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Columbia Generating Station: Economic assessment

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Columbia Generating Station

Economic assessment

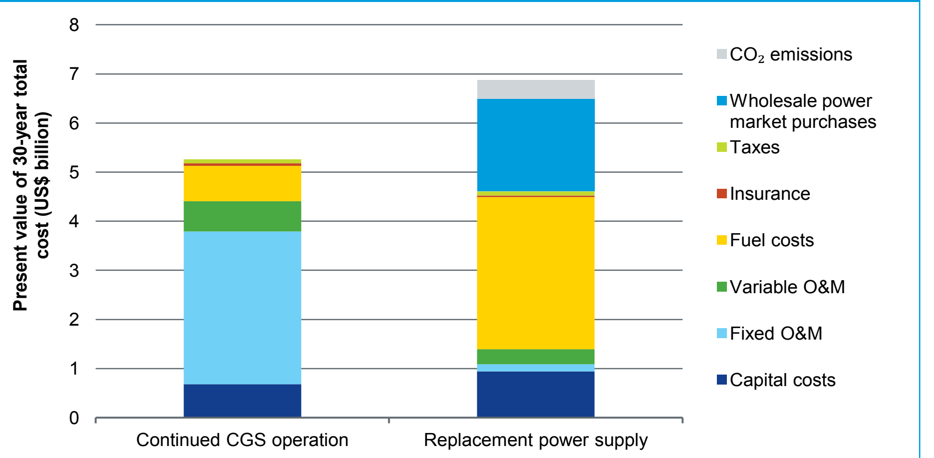
by Lawrence Makovich, Parker Littlehale, Aaron Marks, and Brendan Mrosak

Executive Summary: Continued operation of the Columbia Generating Station is cost-effective

Columbia Generating Station (Columbia or CGS) is currently a key part of the Northwest regional power system supply portfolio. Energy Northwest owns Columbia and is a municipal corporation and joint operating agency of the state of Washington. Columbia is the nuclear power component of the Northwest regional power system supply mix that provides about nine million power customers connected to the grid with the electricity that they want, when they want it, and how they want it—produced in a reliable, efficient, and environmentally responsible way. Looking ahead, Columbia is licensed to operate for another 30 years and remains key to meeting these consumer demands.

FIGURE 1

Costs of continued operation of CGS versus replacement power supply, 2014–43



Note: O&M = operation and maintenance
Source: IHS CERA

The operation of Columbia through 2043 provides a $1.6 billion savings compared with the lowest-cost alternative of closing the plant and replacing it with a natural gas–fired power plant (see Figure 1). These savings are 2% greater if the value of reducing the fuel cost risk to the overall portfolio (i.e., because of the increased exposure to natural gas price variations) is taken into account. In addition, continued operation of Columbia prevents 3.6 million metric tons in annual carbon dioxide (CO_2) emissions. Of course, future costs are not certain, but the cost-effectiveness of the continued operation of Columbia remains a robust conclusion. Sensitivity analysis on key cost uncertainties (natural gas prices, initial capital expenditures, CO_2 emission costs, and discount rates) reveal that the cost of continued Columbia operation is less than the closure and replacement cost in eight out of nine sensitivity cases; it was also roughly equivalent to one case in which the natural gas price over the next 30 years was set equal to the lowest monthly delivered natural gas price over the past dozen years.

Columbia Generating Station is currently a key part of the Northwest regional power system

Every day, electric customers in the Pacific Northwest make countless decisions that involve electricity use to power their homes and businesses. These consumers want reliable, efficient, and environmentally responsible power production at predictable prices.

The most cost-effective way to give consumers what they want is through a power grid that aggregates enough consumer demand to support an efficient mix of generating technologies at efficient scales of operation.[1]

The Northwest regional power system enables this efficient interconnection of consumers and producers.[2] Columbia Generating Station (Columbia or CGS) fits into the integrated power supply mix by providing

- **Capacity**. Measured in megawatts (MW), capacity enables the Northwest regional power system to meet all demand, including the maximum demand level. Columbia provided 1,150 MW of the total power supply to meet the estimated 41,100 MW winter peak demand in the Northwest regional power system in 2012/13.

- **Electric energy production**. Measured in kilowatt-hours (kWh), meets the real time flow of electric energy that consumers utilize. In 2012, Columbia's high availability and low operating costs allowed electricity production in over 90% of all hours.[3] Columbia's electric energy production provided 3% of the electric output in the Northwest regional power system.

- **Risk management**. Columbia is the only nuclear generating resource in the Northwest regional power system and thus adds important diversity to the generation portfolio, providing cost-effective risk management of the power supply's exposure to fossil fuel price cycles. It also provides thermal backup for the hydroelectric supplies that under normal conditions make up approximately 50% of the power generation in the Northwest regional power system but can vary significantly when precipitation and snowpack conditions are below normal.[4]

- **Greenhouse gas (GHG) abatement**. The nuclear generation produced by Columbia has zero carbon dioxide (CO_2) emissions. The Northwest regional power system's carbon intensity is one of the lowest in the country at approximately 40% below the US average, and Columbia is a contributing factor.

1. For further information, see Appendix A: Engineering/economic principles of a cost-effective generation technology mix.

2. Since 2006, the North American Electric Reliability Corporation (NERC) has been responsible for ensuring the reliability of the power system in North America. For regional supply and demand assessment purposes, NERC divides North America into eight regional entities. The Western Electricity Coordinating Council (WECC) covers the US West, Canadian west, and a small part of Mexico and is further divided into eight subregions. Two subregions—Basin and Northwest—are referred to as the Northwest Power Pool-United States and define the Northwest regional power system used in this analysis. The footprint includes the states of Washington, Oregon, Idaho, Utah, northern Nevada, most of Montana, western Wyoming, and a part of northern California. On a more local level, Columbia is part of the Federal Columbia River Power System (FCRPS) which also includes 31 hydroelectric projects owned by the Bureau of Reclamation and US Army Corps of Engineers. The Bonneville Power Administration (BPA) sells the electricity generated from these power plants throughout its service territory.

3. International Atomic Energy Agency's Power Reactor Information System.

4. Thermal power plants use heat to drive a turbogenerator to produce electricity. Nuclear, coal-fired, and natural gas–fired power plants are examples of thermal power plants.

Maintaining reliable, cost-effective power supply requires periodic economic assessments

Prudent business managers periodically assess whether it makes economic sense to continue to operate an existing power plant. In any assessment, the decision hinges on the best alternative option. The option of closure without replacement is seldom a realistic alternative. This option only exists when a power plant is no longer needed for capacity, energy, risk management, or GHG emissions management. In this case, closing Columbia without replacing it is not a realistic option because the Northwest regional power system has an ongoing need for the capacity, energy, risk management, and GHG emissions management.

To meet demand, the Northwest regional power system needs Columbia's capacity or a replacement power plant in the years ahead. An IHS CERA demand/supply assessment projects that the Northwest regional power system would fall below its target reserve margin after the 2019/20 winter season if Columbia were to retire without being replaced.[5] Cost-effective power systems are built to accommodate aggregate consumer needs including an adequate capacity reserve to insure reliability in the event of an unexpected outage or system disruption. To set a target reserve margin, power systems balance the benefits of additional reliability to customers against the costs. The Northwest regional power system has a target reserve margin above expected peak demand of at least 18% to establish the power system capacity needed to produce the desired power supply reliability.[6]

Looking ahead, IHS CERA expects the underlying trend rate of power demand growth in the Pacific Northwest to be 1.1% per year. This is a slower rate of increase than in the past decade. Measuring this underlying trend rate in recent power demand requires correcting for the temporary effects of the business cycle and weather variations from normal conditions. The recession caused a 5.5% decline in power demand in 2009 versus 2008. However, this cyclical decline is expected to reverse as the economy fully recovers. Measuring power demand growth from business cycle peak to peak adjusts for business cycle impacts. Electricity demand in the Northwest grew at a historical compound annual growth rate of 2.5% when measured from the business cycle peak of 2001 to the business cycle peak of 2007. Correcting for temporary weather impacts is also necessary to measure underlying trends if the weather deviates significantly from normal between time periods. Weather drives power use, and in particular, the colder temperatures drive the Northwest regional power system demand to peak in the winter. However, over the same period the impact of weather was minor because the heating degree-days (HDDs) were roughly the same and the cooling degree-days (CDDs) were 15% higher in 2007 versus 2001.[7]

As long as the demand for electric services continues to rise, the capacity provided by Columbia or its replacement will be needed. Appendix A explains the engineering/economic principles that show the most cost-effective way to meet aggregate customer demands for electric services is with a mix of available options—demand-side resources plus supply-side resources including peaking, cycling, and base-load generating technologies. Therefore, cost-effectively meeting increasing consumer demand for electrical services requires all of the components of the least-cost mix. The implication is that if cost-effective

5. The target reserve margin is a metric used in the power business to measure supply in relation to peak demand. Projected reserve margin is based on projected peak demand compared with the total existing supply, plus expected new supply minus expected retirements. Reserve margin = (total supply - peak demand)/(peak demand).

6. NERC sets a minimum reserve margin requirement that varies by power system. The 18% target for the Northwest regional power system represents a weighted average between the two NERC subregions—the Northwest subregion (19.9%) and the Basin subregion (13.5%). The penalties NERC imposes for noncompliance range from $2,000 to $335,000 per violation per day.

7. According to the National Oceanic and Atmospheric Administration, a HDD is the sum of negative differences between the mean daily temperature and the 65°F base, and CDDs are the sum of positive differences from the same base. Because it is a winter-peaking region, HDDs affect the Northwest power system demand more significantly than CDDs.

base-load generation—such as Columbia—is removed, then this base-load component of the cost-effective mix needs to be replaced.

Conditions in the Northwest regional power system mean that if Columbia were to close down, then replacement capacity would have to be in place by 2020.

An economic decision framework exists for closure and replacement assessments

Prudent power system management requires ongoing economic assessments to determine when it becomes economic to close an existing generating plant and replace it with the best alternative. Nothing lasts forever, and, typically, operating costs increase over the life of the power plant as equipment wears down and performance declines. Eventually, a power plant comes to the end of its economic life. At this point, the cost of continued operation exceeds the cost to retire the plant and replace it with something new.

Columbia is 29 years old. Nuclear power plants similar to Columbia were built with an expected economic operating life of 40 to 60 years. However, operating costs and market conditions vary from the initial expectations as well as from one nuclear power plant to another. Therefore, economic assessments of the costs and benefits of continued operation are common across the 100 nuclear reactors currently in operation in the United States, but the results of these assessments do not produce a common result.

Most nuclear plant owner's economic assessments support continued operation through the original licensed life of 40 years. Most economic assessments also support continued operation for another two decades. The US Nuclear Regulatory Commission has already approved 20-year license extensions for about two-thirds of the operating nuclear fleet, and another 18 nuclear reactors (21,000 MW) are in the queue for life extension approvals.

On the other hand, some nuclear plant owners have determined that continued operation is not economic. Some US nuclear power plants are being retired and replaced before the expirations of their operating licenses. Entergy Corporation's 605 MW Vermont Yankee plant in Vermont and Dominion's 566 MWKewaunee plant in Wisconsin received 20-year license extensions in 2011, yet updated economic assessments led to recent retirement decisions. In the past year, Duke Energy's 860 MW Crystal River 3 plant in Florida and Edison International's 2,250 MW San Onofre plant in California also announced plans to retire, specifically because of return-to-service issues associated with plant-unique maintenance/repair challenges.

A new natural gas–fired generating plant presents the most economic replacement alternative to Columbia

Since closing Columbia and not replacing it is not an option, the economic assessment must evaluate the cost of continued operation of Columbia compared to the alternative of shutting it down and replacing it with the most economic new base-load power supply available. For most North American power markets, the most economic new thermal base-load power supply currently available is natural gas–fired combined-cycle gas turbines (CCGTs).[8] Efficient scale for these technologies involves constructing units greater than 300 MW. Therefore, to provide the lowest-cost equivalent capacity and electricity production of Columbia, two replacement CCGTs at approximately 575 MW would have to be constructed to replace the capacity and energy Columbia provides to the Northwest regional power system.

8. CCGTs are able to provide both cycling and base-load power supply. For further information, see Appendix B: CCGT schematic.

One idea is to replace Columbia with wind or solar resources. Unfortunately, wind and solar resources cannot be considered realistic substitutes for Columbia because they are not equivalent power supply sources in meeting power customer demands. Wind and solar provide little capacity that can be counted on to meet peak electricity demand. In the Northwest regional power system, wind resources are discounted by 81.3% when calculating the dependable capacity to meet peak demand.[9] Solar is more coincident to peak demand than wind, yet most power systems discount solar capacity by 50% at time of peak demand. However, unlike most other power systems that face peak demands in the summer, the Northwest regional power system faces peak demands in the winter when solar insolation is significantly lower. On the electric energy production side, the typical capacity factor for wind turbines is around 30% to 40%, and the typical capacity factor for solar is 20% to 25%.[10] Since Columbia runs 90% or more of the time, replacement of its electric energy production by wind or solar resources would require construction of three or four times as much capacity.

These operational limitations of wind and solar technologies necessitate backup generating capacity to meet power customer needs when the wind does not blow or the sun does not shine. Most often, natural gas–fired technologies provide the lowest-cost source of power supply to integrate new wind and solar power resources. Wind or solar integrated by natural gas could provide a substitute for Columbia, but these integrated packages are more expensive than the natural gas–fired CCGTs alone. Therefore, CCGTs remain the most cost-effective replacement alternative to Columbia.

Cost assessment: A five-step process

The cost assessment has five steps. First, establish the time horizon of the analysis. Second, outline the relevant power supply cost categories. Third, as a starting point for each cost category, identify the initial year costs. Fourth, apply the cost projection methodology to each cost category. Fifth, aggregate the costs by year and express in an equivalent current dollar amount using a discount rate in order to calculate the present value of the future cost stream. This final step allows the proper comparison of the costs of the two alternatives given the time value of money.

Step 1: Establish the time horizon

- The time horizon relevant to this analysis is 2014 to 2043.
  - **Continued operation of Columbia.** The 30 years from 2014 to 2043 cover the time remaining for Columbia to operate before reaching the end of its current operating license.
  - **Close and replace.** Columbia could be closed quickly; but replacing it with natural gas–fired CCGTs would involve at least a four-year lead time to site, permit, and construct and would have to be completed by 2020 to maintain reliability. Consequently, replacement electric energy production would need to be purchased from the wholesale power market from 2014 to 2019, with 2020 as the online date for the CCGTs.

Step 2: Define the relevant power supply costs

- Internalized costs are recovered through power customers' bills. They include

9. NERC.

10. Energy Information Administration Annual Energy Outlook 2013. Capacity factor refers to a power generation facility's actual power generation as a proportion of its potential power generation output if it were operated at full output continuously.

- **Capital expenditures (Capex).** Land development, plant construction, and initial equipment are known as initial capex. Replacement and additional equipment required to operate the power plant that are recovered over multiple years are known as ongoing capex.

- **Fixed operation and maintenance (O&M).** Payroll and upkeep costs do not vary, regardless of how much electricity the plant generates.

- **Variable O&M.** Operating costs vary depending on how often the power plant operates.

- **Fuel costs.** Natural gas or uranium is required to drive a gas turbine and/or boil water to drive a steam turbine to spin a generator. For nuclear, this cost item includes spent fuel disposal fees paid to the US Department of Energy (DOE) in accordance with the Nuclear Waste Policy Act and costs for interim spent fuel storage.

- **Insurance.** Insurance covers plant property and public liability claim coverage in the case of an accident.

- **Taxes.** State-levied Public Utility District (PUD) privilege tax is paid in lieu of property taxes.

- **Wholesale power market purchases.** If Columbia were to be retired in 2014, electricity would need to be purchased from the wholesale market until replacement supply is completed in 2020.

• Sunk costs are costs incurred whether the choice is made to continue to operate Columbia or to replace it with new power supply. Since sunk costs are incurred in both cases, they can be excluded from the cost comparison without affecting the resulting cost difference. Sunk costs include

- **Decommissioning.** Safely removing a nuclear power plant from service and reducing residual radioactivity is considered decommissioning.

- **Outstanding debt service on Columbia.** The principal and interest payments to service the existing debt obligations of Columbia.

• Externality costs are costs incurred to society or the power system in aggregate. They include

- **CO_2 emissions.** The analysis includes the cost of emitting CO_2 into the atmosphere as a by-product of fossil-fuel combustion.

- **Risk management.** Transforming energy inputs into electricity is an inherently risky business. A greater reliance on natural gas as a fuel input to power production adds volatility to the cost of power production and thus adds a risk premium to the cost of debt capital.

Step 3: The initial year costs

Capital costs involve the return of capital through depreciation and the return on capital from interest payments or dividends. Therefore, the return on capital depends on the capital structure and the market rates for debt and equity.

- **Capital structure**. The owner of Columbia, Energy Northwest (EN), is a municipal corporation and joint operating agency of the state of Washington. EN has relied entirely on debt financing, and as a result, the initial capital structure is 100% debt.

- **Cost of debt capital**. EN reports its weighted average coupon interest rate for new bonds in its annual report. From 2007 to 2012, this rate has consistently been in the 4–5% range. Thus, the starting point for the cost of debt capital is 5%.

The Columbia continued operation cost assessment used IHS CERA industry-specific estimates and actual operating costs for 2012 and 2013 as the basis for the 2014 initial year costs.[11] The cost basis of the new CCGTs reflects IHS CERA new capacity cost and performance profiles. Table 1 provides a summary of initial year costs.

Step 4: Apply cost projection methodology

- Capital structure and cost of debt are held constant over the assessment time horizon.

TABLE 1

Initial year costs, 2014

Cost categories	Unit	CGS	Replacement power supply
Initial capex	$ per kW	sunk	$1,350
Ongoing capex	$ per kW-year	$45	-
Fixed O&M	$ per kW-year	$149	$13.3
Variable O&M	cents per kWh	$0.5	$0.4
Fuel costs	$ per MMBtu	$2.0	$5.3
Insurance	$ per kW-year	$3.1	$3.4
Taxes	$ per kW-year	$4.0	$4.2
Wholesale power market purchases	cents per kWh	-	$3.2

Notes: For CCGTs, fixed O&M includes ongoing capex requirements.
MWh = megawatt-hour; MMBtu = million British thermal units.
Source: IHS CERA

- Cost items were escalated using cost indexes, 2% inflation, and other cost component–specificestimates. [12] Appendix C explains a cost projection methodology by cost category.

- The wholesale power market purchases cost is based on projected market prices using the AURORA model, multiplied by the electric energy production that Columbia would have been expected to produce.[13]

Step 5: Aggregate cost categories by year and adjust for the time value of money

The total cost streams of the two alternatives—continued Columbia operation and closure with replacement—are a total of the individual cost categories in each year. These total cost streams have different patterns through the assessment time horizon. When a cost is incurred is important because there is a value in being able to defer paying a cost. Paying a cost later rather than sooner allows the payee to earn interest on money in hand until the time arrives for payment. Therefore, the discount rate used to account for the time value of money is the return available to the money invested rather than dispersed as a payment. This time value to money means that an accurate comparison of these cost streams requires taking the time value of money into account. To do this, a discount rate is applied to convert future costs into a present

11. "Fiscal Year 2012 Columbia Generating Station Annual Operating Budget" and "Fiscal Year 2013 Columbia Generating Station Annual Operating Budget": *http://www.energy-northwest.com/whoweare/finance/Pages/default.aspx*. These two years reflect the most recent historical cost trends for Columbia and include both a year with a planned refueling and maintenance outage (2013) and one without (2012). See Appendix C for additional cost methodology.

12. IHS CERA Capital Cost Analysis Forum (CCAF)-North American Power index.

13. An adjustment was made to the inputs of AURORA (commercially available power market computer simulation tool) to account for the Columbia retirement scenario in order to capture a representative wholesale power price.

value. The summation of the present value of all cost categories in each year allows a comparison of the cost streams on a present value basis.

The results: Continued operation of Columbia is cost-effective

Under expected conditions the sum, in nominal dollars, of electricity costs across the next 30 years for the continued operation of Columbia is $16 billion compared with $22 billion for the closure and replacement option. Expressing these costs streams in present value indicates that the continued operation of Columbia is $5.3 billion in current dollars compared with the closure and replacement case of $6.9 billion. As a result, the continued operation of Columbia provides an expected savings of $1.6 billion in current dollars across the 2014 to 2043 time frame.[14]

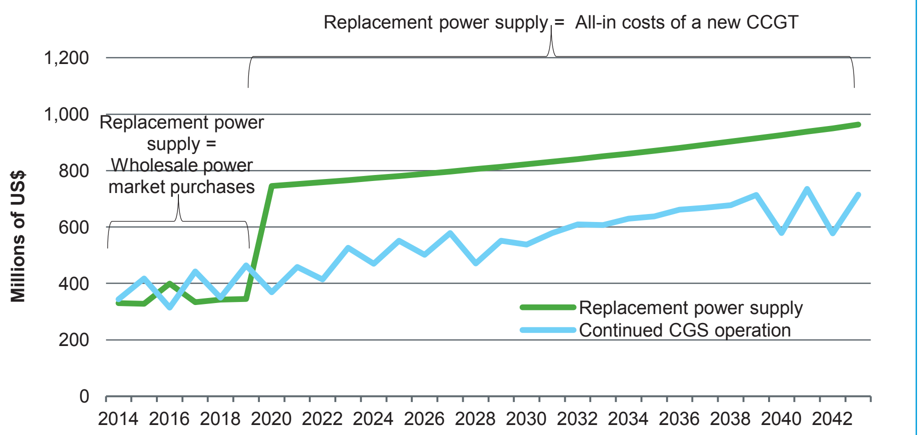
Figure 2 displays the nominal cost streams of continued operation of Columbia versus replacement power supply under expected conditions.

Cost burden

In the Northwest regional power system, nuclear and hydroelectric generation produced in the FCRPS are classified as "Tier 1" under tiered pricing established by BPA. The cost of these resources establishes the price of Tier 1 power. As a result, the closure of Columbia would reduce the amount of electric energy available at Tier 1 prices. To make up for the change in output, wholesale power buyers would need to increase their Tier 2 purchases. The cost of this Tier 2 power would include the higher costs of the replacement of Columbia with CCGT technology. The implication is that the burden of the higher costs in the closure and replacement case would fall onto wholesale power buyers proportional to their mix of Tier 1 and Tier 2 power purchases.

FIGURE 2

Nominal costs to produce 1,150 MW and 9,000 GWh, 2014-43



Note: GWh = Gigawatt-hours. The variation in costs for CGS reflect a combination of changes in O&M every other year for refueling outages and timing of payments that were established in the nuclear fuel purchase contract signed in May 2012 between EN, Tennessee Valley Authority (TVA), the US Enrichment Corporation (USEC), and the Department of Entergy (DOE).

Source: IHS CERA

"Missing money" problem distorts market-clearing power price

Since capacity is not needed until 2020, the closure and replacement power option benefits by being able to delay the new natural gas–fired power plant costs until 2020 and in the meantime, purchasing electric energy at a lower cost in the wholesale power market. Naturally, one wonders why purchases from the wholesale market do not continue as long as the price is below the cost of the new natural gas–fired power plant. This logic makes sense in a textbook marketplace, where prices support new supply development

14. Savings are expressed as a present value and the level depends on the discount rate employed. The present value of these expected savings is $2.2 billion, or $3.4 billion if lower discount rates are used as demonstrated in the sensitivity analysis.

when the market is in balance. In such cases, pricing below the cost of new supply provides an adjustment mechanism that restores the demand and supply balance when surplus supply conditions exist.

Waiting until the cost of wholesale power price purchases increases to an equivalent cost for power from a new natural gas–fired power plant will cause a shortage in the Northwest regional power system. Market-clearing electric energy prices in wholesale markets do not produce a textbook result and instead exhibit a chronic "missing money" problem.[15] As a result, the electric energy price does not move up to the long-run marginal cost of power supply when the market is in balance and instead, only moves to and above the long run marginal cost under shortage conditions. When the power demand and supply are in balance, the market-clearing price does its job by providing a price signal that incentivizes the most efficient utilization of available generating resources to meet aggregate customer needs.

However, the missing money problem means that a power system cannot rely on an energy market alone to provide a price signal to incentivize building new supply in the right amounts and at the right times. Instead, power systems that rely on a market price signal for new investments typically incorporate another electric commodity—a capacity commodity to close the missing money gap. As a result, most competitive power markets augment energy market cash flows with a capacity payment. Without this additional capacity payment, an inevitable capacity shortage arises and produces price spikes. In 2000–01, California learned this power market design lesson the hard way.[16] The implication is clear—the option to close existing generating resources such as Columbia and replace them in the long run with wholesale energy market purchases—including energy markets that incorporate a firm energy charge—will inevitably create a capacity shortage, because we do not expect this price to reach a level that supports new power plant investment when supply and demand comes into balance. As a result, continuing to rely on the wholesale marketplace for replacement power beyond 2020 is not consistent with the goal of reliably maintaining power demand and supply balance in the Northwest regional power system.

GHG emissions differ among options

Although there is no consensus on the societal costs of rising CO_2 emissions, a future cost on CO_2 emissions represents an important consideration for power suppliers in the Northwest. The carbon intensity of the CCGT is approximately 0.9 pounds of CO_2 per kWh. From an emissions management perspective, nuclear power is one of the few available large-scale power generation technologies with zero carbon intensity of power production. Therefore, the decision to prematurely close Columbia and replace it with CCGTs results in more expensive power along with higher CO_2 emissions. IHS CERA estimates that continued operation of Columbia would prevent about 3.6 million metric tons of CO_2 from being emitted on an annual basis compared with substitution of natural gas–fired generation in the 2020 to 2043 time frame. The CO_2 emission abatement from 2014 through 2019 would be even greater because a combination of hydroelectric facilities, CCGTs, natural gas–fired combustion turbines (CTs), and coal-fired power plants would generate the electricity required for the wholesale power market purchases while replacement power is being built. IHS CERA estimates the carbon intensity of this "fuel-on-the-margin" mix to be 1.2 pounds of CO_2 per kWh.

Another way to measure costs: Levelized cost of energy

Power supply costs are often measured using a metric known as the levelized cost of energy (LCOE). This metric yields a familiar cents-per-kWh metric that corresponds to charges people see on their power bills.

15. Peter Cramton and Steven Stoft, The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem, A White Paper for the Electricity Oversight Board, April 25, 2006.

16. Lawrence J. Makovich, "California Electricity Crisis and Implications for the West," prepared testimony to the US Senate Committee on Energy and Natural Resources, Washington, DC, 31 January 2001.

The traditional LCOE involves estimates of annual costs of power generation in each year of a power plant's expected operating life. Since these costs are different year to year, analysts calculate a constant annual amount that has the same discounted value as the uneven cost stream—a technique known as "levelizing" the costs. As a final step, these levelized annual costs are divided by expected annual kilowatt-hour production.[17] Under expected conditions, the LCOE of continued operation of Columbia is 5.2 cents per kWh, and the LCOE of replacement power supply is 6.8 cents per kWh.

Although the decision to continue to operate is made at the plant level, it is worth noting that Columbia's current operating costs per kilowatt-hour are typical of the nuclear industry. For further information, see Appendix D: Relative operating cost efficiency: Columbia versus other single-unit plants in the United States.

Sensitivities: How cost inputs affect the calculations

In determining the range of cost differences between the continued Columbia operation case and the closure and replacement case, four sensitivities were analyzed: natural gas prices, initial capex, CO_2 emission costs, and the discount rate.

- **Natural gas prices**. Natural gas prices are likely to have the most significant impact on the variation in all-in costs of new CCGTs. Shale gas production emerged as a meaningful part of US natural gas supply beginning in 2003. Since then, natural gas prices have remained hard to predict and have moved in multiyear cycles. The projections used in the cost assessment reflect only the expected average price and do not reflect the uncertainty regarding future natural gas prices or the timing of future price cycles. Since 2000, for example, monthly average delivered natural gas prices to the Northwest regional power system have averaged \$5.30 per million British thermal units (MMBtu)—but have been as high as \$11 per MMBtu and as low as \$2.40 per MMBtu.[18] These observed natural gas prices serve as foundation for a prudent range of natural gas price uncertainty to evaluate for the future.

- **Initial capex**. Since 2000, CCGT initial capex have been as high as \$1,454 per kilowatt (kW) and as low as \$746 per kW.[19] These observed initial capex provide a reasonable range of capex uncertainty.

- **CO_2 emission costs**. At least four pricing benchmarks in the United States provide a reasonable range of CO_2 emission costs uncertainty.

  – **Regional Greenhouse Gas Initiative (RGGI).** In 2013, the clearing price for CO_2 allowances in RGGI has been between \$2 and \$3 per short ton.

  – **California cap-and-trade.** In 2013, the price of an allowance in California has been between \$11 and \$14 per metric ton.

  – **Social cost of carbon.** Used by the Environmental Protection Agency (EPA) to determine climate benefit valuations, this cost ranges from \$12 to \$62 per metric ton for 2015.

17. The traditional LCOE is only useful in comparing technologies with similar operating characteristics deployed in similar roles, such as a nuclear and CCGT plants. However, extending the traditional LCOE to intermittent renewable power supply would not be an appropriate metric because the traditional LCOE measures costs without regard to the cost-effectiveness of dispatchable versus nondispatchable power resources in balancing overall power supply with power demand.

18. Ventyx Velocity Suite—A commercially available power market intelligence data service.

19. Real 2013 dollars. See the IHS CERA CCAF—North American Power Index.

- **Implicit cost of CO_2 reduction.** Thirty-seven states have policies to address climate change through Renewable Portfolio Standards (RPS) that mandate a certain percentage of electric generation from renewable energy resources.[20] Such mandates are in place because the lowest-cost mix of generating resources would include little or no wind and solar power generating capacity. Measuring the additional cost of these renewable power sources and dividing by the CO_2 reductions they provide, allows calculation of the implicit cost of GHG reductions associated with these renewable mandates. Wind power currently has an implicit cost of CO_2 reduction of approximately $100 per metric ton, and solar photovoltaics has an implicit cost of CO_2 reduction of over $200 per metric ton.[21]

- **Discount rate**. There is no consensus in finance on the exact discount rate to use when converting a nominal cost stream to present value costs. The discount rate used in this assessment is 8.1% because EN has traditionally had access to the tax-exempt bond market. This rate represents the equivalent taxable yield of a tax-exempt bond rate, or cost of debt capital, of 5%. EPA's social cost of carbon analysis provides two other reasonable discount rates, 2.5% and 5%.

The four sensitivities on the cost profiles revealed that continued operation of Columbia produced meaningful savings compared to the alternative of closure and replacement in eight out of nine sensitivity cases, and it was roughly equivalent to one case that involves a sustained natural gas price of $2.40 per MMBtu for the next 30 years. This natural gas price reflects the lowest monthly delivered cost of natural gas to the Pacific Northwest experienced at any time over the past dozen years. For context, the monthly delivered price of natural gas (on the following page) to the Pacific Northwest was below $3 per MMBtu only 4% of the time since 2000.[22]

Table 2 provides a summary of the sensitivity cases.

Fuel diversity affects power cost risk management

The Northwest regional power system benefits from a diverse fuel mix. In 2012, 52% of generation was hydroelectric, 25% coal-fired, 11% natural gas–fired, 8% renewables, and 3% nuclear power.[23] This fuel diversity—which is the most cost-effective tool the power system uses to manage the inherent uncertainty and risk regarding future fuel costs—will become less diverse in the future because of the 1,400 MW of coal-fired generation that the region has already committed to retire through 2020.

Delivered natural gas prices to the power sector in the Pacific Northwest were the most cyclical of all the fuel inputs to power generation (see Figure 3). In addition, since natural gas is also more expensive on an energy-equivalent basis as compared to other power generation fuels, it accounts for a higher percentage of generation fuel costs than its electric output share. In 2012, power suppliers in the Northwest regional power system spent $522 million to purchase natural gas for power generation—a financial outlay that represented 53% of overall fuel costs and 21% of overall power production costs.[24]

Therefore, increasing reliance on natural gas due to the closure of Columbia and the construction of a natural gas–fired replacement power plant will increase the risk around future power fuel costs of the Northwest regional power system.

20. The RPS in the state of Washington requires that by 2020, 15% of electricity must be generated by renewables.
21. See the IHS CERA Private Report *Recalibrating Power Supply Cost Assessments: Accounting for Integration.*
22. Ventyx Velocity Suite.
23. Ibid.
24. Ibid.

TABLE 2

Summary of cost sensitivities

	Present value of 30-year total cost (billions of US$)	Savings from continued operation of CGS (billions of present value US$)	LCOE (cents per kWh)
Expected conditions			
Continued operation of CGS	$5.3	-	5.2
Replacement power supply ($5.30 per MMBtu, $1,350 per kW initial capex; $14 per metric ton CO_2 emissions, 8.1% discount rate)	$6.9	$1.6	6.8
Natural gas sensitivities			
Replacement power supply (high natural gas [$11 per MMBtu])	$10.2	$5.0	10.2
Replacement power supply (low natural gas [$2.40 per MMBtu])	$5.2	-$0.1	5.2
Initial capex sensitivities			
Replacement power supply (high initial capex [$1,454 per kW])	$7.0	$1.7	6.9
Replacement power supply (low initial capex [$746 per kW])	$6.4	$1.2	6.4
CO_2 emissions cost sensitivities			
Replacement power supply (high CO_2 emissions cost [$100 per metric ton])	$9.7	$4.5	9.7
Replacement power supply (mid-range CO_2 emissions cost [$62 per metric ton])	$8.5	$3.2	8.4
Replacement power supply (low CO_2 emissions cost [$3 per metric ton])	$6.6	$1.3	6.6
Discount rate sensitivities			
Continued operation of CGS (midrange discount rate [5%])	$7.8	-	5.6
Replacement power supply (midrange discount rate [5%])	$10.1	$2.2	7.3
Continued operation of CGS (low discount rate [2.5%])	$11.4	-	6.1
Replacement power supply (low discount rate [2.5%])	$14.9	$3.4	7.9

Note: The discount rate sensitivities were run for both continued operation of CGS and the replacement power supply.
Source: IHS CERA

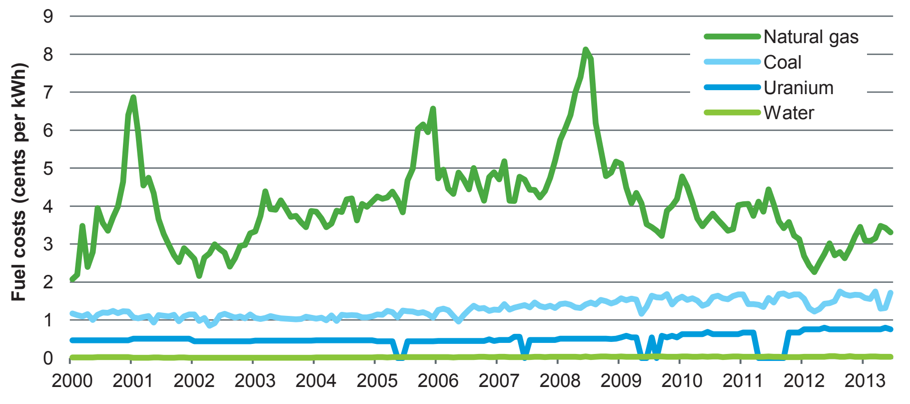
An effective way to illustrate the value of generation diversity for the Northwest is to provide a counterfactual. For example, if the regional power system had been entirely reliant on natural gas–fired generation since 2000, then the average fuel cost for power would have been five times higher on average, and month-to-month fuel cost volatility would have been three times higher (see Table 3).

A diverse generating portfolio is the foundation of a cost-effective risk management strategy to address the unpredictability, volatility, and cycles of fuel input prices to the power production process. And because today's diverse portfolio was inherited from decisions made years ago, fuel diversity is often taken for granted. As a result, the appeal of today's low natural gas prices raises the risk that decisions made in the short term will surrender the advantages offered by a diverse fuel mix over the long run.

As new sources of demand for natural gas come online and drilling rates continue to fluctuate, it is likely that price variations similar to those of the past decade will continue. The significant range in natural gas price sensitivities reflects this and is important to consider when comparing CCGT technology as replacement for Columbia. Because of the length of the nuclear fuel cycle, nuclear power is shielded from some of the volatility in the uranium market; additionally, fuel is a smaller component of costs for nuclear power compared with natural gas–fired generation. Moreover, EN recently signed a contract to accept depleted uranium that would be converted into low-cost nuclear fuel from 2014 to 2028.[25] This agreement should enable Columbia to continue to secure stable and predictable nuclear fuel costs in the years ahead.

FIGURE 3

Delivered monthly fuel costs to the Northwest regional power system



Source: IHS CERA

Data Source: Ventyx Velocity Suite

The risk premium on power cost uncertainty

The natural gas price variation that adds volatility to the cost of power production affects power customers because of four critical linkages:

TABLE 3

2000–13 year-to-date fuel costs (monthly; cents per kWh)

	Natural gas-fired fuel costs	All power sector fuel costs
Average	3.98	0.77
Maximum	7.92	1.61
Minimum	1.98	0.15
Standard deviation	1.12	0.35

Source: Ventyx Velocity Suite

- **Fuel costs and net income**. Increases in fuel cost volatility increase working capital costs and create net income volatility for power producers.
- **Net income and credit ratings**. Lower net income and greater volatility leads to lower credit ratings.[26]
- **Credit ratings and the cost of debt capital**. A lower credit rating results in a higher cost of debt capital.
- **Cost of debt capital and cost of power production**. A higher cost of debt increases power production costs and ultimately means higher power bills for consumers.

Analysis of power suppliers that together account for about 70% of the US power business provides the data required to estimate the risk premium associated with power cost uncertainty. Holding all else constant, IHS CERA estimates that if the impact on the volatility of net income were proportional to the 3% generation share Columbia supplies to the Northwest regional power system, then the cost of debt capital of the replacement generation capacity would rise by 0.4 percentage points. Over the life of the replacement power supply, this higher cost of debt capital as a result of the added volatility to the entire portfolio would increase the cost (i.e., present value) of the replacement power supply by an additional $33 million.

25. EN Press Release, 15 May 2012.

26. See the IHS CERA Decision Brief *Does Earnings Quality Matter in the Power Business?*

Conclusion: Columbia cost-effectively meets future needs

Closing Columbia and not replacing its capacity and energy by 2020 is not an option in the Northwest regional power system. The going forward costs of Columbia's continued operation represent the most economic source of base-load power supply. The alternative of closing Columbia and replacing it with new power supply results in more expensive power production, and the replacement of a zero–carbon-emitting resource with carbon-emitting resources.

Finally, as the Pacific Northwest's only operating nuclear power plant, the premature closing of Columbia would sacrifice a share of the region's diverse generating portfolio—a cost-effective risk management strategy to address the fuel input price cycles associated with the power production process. Internalizing the costs of the risk premium to the entire generation portfolio reinforces the conclusion that continued operation of Columbia is more cost-effective than the next best alternative under a wide range of future conditions.

Appendixes

Appendix A: Engineering/economic principles of a cost-effective generation technology mix

The makeup of power supply is customer driven. Consumers want different amounts of electricity services at various points in time. The aggregate demand for electric services defines the objective that the regional power system needs to satisfy. Engineering/economic principles determine the most cost-effective mix of demand and supply resources and then, within the supply-side, the most cost-effective mix of available generating technologies.

Increased demand for electric services can be met by boosting power generation, improving electricity efficiency, or doing a combination of both. The lowest-cost way to satisfy increased demand for electric services is to do both by balancing the cost of expanding each option. A variety of options exists to expand either demand-side or supply-side resources. In each case, however, expanding resources involves costs. Keeping total costs as low as possible requires expanding the lowest-cost options first. When demand-side and supply-side options have similar expansion costs, then keeping total costs as low as possible involves expanding each depending upon which provides the next most economic option. This results in an ongoing balancing of the next most cost-effective option available on either the demand or the supply side.

To cost-effectively expand electric supply, the same engineering economic principles used to establish the cost-effective mix of demand and supply-side resources are applied. Consequently, the lowest-cost power supply source to meet the variable aggregate pattern of consumer electricity demand involves a mix of generating technologies.

The lowest-cost generating technologies that can meet the highest demand are peaking technologies such as CTs. These technologies can start up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. They have relatively low upfront capex and thus present a trade-off with more efficient but higher-capital-cost generating technology alternatives. Since these resources are used so infrequently, the additional cost of more efficient power generation is not justified by the fuel savings possible with their expected low utilization rates.

Intermediate generating resources are expected to run more hours to meet the typical levels of power demand. Consequently, the trade-off between additional capex and fuel efficiency can make sense because utilization rates can be high enough to generate the fuel savings that cover the additional capex over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power and include fossil-fueled combined–cycle and steam turbine units.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow trading some flexibility in varying output for the lower operating costs associated with high utilization rates. They include nuclear power plants and reservoir hydroelectric power supply resources.

Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speed, and solar insolation levels. Changes in electric output from these resources reflect changes in these external conditions rather than changes initiated to follow the ups and downs in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since these production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Wind and solar generating technologies make up little, if any, of the least-cost generation mix for power production—even when typical externality costs are included. That is why mandates are needed to build these technologies.

The Northwest regional power system

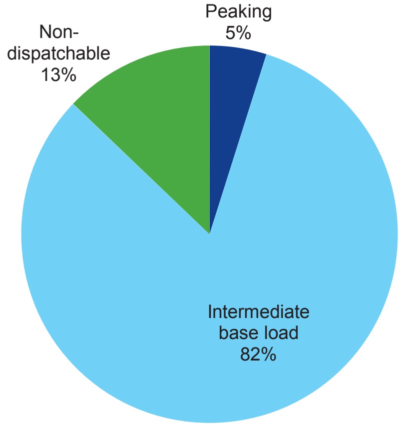
The Northwest regional power system strikes a balance between expanding power efficiency and expanding power supply. Most of the states in the power system have long-standing rate-payer funded electric efficiency programs that together spend roughly $600 million per year.[27] For example in 2010, BPA estimates that the additional $112 million of energy efficiency spending provided savings of 90 MW. This works out to a little more than $1,200 per kW, roughly equivalent to the cost of new power supply.

Continued balancing between expanding energy efficiency measures and expanding supply indicates that Pacific Northwest power demand will rise along with continued increases in electric efficiency. As a result, the longstanding trend in the Pacific Northwest for electricity use to increase slower that the economy is expected to continue. This indicates an expected continued expansion in electricity efficiency as overall electricity use goes up.

The Northwest regional power system is like other generating systems because it deploys a mix of peaking, intermediate, and base-load generating technologies to effectively provide electric production (see Figure 4). Engineering and economic principles drive the regional power system to expand supply with a mix of peaking, intermediate, and base-load resources in order to maintain an efficient generation mix

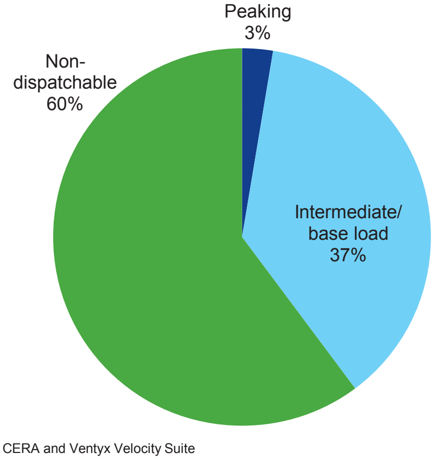
FIGURE 4

Northwest regional power system capacity mix by generating technologies: Operating, 72 GW



Source: IHS CERA and Ventyx Velocity Suite © 2013 IHS

Northwest regional power system capacity mix by generating technologies: Capacity additions under development (2014–20), 13 GW

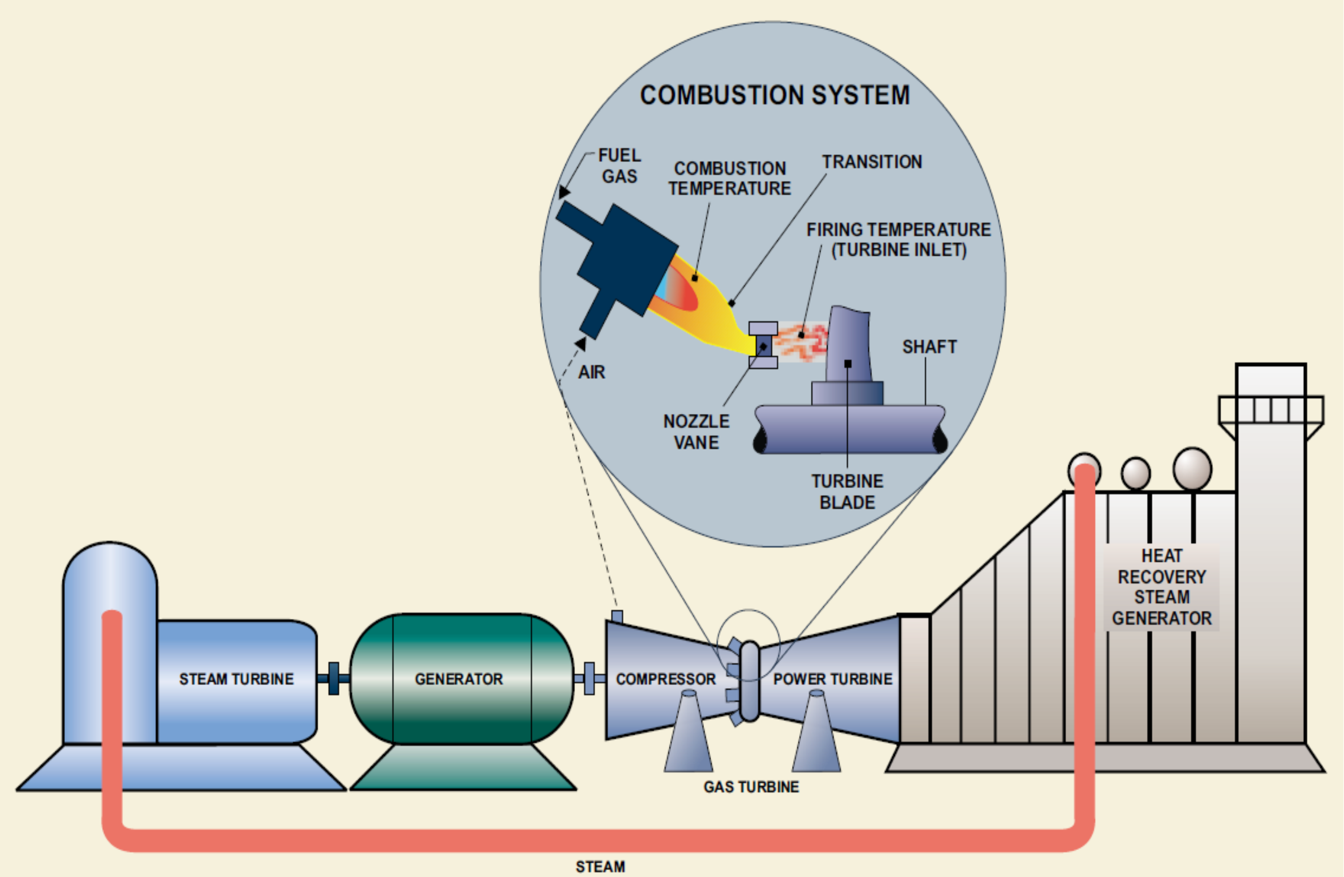


Source: IHS CERA and Ventyx Velocity Suite © 2013 IHS

27. American Council for an Energy-Efficient Economy.

Appendix B: CCGT schematic

Natural gas-fired combined-cycle gas turbine



Source: US Department of Energy

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Appendix C: Cost projection methodology

- **Initial capex**. These include owner's costs—development/permitting, land acquisition, construction general and administration, financing costs, and interest during construction.

- **Ongoing capex**. A fleet average of capex—as opposed to a Columbia-specific estimate—is used to account for variation in capital additions during the life of the plant. This average is derived from Federal Energy Regulatory Commission (FERC) Form 1 cost data covering 1995–2012.[28] Ongoing capex are escalated using a nuclear-specific IHS CERA CCAF-North American Power index, and an age-based regression is applied after the index horizon, post-2022. We assume that capex is financed with a 100% debt capital structure with cost of debt equal to 5%, and the costs are then levelized for the duration of the analysis period (2014–43). Post-Fukushima regulation compliance costs for Columbia are also added to the ongoing capex calculation. These compliance costs were estimated to be about $58 million in 2012 dollars for Columbia.[29] For CCGTs, fixed O&M includes a modest amount of ongoing capital expenditures, including ongoing refurbishment activities.

- **Fixed O&M**. The publically available annual operating budget reports for Columbia combine fixed and variable O&M into an overall O&M category. To separate these items, an 80/20 fixed/variable split of total O&M was used for years without planned refueling and maintenance outages. For years with such outages, fixed O&M included both 80% of nonoutage-related O&M and all of "incremental outage"–related expenses. Changes in fixed O&M, variable O&M, fuel costs, and capacity factor follow the timing of refueling and maintenance outages, with fixed O&M increasing and variable O&M, fuel costs, and capacity factors declining in years with refueling outages. For Columbia, capacity factors fluctuate from 85% during planned outage years to 93% in other years. Fixed O&M was escalated using a nuclear industry–specific fixed O&M index from the IHS CERA CCAF for 2014–22. The CCAF projections are limited to 2022, so an age-based regression and inflation were used to project values into 2023–43. Estimates for ongoing fixed O&M are further increased by 15% each year during 2023–27 to account for a hypothetical life extension maintenance program. As license-extended nuclear plants reach 40 years of operation, life-extension maintenance programs are often undertaken for about five years to ensure reliable operation for another 20 years or more. During this period, maintenance expense is higher than normal. The cost analysis incorporates Columbia beginning such a program in 2023, when the plant is 39 years old. After the maintenance program is completed in 2027, fixed O&M costs adjust down to a longer-run average. For the CCGTs, fixed O&M is escalated using 2% annual inflation.

- **Variable O&M**. Variable O&M is escalated with inflation and adjusted by plant-level capacity factor projections from IHS CERA.

- **Fuel costs**. For Columbia, fuel costs include both fuel for generation and spent fuel disposal fees. Costs related to fuel for generation were provided by EN and are based on payment terms established in the nuclear fuel purchase contract signed in May 2012 between EN, TVA, USEC, and DOE. Spent fuel disposal fees are $1 per megawatt-hour of net generation—the amount utilities with nuclear power generation must pay to DOE in accordance with the Nuclear Waste Policy Act. The natural gas price is based on the historical delivered price of natural gas in the Northwest regional power system. Since 2000, for example, those monthly delivered natural gas prices have averaged $5.30 per MMBtu—but have been as high as $11 per MMBtu and as low as $2.40 per MMBtu.[30]

28. EN is not required to nor does it report Columbia cost data into FERC Form 1. Therefore, Columbia is excluded from the sample used to estimate annual capex from the fleet average.

29. Estimates for capex required to comply with post-Fukushima–related regulation were benchmarked against an industrywide survey conducted by Platts. See Freebairn, William, et al., "Post-Fukushima modifications could cost US nuclear operators $3.6 billion." Platts Nucleonics Week. 6 June 2013: 1, 8–11.

30. Ventyx Velocity Suite.

- **Insurance**. For Columbia, annual insurance costs are $3.5 million in current dollars (figures were provided by EN). This amount includes insurance for public liability claim coverage in the case of a nuclear accident (in accordance with the Price-Anderson Act) and insurance for plant property (paid to Nuclear Electric Insurance Limited). For CCGTs, insurance is calculated as a 0.25% of initial capital deployed.

- **Generating taxes**. The current state-levied PUD privilege tax paid in lieu of property tax is 1.605% of operating revenues for Columbia and the replacement CCGTs. These costs were estimated using capacity factor and Northwest regional power system wholesale price projections.

- **Wholesale power market purchases**. The wholesale power market purchases cost is a calculation of the market prices projected using the AURORA model multiplied by the electricity production that Columbia would have been expected to produce. An adjustment was made in AURORA to account for Columbia retirement in order to capture a representative power price.

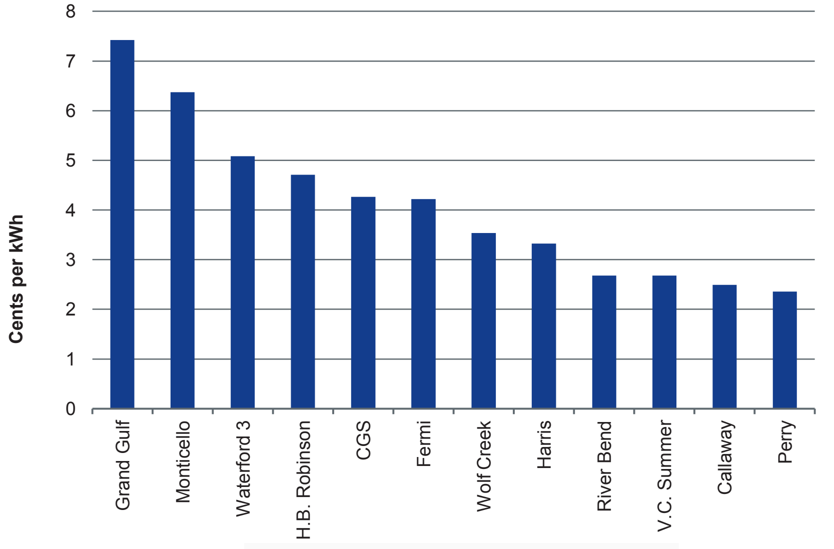
Appendix D: Relative operating cost efficiency: Columbia versus other single-unit plants in the United States

The relative operating cost efficiency of Columbia is best measured against other single-unit nuclear plants. Single-unit plants have less economies of scale than multiunit facilities, as the latter have the ability to share fixed O&M—a nuclear plant's largest cost component—across the complex's multiple reactors. Because of this inherent advantage, multiunit nuclear plants were excluded from the comparison.

When measured against other single-unit US nuclear plants, Columbia is within the typical range of operating costs (see Figure 5). This comparison only uses cost data from single-unit nuclear plants that reported such information into the publically available US FERC Form 1 during 2009–12. FERC Form 1 provides comprehensive operating cost information for plants within FERC jurisdiction. However, since Columbia does not report to FERC Form 1, its cost data was sourced from the "Annual Operating Budget" reports that EN publically releases.[31] The four years of cost data allow for various capex and maintenance programs across plants, refueling and nonrefueling years, and recent cost trends.

FIGURE 5

Average operating costs of CGS compared with similar existing US nuclear plants, 2009–2012*



*Total operating costs only include fixed and variable O&M, fuel, and capex. Insurance and taxes were excluded.
**Excluding CGS, averages only include single-unit US nuclear plants that reported into US FERC Form 1 during 2009–12. CGS cost numbers were sourced from Energy Northwest's "Columbia Generating Station Annual Operating Budget" reports.

Source: IHS CERA, Energy Northwest's CGS "Annual Operating Budget" reports, FERC Form 1, Ventyx Velocity Suite

Referenced IHS CERA index and papers are available through IHS CERA or EN's Office of the Asset Manager/Controller. They include

- IHS CERA Capital Cost Analysis Forum—North American Power index.
- IHS CERA Private Report *Recalibrating Power Supply Cost Assessments: Accounting for Integration*
- IHS CERA Decision Brief *Does Earnings Quality Matter in the Power Business?*

31. *http://www.energy-northwest.com/whoweare/finance/Pages/default.aspx.*

