of cautious disengagement.

This spring, Congressman (now U.S. Senator) Edward Markey (D-MA) wrote:

> I write to urge the Nuclear Regulatory Commission (NRC) to consider fundamental reforms to the methodology and reporting process by which it determines licensees have the financial wherewithal to meet their future decommissioning obligations. In recent months it has become clear that the nuclear power sector is facing great financial challenges that threaten the economic viability of several of the nation's commercial reactors. The value of several nuclear plant assets have significantly declined, the cost to decommission these facilities is rising rapidly, and some early plant retirements are reducing the amount of time licensees have to build up adequate funds to decommission the reactors when they are permanently shut down. It appears that some NRC licensees are failing to maintain the financial resources needed to fully fund their near-term responsibilities related to protecting public health and safety and their long-term responsibilities to clean up radiological contamination during the decommissioning process.[288]

The question this section of the report addresses is whether decommissioning at a date earlier than the end of the current license would be cost effective. All of the evidence suggests that decommissioning costs have climbed – in real terms – over time. If the past is evidence for the future, the answer appears to be that waiting to commence decommissioning may be a costly decision.

Decommissioning at CGS consists of four different programs:

1. Estimates mandated by 10 CFR 50.75(f) – commonly known as the NRC's minimum decommissioning cost standard

2. Site restoration (usually set by the state rather than the NRC)

3. Independent Spent Fuel Storage installation (ISFSI)

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[288] Senator Edward Markey. *Letter to NRC Chair Allison Macfarlane*. 6 May 2013. Page 1.

4. Spent fuel fee as mandated by the 1982 Nuclear Waste Policy Act

With the possible exception of the $1/MWh fee charged under the Nuclear Waste Policy Act, decommissioning estimates at CGS – and the nation's other commercial reactors – have shown a steady increase in real terms.

According to the most recent study from the U.S. Department of Energy, the gradually diminishing fee for spent nuclear fuel will be sufficient to assure a repository for nuclear fuel for the next 86 years.[289] This study glosses over the rapid escalation of cost of Yucca Mountain before its cancellation and the complete absence of a replacement facility. It also fails to consider the estimated $19.1 billion liability in contract breach payments owed due to the non-completion of Yucca Mountain.[290] And, finally, it disregards the cogent arguments of the Blue Ribbon Committee that the Gramm-Rudman Act effectively blocked the operation of the Nuclear Waste Fund.[291] Responding to a number of these concerns, the United States Court of Appeals for the District of Columbia Circuit issued an order effectively ending the current program on November 19, 2013.

As a general rule, the design for the funding of decommissioning costs tends to be inaccurate. One primary cause is that the existing models tend to view the costs as a form of "Lay Away Plan."[292] Since a primary component of cost is the packaging, transportation, and burial of low level wastes, an exact estimate would require a forecast of future tariffs at the disposal facility.[293] Unlike a "Lay-away Plan" there is no implicit contract between the nuclear plant and the disposal facility. This is especially true concerning the future cost of spent nuclear fuel. The current $1/MWh price can be reset on a finding that the current price is insufficient. As noted above, the current assumption that the national long term storage facility will be built at past estimates for Yucca Mountain is highly unlikely.

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289 United States Department of Energy. *U.S. Department of Energy Nuclear Waste Fund Fee Adequacy Assessment Report*. Rep. Jan. 2013. Web. 19 Sept. 2013. <http://energy.gov/sites/prod/files/January 16 2013 Secretarial Determination of the Adequacy of the Nuclear Waste Fund Fee.pdf>.

290 Zabransky, David K., and Office of Standard Contract Management. *Liability Estimate*. Letter to Owen F Barwell. 26 Oct. 2011. cybercemetery.unt.edu, Web. 19 Sept. 2013. <http://cybercemetery.unt.edu/archive/brc/20120620221030/http://www.brc.gov/sites/default/files/comments/attachments/doe_response-liability_estimate_2011_final_102611.pdf>.

291 Disposal Subcommittee. *Report to the Full Commission Updated Report Blue Ribbon Commission on America's Nuclear Future*, January 2012, page 56.

292 Webster's New Collegiate Dictionary, Merriam-Webster Company, 1974, page 652.

> Lay-away n: An article of merchandise reserved for future delivery to a customer who pays a deposit and agrees to complete payment when the article is called for.

293 Nuclear Regulatory Commission. Office of Nuclear Material Reactor Regulation. *Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula*. By S. M. Short, M. C. Bierschbach, R. F. Layton, and B. E. Greenfield. Nrc.gov, Nov. 2011. Web. 19 Sept. 2013. <http://pbadupws.nrc.gov/docs/ML1306/ML13063A190.pdf>, Page 6-3.

From the vantage point of the consumer, decommissioning cost escalation is an additional operating cost of the plant. Consider two cases:

> Case 1: CGS is decommissioned in 2015 at a price of $791,979,196[294]
>
> Case 2: CGS is decommissioned in 2016 at a price of $810,399,737[295]

A decision to operate an additional year and to delay decommissioning by one year costs the consumer $18,369,540 dollars. All indications are that this is a low estimate of the incremental cost of decommissioning delay.

The following subsections address each component of decommissioning costs.

Overall, the current estimates of the decommissioning costs of CGS are incomplete and inaccurate. The NRC describes their decommissioning formula as incomplete:

> Other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction, operation, and decommissioning of an independent spent fuel storage installation (ISFSI), demolition of decontaminated structures, and site restoration activities after residual radioactivity has been removed are not included within the NRC definition of decommissioning.[296]

Most of the gaps in the decommissioning formula are addressed outside of the NRC formula:

Part of the problem is a long held policy at the Nuclear Regulatory Commission to require only a minimum level of funding for decommissioning. A second, and potentially more serious, problem is one of forecasting. Current estimates rely on current prices for burial of radioactive components of decommissioned plants, even though such prices are likely to increase markedly over time.

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[294] Simple linear extrapolation of the 1980, 1983, 1994, 1996, 2001, 2010 site-specific estimates of CGS reported by NRC studies for January 1, 2015 in 2013 real dollars.
[295] Simple linear extrapolation of the 1980, 1983, 1994, 1996, 2001, 2010 site-specific estimates of CGS reported by NRC studies for January 1, 2016 in 2013 real dollars.
[296] Ibid. Page 2.

4.8.1 The NRC Formula

The NRC regulations set specific rules for decommissioning estimates.[297] The NRC web site explains:

> Licensees are to estimate the funding needed for radiological decommissioning either by using the formulas included in 10 CFR 50.75(c) or by using a site-specific methodology. The site-specific decommissioning estimate cannot be lower than the decommissioning estimate using the 10 CFR 50.75(c) formulas. According to NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" (SRP), the NRC formulas in 10 CFR 50.75(c) include only decommissioning costs incurred by licensees to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the license. The formulas do not include the costs of dismantling non-radiological systems and structures or the costs of managing and storing spent fuel on site.

The NRC's rules have created some confusion in the calculation and reporting of decommissioning costs since their rule only sets a minimum value – not a best estimate of actual values.

The formula set by the NRC is based – in large part – by a site-specific methodology based on CGS and Trojan:

> The Washington Public Power Supply System's Nuclear Project Number 2 (CGS), at Hanford, Washington, is used as the reference BWR power station for this study. CGS is an 1155-MWe station that utilizes a nuclear steam supply system with a direct-cycle boiling water reactor manufactured by the General Electric Company. The single-reactor station is assumed to be on a generic site that is typical of reactor locations in the midwestern or middle southeastern United States. The structures, systems, and components are basically typical of the current generation of large BWR power stations.[298,299]

[297] Nuclear Regulatory Commission. *10 CFR 50.75(f)(1) Reports on the Status of Decommissioning Funds*. Nrc.gov, 29 Mar. 2013. Web. 11 Oct. 2013. <http://www.nrc.gov/reading-rm/doc-collections/gen-comm/reg-issues/2001/ri01007.html>.

[298] Oak, G. M. Holter, W. E. Kennedy, Jr., G. J. Konzek. *Technology, Safety and Costs of Decommissioning a Reference Boiling Water Reactor Power Station*, June 1980, H. D. Oak, G. M. Holter, W. E. Kennedy, Jr., G. J. Konzek, Pages 1-2.

[299] Smith, R.I., Konzek, G. J. and Kennedy, W. E. Jr. *Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station*, June 1978.

In 2013, Energy Northwest's estimated that decommissioning would cost $463.5 million (fiscal year 2011 dollars), however the cost has varied dramatically over the past few years.[300,301] In 2005, the estimated decommissioning cost was $629.1 million.[302] This estimate dropped to $567.9 million in 2007[303], rising to $872.7 million in 2009[304], and dropping again in 2011 to $459.7.[305] The following chart compares CGS decommissioning estimates with actual decommissioning costs from Dominion and Duke Energy's annual 10-K reports required by the US Securities and Exchange Commission:

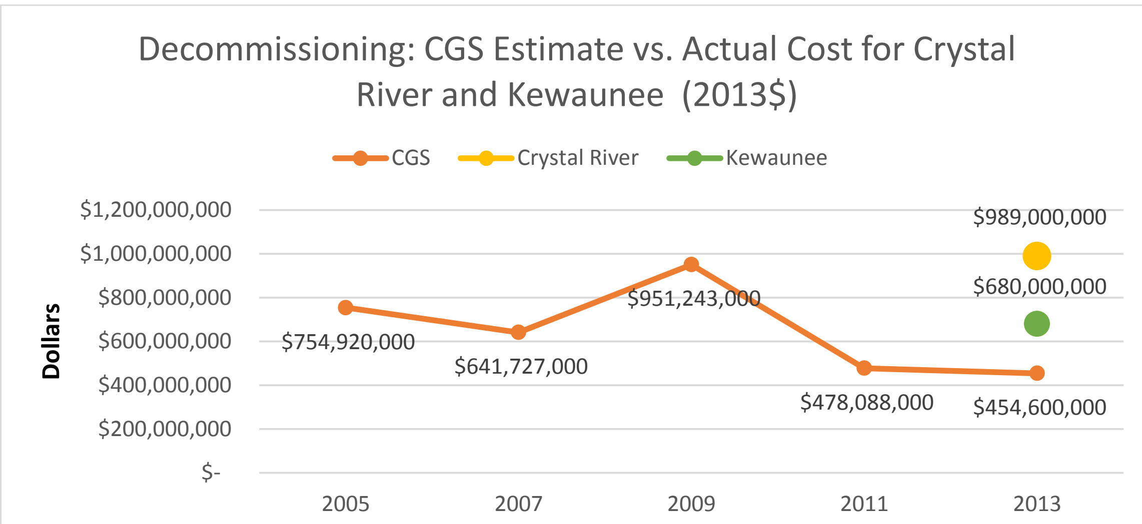

Figure 47

Why would Energy Northwest's decommissioning estimates vary so wildly between given years? And why are the decommissioning costs for Crystal River, a significantly smaller 860 MW reactor, almost double the 2013 estimates to decommission CGS?

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300 2012 Energy Northwest Annual Report, Page 63.

301 Energy Northwest. *Columbia Generating Station, Docket No. 50-397 Decommissioning Fund Status Report.* Letter to U.S. Nuclear Regulatory Commission. 22 Mar. 2011. *nrc.gov*. Web. 1 Oct. 2013. <http://pbadupws.nrc.gov/docs/ML1108/ML110880356.pdf>.

302 Energy Northwest. *Columbia Generating Station, Docket No. 50-397 Decommissioning Fund Status Report.* Letter to U.S. Nuclear Regulatory Commission. 30 Mar, 2005. *nrc.gov*. Web. 1 Oct. 2013. < http://pbadupws.nrc.gov/docs/ML0509/ML050960368.pdf>.

303 Nuclear Regulatory Commission. *Columbia Generating Station, Docket No. 50-397 Decommissioning Fund Status Report.* 2007.

304 Energy Northwest. *Columbia Generating Station, Docket No. 50-397 Decommissioning Fund Status Report.* Letter to U.S. Nuclear Regulatory Commission. Nrc.gov. 31 Mar. 2009. Web. 1 Oct. 2013. < http://pbadupws.nrc.gov/docs/ML0910/ML091040201.pdf>.

305 Nuclear Regulatory Commission. *CGS Decommissioning Fund Status Report*, 2011.

The industry estimates decommissioning costs using the Nuclear Regulatory Commission's formula found in the NUREG-1307 publication.[306] This formula incorporates disposal rates at burial facilities for the disposal of spent fuel. This process involves the NRC nominating which burial facility a given nuclear plant must calculate its spent fuel disposal for. In the case of the CGS, the NRC uses disposal rates for the Hanford, Washington burial facility.[307] This facility charges Energy Northwest to dispose of waste there, according to rates annually adjusted by Washington State. In a letter to the Nuclear Regulatory Commission, Energy Northwest claimed that, in 2000, these rates changed by over $200 million annually.[308] Because of these variations in costs, taking Energy Northwest's most recent estimates at face value is likely to be ill-advised. The estimates over the last twenty years, while they do vary drastically, tend to vary by similar degrees and do not indicate a large trend in either direction over time.

The culprit of this wide variation is the B(x) value from the NUREG-1307 report, specifically the 2008 value in revision 13.[309] This value oscillates from 9.008 (2006) to 20.889 (2008) then drops to 5.458 (2010). According to the NUREG-1307, variations of B(x) values are the result of variations in dose rate charges.[310] Boiling water reactors like CGS have more dose rate materials than PWRs.[311] Exhibit A.1 of the NUREG-1307 lists the disposal rates for the Hanford Disposal Site. Revision 13, from 2008 lists the Dose Rate as follows:

Block No. Dose Rate at Container Surface	Charge per Container
1 Less than or equal to 200 mRih	$177
2 Greater than 200 mRih but less than or equal to 1,000 mRlh	12,580
3 Greater than 1,000 mRih but less than or equal to 10,000 mRlh	50,400
4 Greater than 10,000 mRih but less than or equal to 100,000 mRlh	75,500
5 Greater than 100,000 mRih	1,268,000

306 United States Nuclear Regulatory Commission. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities*. By J. A. Gastelum and S. Short. Revision 15. Washington: Nuclear Regulatory Commission, January 2013 (NUREG-1307).
307 Coleman, D. W. Energy Northwest. *CGS Operating License NPF-21 Decommissioning Fund Targets Comments on NUREG-1307,* March 24, 2000. From Energy Northwest. (Accessed April 15, 2013).
308 Ibid. Page 1.
309 United States Nuclear Regulatory Commission. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities*. By J. A. Gastelum and S. Short. Revision 13. Washington: Nuclear Regulatory Commission, November 2008 (NUREG-1307).
310 Ibid. Page A-1.
311 Nuclear Regulatory Commission. Office of Nuclear Material Reactor Regulation. *Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula*. November 2011. Page 5-5.

Following 2008, where a large spike in dose rates and thus decommissioning estimates occurred, 2010 lists the dose rates as follows:

Block No.	Dose Rate at Container Surface	Charge per Container
1	Less than or equal to 200 mR/h	$17
2	Greater than 200 mR/h but less than or equal to 1,000 mR/h	1,209
3	Greater than 1,000 mR/h but less than or equal to 10,000 mR/h	4,850
4	Greater than 10,000 mR/h but less than or equal to 100,000 mR/h	7,300
5	Greater than 100,000 mR/h	123,000 [312]

As NUREG-1307 concluded:

> Effective January 1, 1996, the operator of the Washington site implemented a restructured rate schedule based on waste volume, number of shipments, number of containers, and dose rate at the container surface. Each waste generator is also assessed an annual site availability charge based on cumulative volume and dose rate at the surface of all containers disposed. The site availability charge appears near the bottom of Table B-1 through Table B-12.
>
> In 2000, charges for all ranges of container surface dose rates were reduced by a factor of eight compared to 1998. This significantly reduced burial costs at the Washington LLW disposal site.
>
> However, effective May 1, 2002, these surface dose rate charges had increased by more than a factor of eight (to about what they were in 1998). In addition, volume, shipment, and container charges had increased by 6.5 percent, 42.2 percent, and 42.2 percent, respectively. Thus, burial charges for 2002 were significantly higher than the charges for 2000, but they are roughly comparable to what they were in 1998.[313]

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312 United States Nuclear Regulatory Commission. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities*. By J. A. Gastelum and S. Short. Revision 14. Washington: Nuclear Regulatory Commission, November 2010 (NUREG-1307). Exhibit A-1.

313 United States Nuclear Regulatory Commission. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities*. By J. A. Gastelum and S. Short. Revision 13. Washington: Nuclear Regulatory Commission, November 2008 (NUREG-1307). Page A-1.

The calculations concerning cost of decommissioning are prepared by Energy Northwest and submitted every two years to the U.S. Nuclear Regulatory Commission as Decommissioning Fund Status Reports.[314] These Status Reports also keep track of the decommissioning fund, predicting when it will reach certain levels. Energy Northwest determines how much must be paid into the fund, in coordination with BPA, based on the changing costs of decommissioning.[315] This fund has been accumulating since 1992, with its increases documented in Energy Northwest's annual reports. The following graph shows the decommissioning fund over the past twenty years.

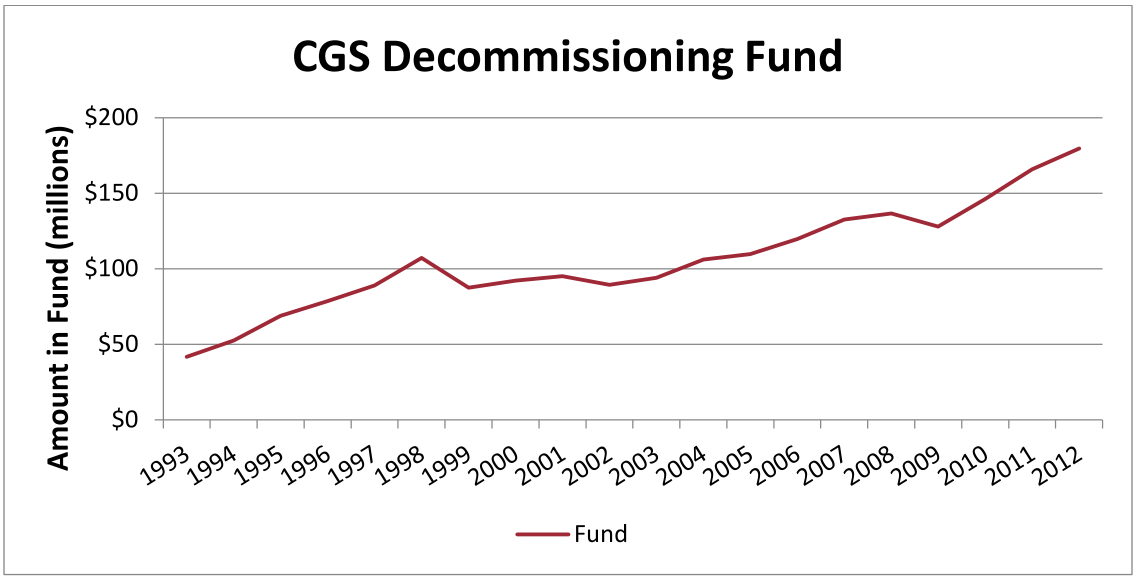

Figure 48

In order to predict the future growth of the fund, it is necessary to examine the Fund Status Report for 2011. In 2012, CGS had its license renewed, extending its potential operating life twenty years from 2023 to 2043. The 2013 Fund Status Report takes into account this increased authorization time, and so plans its decommissioning fund to accumulate much more slowly.

If CGS is closed before the end of the license period, Energy Northwest would more logically adopt the 2011 plan. The 2011 Fund Status Report presented the following projections:

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314 Nuclear Regulatory Commission, CGS Decommissioning Fund Status Report, 2011. Page A-5.

315 Gregoire, Donald W (Regulatory Affairs, Energy Northwest). *Letter to: Richard Q. Quigley (Document Control Desk, Nuclear Regulatory Commission)*. 22 May 2011. Page 3.

	Columbia Decommissioning[2] (in thousands of dollars)		
Fiscal Year[1]	Payment	Interest Earned	Account Balance
FY 2010 Actuals	--	--	134,601
FY 2011	8,849	8,076	151,526
FY 2012	9,956	9,092	170,573
FY 2013	11,200	10,234	192,007
FY 2014	12,600	11,520	216,128
FY 2015	14,175	12,968	243,271
FY 2016	23,424	14,596	281,291
FY 2017	29,011	16,877	327,179
FY 2018	35,930	19,631	382,740
FY 2019	44,500	22,964	450,204
FY 2020	55,113	27,012	532,330
FY 2021	68,257	31,940	632,526
FY 2022	84,537	37,952	755,015
FY 2023	104,699	45,301	905,015
FY 2024	129,669	54,301	1,088,985

[316]

Figure 49

According to this plan, Energy Northwest will have collected enough funds to immediately dismantle CGS by 2021. It is important to separate out the interest being earned from the actual payments being paid into this fund. Each year interest accumulates at an assumed 6% rate.[317]

The Nuclear Regulatory Commission identifies three primary decommissioning approaches:

> Under DECON (immediate dismantling), soon after the nuclear facility closes, equipment, structures, and portions of the facility containing radioactive contaminants are removed or decontaminated to a level that permits release of the property and termination of the NRC license.
>
> Under SAFSTOR, often considered "deferred dismantling," a nuclear facility is maintained and monitored in a condition that allows the radioactivity to decay; afterwards, it is dismantled and the property decontaminated.

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[316] Ibid. Page 2.
[317] Gregoire, Donald W (Regulatory Affairs, Energy Northwest). *COLUMBIA GENERATING STATION, DOCKET NO. 50-397 DECOMMISSIONING FUND STATUS REPORT.* 28 Mar. 2013. Page 1.

> Under ENTOMB, radioactive contaminants are permanently encased on site in structurally sound material such as concrete and appropriately maintained and monitored until the radioactivity decays to a level permitting restricted release of the property. To date, no NRC-licensed facilities have requested this option.[318]

The NRC allows either a site-specific analysis or the use of a generic formula. CGS's cost of decommissioning is estimated by the use of the generic formula in the NRC's NUREG-1307.[319,320] It is important to note that this formula only reflects the efforts necessary to terminate the 10 CFR, Part 50 operating license with the NRC.[321]

Estimated cost (Year X) = [1986 $ cost] [A*L(x) + B*E(x) + C*B(x)]

Where

L(x) = labors, materials, and services cost adjustment
E(x) = energy and waste transportation cost adjustment
B(x) = low level waste 'burial/disposition cost adjustment

In each of these cases, the original cost (in 1986 dollars) is compared to the current costs based on various national indexes.

L(x) is calculated from the Employment Cost Index which indicates the cost of labor from a base labor adjustment factor at the time the ECI was re-indexed. The precise formula is

$$\frac{L(x)}{ECI} = \frac{Base\ L(x)}{100}$$

The E(x) values are taken from two producer price indexes: PPI Codes 0543 and 0573. Both of these track changes in domestic prices of electricity and fuel.[322] E(x) is taken from two values: P(x) and F(x). P(x) and F(x) both indicate the 2012 value of 0543 or 0573, respectively, divided by the 1986 value. E(x) is then calculated with the following formula:

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318 Nuclear Regulatory Commission. *Decommissioning Nuclear Power Plants*. Nrc.gov, May 2013. Web. 11 Oct. 2013. Page 1. <http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html>.
319 Gregoire, Donald W. (Regulatory Affairs, Energy Northwest). *Letter to: Richard Q. Quigley (Document Control Desk, Nuclear Regulatory Commission)*. 2011 May 26. Page 1.
320 Gastelum, J. A., and S. Short. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities (Final Report, NUREG-1307, Revision 15)*. Nrc.gov, Web. 11 Oct. 2013. <http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1307/>. Page v.
321 Nuclear Regulatory Commission. *Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors (NUREG-1713)*. Nrc.gov, 29 Mar. 2013. Web. 11 Oct. 2013. <http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1713/>. Page 2.
322 Bureau of Labor Statistics. *Producer Price Index Commodity Data*. Data.bls.gov, Web. 11 Oct. 2013. <http://data.bls.gov/cgi-bin/surveymost?wp>.

E(x) (BWR) = 0.54P(x) + 0.46F(x)

Finally, B(x) is calculated from the costs of disposing given radioactive waste based on schedules provided by available disposal facilities. For CGS, these values are taken for the Hanford Waste Disposal Site.[323]

This changing B(x) value has caused problems when it comes to the total decommissioning estimate, as discussed in an Energy Northwest letter.[324] The decommissioning estimate varies wildly in 2009, increasing and then dropping by over $300 million as detailed by the following graph.

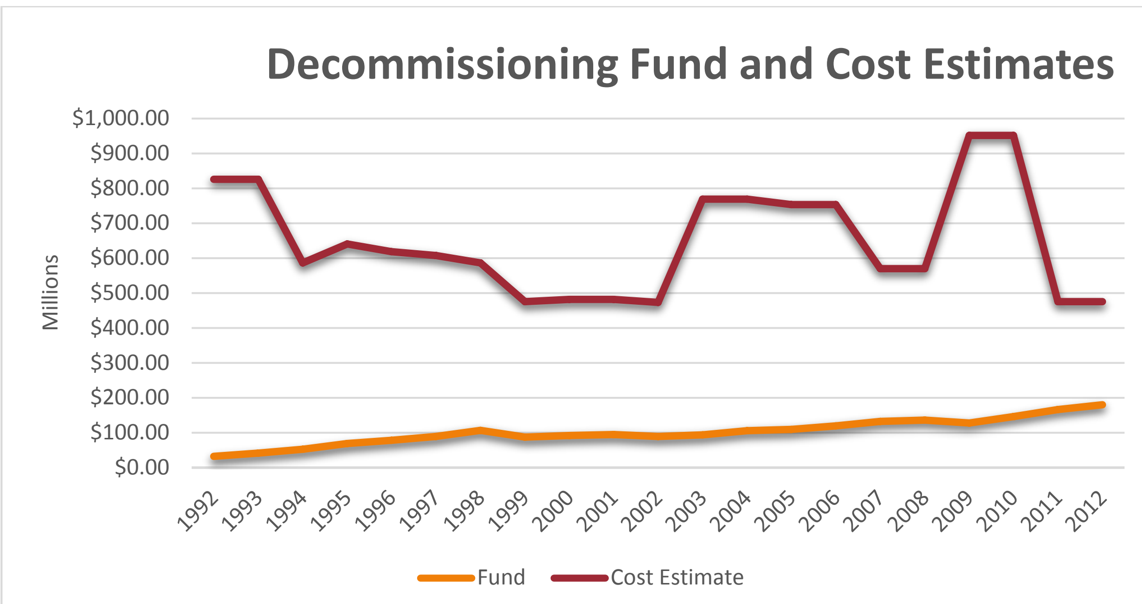

Figure 50

[323] Gastelum, J. A., and S. Short. *Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities (Final Report, NUREG-1307, Revision 15).* Nrc.gov, Web. 11 Oct. 2013. <http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1307/>. Page iii.
[324] Coleman, D. W. Energy Northwest. *CGS Operating License NPF-21 Decommissioning Fund Targets Comments.* 24 Mar. 2000. Page 1.

4.8.2 Site Restoration Costs

As of 2012, the site restoration estimate for CGS was approximately $100 million, and the site restoration fund is at $29.33 million. [325,326] The following graph demonstrates the changes in estimates and the payment into this fund.

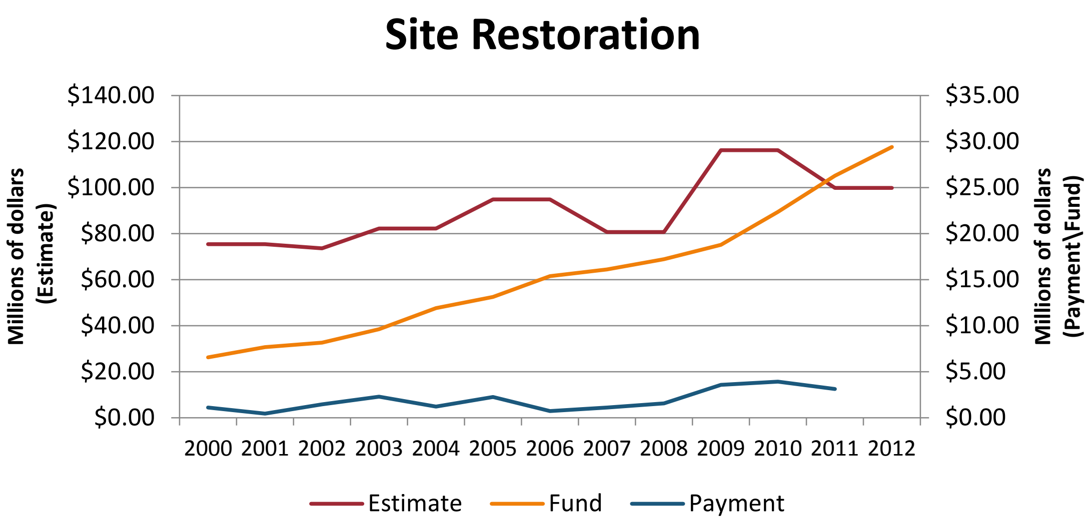

Figure 51

On average since 2000, $1.9 million have been set aside for site restoration each year. If this trend continues at those same amounts, the site restoration estimate of $100 million will be met in 37 years. In this analysis we have assumed that site restoration costs will escalate at the same rate as other decommissioning costs.

4.8.3 Fuel Removal and Dry-Cask Storage

Once all the fuel from CGS has been removed from the reactor to the spent fuel pool, it must undergo a 3-5 year cooling period before it can be transferred to air-cooled dry-cask storage on the CGS site. Even after full decommissioning of the plant, the fuel will remain onsite until the federal government establishes a temporary or permanent repository elsewhere.

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325 Energy Northwest. *Energy Northwest Annual Report*. 2012. Page 63.
326 Ibid. Page 63.

4.8.4 Nuclear Waste Policy Act of 1982

The Nuclear Waste Policy Act of 1982 has largely been rendered inoperable by more recent court orders, administrative actions, and Congressional budget decisions. The January 2012 Blue Ribbon Commission report summarized the situation very succinctly:

> Recommendation #3: Assured access to the balance in the Nuclear Waste Fund (NWF) and to the revenues generated by annual nuclear waste fee payments from utility ratepayers is absolutely essential and must be provided to the new nuclear waste management organization.
>
> The current NWF and fee mechanism is not working as intended. No new policy or organization will succeed unless this changes. Specifically, revenues from the annual fee and the balance in the NWF must be made available to implement the nation's waste management program, as needed, independent of other budgetary pressures. This will require: (1) extricating the NWF from the web of budget rules that have created an unintended and dysfunctional competition between expenditures from the Fund and spending on other federal programs, and (2) removing funding decisions from the annual federal budgeting and appropriations process. Of course, greater budget independence must come with effective oversight mechanisms to ensure that resources—in this case the NWF funds—are being spent wisely to pursue only the objectives for which they are intended.[327]

The budgetary problem is described in more detail on page 56 of their report:

> Since the establishment of the NWF in 1982, Congress enacted several budget control acts that dramatically reduced the funding flexibility originally envisioned in the NWPA:
>
> • The Balanced Budget and Emergency Deficit Control Act of 1985, also known as Gramm-Rudman-Hollings (GRH), made the NWF subject to the government-wide budget sequestration process. In implementing GRH, the Office of Management and Budget (OMB) "split" the NWF; fee receipts were placed on the "mandatory" side of the budget (dealing with activities controlled by permanent laws rather than by annual appropriations), where they are treated like tax revenues and used to offset mandatory spending, while expenditures were placed on the "discretionary" side (dealing with

[327] Blue Ribbon Commission on America's Nuclear Future. *Disposal Subcommittee Report to the Full Commission*. Jan. 2012. Web. 19 Sept. 2013. <http://cybercemetery.unt.edu/archive/brc/20120620220845/http://brc.gov/sites/default/files/documents/disposal_report_updated_final.pdf>. Page v.

activities controlled by annual appropriation acts), where they are subject to the deficit reduction process.

• The 1987 amendments to GRH placed the appropriations from the NWF under the spending cap applicable to all domestic discretionary programs, even though the NWF was self-financed. This had the effect of forcing spending to meet the NWF's legal obligations to compete with other annually-funded spending programs which did not have dedicated funding sources. Also, as a result, OMB dropped its historical practice of setting separate budget planning targets for the NWF, forcing it to compete against other DOE programs within a single DOE budget target for domestic discretionary spending.

• The Budget Enforcement Act of 1990 (BEA) set new caps on discretionary spending accounts. BEA also established new pay-as-you-go (PAYGO) requirements to ensure that the net effects of legislative changes affecting mandatory spending were budget neutral.

• In the Conference Report accompanying the Omnibus Budget Reconciliation Act of 1990, the spending from the NWF was included in domestic discretionary appropriation accounts for Fiscal Year (FY) 1991, and was therefore subject to the spending cap set in the BEA.

• The 1997 Amendments to the Balanced Budget Act extended the caps on discretionary spending accounts and PAYGO requirements for mandatory spending accounts through FY 2002.

This layering of budget requirements seriously eroded the NWF's funding capability in two ways:

• It imposed annual spending and revenue controls on a Fund that was designed to finance a 125-year program on a life-cycle cost basis; and

• It made the NWF dysfunctional by creating separate and unrelated rules applicable to the revenue and spending components of the Fund.

The overall effect, in short, has been to prevent the NWF from being used for its intended purpose. Under PAYGO requirements, increased funding for the waste management program must be offset by cuts in other programs within the annual discretionary appropriations caps. The original NWF requirement for annual appropriations from the NWF was intended to ensure that Congress retained control over the actual activities of the

> program; its purpose was never to limit the funding needed to implement the program, which is what has happened.[328]

Stated simply, if we had a long term nuclear waste repository – which we don't – we could collect funds under the 1982 legislation, but not disburse them without cancelling almost $100 billion in other programs.

The problems facing the selection and funding of a long term repository are outside the scope of this report. Within the scope of this report is the question whether CGS faces a dramatically increased cost of decommissioning from continued operations. As discussed below, in the case of Nuclear Waste Policy Act of 1982, the answer is a clear "yes".

At the heart of the problem is the failure of the U.S. Department of Energy to meet its current commitments for used fuel. On November 19, 2013, United States Court of Appeals for the District of Columbia Circuit issued an order effectively ending the current program:

> Because the Secretary is apparently unable to conduct a legally adequate fee assessment, the Secretary is ordered to submit to Congress a proposal to change the fee to zero until such a time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan.[329]

Even before this order, the failure of the Department of Energy to adequately provide for nuclear fuel storage has led to a large number of litigations. Many of these have settled or been decided. In 2011, in a letter to Owen F. Barwell, the Department of Energy's Acting Chief Financial Officer, David Zabransky conducted a detailed study of the liability the U.S. Government faced from its partial breach of the standard contracts that it executed pursuant to the Nuclear Waste Policy Act of 1982. [330] The estimate, at that time, was a daunting $20.8 billion.

Congress will need to address the problems described in the Blue Ribbon Commission's report. When they do, they will face a very simple set of calculations:

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[328] Ibid. Page 56.
[329] United States Court of Appeals for the District of Columbia Circuit. *Order in NARUC v. U.S. Department of Energy No. 11-1066*. 19 Nov. 2013. Page 7.
[330] Zabransky, David K., Office of Standard Contract Management. *Liability Estimate*. Letter to Owen F Barwell. 26 Oct. 2011. Unt.edu. Web. 19 Sept. 2013. <http://cybercemetery.unt.edu/archive/brc/20120620221030/http://www.brc.gov/sites/default/files/comments/attachments/doe_response-liability_estimate_2011_final_102611.pdf>. Page 13.

1. The Nuclear Waste Fund has a balance of $28.2 billion.[331]
2. The liability from projected payments to commercial nuclear facilities for the failure to accept nuclear waste under the 1982 legislation is $20.8 billion.[332]
3. Forecasted revenues from the existing $1/MWh fee are $20.2 billion.[333]
4. Base forecasted costs for the long term nuclear waste repository are $88.9 billion.[334] The low end of the range is $37.5 billion. The high end is $171.1 billion.

The best case is that the current $1/MWh fee would create a funding shortfall of $9.9 billion.[335] The base case would face a shortfall of $61.3 billion.[336]

To bring this into balance, Congress would either have to agree to fund the shortfall from taxes or increase the fee substantially. To just break even, the base case requires a fee of $2.60/MWh.[337] This is the amount that results from amortizing the existing liability over the life of the nuclear waste facility using the base data as the Secretary of Energy's 2013 Fee Adequacy Assessment.

This back of the envelope calculation does not match the results from the January 2013 determination made by the Secretary of Energy for a long list of reasons.[338] The most important reason is that his determination did not address the ongoing liability owed by the U.S. treasury to the commercial reactors for the government's failure to accept nuclear waste. Other doubtful assumptions include a growing number of commercial reactors, funding from taxes, a high return on existing balances in the fund, and myriad other adjustments in the forty-two different scenarios in the determination.

A Congressional repair of the Nuclear Waste Policy Act of 1982 is unlikely to preserve the $1/MWh used fuel fee at the cost of raising taxes. CGS's cost of delaying decommissioning is the increased amount such a repair would add to future operating costs. In the scenario

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331 US Department of Energy. *U.S. Department of Energy Nuclear Waste Fund Fee Adequacy Assessment Report*. Jan. 2013. Web. 19 Sept. 2013. <http://energy.gov/sites/prod/files/January 16 2013 Secretarial Determination of the Adequacy of the Nuclear Waste Fund Fee.pdf>. Page 2.

332 Zabransky, David K., *Liability Estimate*, Page 13.

333 U.S. Department of Energy. *Nuclear Waste Fund Fee Adequacy Assessment Report*, Office of Standard Contract Management, January 2013, Page A-7.

334 Ibid. Page A-7.

335 Funds available are $28.2 billion currently in hand and $20.2 billion forthcoming from fees or $48.4 billion. The costs are $20.8 in settlement payments and $37.5 billion in facility costs or $58.3 billion, The result is $48.4 billion minus $58.3 billion – negative $9.9 billion.

336 Funds available are unchanged at $48.4 billion. The costs are $20.8 in settlement payments and $88.9 billion in facility costs or $109.7 billion. The result is $48.4 billion minus $109.7 billion – negative $61.3 billion.

337 If the current fee raises $20.2 billion, adding $2.6/MWh to the current fee would raise an additional $60.6 billion in revenue – just meeting the shortfall in the base case.

338 U.S. Department of Energy, Office of Standard Contract Management. *Nuclear Waste Fund Fee Adequacy Assessment Report*. January 2013.

discussed above – raising the fee to $2.6/MWh – this would add $14 million, annually, to CGS's costs.

4.8.5 Waste Confidence Decision

The Waste Confidence Decision and Rule represent the generic determination by the U.S. Nuclear Regulatory Commission (NRC) that spent nuclear fuel can be stored safely and without significant environmental impacts for a period of time after the end of the licensed life of a nuclear power plant. Historically, this generic analysis has been incorporated into the Commission's National Environmental Policy Act (NEPA) reviews for new reactor licenses, license renewals, and Independent Spent Fuel Storage Installation (ISFSI) licenses through the Waste Confidence Rule. The Waste Confidence Decision and Rule satisfy the NRC's obligations under NEPA, with respect to post-licensed-life storage of spent nuclear fuel.

On June 8, 2012, the U.S. Court of Appeals for the DC Circuit found that some aspects of the 2010 Decision did not satisfy the NRC's NEPA obligations and vacated the Decision and Rule. [New York v. NRC, 681 F.3d 471 (D.C. Cir. 2012)]. The court indicated that in making either a Finding Of No Significant Impact based on an Environmental Assessment or an Environmental Impact Statement supporting the rulemaking, the Commission needed to add additional discussions concerning the impacts of failing to secure permanent disposal for spent nuclear fuel, and concerning the impacts of potential spent fuel pool leaks and spent fuel pool fires.

In response to the Court's decision, the Commission decided to stop all licensing activities that rely on the Waste Confidence Decision and Rule (see CLI-12-016). The NRC created a Waste Confidence Directorate within the Office of Nuclear Material Safety and Safeguards to oversee the drafting of a new Waste Confidence Environmental Impact Statement and Rule. The Commission has instructed the Directorate to issue the final Environmental Impact Statement and Rule by no later than September 2014.

4.8.6 Decommissioning Cost Escalation

The formula set out in 10 CFR 50.75(c) has faced substantial criticism both within the NRC and in Congress. In late 2011, the NRC commissioned a study to update the existing formulas:

> In recognition of the significantly expanded nuclear power plant decommissioning experience and knowledge-base, and the evolution in decommissioning technology and practice since the development of the minimum decommissioning fund formula, the NRC commissioned a study to re-evaluate the adequacy of the minimum decommissioning fund requirement specified by the formula. This report summarizes the results of this re-evaluation, including making a recommendation on how the formula

should be updated to reflect the current state-of-knowledge in nuclear power plant decommissioning.[339]

Since CGS has been used as the reference BWR in studies from the 1980s to the present, it is possible to see how the expected costs of decommissioning have evolved over that period:

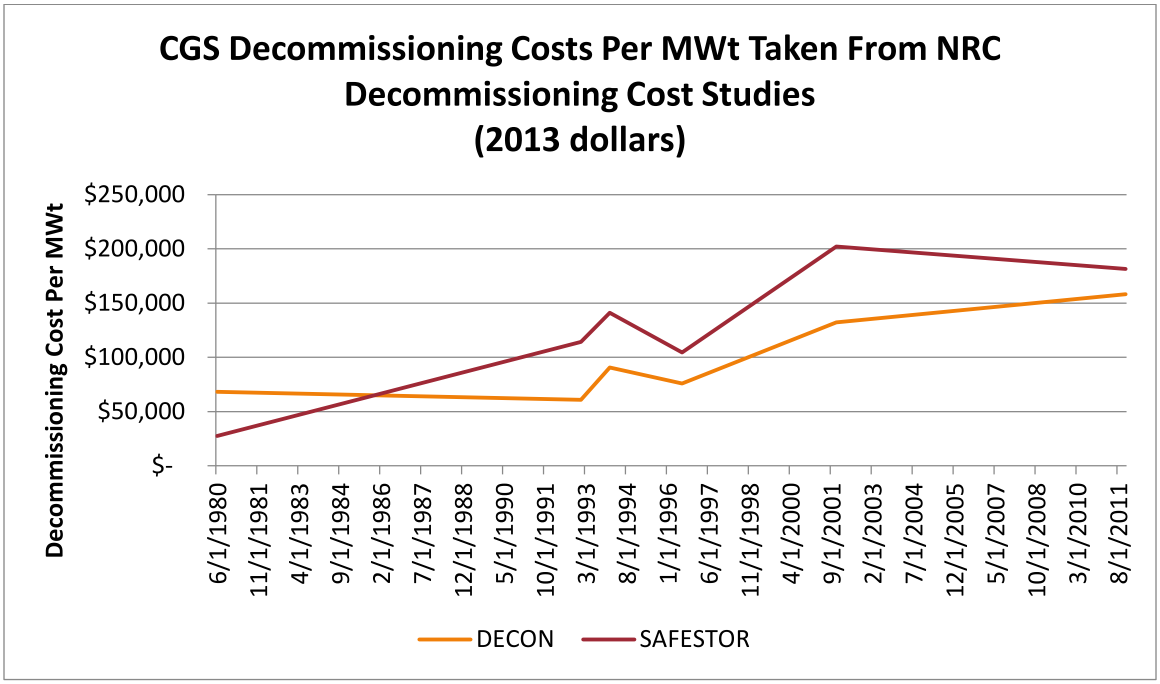

Figure 52

The rapid increase in decommissioning costs is mirrored by recent comments by NRC staff:

> NRC: "Historically, I would say that probably the minimum decommissioning funding formula has increased probably on average around 8% to 9% a year. The primary driver would probably be the burial cost. Disposal of low level waste is getting to be a very expensive proposition for a variety of economic reasons. There are very few places you can dispose of this. There are also three major classifications for low level waste, such that the higher radiological content of the waste will incur higher costs for disposal."[340]

[339] Office of Nuclear Material Reactor Regulation. *Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula*. November 2011, Page iii.
[340] UBS Investment Research. *Nuclear Decommissioning Discussion with the NRC Staff: Conference Call Transcript.* Nrc.gov. 9 Apr. 2013. Web. 20 Sept. 2013. <http://pbadupws.nrc.gov/docs/ML1312/ML13128A305.pdf>.

In discussions with the NRC expert, Michael Dusaniwskyj, we were informed that the source for his estimate was a 2011 Duff and Phelps research report entitled "Historical NDT Fund Balances, Annual Contributions and Decommissioning Cost Estimates."[341,342]

Duff and Phelps concluded that 24 year nominal escalation rates ranged from 4.7% to 9.0% with CGS at the bottom of the range.[343] This corresponds to a real increase of 2.0% to 6.3% per annum.

We undertook a similar analysis using site-specific decommissioning data from four sources:

10 CFR 50.75 Reports

Post-Shutdown Decommissioning Activities Reports (PSDAR)

California Nuclear Decommissioning Cost triennial Review (NDCTP)

NRC Internal Studies (CGS and Trojan)

This provided a data base of 71 detailed site-specific decommissioning studies where the plants had a rating of over 1,000 MWt.[344] The data was then compared to the dates of the underlying studies. Costs were escalated using the Consumer Price Index (CPI) to bring the decommissioning costs per MWt to 2013 dollars.[345]

Such a broad review mirrors the detailed work undertaken in the November 2011 Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula report. While the NRC's report focused on specific cost components, our focus is the continuing increase in decommissioning costs over time.

The following chart summarizes the results:

341 Telephone call between Michael Dusaniwskyj and Jil Heimensen, August 22, 2013.

342 Krauss, David and Phelps, Duff. *Historical NDT Fund Balances, Annual Contributions and Decommissioning Cost Estimates*, April 11, 2011. Page 20.

343 Ibid. Page 20.

344 MWt represents the actual heat output. MWe, the more common term, represents the maximum electric output. We chose MWt since it is more closely linked to decommissioning elements.

345 Nuclear Regulatory Commission. Office of Nuclear Material Reactor Regulation. *Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula*. November 2011, Pages 3-15 through 3-33.

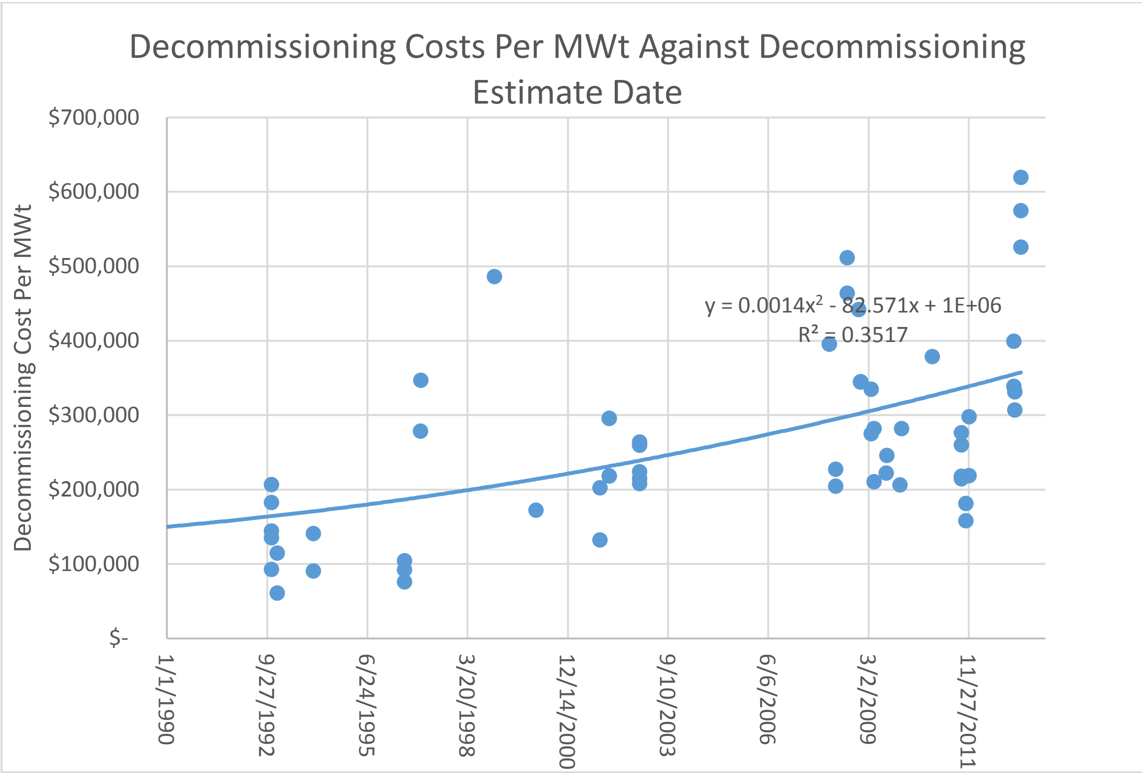

Figure 53

In order to check whether the continuing increase in real decommissioning costs is significant, we conducted a linear regression on Decommissioning Costs/MWt in 2013 dollars against the date of the decommissioning studies. We included the industry standard variables for PWR/BWR technology and the choice of decommissioning methods as well. The variable for decommissioning estimate date is significant at the 99% level. The real annual escalation rate for both BWR and PWR units is 1.85%. The statistical properties of the estimates for decommissioning method were not significant, so we also conducted a regression on the BWR plants alone. The annual escalation rate for BWR decommissioning estimates in our sample was significant at 99%. The value was 2.80% per annum.

A comparable regression on the small data set comprised of site specific estimates for CGS estimated by NRC consultants is significant at 95%. The real escalation rate from 1980 through 2011 for CGS's site specific estimates (SAFSTOR) is 6.19%. A similar regression for DECON is also significant at 95% and indicates an annual escalation rate at 3.10%. If decommissioning costs continue to increase as they have over time, delay of decommissioning will be more costly and less economic than decommissioning at an earlier date. Although Energy Northwest documents indicate a preference for SAFSTOR at this time, DECON would seem to be both less expensive today and with a lower rate of escalation over time.

In conclusion, the costs of decommissioning are very likely to increase in real terms in the future, as they have in the past. Every year that decommissioning is delayed is likely to add 3.1% (above and beyond the impact of inflation) to the existing $464.5 million decommissioning costs.

5 THE MARKET TEST

In 1998, in the course of the extensive regional review of costs and policies, the cost-review committee of the Comprehensive Review recommended that CGS be measured against market prices:

> Washington Nuclear Plant 2: Combine aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable at market prices. Sell a portion of Bonneville's power, equal to the output of CGS, at a price that will recover the plant's operating costs. Test the plant's power prices against market prices every two years, and evaluate terminating the plant if projected operating costs exceed projected revenues. If revenues exceed costs, use a portion to build a decommissioning fund. Estimated annual savings: $19 million.[346]

BPA accepted the recommendations.

> The BPA Proposed Plan:
>
> BPA agrees with the basic objective of the Cost Review recommendation, "to ensure that the operations of the plant not be insulated from the discipline of the marketplace" and to achieve the recommended increase in net operating revenues.
>
> BPA intends to subject CGS operating costs to a market test biennially, testing whether market value of the CGS output recovers annual operating costs of the plant. BPA intends to solicit input on the precise nature of this market test in a public process this year.
>
> Likewise, as recommended in the Review, BPA intends to re-evaluate plant termination if operating costs are projected to exceed revenues achievable at market prices by more than the termination costs.

[346] Northwest Power and Conservation Council. *Issue brief no. 98-10. 1998 Briefing Book*. Nwcouncil.org. May 1998. Web. 15 Oct. 2013. <http://www.nwcouncil.org/reports/1998/98-10>.

> With the cost and revenue projections assumed by the Cost Review, this would require about $19 million of operating cost reductions and/or revenue increases. BPA will work with the Supply System to achieve as much of this enhancement of net revenues as possible through reductions in operating costs.
>
> BPA intends to work with the Supply System to achieve additional operating cost efficiencies, avoid major capital additions, shorten outages, and, potentially, change from an annual to a biennial refueling cycle (would reduce from 5 to 2 the number of refuelings during next 5-year rate period).
>
> Cost reductions assume, in part, that there are no major equipment failures and no extensive additional regulation.
>
> The Cost Review also recommended that BPA market a portion of the FBS equivalent to the planned output of CGS priced in a manner that ensures recovery of the plant's operating costs in the actual sales of the plant's output. Subject to further input, BPA's tentative conclusion is that the problems connected with this piece of the recommendation are not practicably solvable. It would involve selling a portion of the Federal Base System at a higher price equal to CGS's operating costs – a legal difficulty – and reduction of the lowest cost subscription inventory when it appears that we will be over-subscribed. CGS's operating costs are now so close to the market and to BPA's likely subscription power rates that the cost impact of this separation on both the subscription rate and the theoretical CGS rate would be negligible. Equity concerns among parties with subscription rights over who is left with the higher-priced portion of power would likely exacerbate the oversubscription issues (see power markets, revenues and subscription fact sheet). Finally a robust market test should achieve the bulk of the cost review goal, without creating the substantial problems connected with putting a higher price on this portion of the subscription inventory.[347]

As with many regional policies and agreements, this proposed standard was quickly forgotten. In 2002 However, CGS's operator, Energy Northwest, wrote:

> Market test
>
> In 1998, a regional cost review made several suggestions for the operation of Columbia Generating Station. Most significantly, the review suggested that the Northwest's only nuclear power station prove itself on a market basis. As

[347] Bonneville Power Administration. *Issues '98 Fact Sheet #1: Cost Management*. Portland: Bpa.gov, June 1998. PDF.

> BPA and Energy Northwest eventually constructed the test, the plant's power would be given a value based upon daily, weighted-average prices at West Coast trading centers. A reasonable amount would be deducted for transmission losses and the cost of transmission.
>
> In every fiscal year since the challenge was made, Columbia Generating Station has proved itself a viable market asset. Since 1999, the total difference between the cost of operating Columbia and the replacement value of its generation is over $1.526 billion. During the volatile electrical market in 2001 the power worth exceeded cost by a factor of eight due to high market prices and reliability of the station.
>
> Columbia Generating Station
>
> | Fiscal Year | Production Cost* | Power Worth |
> |---|---|---|
> | 1999 | $158,000,000 | $174,000,000 |
> | 2000 | 175,600,000 | 265,650,000 |
> | 2001 | 199,500,000 | 1,597,246,000 |
> | 2002 | 196,000,000 | 218,098.000 |
> | Total | $729,100,000 | $2,255,661,000 |
>
> *Does not include interest and decommissioning costs.
>
> Interest cost ranged from $132 million to $110 million during the four-year period. Decommission contributions for the same time period range from $5 million to $6 million.[348]

This, apparently, was the final mention of the CGS "Market Test." Bonneville never held a proceeding to implement the Market Test, nor, as far as we have been able to determine, ever mentioned the issue again. Document requests to BPA and Energy Northwest concerning the Market Test have received the response that they were unable to find any relevant materials – in spite of the fact that our review has successfully found materials at BPA, Energy Northwest, and the Regional Planning Council.[349,350]

In May 1998, BPA summarized the Market Test implementation in their Keeping Current journal:

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348 Energy Northwest. *Draft Executive Board Report on Nuclear Programs.* 20 Sept. 2002. PDF. Appendix A.
349 Glica, Alex. *Public Records Request 2013-51.* Message to Rose Anderson. 13 Nov. 2013. E-mail.
350 Munro, Christina. *FOIA #BPA-2013-01739-F.* Letter to Charles Johnson. 5 Nov. 2013.

Cost Review Recommendation:

Implement a strategy for Washington Public Power Supply System's nuclear plant, WNP-2, that combines aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable within market constraints. In BPA's subscription process and upcoming rate case, determine how to allocate the plant's costs in BPA rates so that its portion of the Federal Base System on a planning basis can be marketed to ensure full recovery of the plant's operating costs (unless legal or other issues prevent doing so). To the extent revenues can exceed operating costs, use a portion of the resulting net operating revenues to build up the decommissioning fund. Biennially subject the plant's operating costs to a market test. Evaluate termination in the event operating costs are projected to exceed operating revenues. Estimated savings include a combination of reduced O&M expense from the cost baseline and potential increased revenues.

BPA Implementation Plan:

BPA agrees with the basic objective of the Cost Review recommendation "to ensure that the operations of the plant not be insulated from the discipline of the marketplace" and to achieve the recommended increase in net operating revenues.

- BPA intends to subject WNP-2 operating costs to a market test biennially, testing whether market value of the WNP-2 output recovers annual operating costs of the plant. BPA intends to solicit input on the precise nature of this market test in a public process this year.
- Likewise, as recommended in the Review, BPA intends to re-evaluate plant termination if operating costs are projected to exceed revenues achievable at market prices by more than the termination costs.
- With the cost and revenue projections assumed by the Cost Review, this would require about $19 million of operating cost reductions and/or revenue increases. BPA will work with the Supply System to achieve as much of this enhancement of net revenues as possible through reductions in operating costs. [351]

The Committee's Cost Review of the Federal Columbia River Power System makes the following recommendation:

> The overriding intent of the Committee's recommendations regarding CGS is to ensure, insofar as possible, that the operations of the plant not be insulated from the discipline of the marketplace. In order to accomplish this, the Management Committee recommends:
>
> 1. Subject CGS to a market test biennially: annual revenues at market price recover annual operating costs, accounting for hydro firming value provided by the plant.
>
> 2. Implement a strategy that combines aggressive cost management with a flexible response to market conditions and unforeseen costs.
>
> 3. In Bonneville's subscription process and 1998 Rate Case, determine how to allocate the plant's costs in rates and market a portion of the FBS equivalent to the plant's expected output priced in a manner that ensures the recovery of the plant's operating costs and allows a lower price for the rest of the FBS, unless legal or other issues prevent doing so.

[351] BPA. *Keeping Current – Issues '98 Fact Sheet #1: Cost Management.* May 1998. Page 10.

> 4. To the extent that plant revenues exceed operating expenses, use a portion of the resulting net operating revenues first to build up the decommissioning fund to improve future financial flexibility.
>
> 5. Re-evaluate plant termination in the event that operating costs are projected to exceed revenues achievable at market prices by more than the termination costs (i.e., terminate if termination is more economical than continued operation, taking into consideration hydro-firming value of the plant and termination costs).
>
> Rationale:
>
> CGS should continue to be operated only if it can meet a cost recovery test based on market prices. Currently, projected operating costs (defined as all costs except debt service) exceed projected revenues by about $19 million per year. If costs can be managed so it can meet the market test, the plant should continue to be operated.
>
> Separating a portion of the FBS equivalent to the planned output of CGS from the rest of the subscription pool and selling it at rates which would cover the plant's operating costs would allow a lower subscription price for the rest of the federal system power. (Legislation would be necessary to actually separate CGS from other Federal resources and sell its output at market, and such legislation would be risky and take longer than Bonneville's schedule for its 1998 Rate Case. This would mean that Bonneville would be unable to adopt the recommendation as written in the Management Committee's Draft Report when Bonneville sets rates for the FY 2002-2006 period.)
> Implementation:
>
> The biennial market test should compare current projections of annual revenues at market price to current projections of annual operating costs, accounting for hydro firming value.[352]

This was by no means an empty statement. Both the BPA Administrator and Energy Northwest's CEO publicly agreed with this recommendation. As Vic Parrish stated to the Oregonian on January 4, 1998:

[352] Management Committee. *Cost Review of the Federal Columbia River Power System Management Committee Recommendations*. 10 Mar. 1998. PDF. Recommendation #7, Page 27.

> ``It would help us immeasurably," Parrish says. ``We understand real-world economics, and we believe we are something that's valuable to the region. We'd just like to receive a fair shake before precipitous decisions like shutting us down for good take place."[353]

Though the actual calculation of the Market Test was agreed between BPA and Energy Northwest in 1999, the implementation of the Market Test appears to have been lost in history.

However, the results reported in the September 20, 2002 draft Executive Board Report on Nuclear Programs are very close to the chart below. [354,355]

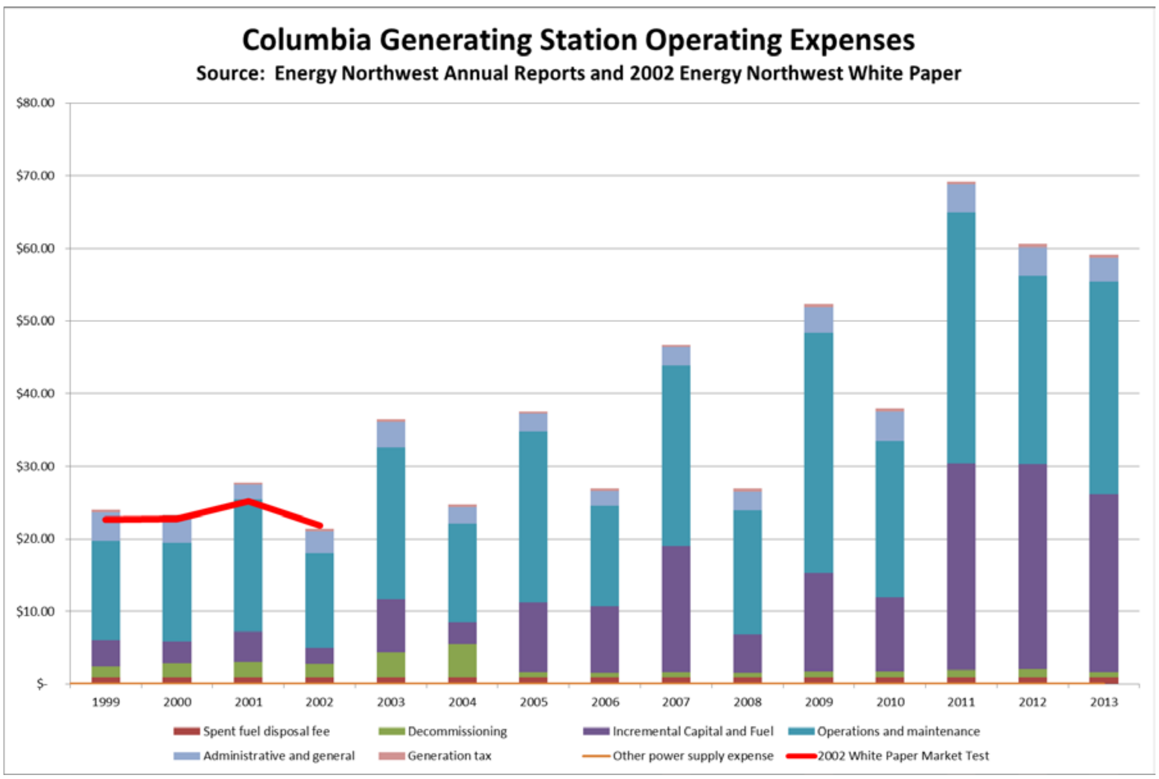

Figure 54

5.1 Avoidable Costs

Almost all nuclear unit costs are primarily determined at the commencement of a new refueling cycle. After the refueling cycle has begun, costs are largely fixed. As can be seen

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[353] Walth, Brent. *On-and-off Nuclear Plant Runs Relentless Tab*. The Oregonian, 4 Jan. 1998. PDF.
[354] Energy Northwest. *Draft Executive Board Report on Nuclear Programs*. 20 Sept. 2002. Page 7.
[355] Ibid. Appendix A.

from the chart above, an excellent opportunity to close CGS was lost in 2011. The refueling cycle has commenced in 2013, so the appropriate period for review of CGS on an ongoing basis will be at the end of FY 2015.

We can divide costs into short term and long term. We can avoid a few – very few – costs in less than a year. For a nuclear plant, the only cost in this category is probably the escalation on decommissioning costs. In the long term – longer than the refueling cycle – almost all costs are avoidable except for the interest and repayment on past borrowings.

Avoidable Costs

	Short Term	Long Term
A&G	Unlikely	Yes
O&M	Unlikely	Yes
Fuel	No	Yes
Additional Fuel Staorage Fees	No	Yes
Decommissioning Escalation	Yes	Yes
Capital Additions	Unlikely	Yes
Bond Interest and Principal	No	No
Existing Fuel Storage Fees	No	No

Figure 55

The exception to this rule concerns decommissioning costs. The evidence reviewed in the previous section indicates a continuing real increase in decommissioning costs over time – both for the industry and for CGS. An additional year of decommissioning cost increases can be avoided by plant closure between refueling cycles. This still would not make closure between refueling optimal, however, because generation might continue at very low short term marginal costs until the end of the current refueling cycle.

5.2 THE FY 2015 MARKET TEST

Any forecast of the future has subjective elements. We have attempted to reduce these by taking elements of the Market Test, already discussed and agreed to by BPA and Energy Northwest, and comparing the avoidable costs with current forward market prices taken from the industry journal "Argus US Electricity." Argus and its predecessor, "Energy Market Report," are widely used and have been in publication since the 1990s. Their forward prices are surveys of existing bids and asks in the industry. The prices are not forecasts. They reflect the open outcry market and are meant to represent prices at which transactions are taking place.

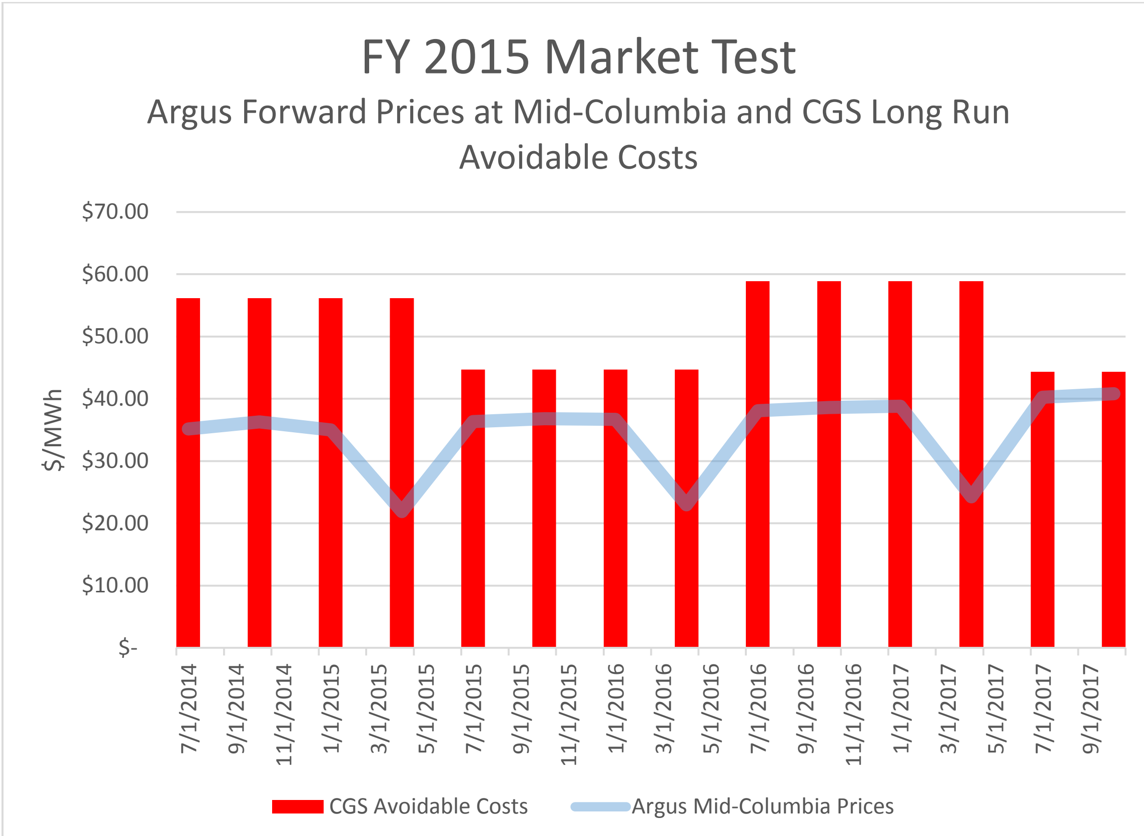

Figure 56

No adjustments have been made to the Argus Mid-Columbia prices other than weighting the on-peak and off-peak prices by the appropriate number of on-peak and off-peak hours. The CGS avoidable costs are taken directly from the 2014 Long Range Plan, with the addition of two categories of avoidable cost – additional spent fuel fees and avoidable decommissioning escalation. These have been discussed in detail above.

In a sense, this is a best case scenario for CGS. We know that past Long Range Plans have significantly under-run actual costs. The decision to "flow" some capital costs out of the current Long Range Plan also would tend to support the assumption that the costs reported above are understated.

It is logical to ask whether the Market Test would have gotten a different answer if spent fuel fees and the avoidable decommissioning escalation were not included. It would not have gotten a different result. The following chart shows the Market Test without these adjustments.

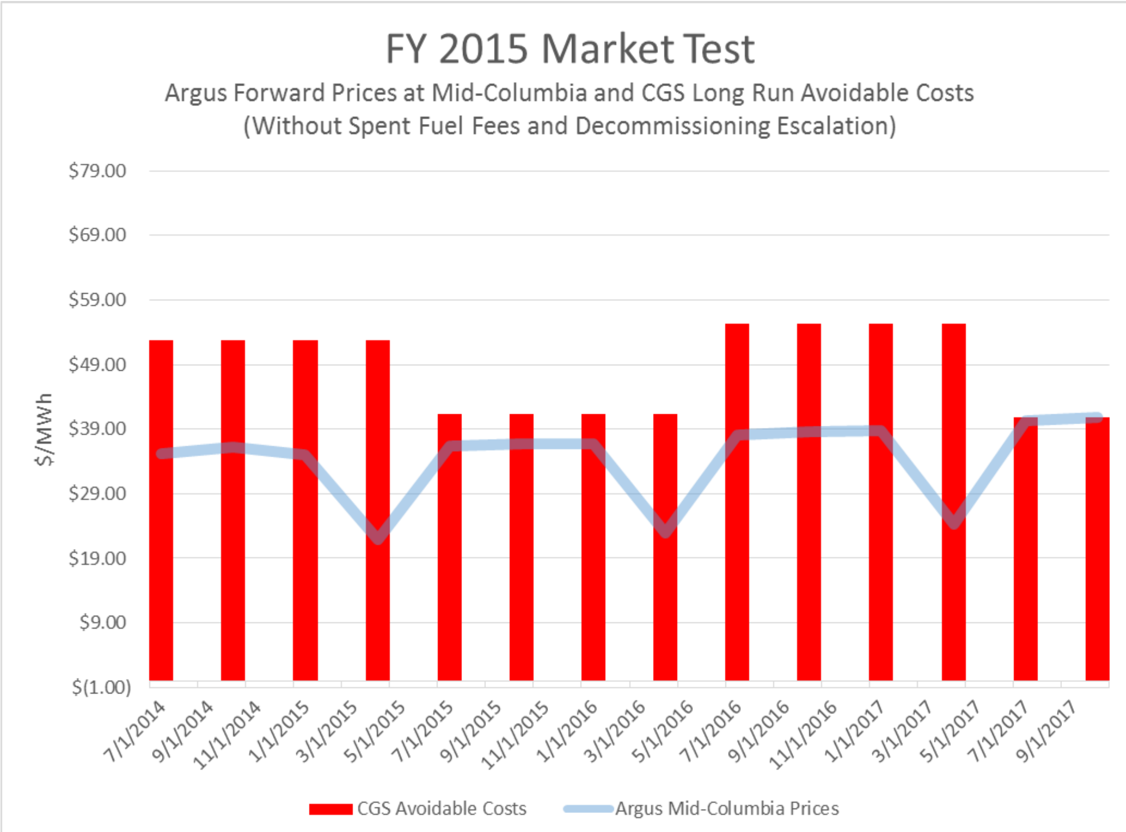

Figure 57

In sum, CGS fails the "Market Test" for FY 2015, and an alternative supplier or suppliers should be considered.

5.3 RECOMMENDATION

It is a frequent case that specific plants have higher operating costs than the market. The industry term for replacing energy from a more expensive plant with less expensive purchases is "displacement." In this case, it is reasonable to consider displacing CGS with market purchases.

Operationally, this would mean the issuance of an RFP by BPA for a portfolio of contracts of varying terms. If the contracts meet cost, reliability, and environmental concerns, CGS would be decommissioned at the end of the current refueling cycle.

Specific recommendations:

1. BPA should seek an opinion from the Office of the General Counsel of the Department of Energy that Section 15(c) of the 1971 Project Agreement gives the Administrator the power to direct the termination of CGS.
2. BPA should issue a Request For Proposals on behalf of Energy Northwest seeking 1,130 megawatts of capacity and 1,004 average megawatts of energy.[356,357] The RFP would specify that suppliers would indicate environmental information, in addition to financial, economic, and engineering information.
3. BPA staff would assemble responses and share the response data with customers and state and federal agencies, including the Northwest Planning Council.[358]
4. Financial theory argues that multiple suppliers and staged contract durations produce optimal outcomes. The result of the review of the offers would be a portfolio of different supplies and suppliers.
5. The final portfolio would be implemented by Energy Northwest.
6. After contract implementation, CGS would begin DECON decommissioning in May 2015.
7. Energy Northwest would handle employment transitions by a combination of methods. First, implementing DECON rather than SAFSTOR decommissioning. Second, training and employing workers in plant decommissioning – following the example of PGE (Trojan) and SMUD (Rancho Seco) and a variety of additional strategies as outlined in section 7 of this document.

5.4 POWER CONTRACTS

In 1978, Congress adopted Public Law 95-617, the Public Utilities Regulatory Policies Act (PURPA). This game-changing legislation mandated that utilities purchase from competitive power suppliers if the suppliers could offer comparable resources at lower "avoided" costs.

The Independent Power Producer (IPP) industry exploded after PURPA was enacted. The vast majority of PURPA resources were purchased under long term contracts. As of August this year, IPPs generated 37.4% of total electric generation in the United States.[359]

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356 Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study. Technical Appendix. Volume 1: Energy Analysis*. Web. 13 Sept. 2013. Page 63. <http://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf >.

357 Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study. Technical Appendix. Volume 2: Capacity Analysis*. Web. 13 Sept. 2013. Page 172. <http://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf >.

358 Bonneville's frequently adopted "steering committee" process would be a useful approach that would maintain bidders' desire for confidentiality while allowing options to be explored by regional representatives.

359 Energy Information Administration. *Electric Power Monthly August 2013*. Table ES1.A. Total Electric Power Industry Summary Statistics, 2013 and 2012.

In the early 1980s, BPA inaugurated the bulk power market for electricity by selling non-firm energy on the open market to the highest bidder. Bulk power markets are now universal across the United States and Canada – ranging from the competitive open markets of the Western United States and Canada (outside of California and Alberta) and highly regimented administered markets like that of PJM and other Regional Transmission Organizations and Independent System Operators.[360]

As part of restructuring in many states utilities were forced to divest generation. Depending on the state and the Independent System Operator, utilities sold their generation to third parties. In some states, like Illinois and California, the existing utility sold some units to a third party and transferred a large block of the more efficient units to a new subsidiary. In other states, like New York, full divestiture was required.

As part of divestiture, huge auctions are common where many thousands of megawatts of energy and capacity are purchased on a long term basis. This is especially true in PJM where many states require annual Provider of Last Resort (POLR) purchases to serve utility customers.

In some ISOs, capacity auctions are conducted for huge amounts – the most recent PJM capacity auction purchased over 26,000 megawatts of capacity for 2016/2017.[361]

Although exact numbers are not available, the vast majority of load serving entities in the United States are not vertically integrated. In the Pacific Northwest, BPA serves as "G&T" – a generation and transmission wholesale utility for the region's utilities. This is not an uncommon solution for publicly owned utilities throughout the United States.

Appendix A to this report contains many examples of long term contracts. Even the most stressed of examples – California Governor Gray Davis's long term emergency purchases during the California Crisis – have shown the effectiveness of power contracts as part of generation portfolios.[362]

Overall, power contracts are an almost universal component of generation portfolios throughout the United States.

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360 PJM stands for the Pennsylvania New jersey Maryland power pool which now encompasses northern Illinois, Ohio, West Virginia, and pasts of neighboring states.

361 PJM. *2016/2017 RPM Base Residual Auction Results*. 24 May 2013. Page 1.

362 In 2001, faced by the complete collapse of the preposterously unworkable California administered markets, Governor Gary Davis embarked on the long term purchase of 10,000 megawatts of long term contracts on an emergency basis. While the wisdom of his actions was debatable, even these highly stressed arrangements proved operational.

5.4.1 Contract Basics

Since the advent of PURPA, power purchase agreements (PPAs) have gone through intense development. Contract models have been developed by many different parties. BPA, for example, provides a model contract for wind projects.[363] A very common model for power contracts is provided by the Edison Electric Institute. This model, named the "EEI Master Contract" has been used widely in the industry.[364]

The basic elements of a PPA include term, commissioning, pricing, force majeure, transmission, performance, default, credit support, insurance, and environmental issues.

5.4.1.1 Term

PPAs commonly set specific dates for beginning and end. This facilitates financing and planning. Specific options for renewal are also included.

5.4.1.2 Commissioning

Plant commissioning for new units is a very important step. The PPA sets the milestones prior to the official in-service date. The PPA also sets preliminary certification, permit, and licensing steps. A very significant step is the determination of plant capacity and energy capability.

5.4.1.3 Pricing

Pricing arrangements are often complex. Cost plus agreements, such as the 1971 Project Agreement, are not common, but are not unheard of. More common pricing involves specific prices, by product, with escalation factors agreed on in advance.

5.4.1.4 Force majeure

Force majeure, an unavoidable event or occurrence usually from natural causes, is a common source of disputes. A clear definition is important. The EEI Master Agreement provision reads:

> To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify

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[363] Bonneville Power Administration. *POWER PURCHASE AGREEMENT Executed by the UNITED STATES OF AMERICA, DEPARTMENT OF ENERGY acting by and through the BONNEVILLE POWER ADMINISTRATION And [SELLER]*. 22 Mar. 2001.

[364] Edison Electric Institute. *Master Contract.* 25 Apr. 2000.

> otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.[365]

The 1971 Project Agreement does not include a Force Majeure definition.

5.4.1.5 Transmission

Specific locations, costs, and terms are a standard part of any PPA.

5.4.1.6 Performance

Performance and report terms are very important. BPA's wind contract, for example, sets specific standards for maintenance, reporting, and governance.

5.4.1.7 Default

The 1971 Project Agreement has been tested in many different litigations and has survived. Strong default language will be part of any future PPA.

5.4.1.8 Credit support

The PPA directly specifies the source and amount of credit support for the transaction. Unlike the current 1971 Project Agreement, the amount of credit support is negotiable and will likely be large.

5.4.1.9 Insurance

If the PPA is part of a specific resource, the region will require insurance to cover outage and closure risks.

5.4.1.10 Environmental issues

The PPA can set specific conditions for fuel, operation, and emissions. This is increasingly important given the evolving standards for carbon and traditional NOx and SO^2 regulation. BPA has raised the issue of possible impacts of displacement contracts on California's carbon cap and trade markets. These can be expressly addressed in the PPA.

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[365] Ibid. Page 13.

5.4.2 Contract Comparison

The 1971 Project Agreement predated the extensive contract development that followed PURPA and the deregulation of retail and wholesale electric markets. As such, it is not surprising that the 1971 Project Agreement has many deficiencies. As discussed above, this has contributed to past operating and cost issues and is likely to continue to pose problems in the future.

Contract Comparison		
	1971 Project Agreement	EEI Master Contract
Structure	Take or Pay	Take and Pay
Duration	Unknown	Set per agreement
Commissioning	Completed	Set per agreement
Pricing	Cost plus	Set per agreement
Credit Support	Nuclear Insurance and BPA's Customers	Vendor
Fuel Source	Nuclear	Unknown (probably Gas/Wind)
Operating Risks	Nuclear	Force Majeure
Insurance	Nuclear insurance	Set per agreement
Environmental Issues	None	Set per agreement

Figure 58

5.5 LONG TERM COST COMPARISON

The industry has little data concerning the operating costs of aging nuclear stations. An aging fossil fuel thermal unit can be maintained on a component by component basis in most cases. Turbines, boilers, and fuel handling equipment can be upgraded or replaced in a relatively predictable fashion.

Nuclear units are more complex. The recent closure of San Onofre 2 and 3 followed the unsuccessful repair of steam generators. Replacement of equipment within the containment vessel is especially complex, and costs and feasibility of replacements is almost impossible.

We have conducted a detailed analysis of market prices at Mid-Columbia both with and without CGS. The methodology of this forecast is described in the next section. A long term forecast of CGS avoidable costs is more problematic. This is all the more complex given the cost of major replacements and the virtual impossibility of determining the schedule of future replacements.

For our Market Test we used the FY 2014 Long Range Plan estimates in the interest of conservatism, but the Long Range Plan forecasts have tended to be very poor forecasts of future costs. The FY 2007 forecast predicted flat costs for the next five years. This forecast was all the more surprising since Energy Northwest was actively lobbying for needed repairs to the steam condenser and should have anticipated increased costs.

The following chart shows actual costs at CGS from FY 2000 through FY 2012. The FY 2007 Long Range Plan forecast is the significantly lower line. Overall, the actual costs from FY 2007 through FY 2012 were roughly twice the forecasted amounts.

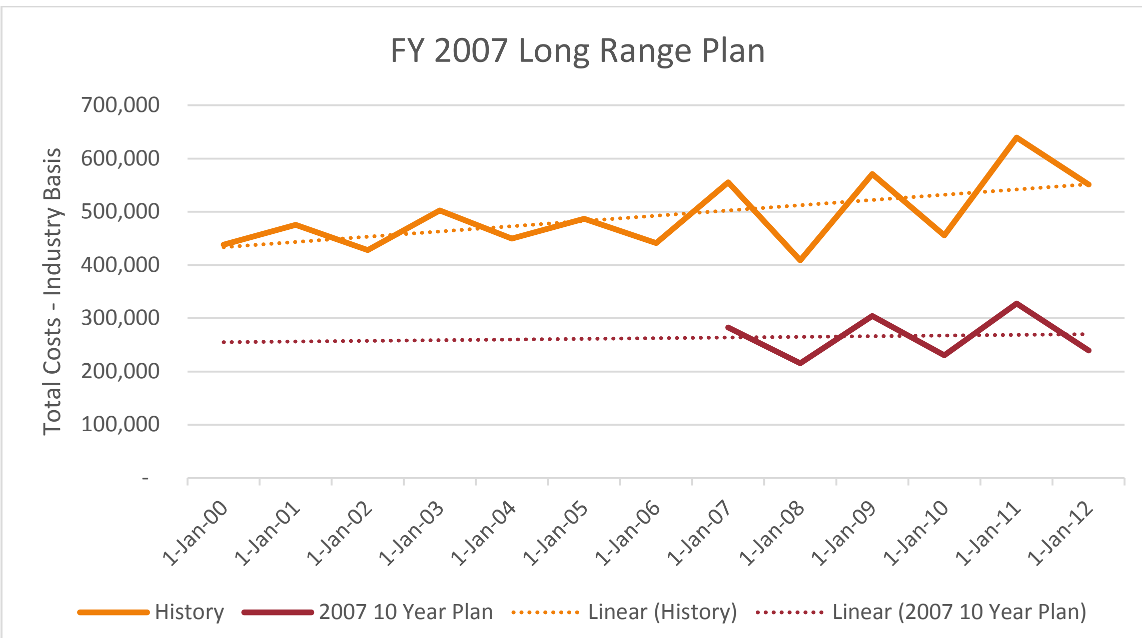


Figure 59

The situation is no better today. The FY 2014 Long Range Plan predicts a surprising downward trend in costs for a plant that is exceeding its planned life expectancy. It goes without saying that the hypothesis that costs are falling over time would be rejected by the simplest statistical test.

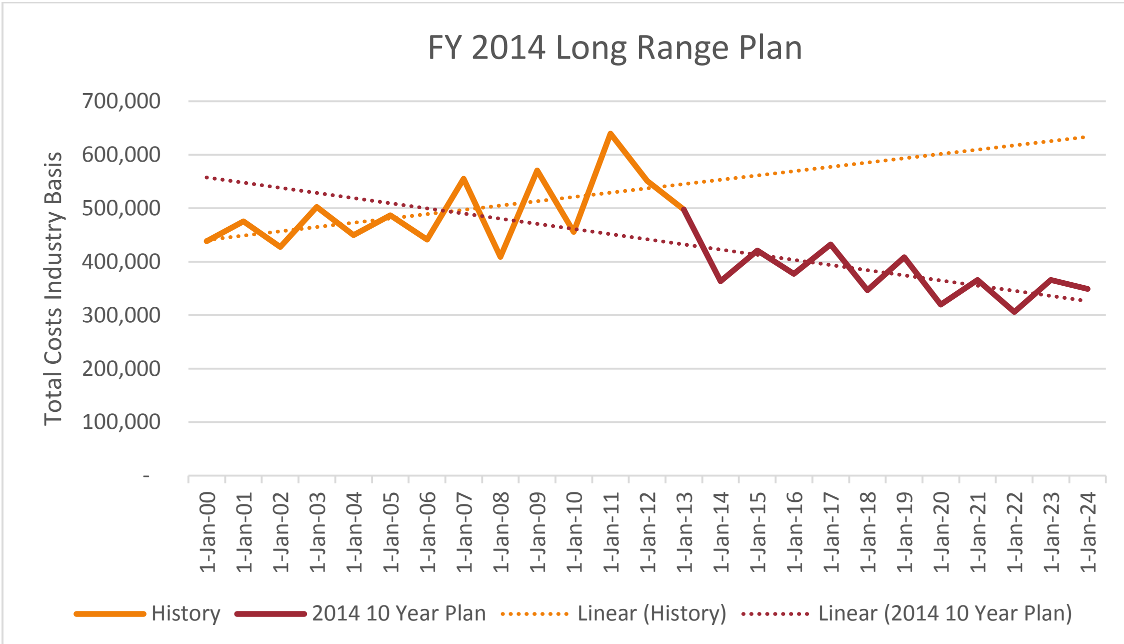


Figure 60

Since there is no correct answer – we simply do not know what the years to come will mean for costs at a plant exceeding its planned lifetime, we have taken the simplest assumption and averaged the two estimates.

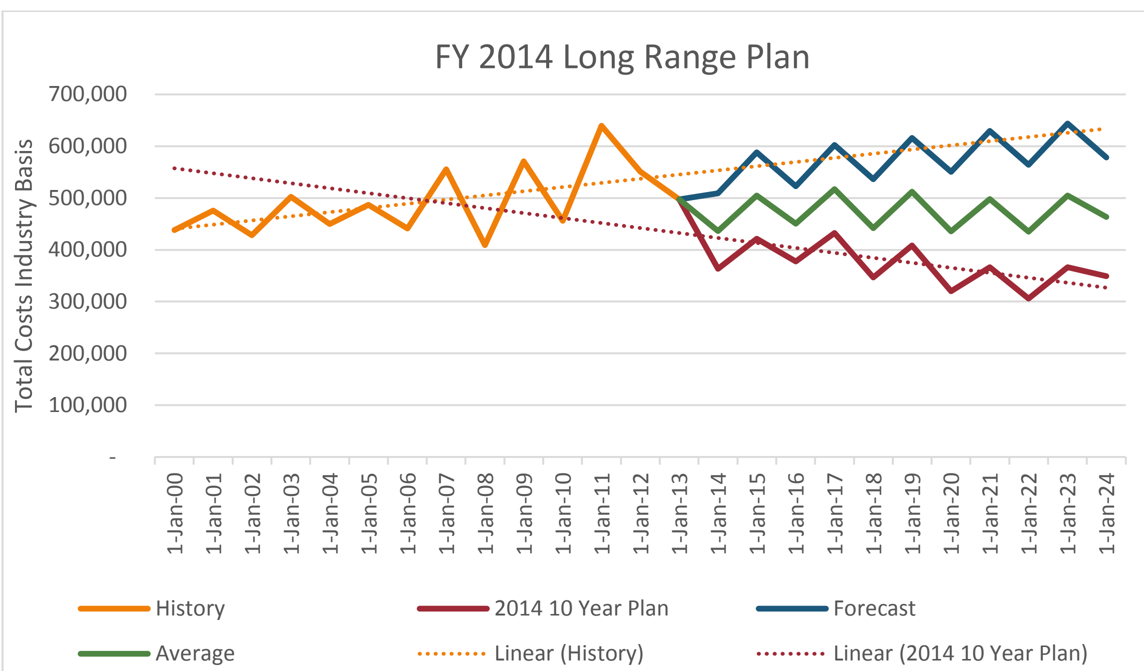


Figure 61

The simple CGS cost forecast continues to outpace our Mid-Columbia price forecasts through to the end of the license period:

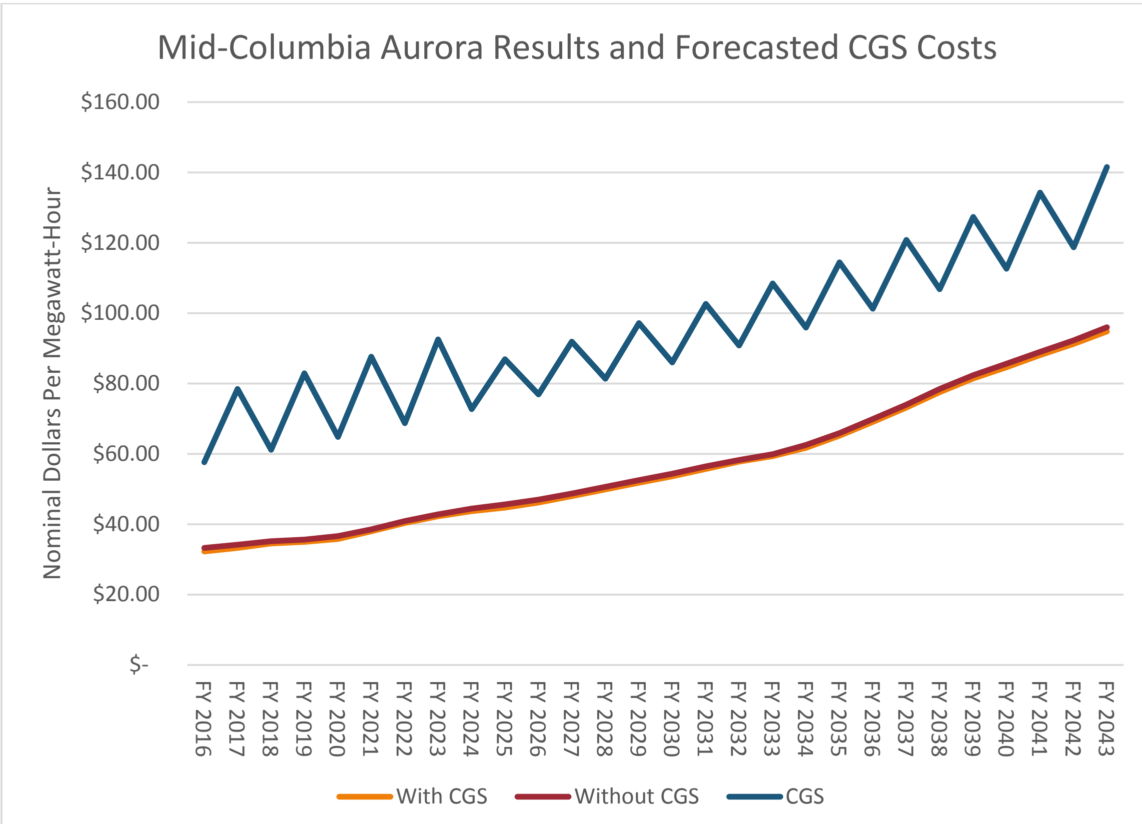


Figure 62

5.6 AURORAXMP® PRICE ANALYSIS

Monte Carlo analysis is commonly used when forecasting problems have a random component that is difficult to forecast. The most common examples are nuclear physics, weather, wind generation, and hydro-electric inflows.

The term "Monte Carlo" references the famous casino in Monte Carlo. The scientists at Los Alamos faced problems in nuclear physics that were fundamentally unpredictable. They developed a modeling technique where values were picked randomly. Each random pick represented one "game" in the Monte Carlo study. If the distribution of random picks approximates the actual distribution of nuclear reactions, wind generation, or hydro-electric inflows, the results will give a good forecast – considering all of the different combinations of events.

In this case, a significant determinant of prices in the Mid-Columbia market is the rapidly increasing amount of wind generation combined with the inflows to the Columbia River basin. In order to appropriately address the effect of wind and hydro on prices, we used a standard industry model to calculate prices for each year from 2015 through 2043 10,000 times, using different picks for wind and hydro generation in each "game".

5.6.1 AURORAxmp®

AURORAxmp® ("Aurora") is a fundamentals-based model employing a transmission-constrained, multi-area dispatch logic to simulate real market conditions while capturing the dynamics and economics of electricity markets. The model was introduced in 1997 and is the industry's standard model for reliable market-risk analysis, resource valuation, and market price forecasting. [366]

The Aurora production cost model consisted of two case studies, with and without CGS, run in two phases. Phase I simulated expansion, retirement, and operation of generators in the Western Interconnection from 2015 to 2048. The model assumed expected output from hydroelectric and wind-powered generators. Phase II held acquisition and retirement of generators fixed, and simulated operation of the system from 2015 to 2043 using 10,000 randomly-selected "games" quantifying hydroelectric and wind output.

Overall price inflation was generally assumed to be 1.65% annually. Real and nominal discount rates of 5.00% and 6.73%, respectively, were applied in modeling resource acquisition and retirement and in other calculations. These are consistent with Appendix N of the Sixth Northwest Conservation and Electric Power Plan published by the Northwest Power and Conservation Council. The expected price of natural gas was taken from the reference case in the 2013 early release of the *Annual Energy Outlook*, published by the U.S. Department of Energy, Energy Information Administration.

5.6.2 Inputs Specific to the CGS

Table 1, shows assumed costs at CGS that were input to Aurora in 2010 dollars. These costs are based on data from Energy Northwest's annual reports. Monthly maintenance and forced outage rates for a generic nuclear plant listed in the Aurora database were scaled for CGS so that it would be unavailable due to maintenance and forced outage 25%.[367]

[366] A description of the model is available at http://epis.com/aurora_xmp/, accessed March 19, 2013.
[367] Forecasting CGS's future availability is as difficult as forecasting its costs. Over the life of the plant, CGS has averaged an availability factor of 78.2%. The availability rate since 2000 when the plant moved to a two year refueling cycle is 82.6%. Surprisingly, since 2009, the availability rate fell to 77.1% -- primarily due to the extensive outage connected with the replacement of the condenser in 2011.

Table 1: Costs for WNP-2 Input to AURORAxmp®; 2010$

Year	Fixed O&M ($/MW-Week)	Variable O&M ($/MWh)	Fuel Price ($/MMBtu)
2015	589.69	0.88	0.56
2016	584.78	0.88	0.61
2017	596.95	0.87	0.65
2018	608.48	0.87	0.63
2019	638.27	0.89	0.61
2020	611.24	0.91	0.62
2021	529.13	0.93	0.62
2022	503.27	0.93	0.63
2023	578.43	0.96	0.63
2024	535.79	0.97	0.65
2025	532.88	0.98	0.66
2026	530.04	0.99	0.67
2027	527.26	1.00	0.68
2028	524.54	1.01	0.69
2029	521.88	1.02	0.71
2030	519.28	1.04	0.72
2031	516.74	1.05	0.73
2032	514.26	1.06	0.75
2033	511.84	1.07	0.76
2034	509.48	1.08	0.78
2035	507.17	1.10	0.79
2036	504.93	1.11	0.81
2037	502.75	1.12	0.82
2038	500.62	1.14	0.84
2039	498.55	1.15	0.86
2040	496.54	1.16	0.87
2041	494.59	1.18	0.89
2042	492.70	1.19	0.91
2043	490.86	1.20	0.93

Source: Energy Northwest Annual Reports

Figure 63

5.6.3 PHASE I: Acquisition, Retirement, and Operation of Generators with Expected Hydroelectric and Wind Output

The Nuclear Regulatory Commission recently extended the expiration date of Energy Northwest's license to operate CGS to 2043. The acquisition, retirement, and operation of generators were simulated five years beyond 2043 so that all decisions regarding acquisition and retirement could be modeled as forward-looking. Three hour blocks of a typical Tuesday were simulated for each month of the study period.

Aurora's database was modified to account for the effects of Renewable Portfolio Standards (RPS) in Washington, Oregon, and California on acquisition and retirement of generators. Generators with a known retirement date were assumed to retire then; generators now less than ten years old were assumed not to retire during the study period. The RPS in Washington requires that 9% of energy load be served using renewable resources by 2016, and 15% by 2020 and thereafter. The RPS in Oregon requires that 15% of energy load be served using renewable resources by 2015, 20% by 2020, and 25% by 2025 and thereafter. The RPS in California requires that 20% of energy load be served using renewable resources by 2014, 25% by 2017, and 33% by 2020 and thereafter.[368]

These assumptions are summarized in Table 2:

[368] Descriptions of the RPS' in Washington, Oregon, California and other states are available using the Database of State Incentives for Renewables & Efficiency; their website is http://www.dsireusa.org/, accessed March 19, 2013.

Table 2: Minimum Number of 50 MW Wind and Solar Acquisitions by Area Imposed to Model Renewable Portfolio Standards

	Pacific Gas & Electric North		Pacific Gas & Electric ZP26	Southern California Edison		San Diego Gas & Electric	Oregon East	Washington Central
	Wind	Solar	Solar	Wind	Solar	Wind	Wind	Wind
2013	52	1	1	84	24	1	0	6
2014	53	1	1	87	25	1	0	7
2015	14	0	0	24	6	0	0	9
2016	15	1	0	25	7	1	0	8
2017	16	0	1	27	8	0	4	0
2018	23	1	0	37	11	0	6	1
2019	25	0	1	41	11	1	5	0
2020	27	1	0	46	13	1	5	49
2021	3	0	0	4	2	0	6	1
2022	2	0	0	4	1	0	5	1
2023	2	0	0	4	1	0	6	0
2024	3	0	0	5	1	0	6	1
2025	2	0	0	4	1	0	6	1
2026	2	0	0	4	2	0	1	1
2027	3	0	0	5	1	0	0	1
2028	2	0	1	4	1	0	1	1
2029	3	0	0	5	1	0	0	0
2030	2	0	0	4	2	0	1	1
2031	3	0	0	5	1	0	0	1
2032	2	1	0	5	1	0	1	1
2033	3	0	0	4	2	0	0	1
2034	3	0	0	5	1	1	1	1
2035	2	0	0	5	1	0	0	1
2036	3	0	0	5	2	0	1	1
2037	3	0	0	5	1	0	0	1
2038	2	0	0	5	2	0	1	1
2039	3	0	0	5	1	0	0	1
2040	3	0	0	5	1	0	1	1
2041	3	0	0	5	2	0	0	0
2042	3	0	0	5	1	0	1	1
2043	3	0	0	5	2	0	1	1
2044	2	0	0	6	1	0	0	1
2045	3	0	0	5	2	0	1	1
2046	3	0	1	5	2	0	0	1
2047	3	0	0	6	1	0	1	2
2048	3	1	0	5	2	1	1	1
2049	3	0	0	6	1	0	0	1
2050	4	0	0	6	2	0	1	1
2051	3	0	0	5	2	0	0	1
2052	3	0	0	6	1	0	1	1
2053	3	0	0	6	2	0	1	1
2054	3	0	0	6	2	0	0	1

Figure 64

Annual minima were imposed on the number of wind and solar generators acquired in those states sufficient to satisfy their respective RPS'. Minima were apportioned to areas within the states according to their wind and solar capacity in 2012 as listed in the Aurora database. The possibility of complying with an RPS using imports from out of state were not modeled, though output from renewables is regularly traded across state lines in Aurora simulations. Table 2 shows the annual minimum numbers of 50 MW wind and solar acquisitions imposed by area.[369] The areas are defined in the Aurora database. Only some areas are identified with retail service territories of load serving entities (LSE); none of them corresponds precisely with the LSE's service territory.

5.6.4 PHASE II: Operation of Generators with Stochastic Hydroelectric and Wind Output

Output of hydroelectric plants throughout much of the Western Interconnection was drawn randomly from normal probability distributions with means and variances based on historic hydroelectric generation. This functionality is built in to Aurora.

Output from wind powered generators in Oregon and Washington was drawn randomly from uniform probability distributions with means and variances defined monthly. These parameters were based on wind output in the control area of the Bonneville Power Administration between 2008 and 2012.[370,371]

As in the first phase of our modeling, three hour blocks of a typical Tuesday of each month were simulated for the study period. For each Tuesday, energy output from wind in Washington and Oregon was drawn from a uniform distribution such that

$$mw_{day}^{plant} = E\left[mw_{day}^{plant}\right] * \left(1 + \frac{\sigma_{month}^{bpa}}{E\left[mw_{month}^{bpa}\right]} * u_{-0.5}^{0.5}\right)$$

where

[369] The 712 MWa (2,450 MW at a plant factor of 29%) in Washington Central in 2020 could have been ramped in gradually, as in other areas. Ramping the acquisitions in would have put them in the system for a greater part of the study period and, therefore, lowered Mid-Columbia prices, making C2GS appear less economic.
[370] Bonneville Power Administration. *Wind Generation & Total Load in the BPA Balancing Authority*. Bpa.gov. Web. 23 Feb. 2013. <http://transmission.bpa.gov/business/operations/wind/>.
[371] Observations were hourly, covering 2008-2012.

$mw_{wind}^{plant} \equiv$ generation at a single plant on a single day in a single game;

$E\left[mw_{wind}^{plant}\right] \equiv$ expected output from the plant from the Aurora database;

$\sigma_{month}^{bpa} \equiv$ the average absolute deviation of actual wind generation in the BPA control area from its predicted value;

$E\left[mw_{month}^{bpa}\right] \equiv$ the predicted value from a regression of said generation on monthly dummy variables, a linear time trend, and the dependent variable lagged 24 hours;

$u_{-0.5}^{0.5} \equiv$ a random draw from a uniform distribution with range $[-0.5, 0.5]$.

The possibility of a nuclear catastrophe or unexpected changes in the cost of 1) disposal of nuclear waste, 2) natural gas, or 3) operation and maintenance of CGS were not considered. The analysis focuses on variability in output of wind-powered generators and hydroelectric generation, not significant changes in CGS fortunes. Recent acquisitions of wind-powered generators with intermittently high output have led to instances of extremely low off-peak prices at the Mid-Columbia hub. Such instances, if frequent enough, can have a significant impact on the economics of a base load generator like CGS.

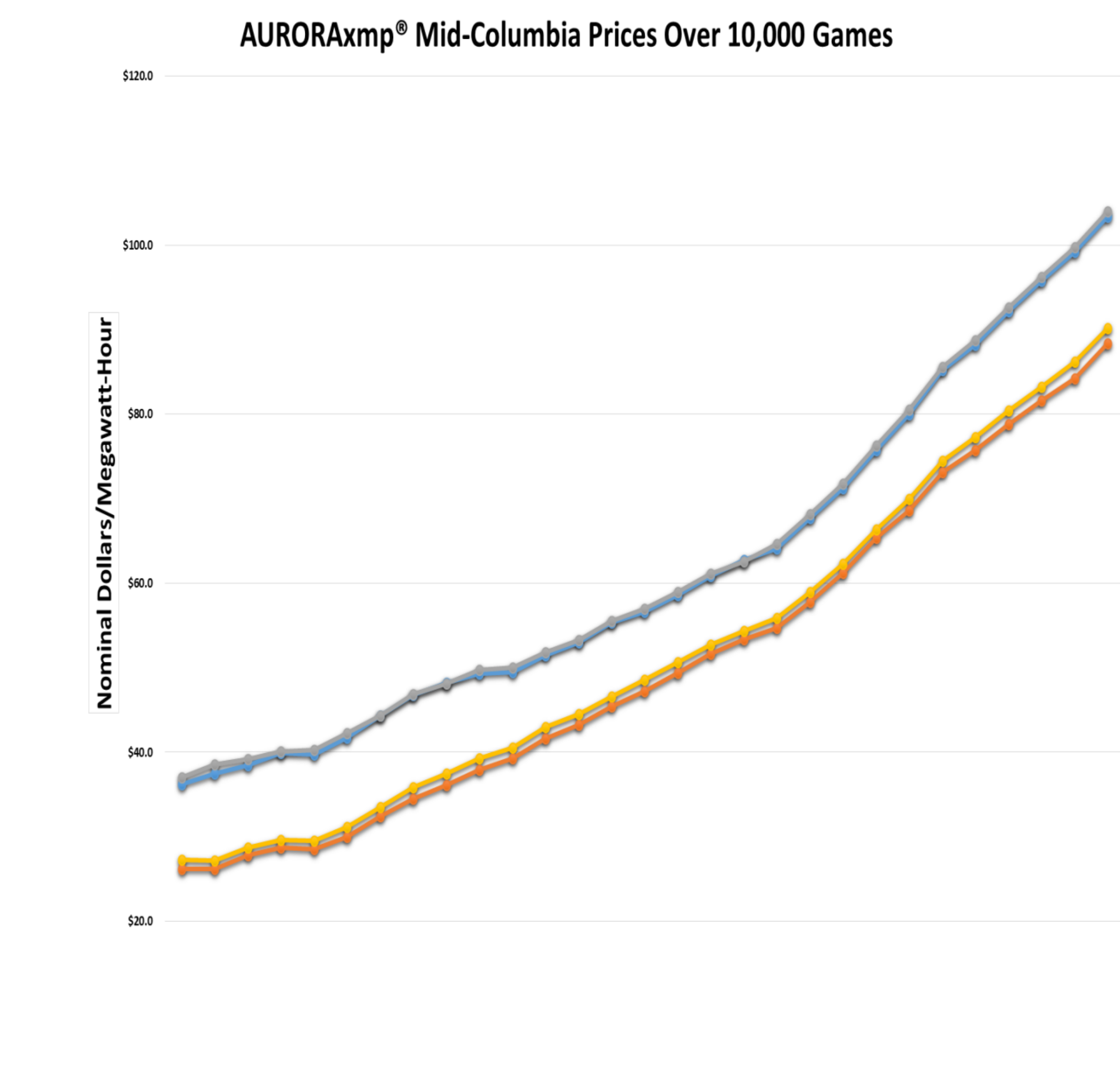
5.6.5 Results

The Monte Carlo involved the calculation of 10,000 games for two scenarios:

1. The West Coast of the U.S. and Canada with CGS through 2043; and,
2. The West Coast of the U.S. and Canada without CGS through 2043.

Large Monte Carlo models are challenging projects. In this case, we ran the simulation on twenty different computers for 24 hours a day for approximately two weeks. The results from each "game" were then transferred to an Access database for post processing. The results below show the final outcome.

One specific challenge was to make sure that the "with" and "without" CGS cases had exactly the same random picks for hydro and wind. This was accomplished by using the same random number generator seeds for the two cases. This avoided using different final distributions for wind and hydro in the two cases.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Avg. WNP-2 Peak	$36.2	$37.5	$38.5	$39.9	$39.7	$41.7	$44.3	$46.8	$48.2	$49.3	$49.5	$51.4	$53.0	$55.3
Avg. WNP-2 Off-Peak	$26.2	$26.2	$27.8	$28.7	$28.5	$30.0	$32.4	$34.5	$36.1	$37.9	$39.3	$41.6	$43.2	$45.4
Avg. Non-WNP-2 Peak	$37.0	$38.5	$39.2	$40.1	$40.3	$42.2	$44.3	$46.9	$48.1	$49.7	$50.0	$51.8	$53.2	$55.6
Avg. Non-WNP-2 Off-Peak	$27.2	$27.2	$28.7	$29.6	$29.6	$31.1	$33.5	$35.8	$37.5	$39.3	$40.5	$43.0	$44.5	$46.6

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Avg. WNP-2 Peak	$56.6	$58.5	$60.9	$62.7	$64.1	$67.7	$71.3	$75.8	$80.0	$85.2	$88.2	$92.2	$95.8	$99.2	$103.
Avg. WNP-2 Off-Peak	$47.2	$49.4	$51.6	$53.3	$54.7	$57.8	$61.2	$65.4	$68.6	$73.1	$75.8	$78.8	$81.6	$84.2	$88.4
Avg. Non-WNP-2 Peak	$57.0	$58.9	$61.1	$62.6	$64.6	$68.1	$71.8	$76.3	$80.5	$85.6	$88.7	$92.6	$96.2	$99.8	$104.
Avg. Non-WNP-2 Off-Peak	$48.6	$50.6	$52.7	$54.3	$55.8	$58.9	$62.3	$66.4	$70.0	$74.5	$77.2	$80.4	$83.2	$86.2	$90.2

Figure 65

Each "game" started with building resources throughout the West Coast on a least cost basis. Not surprisingly, the primary builds chosen by the model were Simple Cycle Gas Turbines. In the main, these were built at load center along the I-5 corridor. AURORAxmp® did choose to build a single coal station after our study period. This anomalous choice did not affect our results as it took place after the study period ended in 2043.[372]

The difference in Mid-Columbia prices with and without CGS was minimal – approximately $1 per megawatt-hour.

A primary driver of the results is the large number of renewables required under the Oregon, Washington, and California Renewable Portfolio Standards. The viability of the California RPS standard is viewed as doubtful by many industry participants. As with the coal price assumptions in the model, we adopted the RPS renewable builds as modeled by the WECC and did not implement our own forecast.

5.7 AEO 2013 PACIFIC NORTHWEST FORECAST

As a credibility check on our AURORAxmp®, we requested the Northwest Power Pool sub module of the U.S. Energy Information Administration's AEO 2013 forecast.[373] The Energy Information Administration (EIA) has published the Annual Energy Outlook since 1979. Unlike other models, the EIA forecasts all major energy components – most importantly for our purposes, natural gas – and forecasts specific results by region and sub region throughout the United States out to 2040.

The EIA model is vast, but has less regional detail than AURORAxmp®. The EIA output provides marginal energy costs for the Pacific Northwest, but does not break down the prices by specific markets like the Mid-Columbia hub. The EIA also does not model wind and hydro to the detail we undertook in our Monte Carlo analysis. The results are comparable, but more extreme than our more detailed analysis:

372 The coal price assumptions bring coal back into cost effectiveness at the end of the period. We viewed this as questionable, but did not want to deviate from the forecasts used in AURORAxmp®.
373 Aniti, Lori. Office of Energy analysis, Energy Information Administration. *AEO electricity prices forecast question*. 10 Apr. 2013

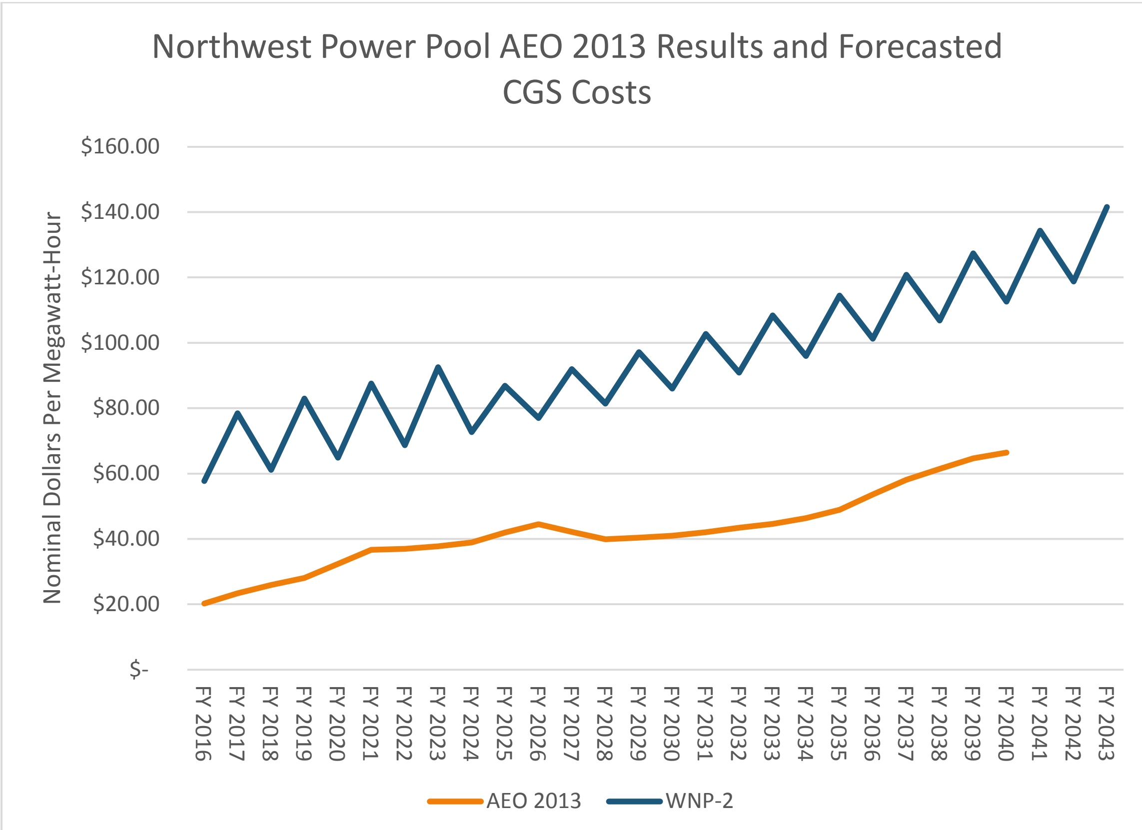


Figure 66

5.8 GAS IS QUEEN, WHETHER I LOVE HER OR NOT

In 2011, John Rowe, CEO of Exelon, used the phrase "gas is queen, whether I love her or not."[374] The irony was that Exelon is one of the world's largest owners of nuclear power stations.

A driving factor behind recent economic challenges to the nuclear industry is low prices for natural gas. A significant factor in the low prices of natural gas is continuing discoveries using new technologies that have increased proven reserves enormously in recent years.

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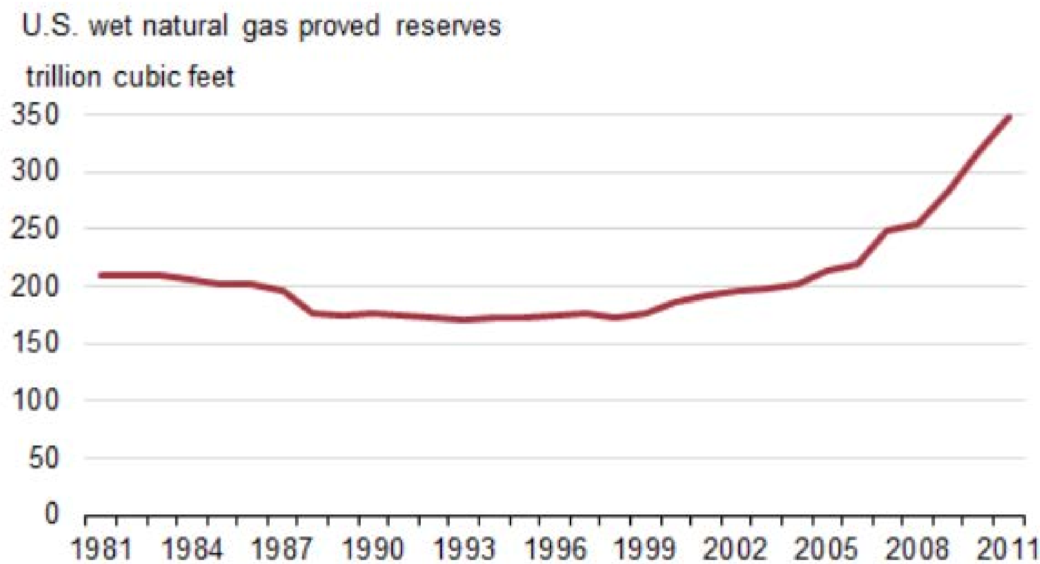
[374] Rowe, John. "Energy Policy: Above All, Do No Harm," American Enterprise Institute. March 8, 2011, Page 14.



[375]

Figure 67

The collapse of natural gas prices after 2008 can be traced to a variety of causes – new technologies in exploration and extraction, better transportation infrastructure, and the distorted prices in the international oil markets.

The price of oil has cycled around $100 barrel for the last three years. This is curious, since the cost of exploration, development, and delivery for oil in the United States is roughly two thirds that figure. Elsewhere in the world, costs are even lower. The outcome has been an explosion of oil drilling in the U.S. and Canada. This past spring the U.S. returned to its previous role as the world's largest oil producer, surpassing both Russia and Saudi Arabia.

A common byproduct of oil exploration is natural gas. Oil development in North Dakota has been so rapid that an estimated one billion dollars of natural gas was flared off – simply disposed of – last year.

The current forecast from the Energy Information indicates that a return to 2008 natural gas prices – in nominal terms – will not occur before 2035:

[375] Energy Information Administration. *U.S. Crude Oil and Natural Gas Proved Reserves, 2011. Eia.gov.* EIA, Aug. 2013. Web. 04 Nov. 2013. <http://www.eia.gov/naturalgas/crudeoilreserves/pdf/uscrudeoil.pdf>.

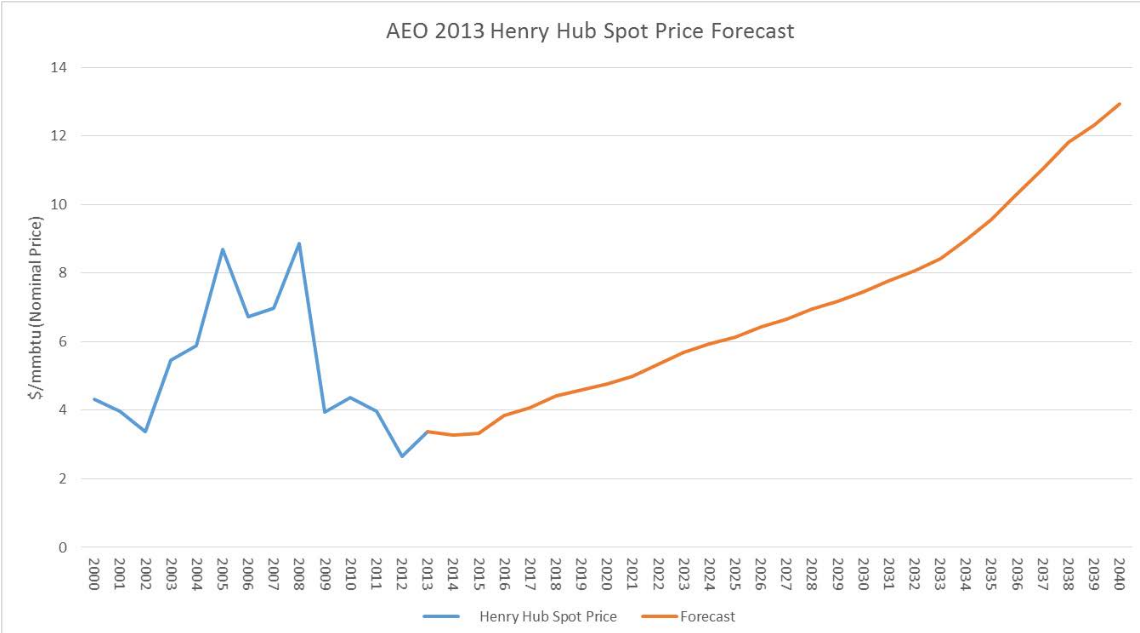


Figure 68

The impact on electric generation has been massive. While the impact of low market prices has been in some detail above, a similar impact has occurred in the coal sector. Edison International's massive coal resources in the Midwest declared bankruptcy this year. A similar bankruptcy is pending in Texas.

The shift in natural gas prices has been a game changing event which is shifting generation from nuclear and coal to natural gas across the United States and Canada.

5.9 WIND ENERGY

Wind – the current renewable resource of choice in the Pacific Northwest - will expand sharply in the next decade as a result of Renewable Portfolio Standards. [376, 377] Wind development will likely create opportunities for flexible generating resources and adversely affect inflexible resources like CGS, as well as create load balancing and transmission challenges.

[376] Nirappil, Fenit. *Dimming Future for Large Solar Projects in Oregon as Incentives Dry up*.Oregonlive.com. The Oregonian, 14 Feb. 2013. Web. 19 Sept. 2013. <http://www.oregonlive.com/business/index.ssf/2013/02/dim_future_for_large_solar_pro.html>.

[377] Environmental Protection Agency. *Renewable Energy Cost Database*. Epa.gov. Web. 19 Sept. 2013. <http://www.epa.gov/cleanenergy/energy-resources/renewabledatabase.html>.

Currently, the Bonneville Power Administration lists 41 projects with a combined nameplate capacity of 4,711 MW.[378] The Western Electricity Coordinating Council's 10-Year regional plan projects massive increases in renewables, including 18,000 MW in wind.[379] Much of this enormous growth in wind development will take place in the eastern desert counties of Oregon and Washington in close proximity to the massive hydroelectric resources along the Columbia River, as this area has excellent wind characteristics.[380]

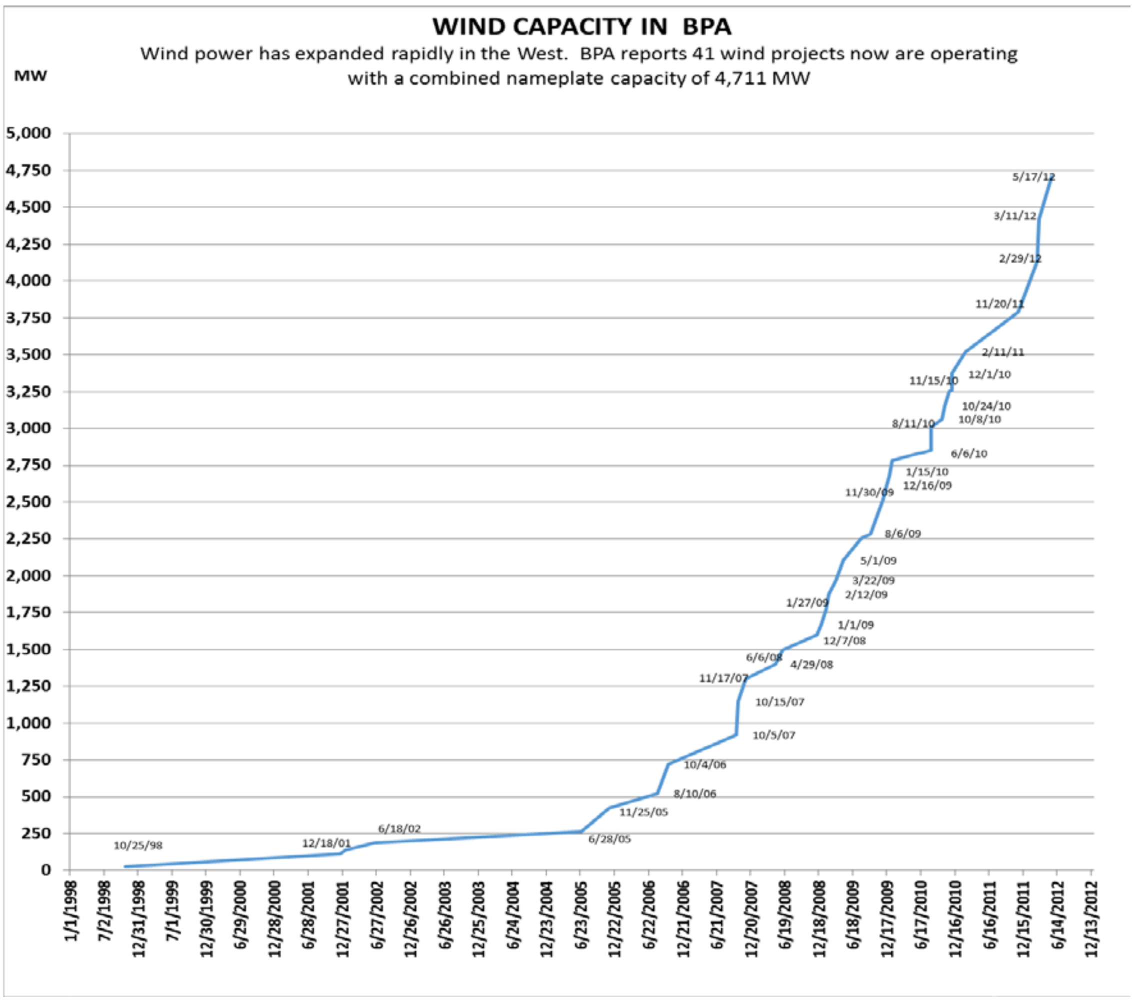


Figure 69

[378] Bonneville Power Administration. *Wind Generation Capacity in the BPA Balancing Authority Area*. Bpa.gov. 10 Apr. 2010. Web. 19 Sept. 2013. <http://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_Plot.pdf>.
[379] Western Electricity Coordinating Council. *10-Year Regional Transmission Plan. Wecc.biz*. 2011. Web. 19 Sept. 2013. <http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf>. Page 19.
[380] The dams comprising the Federal Columbia River Power System.

In a perfect world, the extra wind generation could be easily stored for later use. The Pacific Northwest has a huge "battery" in the form of potential energy stored in reservoirs throughout the Columbia River basin. However, this "battery" is subject to a variety of constraints – including environmental constraints -- limiting the amount of water that can be released.[381]

Hydroelectric generation varies due to changing yearly patterns of snow pack, precipitation, and melt in the spring.

Wild swings in wind generation can cause lower market prices and increased volatility in the spot wholesale market. The recent integration of over 4,000 MW of wind generation into the BPA transmission system coupled with a generous hydroelectric water year resulted in negative off-peak prices in the Mid-Columbia wholesale market for 127 days in 2011 and 2012, as demonstrated by the following chart:

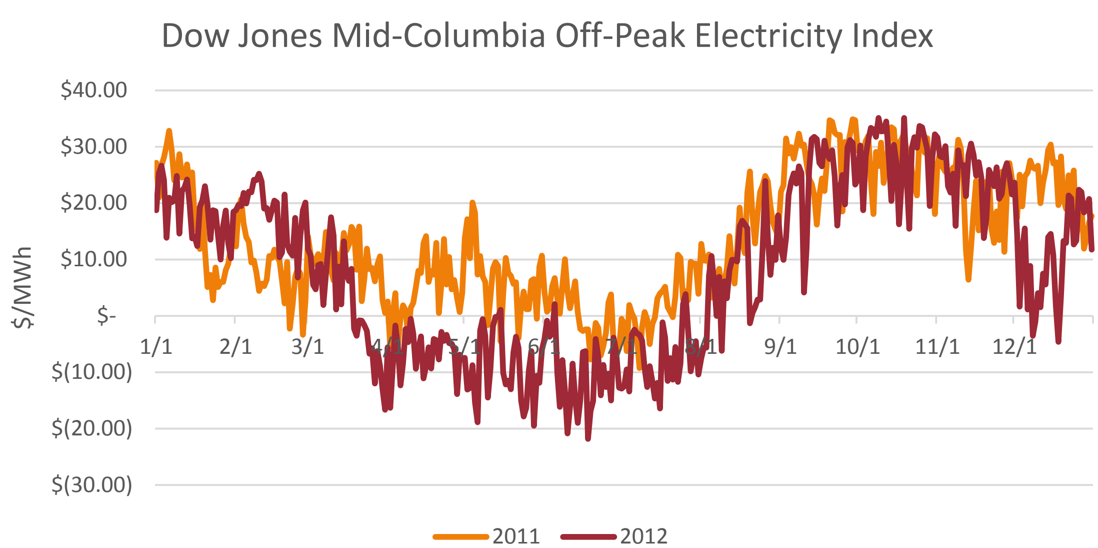


Figure 70

If similar hydro flows experienced in 2012 were to occur in 2025, we could expect even more days with negative off peak prices because of the expected expansions of wind energy mandated in the Renewable Portfolio Standards.

Other emerging risks could put a damper on wind development.[382] As more wind generation comes online and hydroelectric "battery" capability is maxed out, new methods will be needed to absorb wind intermittency, such as dispatchable load and generation or

[381] Clean Water Act (CWA), the Endangered Species Act (ESA) and various court orders
[382] Portland General Electric. *2011 Integrated Resource Plan Update*. Page 48.

smaller trading and scheduling time horizons. The greater risk is that the California market for renewable energy generated in the Pacific Northwest has been curtailed substantially through SB X 1-2, a law that aggressively favors in-state renewable energy for meeting California's ambitious RPS targets.[383] There is currently some uncertainty around whether this type of law will be considered in violation of the interstate commerce clause of the U.S. Constitution.

5.10 REGIONAL LOAD RESOURCE BALANCE

In several interviews with Energy Northwest board members, a concern was raised that the displacement of CGS would possibly cause a capacity shortage in the Pacific Northwest.

This is certainly a legitimate question, although during a period of burgeoning fuel supplies and increasing energy efficiency, the possibility seems remote. In fact, as discussed above, much of our attention in recent years has been focused on the problem of oversupply rather than shortage.

The organization tasked by the Federal Energy Regulatory Commission with oversight of reliability on the West Coast is the Western Electricity Coordinating Council (WECC). WECC staff issue an annual study to address reliability issues named the "State of the Interconnection." The most recent study was issued in July 2013.[384]

The capacity shortage issue is addressed by two tables on page 10 of the report:

[383] Under Section 399.16, each provider must ensure that by the end of 2013, no less than 50% of its renewables consist of California Content, with such percentage increasing to 65% by the end of 2016, and 75% thereafter. Also, each provider must ensure that by the end of 2013, no more than 25% of its renewables portfolio comprises REC Content, with such percentage declining to 15% by the end of 2016, and 10% thereafter.

[384] WECC. *2012 State of the Interconnection.* 1 July 2013.

Table 1: Summer Expected Maximum Capacity (MW) as of 12/31/2012 by Subregion[7]

Summer Expected Maximum Capacity (MW) as of 12/31/2012 by Subregion										
	AESO	BASN	BC	CALN	CALS	DSW	MEX	NWUS	ROCK	WECC Total
Coal	5,654	5,438	-	129	1,940	11,271	-	6,530	7,837	38,798
Gas	5,550	4,149	1,295	17,869	23,939	21,223	1,943	8,043	6,870	90,879
Nuclear	-	-	-	2,240	2,246	3,937	-	1,130	-	9,553
Hydro	911	2,379	12,676	6,864	1,555	3,954	-	31,851	1,381	61,570
Geothermal	-	412	-	841	773	-	570	-	-	2,597
Wind	1,097	2,460	403	2,261	3,567	724	10	6,846	2,384	19,753
Biomass	280	47	344	470	391	48	-	633	4	2,217
Solar	-	21	-	503	956	520	5	30	90	2,124
Other Conv.	-	73	15	2,492	1,761	328	89	214	620	5,592
Total	13,491	14,980	14,733	33,670	37,127	42,003	2,617	55,275	19,186	233,083

Figure 71

Table 2: Actual Peak Demand (MW) by Subregion

Actual Peak Demand (MW) by Subregion										
	AESO	BASN	BC	CALN	CALS	DSW	MEX	NWUS	ROCK	WECC coincident
2012 Summer	9,885	13,809	7,774	25,201	34,008	28,426	2,302	24,616	11,666	150,913
2011-12 Winter	10,599	10,744	9,840	17,820	22,242	16,284	1,466	27,298	10,016	124,369

Figure 72

Although energy – as opposed to capacity – is not an immediate concern, it is interesting to note the figure on page 12 as well:

Figure 2: 2012 Energy Load Growth

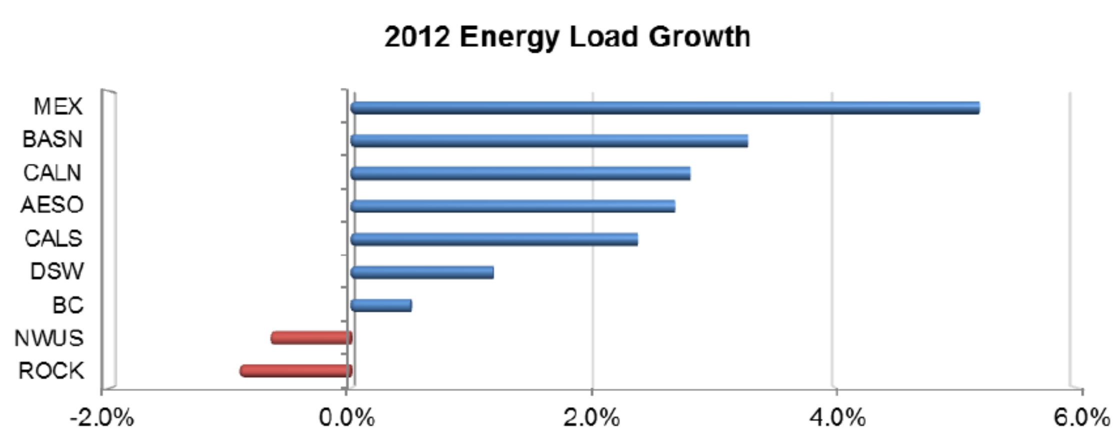


Figure 73

Overall, the coincidence of low prices and low load growth (or as shown above, even negative load growth) makes this a good time to shop for CGS displacement supplies.

5.11 LONG TERM COST SAVINGS

The estimate of cost savings from displacement of CGS is an uncertain combination of uncertain forecasts from many sources, ranging from Energy Northwest to the Energy Information Administration. However cloudy a crystal ball may be, a forecast of the cost savings is a necessary part of this study. It should be remembered that the test of the savings will actually come from the RFP for displacement power, not from forecasts.

The primary components of the analysis are:

1. The expected lifetime of CGS: 17.1 years from Section 4.7 above.
2. A higher spent fuel storage fee from Section 4.8.4.
3. Avoidable decommissioning costs from Section 4.8.6.
4. CGS avoidable operating and capital costs: The compromise forecast from Section 5.5.
5. Mid-Columbia market prices from Section 5.6.
6. BPA's estimate of CARB emission factor costs from Section 6.4.
7. A nominal discount rate of 6.73 from Section 5.6.1.

The basic calculation is the total avoidable costs at CGS, including operating and capital costs, additional spent fuel costs, and incremental decommissioning costs minus displacement energy costs and BPA's CARB impact. All sunk costs prior to the assumed decommissioning date are not included.

The following table shows the comparison on CGS costs and Mid-Columbia prices through 2030:

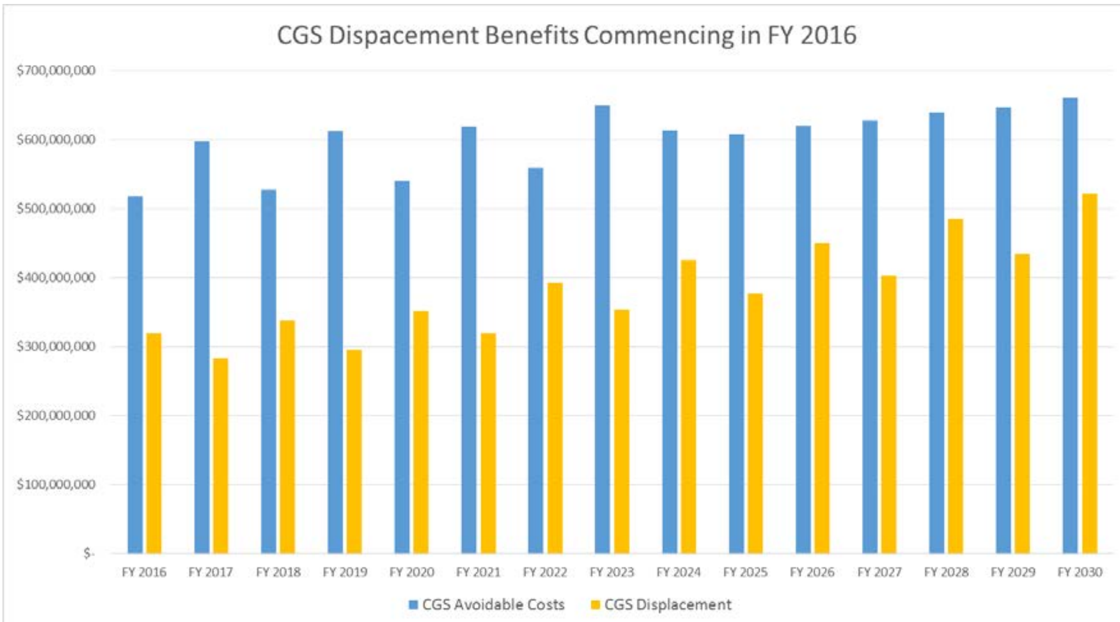


Figure 74

The present value of the expected avoidable costs of CGS is $4,518,798,379 in 2013. The present value cost of CGS displacement purchases is $2,794,656,824 including the possible emission factor impact (worst case) estimated by BPA.

The potential cost savings to the region is $1,724,141,555 if discounted to 2013.

6 CALIFORNIA AIR RESOURCES BOARD CAP-AND-TRADE PROGRAM

6.1 BPA CONCERNS

In a number of meetings with BPA staff, concerns were raised that a major change in BPA's environmental submission to the California Air Resources Board would result in a higher emissions factor being assigned to BPA's California exports. The structure of the problem is as follows:

1. CARB assigns a default carbon emissions factor of zero for nuclear power – apparently on the assumption that the nuclear fuel cycle produces no carbon. As noted above, this is incorrect, but California's rules and regulations are beyond the scope of this report.
2. The RFP for CGS displacement resources is successful.

3. BPA will be forced to file a new "Workbook 4 EPE Optional Asset Controlling Report" with a higher emissions factor since some of the resources have high carbon emissions.
4. The impact on BPA export revenues could range from $.4 to $2.7 million per annum.

While we could debate the many assumptions and forecasting issues in such estimates, the appropriate place to address such impacts is in the acquisition of CGS displacement supplies. As such, we have included this in our second recommendation above.

6.2 OVERVIEW

The California Air Resources Board (CARB, or just ARB) Emissions Trading Program is an element of legislation requiring California to return to 1990 levels of greenhouse gas (GHG) emissions by 2020. It creates a statewide emissions limit which applies to sources responsible for 85% of all California GHG emissions. About 350 businesses representing 600 facilities are covered; they include electric utilities, large industrial facilities, and electricity importers. The program is designed to create a price-signal to stimulate investment in cleaner energy sources while allowing covered entities to seek out lowest-cost methods of reducing emissions. It is designed to be capable of linking with similar programs in other regions. [385,386,387]

Starting in 2012 California has required major GHG emitters, such as electricity producers and other large industrial sources, to participate in the cap-and-trade program. [388] The emissions cap will decline about 3% annually from 2015 to 2020. Participants must cover their GHG emissions by purchasing compliance instruments (allowances and offsets). Allowances give the participant permission to emit a certain amount of greenhouse gasses, and offsets counterbalance emissions with certified GHG-reduction projects located in the US. Offset projects are often in areas such as forestry, dairy digesters, and destruction of greenhouse gasses.

The first auction was held in November of 2012. The CARB reported that the auction had ample participation and generated about $289 million in revenues for the state. The settlement price for each 2013 allowance was $10.09, slightly above the $10 floor price. The

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[385] California EPA. *OVERVIEW OF ARB Emissions Trading Program*. Arb.ca.gov. 20 Oct. 2011. Web. 4 Nov. 2013. <http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf>. Page 1

[386] California EPA. *Cap and Trade: Market Oversight and Enforcement*" Arb.ca.gov. 20 Oct. 2011. Web. 4 Nov. 2013. <http://www.arb.ca.gov/cc/capandtrade/market_oversight.pdf>.

[387] California EPA, "*OVERVIEW OF ARB Emissions Trading Program*."

[388] California Environmental Protection Agency. *California Cap-and-Trade Program Implementation Frequently Asked Questions*. *Arb.ca.gov*. 24 May 2013. Web. 4 Nov. 2013. <http://www.arb.ca.gov/cc/capandtrade/implementation/faq_5_24_2013.pdf>.

auction participants were not revealed, but CARB did provide a list of entities qualified to participate, as well as a set of summary statistics. "About 97 percent of the allowances sold were purchased by entities with compliance obligations under cap and trade, CARB said, while about 3 percent of purchases were from the financial sector"[389]

Some features of the market:

- Allowances can be traded outside of official auctions, allowing entities to minimize cost by buying allowances from another facility that can reduce emissions more efficiently.
- Banking of allowances is allowed.
- Facilities may meet up to 8 percent of their reductions by purchasing offsets from GHG-reduction projects in the US.[390]

6.3 MARKET TRACKING, OVERSIGHT, AND ENFORCEMENT

The program places participants into three categories: covered entities, which have a compliance obligation; opt-in covered entities, which are not required to participate but choose to opt in; and voluntary entities, which do not meet the requirements of a covered entity but do intend to participate in the market. Covered entities must register with the ARB and have their annual emissions verified by a third party. Any entity or individual wishing to participate in transactions must register with the Compliance Instrument Tracking System Service (CITSS), which is intended to facilitate market oversight.[391]

The design of the cap-and-trade regulation, combined with market oversight, is intended to protect against potential market gaming through collusion, market power, and price manipulation. ARB requires participating entities to register with the ARB and disclose direct or indirect associations with other registered entities. To prevent participants from gaining market power, the amount of allowances any participant can hold or purchase at one time is limited. Non-utility covered entities are barred from purchasing more than 15% of the allowances at any auction. Other entities are limited to 4%. ARB can treat groups of associated entities as a single entity when determining compliance with transaction limits. A reserve price is set to limit the potential for manipulation of allowance prices.

All transactions exist within a centralized tracking system. Both parties must report transaction and price data to ARB within 3 days of a transaction. The Regulation prohibits trading that involves a manipulative device, an attempt to corner the market, fraud, or

389 Energy Newsdata. Clearing Up. November 26, 2012. No. 1571.
390 California Environmental Protection Agency. *OVERVIEW OF ARB Emissions Trading Program*. Pages 1-2.
391 California Environmental Protection Agency. *California Cap-and-Trade Program Implementation Frequently Asked Questions*. Pages 2-3.

inaccurate reports. Civil and criminal penalties apply to infractions, and perjury would apply where a signature is required. ARB must certify the results of each auction prior to the transfer of allowances.

ARB works with the European Union Emissions Trading System and the Regional Greenhouse Gas Initiative to minimize potential for market manipulation.

An independent market monitor is assigned review procedure and advise ARB on creating a fair auction. The market monitor also reviews allowance acquisition and information on participants' ownership of other allowances.

6.3.1 The Market Monitor:

- Is independent of other entities in the market
- Reviews sales procedures to ensure fair auctions
- Monitors allowance holding and transfer activity, looking for design flaws in the rules and procedures or structural problems in the market
- Prepares reports and provides advice for improvement

6.3.2 Market Surveillance Committee:

- Consists of experts in economics, and commodity markets
- Analyzes, advises, and recommends market design and oversight improvements.[392]

ARB has several structures in place to achieve accurate reporting of offsets and emissions.

- Capped industries must register with the ARB and report their annual emissions, which must be verified by a third party.[393]
- Offset verifiers must show competence in each project type they verify, employ conflict of interest assessments, and include random audits to ensure proper and accurate verification.[394]

[392] California Environmental Protection Agency, *Cap and Trade: Market Oversight and Enforcement,* Pages 1-2.
[393] California Environmental Protection Agency. *OVERVIEW OF ARB Emissions Trading Program,* Page 2.
[394] California Environmental Protection Agency, *Cap and Trade: Market Oversight and Enforcement*, Page 2.

- The registry system for compliance instruments is designed to prevent double-counting, and is subject to ownership and public disclosure requirements.[395]

6.4 BPA EMISSION FACTOR AND CGS

CARB assigns emission factors to power sold by the BPA based on BPA's Workbook 4 EPE Optional Asset Controlling Report submission. Critical components of the workbook are:

- Emission factor: a number assigned to entities selling or producing power in California that quantifies the GHG's associated with producing that power

- Specified source: power that consistently comes from one source or from an asset-controlling supplier

- Unspecified source: not specified at the time of transaction and assigned a default emission factor.

In the event of closing CGS and replacing its 1,130 megawatts of capacity with power purchased from the market, BPA's initial analysis shows that BPA's emissions factor would remain relatively low, since the largest portion of BPA's electricity is from low-emission hydropower. Replacing CGS's 1,100 MW of specified-source power with market purchases would increase BPA's emission factor from .019 to .060.[396] In comparison, the emission factor for unspecified source power is .428 by default.

In scenarios where the price of carbon allocations is higher, BPA earns a higher premium on its especially low-carbon mix of energy. The price on high-carbon energy sources makes BPA's power more valuable and attenuates BPA's cost of complying with the cap-and-trade regulation. The middle range scenario in this analysis predicts a cost of about $1.2 million, due to an increased emission factor because of CGS closure. In the high range scenario, predicted annual cost from CGS closure's effect on BPA's emission factor is about $2.8 million.

[395] As is common with California market mechanisms, the CARB cap and trade system is relatively opaque. Materials submitted to CARB are secret even if they come from public sources. For example, Workbook 4 EPE Optional Asset Controlling Report is secret in California, public under federal FOIA requirements, and based on data publicly available at BPA and FERC.

[396] .019 is the preliminary estimate of BPA's emission factor for 2014, not yet approved by CARB. In 2013, BPA's emission factor is .0249. System emission factor is calculated on the basis of energy mix from a previous calendar year.

Scenario Analysis: The impact on BPA's system emission factor from a hypothetical loss of CGS

				B - A			C x D x E		F x G
		A	B	C	D	E	F	G	H
	Low Scenario	BPA ACS EF: (MT CO2e/MWh)	Unspecified EF: (MT CO2e/MWh)	EF Difference: Unspecified minus BPA ACS	Allowance Price: ($/MT CO2e)	BPA % share of Carbon Premium	Carbon Premium: ($/MWh)	BPA Specified Secondary Sales per Year (MWh)	BPA Carbon Premium per Year:
1	*** BPA status quo**	0.019	0.428	0.409	**$12**	50%	$2.48	***1,500,000***	$3,726,261
2	**1,100 MW purchase**	0.060	0.428	0.368	**$12**	50%	$2.23	***1,500,000***	$3,349,142
3	***Difference (row 2 - row 1)***	*0.041*	*0*	*-0.041*	***$0***	*0%*	*-$0.25*	***0***	***-$377,119***

				B - A			C x D x E		F x G
		A	B	C	D	E	F	G	H
	Middle Scenario	BPA ACS EF: (MT CO2e/MWh)	Unspecified EF: (MT CO2e/MWh)	EF Difference: Unspecified minus BPA ACS	Allowance Price: ($/MT CO2e)	BPA % share of Carbon Premium	Carbon Premium: ($/MWh)	BPA Specified Secondary Sales per Year (MWh)	BPA Carbon Premium per Year:
1	*** BPA status quo**	0.019	0.428	0.409	**$20**	50%	$4.09	***3,000,000***	$12,270,000
2	**1,100 MW purchase**	0.060	0.428	0.368	**$20**	50%	$3.68	***3,000,000***	$11,028,207
3	***Difference (row 2 - row 1)***	*0.041*	*0*	*-0.041*	***$0***	*0%*	*-$0.41*	***0***	***-$1,241,793***

				B - A			C x D x E		F x G
		A	B	C	D	E	F	G	H
	High Scenario	BPA ACS EF: (MT CO2e/MWh)	Unspecified EF: (MT CO2e/MWh)	EF Difference: Unspecified minus BPA ACS	Allowance Price: ($/MT CO2e)	BPA % share of Carbon Premium	Carbon Premium: ($/MWh)	BPA Specified Secondary Sales per Year (MWh)	BPA Carbon Premium per Year:
1	*** BPA status quo**	0.019	0.428	0.409	**$30**	50%	$6.14	***4,500,000***	$27,607,500
2	**1,100 MW purchase**	0.060	0.428	0.368	**$30**	50%	$5.51	***4,500,000***	$24,813,465
3	***Difference (row 2 - row 1)***	*0.041*	*0*	*-0.041*	***$0***	*0%*	*-$0.62*	***0***	***-$2,794,035***

References:
Greenhouse Gas = (**GHG**). Metric Ton = (**MT**). Carbon dioxide equivalent = (**CO2e**). Emission Factor = (**EF**) with units = MT CO2e/MWh. Asset-Controlling Suppler = (**ACS**); can be a specified source of electricity. Unspecified source of electricity has a constant EF of 0.428 MT CO2e/MWh. An allowance represents the right for an entity to emit 1 MT CO2e. The allowance price has the units = $/MT CO2e.

Key Points:

1. BPA's resource system mix is primarily hydro generation. Even without CGS, BPA would retain a relatively clean system emission factor.

2. The economic value of selling specified source electricity is expected to be positive. Losing CGS would only diminish the positive economic value.

*** The "BPA Status Quo", 2014 BPA emission factor is preliminary, unaudited, and is not yet CARB approved or published.**

[397]

Figure 75

6.5 ADDRESSING BPA'S CONCERNS

Although the impact of the CARB emissions factor on BPA's exports is relatively small compared to the estimated savings from the displacement of CGS, this is a reasonable issue to address. Our second recommendation in our study is:

> 2. BPA should issue a Request For Proposals on behalf of Energy Northwest seeking 1,130 megawatts of capacity and 1,004 average megawatts of energy. The RFP would specify that suppliers would indicate environmental information in addition to dispatchability, financial, economic, and engineering information.

The inclusion of environmental information is to explicitly calculate any impacts at CARB on the economics of a specific displacement resource. While it is relatively unlikely that a traditional coal unit would be offered in response to the RFP – and at a competitive price – the CARB emission factor impacts would be part of the economic evaluation. BPA's

[397] Germer, Matt and Kristina Rohe. *Carbon Analysis on CGS 06_18_2013_v2*. 2013. Docx.

analysis, summarized in Section 6.4, assumes that the displacement resources will be difficult to identify. A well-crafted RFP and offer evaluation will address this issue.

7 JOB LOSS MITIGATION AND LOCAL ECONOMIC DEVELOPMENT

There are about 1,150 Full Time Equivalent positions at CGS.[398] Nuclear plants pay their workers approximately 36 percent more than average salaries in the local area: For example, the median salary for an electrical technician at a nuclear plant is $67,571; for a mechanical technician, $66,581; and for a reactor operator, $77,782.[399]

The availability of high paying jobs at this level in the area is uncertain. Although the existing work force is well qualified for similar jobs elsewhere in the industry, this may not benefit the local economy.

Unlike many other areas hosting aging nuclear plants, the economy of the Tri-Cities area is quite robust:

[398] Energy Northwest. *2013 Annual Budget Summary Draft.* Energy-northwest.com. Web. 11 Nov. 2013. < http://www.energy-northwest.com/whoweare/finance/Pages/2013-Annual-Budget.aspx>

[399] Nuclear Energy Institute. *Nuclear Industry's Comprehensive Approach Develops Skilled Work Force for the Future.* Nei.org. Sept. 2010. Web. 18 Sept. 2013. <http://www.nei.org/corporatesite/media/filefolder/Nuclear_Industrys_Comprehensive_Approach_Devlops_Skilled_Work_Force_for_the_Future_Sept_2010.pdf>.

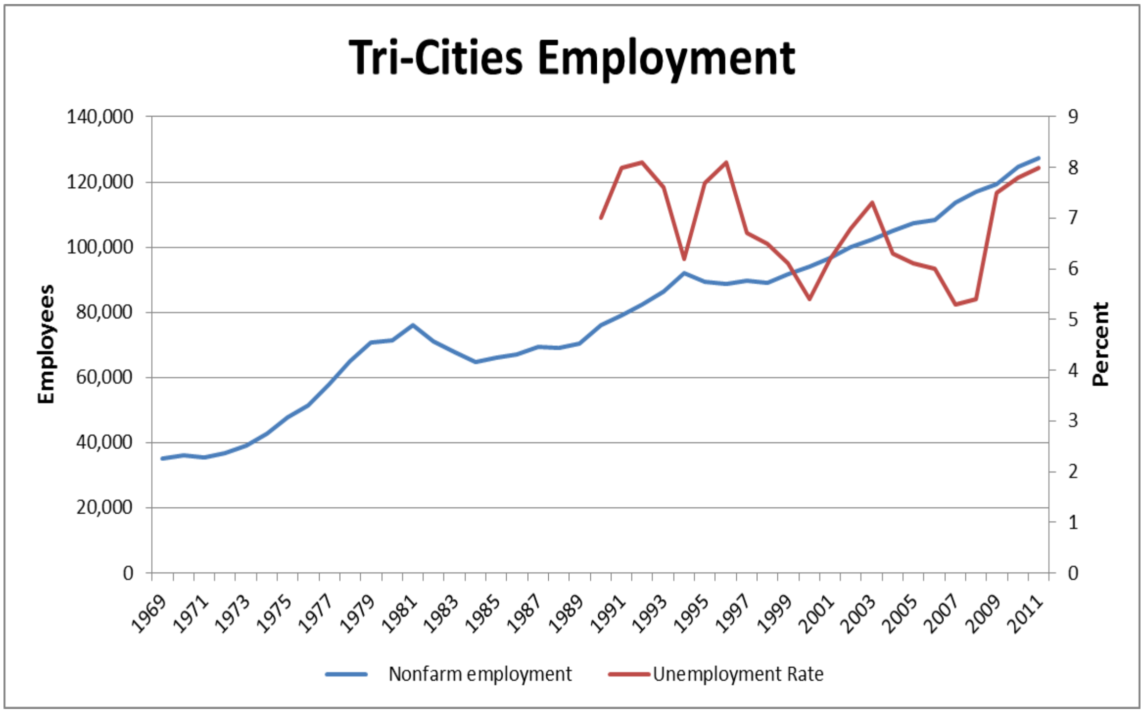

Figure 76

Continued job growth in areas affected by nuclear plant closures – Columbia County (Trojan) and Sacramento County (Rancho Seco) – has been very positive. Although each closure removed a substantial level of employment, decommissioning activities and overall economic growth forestalled an employment downturn in both cases.

The lessons from Trojan and Rancho Seco are that DECON is a better choice for the local economy than SAFSTOR, and that the choice to decommission directly by the plant owner, rather than rely primarily on an outside firm, also helps maintain the local economy.

7.1 Trojan and Rancho Seco Decommissioning

7.1.1 Trojan Nuclear Plant Decommissioning

The Trojan Nuclear Station (TNP) was located in Columbia County, Oregon (population 49,286). It began operation in May 1976 and had a net output rating of 1130 MWe. Trojan was permanently shut down after 17 years of operation in November of 1992. PGE decided to perform the decommissioning itself rather than contracting the work to another party. NRC formally terminated the TNP license in May of 2005. An NRC report describes the employment trajectory for the decommissioning of Trojan:

> "Prior to permanent shutdown of TNP in December 1992, the number of regular TNP full-time employees at TNP was about 950 with a total of about 1400 staff including contractors. This was reduced to about 190 PGE full-time staff within about one year after permanent shutdown, with a further reduction to about 150 PGE full-time staff by December 2005. As shown in Table 4.24, permanent PGE staffing levels then increased to about 250 by February 2000 with another about 40 temporary staff and about 140 subcontractor staff."[400]

[400] Nuclear Regulatory Commission. *Assessment of the Adequacy of the 10 CFR 50.75*(c)*Minimum Decommissioning Fund Formula*. November 2011. Page 4-65 – 4-67.

Table 4.24. TNP Organization and Staffing Level in February 2000

Level 1	Level 2	Level 3	Number of Staff
Trojan Site Executive and Plant General Manager	General Manager's Office	Not Applicable	PGE – 2
	Nuclear Oversight	Managers, Engineers, Specialists	PGE – 6 Contract – 3
	Plant Support and Technical Functions	General Manager's Office	PGE – 3 Contract – 1
		Cost Control	PGE – 3
		Nuclear Security	PGE – 31 Contract – 2
		Nuclear Regulatory Affairs	PGE – 4 Contract – 1
		Total	PGE – 41 (2 temporary) Contract – 4
	Engineering/ Decommissioning	General Manager's Office	PGE – 3
		Decommissioning Projects	PGE – 8 Contract – 86
		Engineering	PGE – 12 Contract – 10
		Decommissioning Planning	PGE – 6 Contract – 1
		Project Controls	PGE – 1 Contract – 5
		Total	**PGE – 30** **Contract – 102**
	Independent Spent Fuel Storage Installation	Manager's Office and Specialists	PGE – 11
	Maintenance	Manager's Office	PGE – 1
		Mechanical	PGE – 13
		Decommissioning 1	PGE – 32
		Decommissioning 2	PGE – 28
		Instrumentation and Electrical	PGE – 8
		Radwaste Worker	PGE – 21
		Project Planning	PGE – 9
		Storeroom	PGE – 3
		Surface Remediation	PGE – 11 Contract – 1
		Total	**PGE – 126 (41 temporary)** **Contract – 1**

Table 4.24. (contd)

Level 1	Level 2	Level 3	Number of Staff
	Operations	Manager's Office	PGE – 2
		Shift Managers (control and auxiliary operators)	PGE – 13
		ISFSI Loading	PGE – 1 Contract – 5
		Total	**PGE – 16** **Contract – 5**
	Radiation Protection	Manager's Office	PGE – 2 Contract – 1
		Chemistry/Radiation Protection	PGE – 47 Contract – 17
		Radiation Protection Technical Support	PGE – 8 Contract – 3
		Total	**PGE – 57** **Contract – 21**
	Corporate Support	Not Applicable	PGE – 5 Contract – 2
	TOTAL	**Not Applicable**	**PGE – 294 (43 temporary)** **Contract – 138**

[401]

Figure 77

Trojan generation and non-farm employment in Columbia County during decommissioning indicates that the local economy prospered even after decommissioning was largely completed:

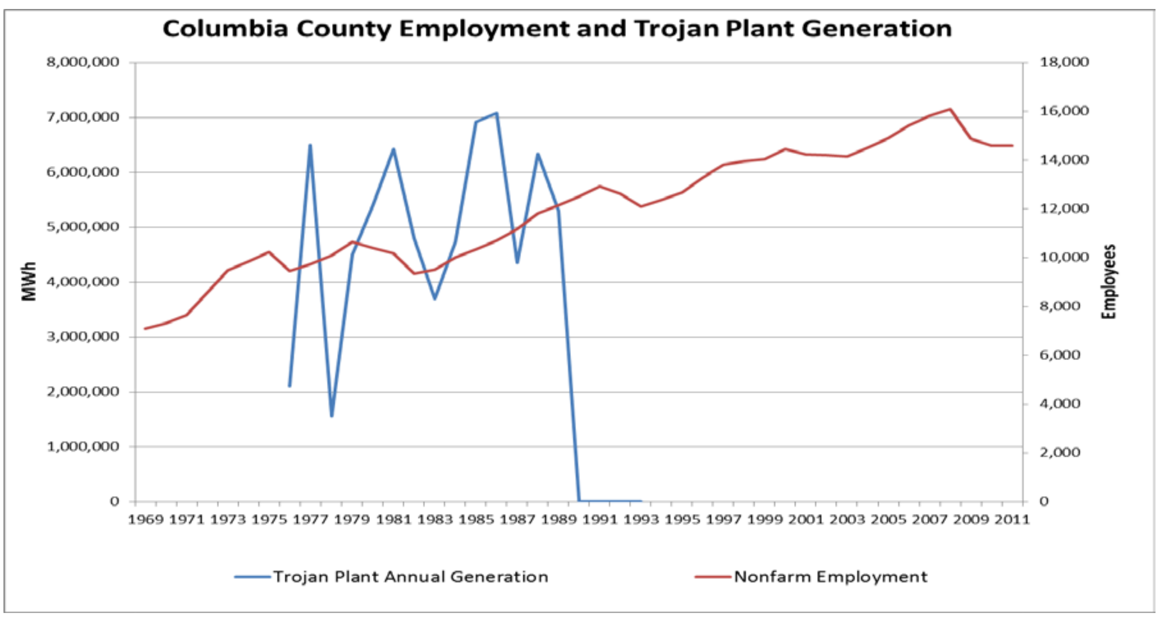

Figure 78

[401] Ibid. 4-70 - 4-71.

7.1.2 Rancho Seco Decommissioning

Rancho Seco began operation in April 1975. It was a 913 MWe Pressurized Water Reactor with more than 1,400 employees.[402] The plant was permanently shut down by public referendum in June 1989. At first, in order to allow the plant's owner time to accumulate sufficient decommissioning funds, a SAFSTOR decommissioning was planned. However, increasing costs for staff and maintenance as well as escalating cost projections for low-level waste disposal motivated the owner, SMUD, to search for other options.

When alternative waste disposal options became available, SMUD began implementing what they referred to as "incremental decommissioning," resulting in a shorter 8-year SAFSTOR period. SMUD chose to self-perform decommissioning rather than hiring a third party, and decommissioning activities began in February 1997. For planning and oversight of the decommissioning, SMUD used about 100 SMUD staff and about 80 contractors.[403]

Table 4.32. Rancho Seco Decommissioning Organization in April 2004

Level 1	Level 2	Level 3
Nuclear Plant Closure and Decommissioning Manager	Quality Assurance/ Licensing/Administration	Not Applicable
	Decommissioning	Radiological Engineering
		Radwaste Operations
		Dismantlement
		Project Controls
	Plant Support	Not Provided
	Nuclear Maintenance	Not Provided
	Nuclear Radiation Protection/Chemistry	Not Provided

Figure 79

The plant stopped generating power in 1989 and physical decommissioning was completed in December 2008: [404,405]

[402] Los Angeles Times. *Layoffs Set at Rancho Seco Nuclear Plant.* 19 Feb. 1989.
[403] A detailed breakdown of total staffing levels is not available for Rancho Seco.
[404] Nuclear Regulatory Commission. *Assessment of the Adequacy of the 10 CFR 50.75(c) Minimum Decommissioning Fund Formula.* November 2011. Page 4-117.
[405] Ibid. 4-94.

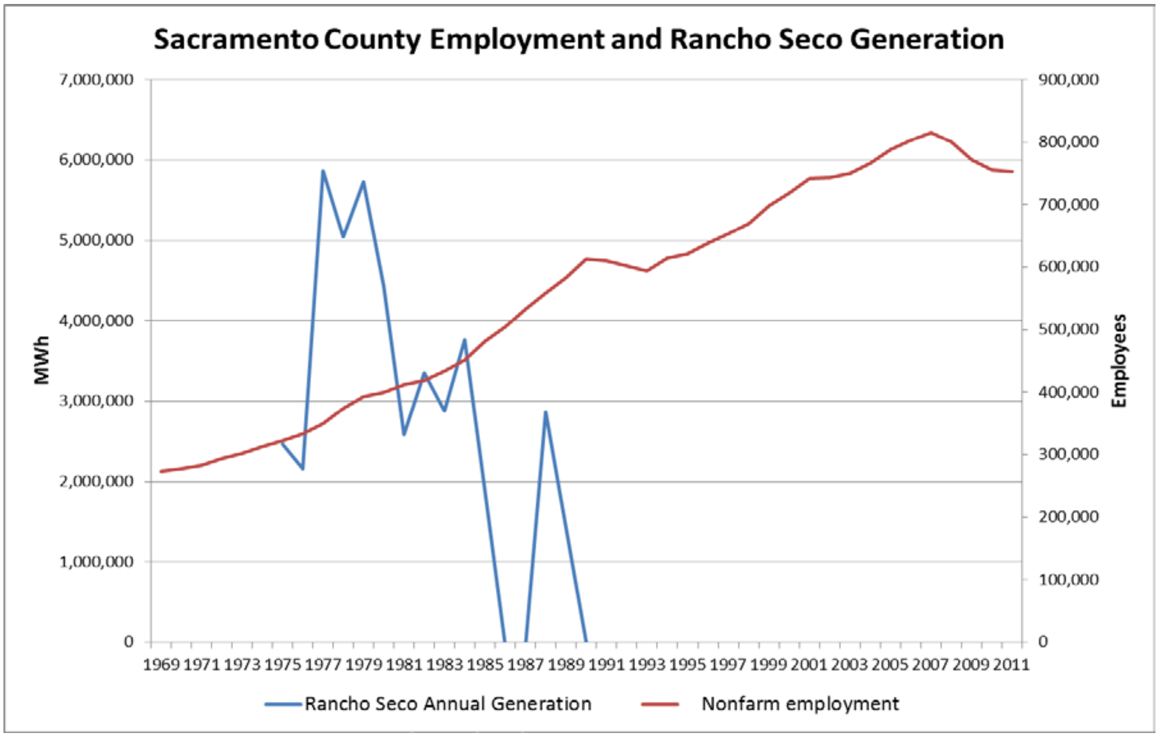

Figure 80

7.2 USE OF EXISTING EMPLOYEES VS. CONTRACTING WITH AN OUTSIDE FIRM

Generally, there are two staffing approaches for decommission a nuclear plant: Use as many current employees as possible supplemented by specialized contractors, or hire an experienced outside contractor to dismantle the plant. [406]

The use of existing employees to perform the decommissioning has advantages:

- Maximum use of staff who have a wealth of experience and knowledge of the plant
- Some decommissioning activities are similar to maintenance activities
- Use of existing staff provides local employment opportunities

There are potential downsides to using existing staff. Experienced staff may leave for new jobs with longer career prospects. Others may have difficulty accepting changes as the plant moves to decommissioning mode. Maintaining local staff will require training for

[406] International Atomic Energy Agency. *Organization and Management for Decommissioning of Large Nuclear Facilities*. Tech. no. 399. Vienna: IEAE, 2000. Technical Report. pub.iaea.org. IEAE. Web. 18 Sept. 2013. <http://www-pub.iaea.org/MTCD/publications/PDF/TRS399_scr.pdf>.

decommissioning tasks and a reorientation toward project completion.[407] An outside contractor may have the ability to perform dismantling more efficiently since those activities are performed on a regular basis, yet that approach could have a negative impact on the local workforce.

Until all of the fuel is removed from the reactor and the primary circuit decontamination is completed, staffing levels remain similar to levels when the plant was operating. Once the fuel is removed, staffing levels will fall and the skills required will change.[408]

7.3 Options for Displaced Employees

7.3.1 Assist with Decommissioning

When current staff are kept on to implement decommissioning, some retraining and redefining of job duties is necessary. Retraining can be provided through contracts with specialists.[409] The Facility Decommissioning Course at Argonne National Laboratory is a training course for employees interested in staying onboard during decommissioning. The course provides information on the basic steps of the decommissioning process, and imparts lessons learned from the past. It will assist in decision-making, planning, and implementation, as well as emphasizing the need for early and complete project planning to achieve safe and cost effective decommissioning. Sixteen hours can be used toward Certified Health Physicist (CHP) recertification.

7.3.2 Early Retirement

Approximately 39% of the nuclear workforce will be eligible to retire by 2016, which translates to about 449 CGS workers.[410] The rapid aging of the nuclear workforce has been discussed extensively in a variety of studies including the IAEA's study "The nuclear power industry's ageing workforce: Transfer of knowledge to the next generation," Overcoming The Challenges of The Ageing Nuclear Workforce & Knowledge Transfer," by Charles Goodnight, and "Maintaining a highly-qualified nuclear industry workforce" by Elizabeth McAndrew Benavides.[411,412,413]

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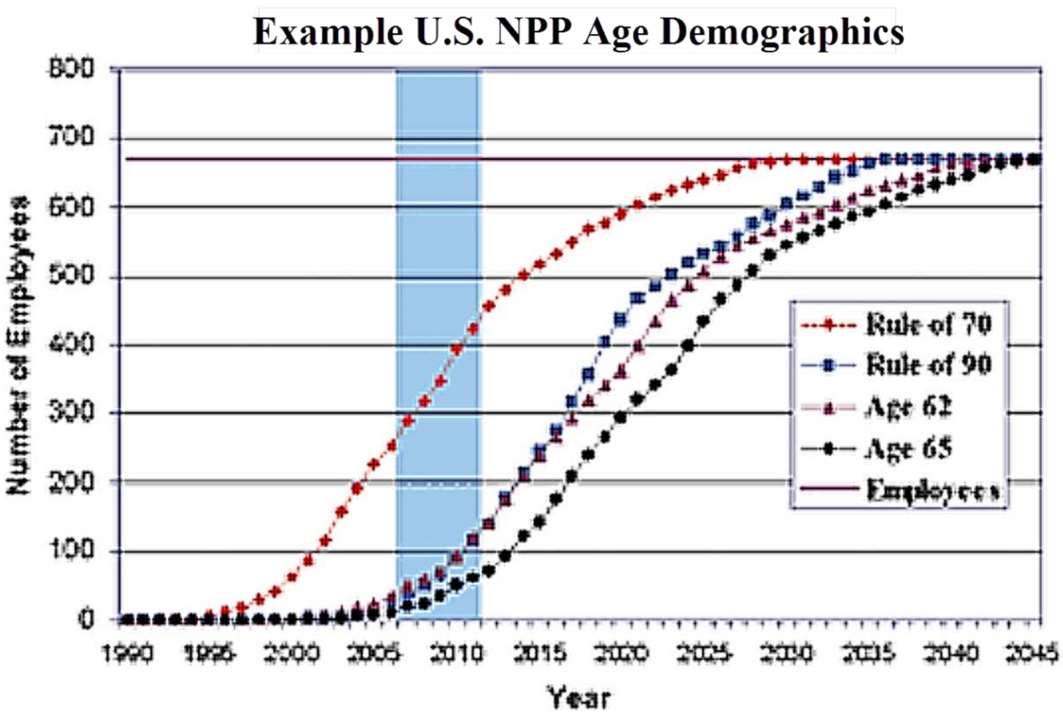
[407] Ibid. Page 5.
[408] Ibid. Page 7.
[409] Ibid. Page 38.
[410] Nuclear Energy Institute. *Nuclear Energy's Economic Benefits – Current and Future.* Nei.org. Sept. 2013. Web. 4 Nov. 2013.
<http://www.nei.org/CorporateSite/media/filefolder/economicbenefitscurrentfuture.pdf?ext=.pdf >. Page 2.
[411] International Atomic Energy Agency. *The Nuclear Power Industry's Ageing Workforce: Transfer of Knowledge to the next Generation.* Iaea.org, June 2004. Web. Nov. 2013. <http://www-pub.iaea.org/mtcd/publications/pdf/te_1399_web.pdf>.

Challenges to the industry may be a benefit to the local area, however. As the chart below indicates, workforce age and early retirement opportunities are increasing:



414

Figure 81

7.3.3 Relocation

Companies with multiple nuclear reactors have a much easier time relocating workers because the same technical methods, operating and maintenance rules, and software can be used. The nearest nuclear plant to CGS is over 1000 miles away, so employees considering this option would need adequate relocation funds for a long distance move.

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[412] Goodnight, Charles. *Overcoming The Challenges of The Ageing Nuclear Workforce & Knowledge Transfer.* World.nuclear.org. 2006. Web. 22 Nov. 2013. Page 3. < http://www.world-nuclear.org/sym/2006/goodnight.htm>

[413] Elizabeth McAndrew Benavides. *Maintaining a highly-qualified nuclear industry workforce.* Health Phys. 2011 Jan;100(1):86-7.

[414] Goodnight, Charles. *Overcoming The Challenges of The Ageing Nuclear Workforce & Knowledge Transfer.* Page 2.

7.3.4 Find new position

Because of continued employment opportunities in industries and laboratories on the Hanford Nuclear Reservation and growing manufacturing in the Mid-Columbia basin, displaced workers may have an easier time finding new employment than in other areas.

Several educational opportunities exist for career retraining in the area. Washington State University Tri-Cities, a four year institution, and Columbia Basin Community College can retrain displaced workers and provide local manufacturers and a variety of other employers with an exceptionally skilled workforce.

A possibility that could bring thousands of new skilled jobs into the Tri-Cities is being proposed and will be discussed in the next section. In addition, in discussions with the Washington Energy Office, a recommendation was made to consider addressing potential job losses using lessons learned from the planned closure of the Centralia coal plant.

7.4 PROPOSAL TO TRANSFER DOE PROPERTY FOR ECONOMIC DEVELOPMENT

On May 31, 2011, the Tri-City Development Council (TRIDEC) and its partners at the City of Richland, the Port of Benton, and Benton County requested the transfer of 1,341 acres near the southern boundary of the Hanford Site for economic development purposes. The land transfer was proposed to partially offset job losses from Hanford workforce restructuring. [415] An amendment was made on October 13, 2011 requesting an additional 300 acres previously requested for lease by Energy Northwest, for a total of 1,641 acres.

[415] Tri-city Development Council. *10 CFR 770 Proposal to Transfer Tract 1 at DOE Hanford Site to the Community Reuse Organization*. Tridec.org. 31 May 2011. Web. 18 Sept. 2013. Page 1. <http://tridec.org/images/uploads/770 - 6_1_11 Revised Final (Including WA State Leg) (Reduced Size).pdf>.

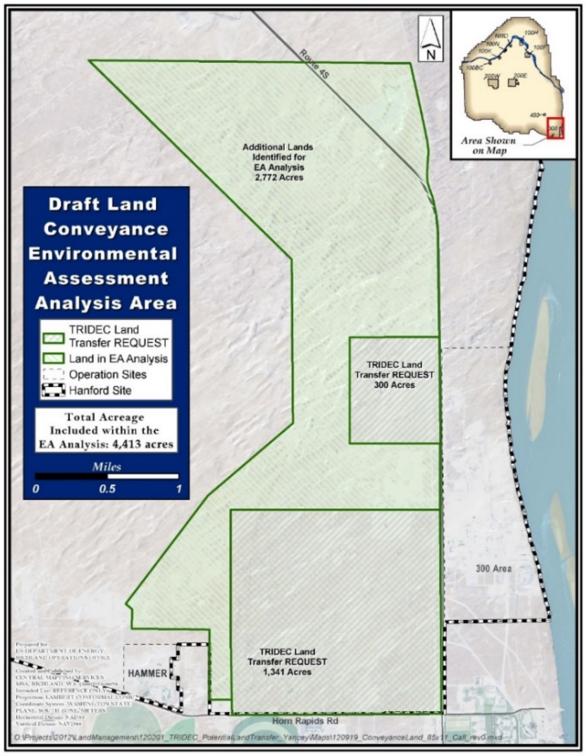


Figure 82

Without placing value judgments or going into details about specific plans for the use of these lands, new jobs attracted to industry there could help displaced workers after the closure of the CGS plant.

Whether the Tri-Dec proposal gathers support or not, the Tri-Cities community remains a strong region for employment and would be better prepared to employ displaced workers than most regions of the United States.

The Tri-Cities offers great value for employers, with a highly educated workforce, quality lifestyle, affordable housing, available sites and land, great infrastructure, and superior schools and medical facilities. According to the ACCRA Cost of Living Index, the Tri-Cities have the lowest cost of living in the State of Washington (3rd quarter, 2010). Smart Money ranked the Tri-Cities No. 1 in the nation for housing in March of 2010.

Since 2000, Franklin County is the 18th fastest growing county in the nation, while Benton County also grew by nearly 2% per year. The Tri-Cities is one of the Northwest's strongest growth regions. The Tri-Cities is home to manufacturers in energy (solar dishes, sterling engines, and fuel cells), high-tech products, aerospace, food processing, transportation, and health care.

The aforementioned Washington State University Tri-Cities and Columbia Basin Community College provide educational and training opportunities to support the growing workforce in the region.

7.5 LESSONS FROM THE CENTRALIA COAL PLANT

In discussions with the Washington State Energy Office, a recommendation was made that we analyze the arrangements for the closure of the Centralia coal plant when we address the potential job losses from the closure of CGS.

The Centralia coal plant began operation in 1971 and has a net capacity of 1,340 MW. It is a merchant plant and is owned by TransAlta US. Political pressure and increasing regulations in Washington around greenhouse gasses have led to a plan to shut the Centralia coal plant down completely by 2025. The shutdown is scheduled to occur in stages, with one boiler shut down by 2020 and the second by 2025.

Centralia is a former center of forest products industry activity located south of Olympia, Washington, with a population of approximately 16,400 people. Unlike the Tri-Cities, Centralia has relatively high unemployment. Accounting for jobs and the local economy was central to the negotiations around closing the Centralia coal plant, which employs about 250 people.[416,417]

Our proposal is to market test the CGS nuclear power plant on a much shorter timetable than was set forth in the agreement to close the Centralia coal plant. Nevertheless, one aspect of their plan may have applicability in this case.

In the agreement to close the Centralia coal plant, TransAlta agreed to contribute $55 million to the local community for economic development and funding of innovative energy solutions, $30 million to invest in energy efficiency in the local community and $25 million for innovative energy technology. It may be that some specific plans for alternative energy development by Energy Northwest could be arranged: a wind or solar project on the Hanford site, for example, that would allow workers not involved in decommissioning to find employment and mitigate the shock of the closure of the nuclear plant.

As appears to be the case with CGS, many of the coal plant's workers will be of retirement age by the plant's closure date, union sources report. TransAlta also stated a strong interest in keeping on as many employees as possible after the plant closure, when they plan to invest

[416] Utilities and Transportation Commission. "News: State Regulators Uphold Centralia Coal Plant Contract." *Utc.wa.gov*, 25 June 2013. Web. 22 Nov. 2013. <http://www.utc.wa.gov/aboutUs/Lists/News/DispForm.aspx?ID=205>.

[417] Martelle, Scott. *Kick Coal, Save Jobs Right Now*. Sierraclub.org. Jan/Feb 2012. Web. Nov. 2013. <http://www.sierraclub.org/sierra/201201/kick-coal-save-jobs.aspx>.

in a new energy project in the area. As suggested above, it may be appropriate for Energy Northwest to consider similar plans.

Energy Northwest's plans for assisting workers after the closure of CGS would benefit greatly from the fact that, unlike Centralia, the Tri-Cities remains an economically vibrant area with relatively abundant job opportunities.

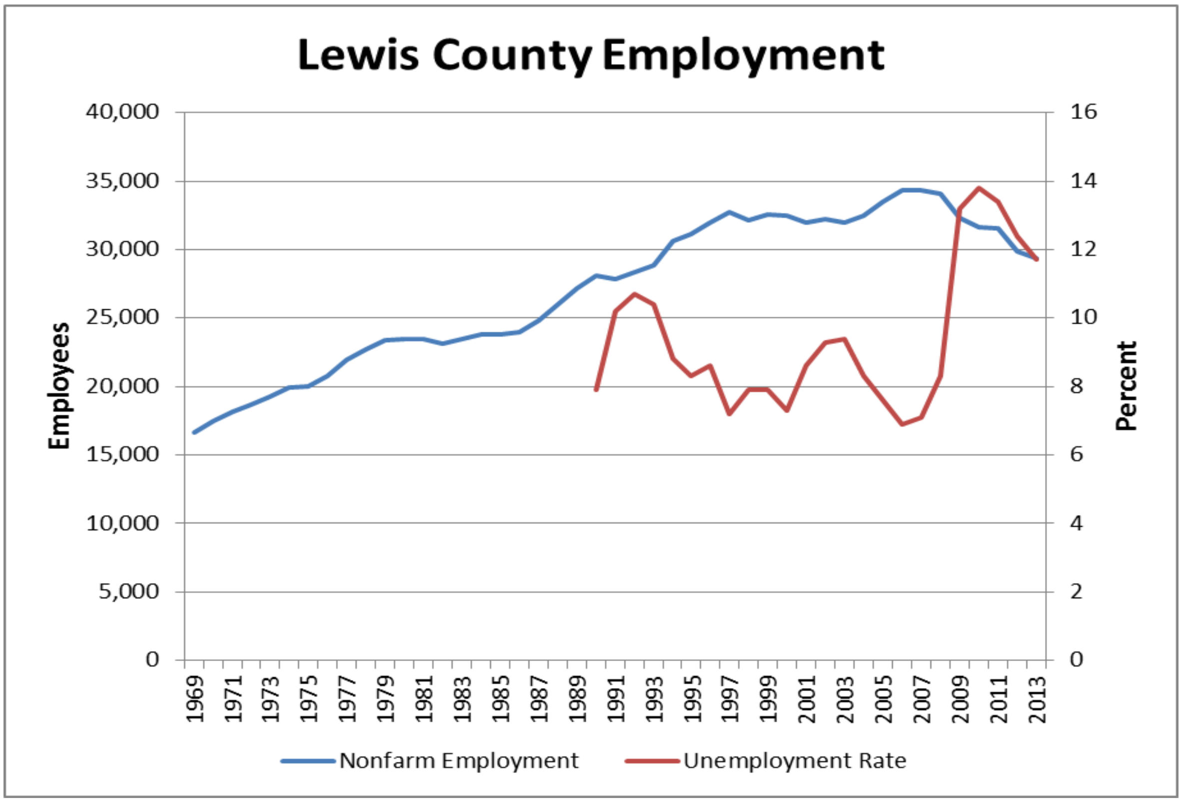


Figure 83

8 RECOMMENDATIONS

Specific recommendations:

1. BPA should seek an opinion from the Office of the General Counsel of the Department of Energy that Section 15(c) of the 1971 Project Agreement gives the Administrator the power to direct the termination of CGS.
2. BPA should issue a Request For Proposals on behalf of Energy Northwest seeking 1,130 megawatts of capacity and 1,004 average megawatts of energy.[418,419] The RFP would specify that suppliers would indicate environmental information in addition to dispatchability, financial, economic, and engineering information.
3. BPA staff would assemble responses and share the response data with customers and state and federal agencies, including the Northwest Power and Conservation Council.[420]
4. Financial theory argues that multiple suppliers and staged contract durations is an optimal outcome. The result of the review of the offers would be a portfolio of different supplies and suppliers.
5. The final portfolio would be implemented by Energy Northwest as a displacement of existing generation.
6. After contract implementation, CGS would begin DECON decommissioning in May 2015.
7. Energy Northwest would handle employment transitions by a combination of methods. First, implementing DECON rather than SAFSTOR decommissioning. Second, training and employing workers in plant decommissioning – following the example of PGE (Trojan) and SMUD (Rancho Seco) and a variety of additional strategies as outlined in section 7 of this document.

[418] Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study. Technical Appendix. Volume 1: Energy Analysis*. Web. 13 Sept. 2013. Page 63. <http://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf >.

[419] Bonneville Power Administration. *2012 Pacific Northwest Loads and Resources Study. Technical Appendix. Volume 2: Capacity Analysis*. Web. 13 Sept. 2013. Page 172. <http://www.bpa.gov/power/pgp/whitebook/2012/TechnicalAppendix-Volume1EnergyAnalysisRevised6-6-2013.pdf >.

[420] Bonneville's frequently adopted "steering committee" process would be a useful approach that would maintain bidders' desire for confidentiality while allowing options to be explored by regional representatives.

APPENDIX A: LONG TERM CONTRACTS

Long term power contracts have been a central feature of power supplies in the Pacific Northwest since the development of the Columbia River dams. The major privately owned utilities have purchased energy and capacity from the publicly owned hydro-electric plants since the 1930s. One central reference work is BPA's Annual White Book. The most recent edition contains many pages of regional and interregional contracts:

Table A-4: Regional: Intra-Regional Transfers
Operating Year 2014 to 2023
2013 White Book Report Date: **10/1/2013**
S110-WB-20131023-150804

	Energy-aMW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Intra-Regional Transfers										
	Contracts	**830**	**695**	**692**	**546**	**451**	**356**	**239**	**226**	**226**	**226**
1	AVWP to BPA-P Setl WNP3 Rtn	41.6	41.6	41.7	41.6	0	0	0	0	0	0
2	AVWP to PGE CapX Del	44.6	44.6	44.6	18.7	0	0	0	0	0	0
3	BPA-P to AVWP Setl WNP3 Del	41.7	41.7	41.8	41.6	41.6	0	0	0	0	0
4	BPA-P to BPA-T Ops IntrlAgmt	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
5	BPA-P to Other Entities	51.5	0	0	0	0	0	0	0	0	0
6	BPA-P to PPL SNX SprgDel	0	0	0	0	0	0	0	0	0	0
7	BPA-P to PPL SNX SumrDel	0	0	0	0	0	0	0	0	0	0
8	BPA-P to PSE Ops UBkr Repl	1.28	1.28	1.28	1.28	1.28	1.28	1.29	1.27	1.28	1.28
9	BPA-P to PSE Setl WNP3 Del	41.7	41.7	41.8	41.6	41.6	0	0	0	0	0
10	CIDF to RMP PwrS LTFirm	5.48	5.48	5.46	5.47	5.47	5.47	5.46	5.47	5.47	5.47
11	CLAT to IPC NX Ret	4.75	4.75	1.26	0	0	0	0	0	0	0
12	DOPD to Other Entities	0	0	0	0	0	0	0	0	0	0
13	EWEB to PGE CapX Del	2.50	0	0	0	0	0	0	0	0	0
14	GCPD to PPL PwrS LTFirm	9.99	10.0	10.00	10.0	9.99	10.0	10.00	10.0	9.99	10.0
15	GHPD to GHP PwrS LTFirm	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
16	IPC to CLAT NX Del	5.02	5.02	3.00	0	0	0	0	0	0	0
17	JPMV to BPA-P PwrP T2	0	0	42.5	8.52	0	0	0	0	0	0
18	NWE to MVP PwrS LTFirm	9.66	9.66	9.65	9.66	9.66	9.66	9.65	9.66	9.66	9.66
19	Other Entities to BPA-P	147	89.5	45.4	83.1	100.0	88.5	13.0	0	0	0
20	Other Entities to COPD	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
21	Other Entities to DOPD	20.0	22.5	25.1	8.96	0	0	0	0	0	0
22	Other Entities to Other Entities	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
23	Other Entities to PGE	92.1	92.1	92.1	15.4	0	0	0	0	0	0
24	PGE to AVWP CapX Repl	44.6	44.6	44.6	18.7	0	0	0	0	0	0
25	PGE to EWEB CapX Repl	2.50	0	0	0	0	0	0	0	0	0
26	PGE to PPL PwrS LTFirm	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
27	PPL to BPA-P SNX SprgRtn	0	0	0	0	0	0	0	0	0	0
28	PPL to BPA-P SNX SumrRtn	22.8	0	0	0	0	0	0	0	0	0
29	PSE to AVWP PwrS LTFirm	0	0	0	0	0	0	0	0	0	0
30	PSE to BPA-P Setl WNP3 Rtn	41.6	41.6	41.7	41.6	41.6	41.6	0	0	0	0
31	SCL to POPD PwrS LTFirm	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7
32	SPN to PGE PwrS LTFirm	104	104	104	104	104	104	104	104	104	104
33	TAUC to AVWP PwrS LTFirm	0	0	0	0	0	0	0	0	0	0
34	**Total Intra-Regional Transfers**	**830**	**695**	**692**	**546**	**451**	**356**	**239**	**226**	**226**	**226**

[421]

Figure 84

[421] BPA. *2013 Pacific Northwest Loads and Resources Study: Technical Appendix, Volume 1*. Oct. 2013. Page 27.

The bewildering variety of such contracts in the Pacific Northwest reflects a variety of solutions to meeting long term power supply requirements. These range from allocating risk of major plant investments, regional and inter-regional seasonal transactions and, more recently, the locational advantages of siting wind in the eastern Washington and Oregon desert.

Such arrangements were unusual outside of the Pacific Northwest – especially in the eastern part of the United States – until wholesale and retail competition became common.

Competitive bulk power markets have come slowly to the rest of the U.S., but a wide variety of power contracts have resulted from Purchaser of Last Resort (POLR) auctions in states where utility companies are required to supply power to customers who have not switched to a competitive supplier. POLR auctions are implemented in Illinois, Maryland, New Jersey, Ohio, Pennsylvania, and other states as a method for the utility to procure power for these customers at market-based rates.[422]

In Maryland, POLR auctions were established in April of 2003. The incumbent utilities hold auctions overseen by the Maryland Public Service Commission and accept the lowest bids from generators that compete to supply portions of the utilities' load. The power is then provided at market price to any customer that has not switched to a competitive electric provider. Utilities moderate the intensity of price swings with a variety of techniques designed to keep prices from changing too dramatically during any one auction. These auction design techniques include submitting Requests for Proposals for contracts of varying duration, holding auctions several times each year, and only requesting proposals for a portion of load at any one time.[423] For example, Pepco holds auctions twice a year, offering about 25% of peak load for bid at each auction in two-year contracts.[424] Contracts for the four Maryland utilities range from three months to two years in duration, and auctions occur 2-4 times per year. In the most recent RFP, Pepco requested proposals totaling 870 MW, PE requested 611 MW, BGE requested 1,831 MW, and Delmarva Power requested 304 MW for a total of 3,616 MW.[425]

[422] Maurer, Luiz T.A., and Luiz A. Barroso. *Electricity Auctions: An Overview of Efficient Practices*. World Bank Study. Washington, D.C.: World Bank, 2011. World Bank. Web. 2 Dec. 2013. <http://www.ifc.org/wps/wcm/connect/8a92fa004aabaa73977bd79e0dc67fc6/Electricity+and+Demand+Side+Auctions.pdf?MOD=AJPERES>.

[423] Baltimore Gas and Electric. *Provider of Last Resort Information*. Bge.com. 2011. Web. Dec 5, 2013. <https://supplier.bge.com/tariffs/polr.htm>.

[424] Pepco. "MD – SOS Frequently Asked Questions." *Pepco.com*. Web. 5 Dec. 2013. <http://www.pepco.com/home/choice/md/afterjune0607sos/>

[425] Baltimore Gas and Electric. MARYLAND UTILITIES ISSUE REQUEST FOR PROPOSALS FOR THE SUPPLY OF WHOLESALE ELECTRIC POWER. 13 Sept. 2013. Web 5 Dec. 2013. <http://rfp.bge.com/GeneralDocs/2014PressReleaseFinal.pdf>

In New Jersey, the four incumbent utility companies have used the statewide Basic Generation Service (BGS) auction, equivalent to a POLR auction, to procure electric supply for customers not served by a competitive electric provider. Contracts worth several billion dollars are awarded each year in the BGS auction, with suppliers competing for contracts to supply a portion of each utility's load requirement.[426]

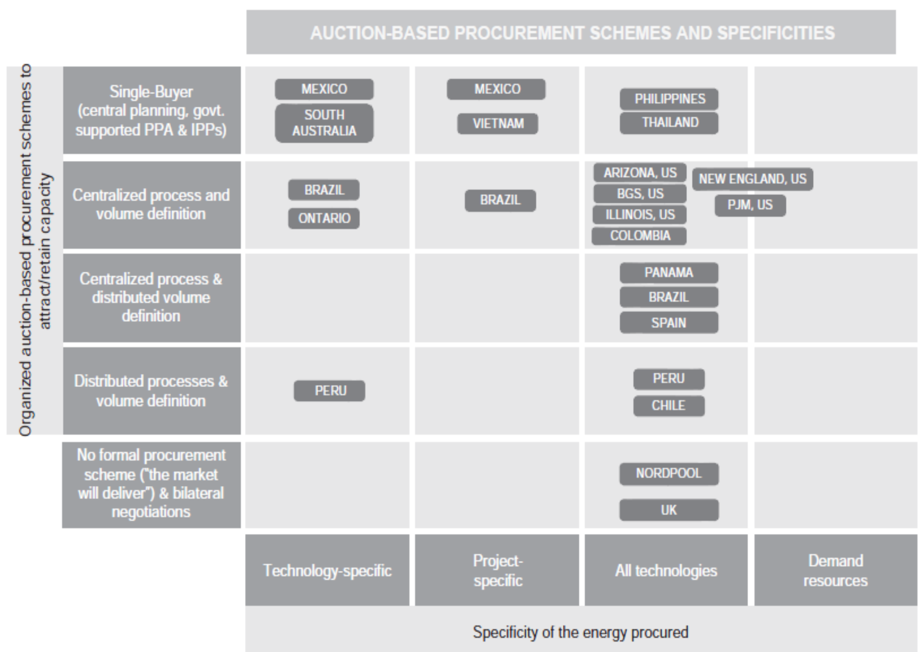
Illinois began to deregulate electricity markets In December 1997, with a transition period lasting through 2006. During the transition period, residential and small commercial tariffs were frozen and demand was met using long-term contracts. After this transition period, rates were unfrozen and utilities began buying power in short and mid-term contracts. Prices increased dramatically and in response, the state passed a law in 2007 creating the Illinois Power Agency (IPA) to purchase power on behalf of the utilities.

The Procurement Plan consists of a forecast of how much energy and/or capacity is required by retail customers, the current supply under contract, and the quantity and type of supply needed to meet load and other requirements, such as renewable portfolio standards. Each year the IPA develops a competitive procurement process to secure electricity and transmission services for customers in the ComEd and Amaren service areas. Electricity is purchased in three-year contracts in a competitive POLR auction. [427,428] Historically, the IPA has purchased supply in standard 50 MW peak/off-peak/around the clock blocks. To minimize price risk, a "ladder" of standard energy products are procured in contracts such that 100% of the first year is fully hedged, 70% of the second year is hedged, and 35% of the third year is hedged.[429]

[426] New Jersey Statewide Basic Generation Service Electricity Supply Auction. *Overview.* Web. 5 Dec. 2013. <http://www.bgs-auction.com/bgs.auction.overview.asp>.
[427] Citizen's Utility Board of Illinois. *The IPA and June 1 Changes to your Power Bill.* Web. 5 Dec. 2013. <http://www.citizensutilityboard.org/ciElectric_cubfacts_ipa.html>
[428] Section 16-115.5 of the Public Utilities Act
[429] Hedging in this context means that existing contracts cover 100% of forecast load

Similar auctions have been implemented in many countries. The World Bank monograph by Maurer and Barroso identifies a variety of contractual power supply auctions across the planet and the variety of purposes they serve:

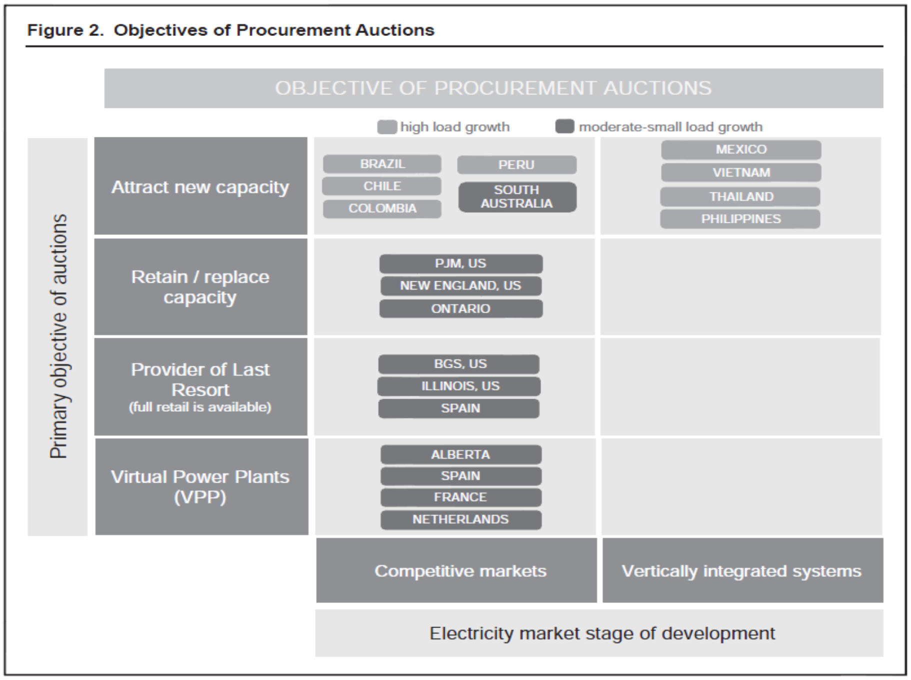
Figure 1. Auction Organization



[430]

Figure 85

[430] Maurer, Luiz T.A., and Luiz A. Barroso. *Electricity Auctions: An Overview of Efficient Practices.* World Bank Study. Washington, D.C.: World Bank, 2011. World Bank. Web. 2 Dec. 2013. Page xiii. <http://www.ifc.org/wps/wcm/connect/8a92fa004aabaa73977bd79e0dc67fc6/Electricity+and+Demand+Side+Auctions.pdf?MOD=AJPERES>.



[431]

Figure 86

An example of the rapid purchase of very large amounts of energy occurred in the closing days of the California Energy Crisis. California had committed its utilities to very restrictive power purchasing arrangements through two complex administered electricity markets – the California Power Exchange and the California Independent System Operator. Prices in these markets were set by complex computer programs that facilitated a vast array of manipulative schemes – many of which with colorful names taken from popular movies like "Death Star" or "Get Shorty". The Governor of California decided to make long term purchases to circumvent the failing administered markets in the spring and summer of 2001. While the situation was both unusual and reprehensible, it is worth noting that even in this highly stressed example, the power contracts were signed and the power delivered. The contemporaneous report from the California State Auditor lists 55 contracts in their analysis:

> As of the end of October 2001, the Department of Water Resources (department) had entered into 55 long-term contracts and 2 agreements in principle to meet a portion of its net-short obligations. These contracts have terms that range from a few months to as long as 20 years and could cost

[431] Ibid. Page xv.

> ratepayers of the investor-owned utilities up to $42.6 billion over the 10-year period ending December 31, 2010.[432]

Six of the contracts were potentially comparable to CGS and the total portfolio represented a capacity purchase of between 12,000 and 18,000 megawatts.

The portfolio of contracts has gradually diminished over time as specific contracts expire or are renegotiated. A detailed history of the contracts as well as the costs and deliveries associated with them is contained in the annual reports submitted by the California Department of Water Resources to the California Public Utilities Commission at: http://www.cers.water.ca.gov/revenue_requirements.cfm.

432 California State Auditor. *California Energy Markets: Pressures Have Eased, but Cost Risks Remain.* Dec. 2001. Page 189.

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