Wholesale Electricity Price Forecast

This appendix describes the wholesale electricity price forecast of the Fifth Northwest Power Plan. This forecast is an estimate of the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This price represents the marginal cost of electricity and is used by the Council in assessing the cost-effectiveness of conservation and new generating resource alternatives. The price forecast is also used to estimate the cost implications of policies affecting power system composition or operation. A forecast of the future Western Electricity Coordinating Council (WECC) generating resource mix is also produced, as a precursor to the electricity price forecast. This resource mix is used to forecast the fuel consumption and carbon dioxide (CO_2) production of the future power system.

The next section describes the base case forecast results and summarizes the underlying assumptions. The subsequent section describes the modeling approach. The final section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions. Costs and prices appearing in this appendix are in year 2000 dollars unless otherwise noted.

BASE CASE FORECAST

The base case wholesale electricity price forecast uses the Council's medium electricity sales forecast, medium fuel price forecast, average hydropower conditions, the new resource cost and performance characteristics developed for this plan, and the mean annual values of future CO_2 mitigation cost, renewable energy production tax credits and renewable energy credits of the portfolio analysis of this plan. These are summarized in Table C-1.

Table C-1: Summary of assumptions underlying the base case forecast

Hydropower	Average hydropower conditions Linear reduction of available Northwest hydropower by 450 MW 2005 through 2024
Fuel prices	5th Plan forecast, Medium case
Loads	5th Plan electricity sales forecast, Medium case, adjusted for 150 aMW/yr conservation, 200 aMW Direct Service Industry load and transmission and distribution losses
Northwest resources	Resources in service as of Q4 2004 Resources under construction as of Q4 2004 Retirements scheduled as of Q4 2004 75 percent of Oregon and Montana system benefit charge target acquisitions 50 percent of demand response potential by 2025
Other WECC resources	Resources in service as of Q1 2003 Resources under construction as of Q1 2003 Retirements scheduled as of Q1 2003 75 percent of state renewable portfolio standard and & system benefit charge target acquisitions 50 percent of demand response potential by 2025.

New resource options	610 MW natural gas-fired combined-cycle gas turbines 100 MW wind power plants - prime resource areas 100 MW wind power plants - secondary resource areas 400 MW coal-fired steam-electric plants 425 MW coal gasification combined-cycle plants 2x47 MW natural gas-fired simple-cycle gas turbines 100 MW central-station solar photovoltaic plants Montana First Megawatts 240 MW natural gas-fired combined-cycle plant Mint Farm 286 MW natural gas-fired combined-cycle plant Grays Harbor 640 MW natural gas-fired combined-cycle plant
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades as of Q1 2003
Carbon dioxide penalty	Washington & Oregon: \$0.87/ton CO_2 for 17% of production until exceeded by the mean annual values of the portfolio analysis. Other load-resource zones: The mean annual values of the portfolio analysis
Renewable resource incentives	Federal production tax credit at mean annual values of the portfolio analysis Green tag revenue at mean annual values of the portfolio analysis

The forecast Mid-Columbia trading hub price, levelized for the period 2005 through 2025 is \$36.20 per megawatt-hour. In Figure C-1, the current forecast is compared to the base case ("Current Trends") forecast of the Draft 5th Power Plan (levelized value of \$36.10 per megawatt-hour).

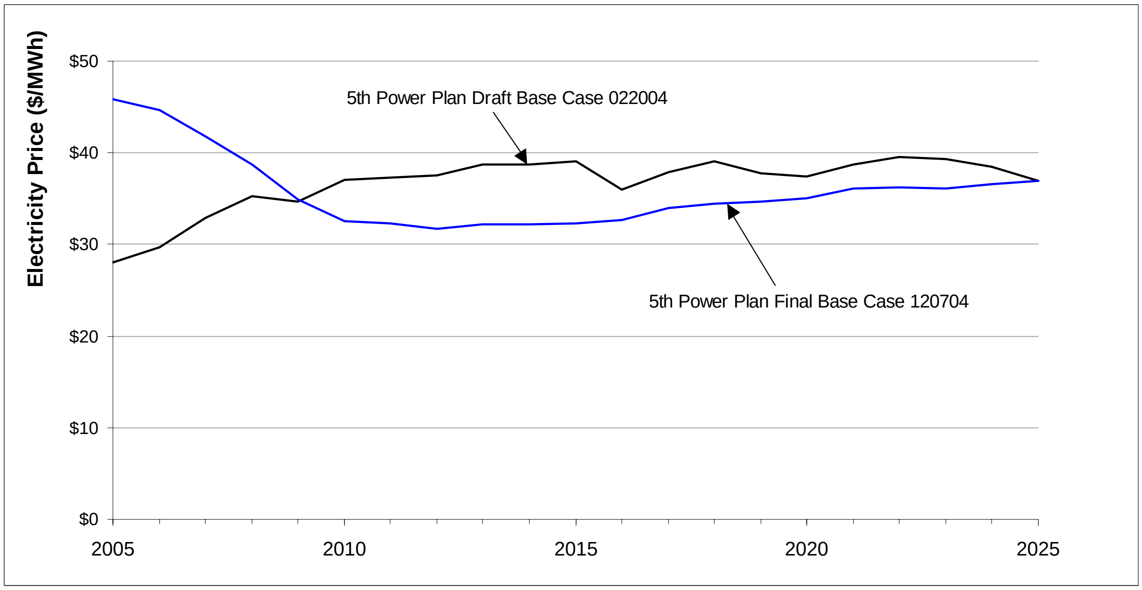

Figure C-1: Draft and final base case forecasts of average annual wholesale electricity prices at the Mid-Columbia trading hub

The final forecast prices decline from 2003 highs as gas prices decline, leveling off about 2012 as growing loads exhaust the current generating capacity and new capacity development ensues. Prices slowly increase through the remainder of the planning period under the influence of slowly increasing natural gas prices, new resource additions, declining renewable energy incentives and increasing CO_2 penalties. Not included in the forecast are likely episodic price excursions resulting from gas price volatility or poor hydro conditions.

The annual average prices of Figure C-1 conceal important seasonal price variation. Seasonal variation is shown in the plot of monthly average Mid-Columbia prices in Figure C-2. Also plotted in Figure C-2 are monthly average Northwest loads and monthly average Southern California loads. The winter-peaking character of Northwest loads (driven by lighting and heating loads) and the more pronounced summer-peaking character of the Southern California loads (driven by air conditioning and irrigation loads) are evident. A strong winter Mid-Columbia price peak, driven by winter peaking Northwest loads is present throughout the forecast. A secondary summer price peak is also present because spot market prices in the Northwest will follow Southwest prices as long as capacity to transmit electricity south is available on the interties. The summer Mid-Columbia price peak begins to increase in magnitude midway through the planning period as California loads grow relative to Northwest loads. The summer price peak increases the value of summer-peaking efficiency resources such as irrigation efficiency improvements.

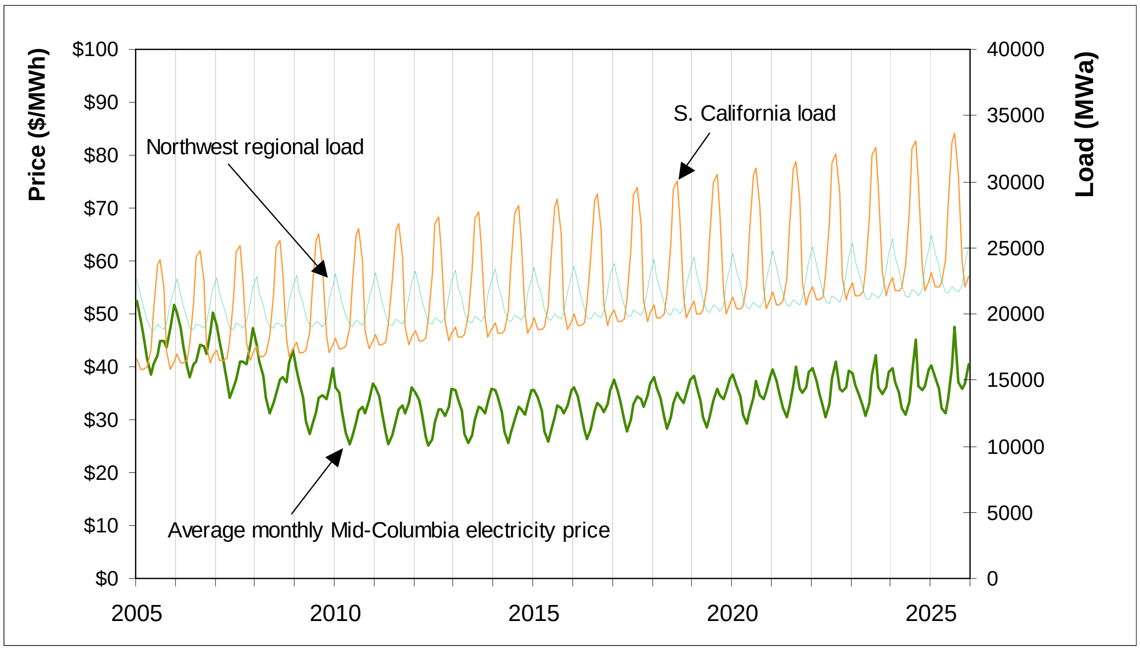

Figure C-2: Monthly wholesale Mid-Columbia prices compared to Northwest and Southwest load shapes

Daily variation in prices is significant as well, with implications for the cost-effectiveness of certain conservation measures. Typical daily price variation is shown in Figure C-3 - a snapshot of the hourly Mid Columbia forecast for a summer week.

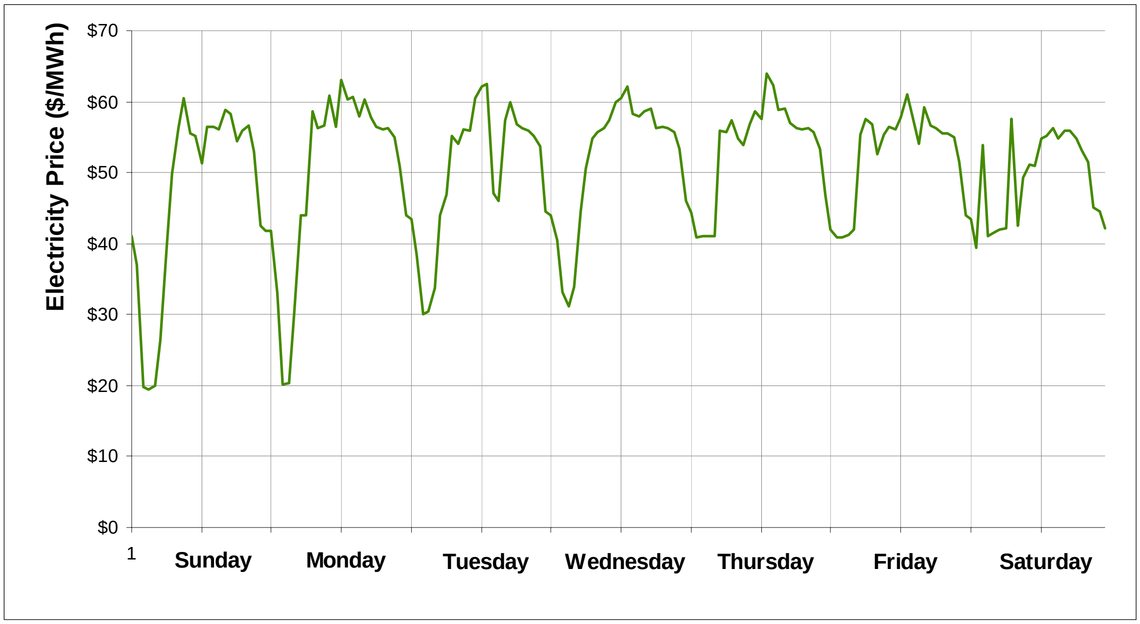

Figure C-3: Illustrative hourly prices (July 31- August 7, 2005)

The forecast annual average prices for the Mid-Columbia trading hub and for other Northwest load-resource zones is provided in Table C-1. Monthly and hourly price series are available from the Council on request.

Table C-1: Forecast annual average wholesale electricity prices for Northwest load-resource zones

Year	West of Cascades	Mid-Columbia (Eastside)	S. Idaho	E. Montana
2005	45.99	45.84	45.16	44.86
2006	44.84	44.68	44.02	43.67
2007	41.99	41.76	41.06	40.79
2008	38.93	38.71	37.82	37.72
2009	35.11	34.94	33.87	33.84
2010	32.65	32.52	31.50	31.39
2011	32.42	32.31	31.41	31.20
2012	31.85	31.75	30.91	30.64
2013	32.27	32.17	31.35	31.06
2014	32.25	32.15	31.35	31.04
2015	32.37	32.28	31.49	31.18
2016	32.76	32.66	31.90	31.54
2017	34.07	33.99	33.24	32.86
2018	34.54	34.46	33.78	33.34
2019	34.74	34.67	34.08	33.60
2020	35.12	35.05	34.55	33.97
2021	36.16	36.08	35.80	35.04
2022	36.25	36.18	36.11	35.15
2023	36.10	36.05	36.12	35.00
2024	36.58	36.52	36.70	35.53
2025	37.06	36.99	37.40	36.01

The base case forecast resource mix for the interconnected Western Electricity Coordinating Council (WECC) area is shown in Figure C-4. Factors affecting resource development through the 2005-2025 period include load growth, natural gas prices, generating resource technology improvement, continued renewable resource incentives and increasing probability of carbon dioxide production penalties. Principal additions between 2005 and 2025 include approximately 4,600 megawatts of renewable resources resulting from state renewable portfolio standards and system benefit charges, 17,000 megawatts of combined-cycle plant, 20,000 megawatts of steam coal capacity, 22,000 megawatts of wind capacity and 9,000 megawatts of coal gasification combined-cycle plant. Retirements include 1,650 MW of steam coal, 1,400 MW of gas combined-cycle and 1,400 MW of gas steam units. The 2025 capacity mix includes 33 percent natural gas, 25 percent hydropower, 24 percent coal and 11 percent intermittent renewables (wind and solar). Not shown in the figure is about 9,000 megawatts of demand response capability assumed to be secured between 2007 and 2025.

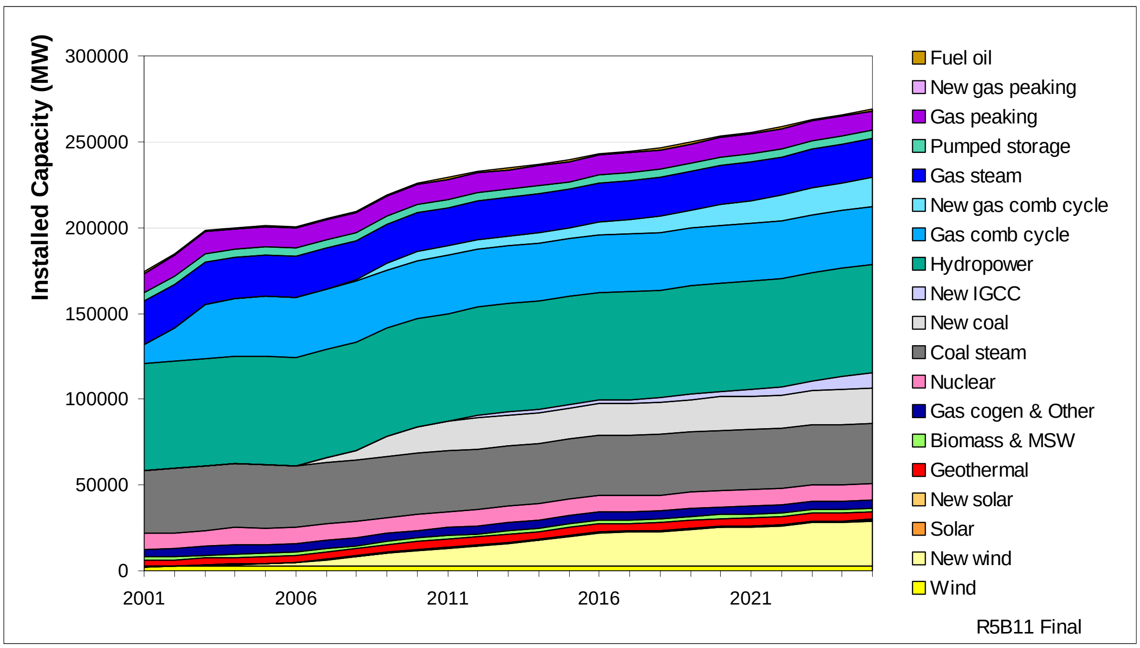

Figure C-4: Base case WECC resource mix

The Northwest resource mix is shown in Figure C-5. About 960 megawatts of renewables funded by state system benefit charges (modeled as wind) and 2,900 additional megawatts of new, market-driven wind power are added during the period 2005-25 in addition to the 399 MW Port Westward combined-cycle plant, currently under construction. No capacity is retired. The regional capacity mix in 2025 includes 67 percent hydropower, 13 percent natural gas, 9 percent wind and 8 percent coal. Not shown in the figure is about 1,900 megawatts of demand response capability assumed to be secured between 2007 and 2025. Because the capacity addition logic used for this forecast uses deterministic fuel prices, loads, renewable production credits, CO_2 penalties and other values affecting resource cost-effectiveness, the resulting resource additions differ somewhat from the recommendations resulting from the more sophisticated risk analysis described in Chapter 7 of the plan.

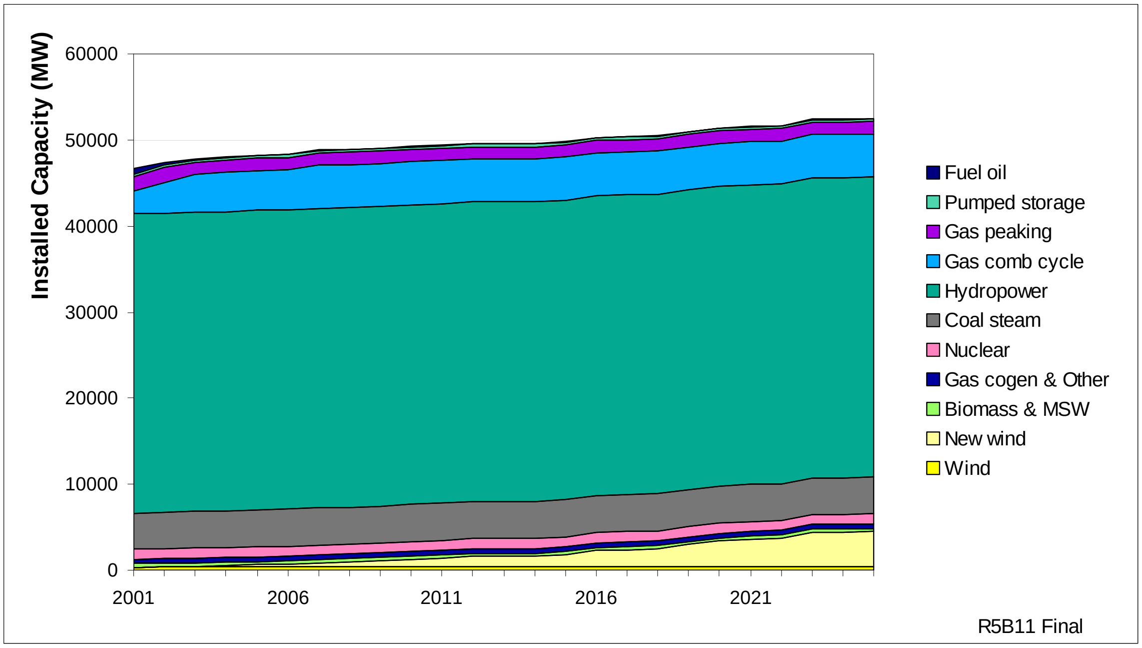

Figure C-5: Base case Pacific Northwest resource mix

Other base case results are summarized in Table C-3. Further detail can be found in the workbook PLOT R5B11 Final Base 012705.xls, posted in the Council's website dropbox.

APPROACH

The Council forecasts wholesale electricity prices using the AURORA$^{xmp®}$ electricity market model. Electricity prices are based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. A forecast is developed using the two-step process illustrated in Figure C-6. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using the AURORA$^{xmp®}$ long-term resource optimization logic. This is an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, operation, maintenance and fuel, including a return on the developer's investment and a dispatch premium. This step results in a future resource mix such as depicted for the base case in Figure C-4.

The electricity price forecast is developed in the second step, in which the mix of resources developed in the first step is dispatched on an hourly basis to serve forecast loads. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the forecast price.

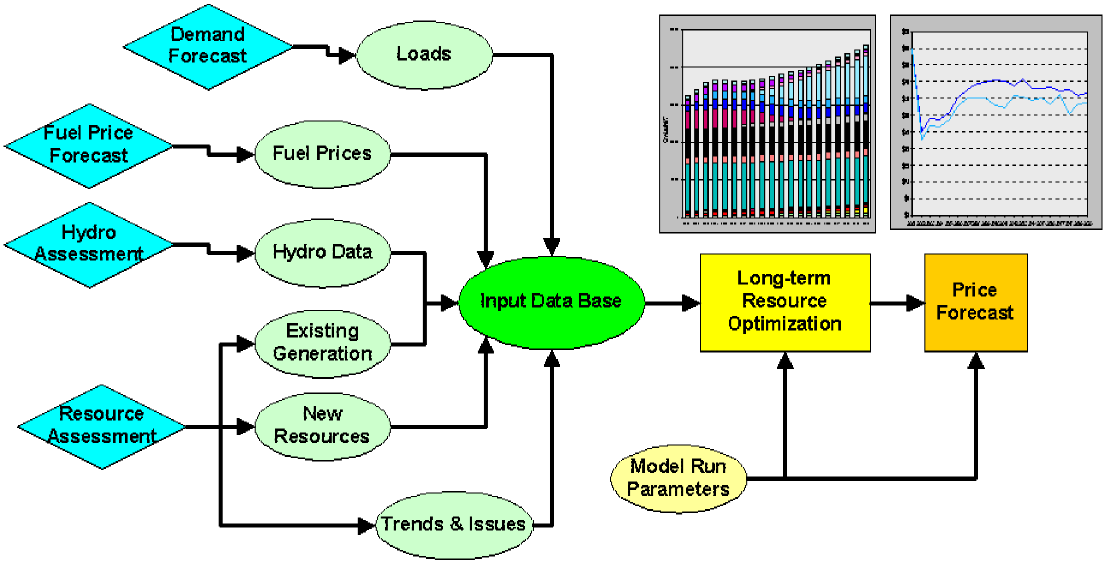

Figure C-6: Price forecasting process

As configured by the Council, AURORA[xmp®] simulates power plant dispatch in each of 16 load-resource zones that make up the WECC electric reliability area (Figure C-7). These zones are defined by transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource zone may be served by native generation, curtailment, or by imports from other load-resource zones if economic, and if transmission transfer capability is available.

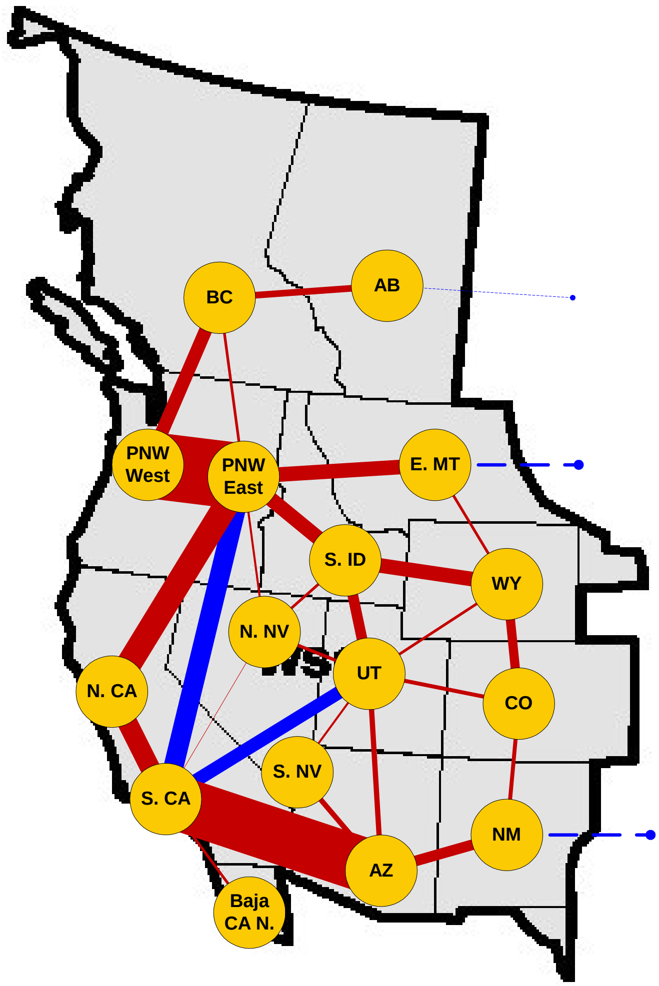

Figure C-7: Load-resource zones

DATA, ASSUMPTIONS AND SENSITIVITY ANALYSES

The data and assumptions underlying the electricity price forecast are developed by the Council with the assistance of its advisory committees (Appendix C-1). The base forecast is an expected value forecast using the medium case electricity sales forecast, the medium case forecast of fuel prices and average water conditions. Though possible future episodes of fuel price and hydropower volatility are not specifically modeled, water conditions and fuel prices are adjusted to compensate for the biasing effect of volatility on electricity prices. The base case forecast uses the mean annual values of federal renewable production tax credits, renewable energy credit revenues and possible future carbon dioxide penalties from the portfolio risk analysis.

Electricity Loads

The Council's medium case electricity sales forecast is the basis for the base case electricity price forecast for Northwest load-resource zones. Transmission and distribution losses are added and the effects of price-induced and programmatic conservation deducted to produce a load forecast. In the medium-case forecast, Northwest loads, including eastern Montana are forecast to grow at an average annual rate of approximately 0.7 percent per year from 20,875 average megawatts in 2005 to 23,850 average megawatts in 2025. Direct Service Industry loads average 200 megawatts in the medium case.

Total WECC load is forecast to grow at an annual average rate of 1.7 percent, from about 94,800 average megawatts in 2005 to 132,100 average megawatts in 2025. Most load-resource zones outside the Northwest are forecast to see more rapid load growth than Northwest areas (Table C-2). The approach used to forecast loads for load-resource zones outside the Northwest was to calculate future growth in electricity demand as the historical growth rate of electricity use per capita times a forecast of population growth rate for the area. Exceptions to this method were California, where forecasts by the California Energy Commission were used, and the Canadian provinces, where load forecasts are available from the National Energy Board.

Table C-2: Base loads and medium case forecast load growth rates[a]

Load-resource zone	2005 (Average Megawatts)	2025 (Average Megawatts)	Average Annual Load Growth, 2005-2025
PNW Eastside (WA & OR E. of Cascade crest, Northern ID & MT west of Continental Divide.	4695	5341	0.6 percent
PNW Westside (WA & OR W. of Cascade crest)	12832	14661	0.7 percent
Southern Idaho (~IPC territory)	2518	3022	0.9 percent
Montana E. (east of Continental Divide)	830	829	0.0 percent
Alberta	6023	8489	1.6 percent
Arizona	8513	13867	1.4 percent
Baja California Norte	1117	1883	2.6 percent
British Columbia	7798	10199	1.4 percent
California N. (N. of Path 15)	13842	18794	1.5 percent
California S. (S. of Path 15)	18431	25686	1.7 percent
Colorado	6011	9498	2.3 percent
Nevada N. (~ SPP territory)	1294	1941	2.0 percent
Nevada S. (~ NPC territory)	2586	4466	2.8 percent
New Mexico	3099	5670	3.1 percent
Utah	3256	5702	2.7 percent
Wyoming	1814	2046	0.6 percent
Total	**94847**	**132094**	**1.7 percent**

a) Load is forecast sales plus 8 percent transmission and distribution loss.

Sensitivity studies were run using the Council's medium-low and medium-high case electricity sales forecast to assess the implications of long-term load growth uncertainty on electricity prices and resource development. Growth rates for load-resource zones outside the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the percentile growth rate differences between the Northwest medium case (0.7%/yr) and medium-low case (0.1%/yr) and medium-high case (1.3%/yr), respectively.

As expected, the faster load growth of the medium-high load growth case result in higher electricity prices throughout the forecast period (Figure C-8). Beginning about 2017, the medium-high case prices climb rapidly away from the base case prices. This appears to result from accelerated development of natural gas combined-cycle plants at this time. It is likely that gas is selected over coal because of increasing CO_2 mitigation cost. Levelized Mid-Columbia prices are $37.70 per megawatt-hour, 4 percent higher than the base case.

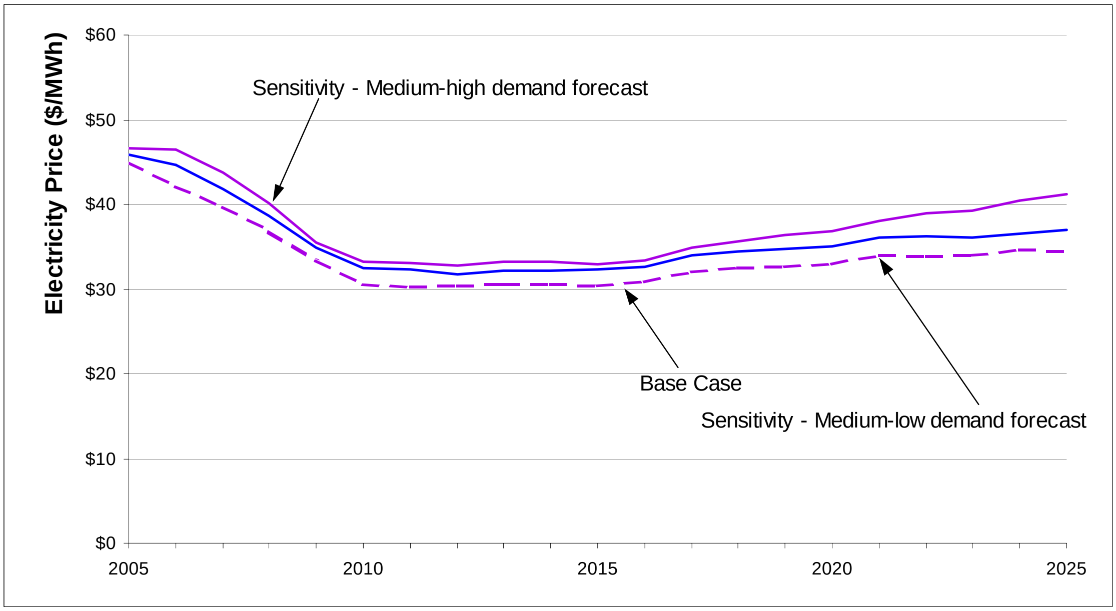

Figure C-8: Sensitivity of Mid-Columbia electricity price to load growth uncertainty

The medium-low case results in consistently lower Mid-Columbia prices (Figure C-8). Levelized Mid-Columbia prices are $34.30 per megawatt-hour, 5 percent lower than the base case.

Other results of the load sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final MLDmd 033005.xls, PLOT R5B11 Final MHDmd 041005.xls, posted in the Council's website dropbox.

Fuel Prices

The Council's medium case fuel price forecast is used for the base case electricity price forecast. Coal prices are based on forecast Western mine-mouth coal prices, and natural gas prices are based on a forecast of U.S. natural gas wellhead prices. Basis differentials are added to the base prices to arrive at delivered fuel prices for each load-resource zone. Natural gas prices are further adjusted for seasonal variation. For example, the price of natural gas delivered to a power plant located in western Washington or Oregon is based on the annual average U.S. wellhead price forecast, adjusted by price differentials between wellhead and Henry Hub (Louisiana); Henry Hub and AECO hub (Alberta); AECO and (compressor) Station 2, British Columbia; and finally, Station 2 and western Washington and Oregon. A monthly adjustment is applied to the AECO - Station 2 differential. The fuel price forecasts and derivation of load-resource area prices are more fully described Appendix B.

In the medium case, the price of Western mine-mouth coal is forecast to hold at $0.51 per million Btu from 2005 through 2025 (constant 2000$). Average distillate fuel oil prices are forecast to stabilize at $6.58 by 2010, following a decline from $7.15 per million Btu in 2005. Price-driven North American exploration and development, increasing liquefied natural gas imports and demand destruction are expected to slowly force down average annual U.S. wellhead natural gas prices from $5.30 per million Btu in 2005 to a low of $3.80/MMBtu in 2015. The annual average price is then forecast to then rise slowly to $4.00 per million Btu in 2025 (2000$), capped by the expected cost of landed liquefied natural gas.

Forecast medium-case delivered prices for selected fuels are plotted in Figure C-9. Fuel prices are shown in Figure C-9 as fully variable (dollars per million Btu) to facilitate comparison. However, the price of delivered coal and natural gas is modeled as a fixed (dollars per kilowatt per year) and a variable (dollars per million Btu) component to differentiate costs, such as pipeline reservation costs that are fixed in the short-term.

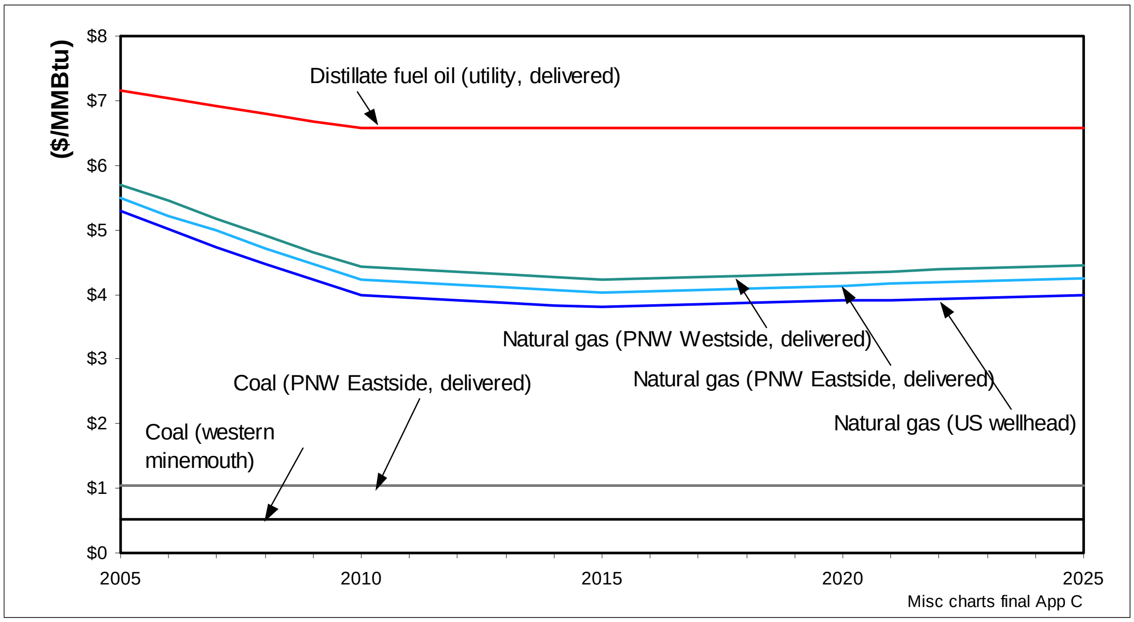

Figure C-9: Forecast prices for selected fuels - Medium Case

Sensitivity analyses were run using the Council's high case and low case fuel price forecasts to examine the effects of higher or lower fuel prices on the future resource mix and electricity prices. The high case and the low case fuel price forecasts for wellhead gas and minemouth coal are compared to the medium case forecasts in Figure C-10.

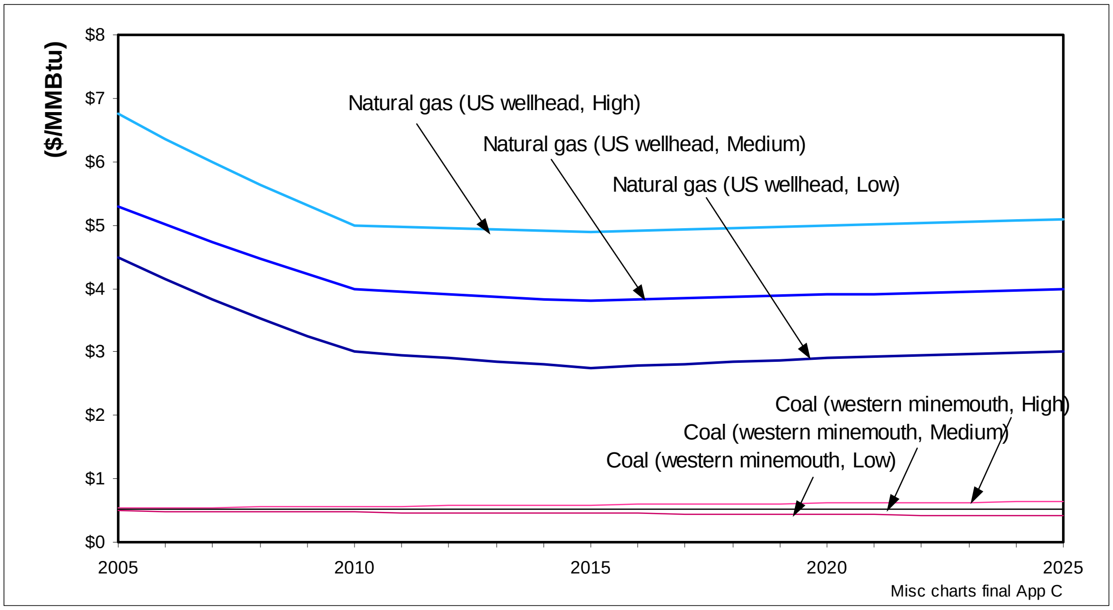

Figure C-10: Natural gas and coal price forecast cases

The low fuel price forecast results in levelized Mid-Columbia electricity prices of $29.80 per megawatt-hour, 18 percent lower than the base case. The lower price is evident throughout the forecast period, possibly as a manifestation of continued reliance on gas-fired combined-cycle power plants (Figure C-11). The 2025 resource mix (Table C-3) shows a shift away from new coal and wind to new gas-fired units. Also evident in Table C-3 is the substantial reduction in CO_2 production associated with the greater penetration of natural gas. If this were intended to be a scenario rather than a sensitivity case, the higher loads resulting from lower prices would offset a portion of the potential CO_2 reduction.

The high fuel price forecast results in levelized Mid-Columbia electricity prices of $39.60 per megawatt-hour, 9 percent higher than the base case. Prices are substantially higher in the near-term, but moderate toward base case values by 2015 as new coal-fired power plants supplement existing gas-fired capacity (Figure C-11). The 2025 resource mix (Table C-3) shows a strong shift to new conventional coal and IGCC plants and wind in lieu of new gas-fired capacity. Towards the end of the forecast period, increasing CO_2 mitigation costs result in electricity prices again rising above base case values.

Other results of the fuel price sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final LoFuel 031705.xls, PLOT R5B11 Final HiFuel 031605.xls, posted in the Council's website dropbox.

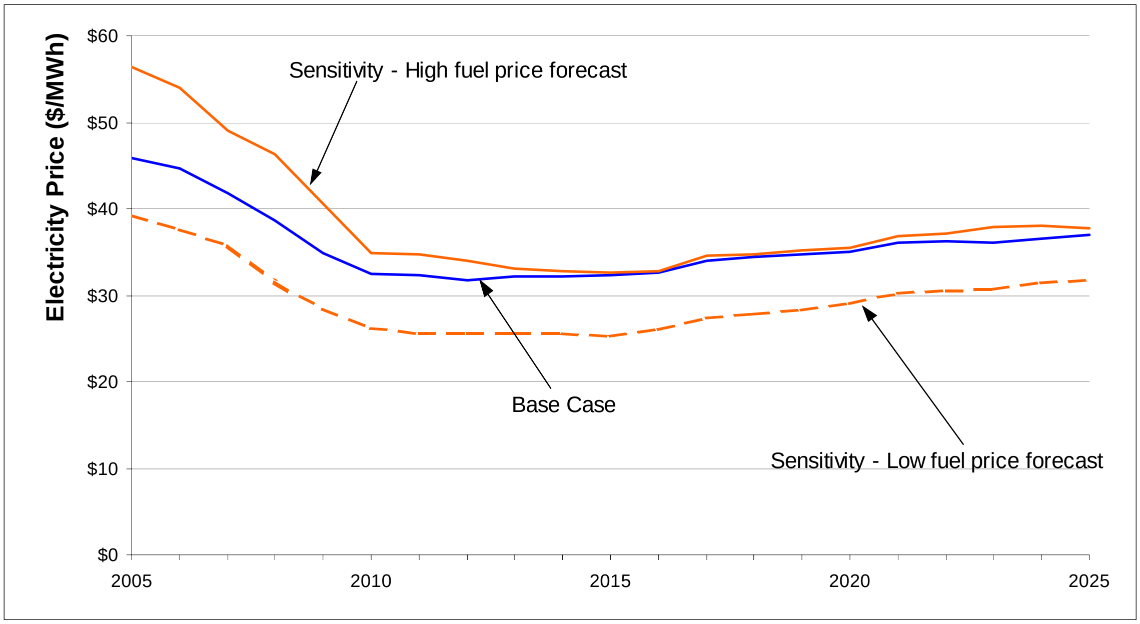

Figure C-11: Sensitivity of Mid-Columbia electricity price to fuel price uncertainty

Demand Response

Demand response is a change in the level or quality of service that is voluntarily accepted by the consumer, usually in exchange for payment. Demand response can shift load from peak to off-peak periods and reduce the cost of generation by shifting the marginal dispatch to more efficient or otherwise less-costly units. Demand response may also be used to reduce the absolute amount of energy consumed to the extent that end-users are willing to forego net electricity consumption in return for compensation. The attractiveness of demand response is not only its ability to reduce the overall cost of supplying electricity; it also rewards end users for reducing consumption during times of high prices and possible supply shortage. Demand response also offers many of the environmental benefits of conservation.

Though the understanding of demand response potential remains sketchy, preliminary analysis by the Council suggests that ultimately up to 16 percent of load might be offset at a cost of $50 to $400 per megawatt-hour through various forms of time-of-day pricing and negotiated agreements. For the base case forecast, we assume that 50 percent of this potential is secured, beginning in 2007 and ramping up to 2025. Similar penetration is assumed throughout WECC.

Existing Generating Resources

The existing power supply system modeled for the electricity price forecast consisted of the projects within the WECC interconnected system in service and under construction as of the first quarter of 2003. Three Northwest gas combined-cycle power plants for which construction was suspended, Grays Harbor, Mint Farm and Montana First Megawatts were included as new generating resource options. Projects having announced retirement dates were retired as scheduled.

New Generating Resource Options

When running a capacity expansion study, AURORA$^{xmp®}$ adds capacity when the net present value cost of adding a new unit is less than the net present market value of the unit. Because of study run time considerations, the number of available new resource alternatives is limited to those possibly having a significant effect on future electricity prices. Some resource alternatives such as gas combined-cycle plants and wind are currently significant and likely to remain so. Others, such as new hydropower or various biomass resources, are unlikely to be available in sufficient quantity to significantly influence future electricity prices. Some, such as coal gasification combined-cycle plants or solar photovoltaics do not currently affect power prices, but may do so as the technology develops and costs decline. Resources such as new generation nuclear plants or wave energy plants were omitted because they are unlikely to be commercially mature during the forecast period. Others, such as gas-fired reciprocating generator sets were omitted because they are not markedly different from simple-cycle gas turbines with respect to their effect on future electricity prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, wind power, coal-fired steam-electric power plants, coal gasification combined-cycle plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

Natural gas-fired combined cycle power plants

The high thermal efficiency, low environmental impact, short construction time and excellent operating flexibility of natural gas-fired combined-cycle plants helped make this technology becoming the “resource of choice” in the 1990s. In recent years, high natural gas prices have dimmed the attractiveness of combined-cycle plants and many projects currently operate at low load factors. Though technology improvements are anticipated to help offset high natural gas prices, the future role of this resource is sensitive to natural gas prices and global climate change policy. Higher gas prices could shift development to coal or windpower. More stringent carbon dioxide offset requirements might favor combined-cycle plants because of their proportionately lower carbon dioxide production. The representative natural gas combined-cycle power plant used for this forecast is a 2x1 (two gas turbines and one steam turbine) plant of 540 megawatts of baseload capacity plus 70 megawatts of power augmentation (duct-firing) capacity.

Wind power plants

Improved reliability, cost reduction, financial incentives and emerging interest in the hedge value of wind with respect to gas prices and greenhouse gas control policy have moved wind power from niche to mainstream over the past decade. The cost of wind-generated electricity (sans financial incentives) is currently higher than electricity from gas combined-cycle or coal plants, but it is expected to decline to competitive levels within several years. The future role of wind is dependent upon gas price, greenhouse gas policy, continued technological improvement, the cost and availability of transmission and shaping services and the availability of financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is an expectation that coal may be subject to future CO_2 penalties. At current costs, it is infeasible to extend transmission more than several miles to integrate a wind project with the grid. This limits the availability of wind to prime resource areas close to the grid. As wind plant costs decline, feasible interconnection distances will extend, expanding wind power potential. Two cost blocks of wind in 100 MW plant increments were defined for this study - a lower cost block representing good wind resources and low shaping costs, and a higher cost block representing the next phase of wind development with somewhat less favorable wind (lower capacity factor) and higher shaping costs.

Coal-fired steam-electric power plants

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, relatively low fuel prices, improvements in technology and concerns regarding future natural gas prices have repositioned coal as a potentially economically attractive new generating resource. Conventional steam-electric technology would likely be the coal technology of choice in the near-term. Supercritical steam technology is expected to gradually penetrate the market and additional control of mercury emissions is likely to be required. The representative new coal-fired power plant defined for this forecast is a 400-megawatt steam-electric unit. Costs and performance characteristics simulate a gradual transition to supercritical steam technology over the planning period.

Coal-gasification combined-cycle power plants

Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation. This improves fuel use efficiency, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers. A 425-megawatt coal-gasification combined-cycle power plant without CO2 separation and sequestration was modeled for the price forecast.

Natural gas-fired simple-cycle gas turbine generators

Gas turbine generators (simple-cycle gas turbines), reciprocating engine-generator sets, supplementary (duct) firing of combined-cycle plants are potentially cost-effective means of supplying peaking and reserve power needs. As described earlier, the Council also views demand response as a promising approach to meeting peaking and reserve power needs. Supplementary ("duct") firing of gas combined-cycle plants can also help meet peaking or reserve needs at low cost and is included in the generic combined-cycle plant described above. Additional requirements can be met by simple-cycle gas turbine or reciprocating generator sets. From a modeling perspective, the cost and performance of gas-fired simple-cycle gas turbines and gas-fired reciprocating engine-generator sets are sufficiently similar that only one need be modeled. The Council chose to model a twin-unit (2 x 47 megawatt) aeroderivative simple-cycle gas turbine generator set.

Central-station solar photovoltaics

Solar power is one of the most potentially attractive and abundant long-term power supply alternatives. Economical small-scale applications of solar photovoltaics are currently found throughout the region where it is costly to secure grid service, however for bulk, grid-connected supply, solar photovoltaics are currently much more expensive than other bulk supply alternatives. Because of the potential for significant cost reduction, the Council included a 100 MW central-station solar photovoltaic plant as a long-term bulk power generating resource alternative.

The cost and performance characteristics of these generating resource alternatives are further described in Chapter 5 and Appendix I.

Transmission

Transfer ratings between load-resource zones are based on the 2003 WECC path ratings plus scheduled upgrades to Path 15 between northern and southern California (since completed) and scheduled upgrades between the Baja California and southern California.

Renewable Energy Production Incentive

Federal, state and local governments for many years have provided incentives to promote various forms of energy production, including research and development grants and favorable tax treatment. A federal incentive that significantly affects the economics of renewable resource development is the renewable energy production tax credit (PTC) and the companion renewable energy production incentive (REPI) for tax-exempt entities. Enacted as part of the 1992 Energy Policy Act, and originally intended to help commercialize wind and certain biomass technologies, these incentives have been repeatedly renewed and extended, and currently amount to approximately $13 per megawatt hour (2004 dollars) when levelized over the life of a project. The incentive expired at the end of 2003 but, in September 2004, was extended to the end of 2005, retroactive to the beginning of 2004. In addition, the scope of qualifying facilities was extended to forms of biomass, geothermal, solar and certain other renewable resources not previously qualifying. The long-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as above-market resource costs are reduced. In addition, federal budget constraints may eventually force reduction or termination of the incentives. However, the incentives remain politically popular, as they encourage development that produces rural property tax revenues and revenue for local landowners on whose land wind turbines are sited. Moreover, the incentives serve as a crude carbon dioxide control mechanism in the absence of a federal climate change policy.

Because of these uncertainties, future federal renewable energy production incentive were modeled as a stochastic variable in the portfolio risk analysis, as described in Chapter 6. The mean annual value from the portfolio risk analysis was used for the base case electricity price forecast and for all sensitivity cases (Figure C-12). Because of practical considerations, state and local financial incentives, such as sales and property tax exemptions, were not modeled.

Renewable Energy Credits

Electricity from renewable energy projects often commands a market premium. Typically, the premium is traded separately from the electricity, in the form of renewable energy credits (RECs, or “green tags”). The REC market is driven by the demand for green power products, the nascent demand for CO_2 offsets and by the demand for resources to meet state renewable portfolio standard obligations. The current market value of green tags for electricity from newer windpower projects is reported to be $3 to $4 per megawatt-hour. Tag prices for solar-generated electricity generally higher than wind tags, and tag prices for hydro, biomass and geothermal power are generally lower. Electricity from newer renewable energy projects typically commands higher tag prices than that from older projects. Future REC revenues were modeled as a stochastic variable in the portfolio risk analysis as described in Chapter 6. The mean annual REC value from the portfolio risk analysis (Figure C-12) was used for both wind and solar power in the base and sensitivity cases.

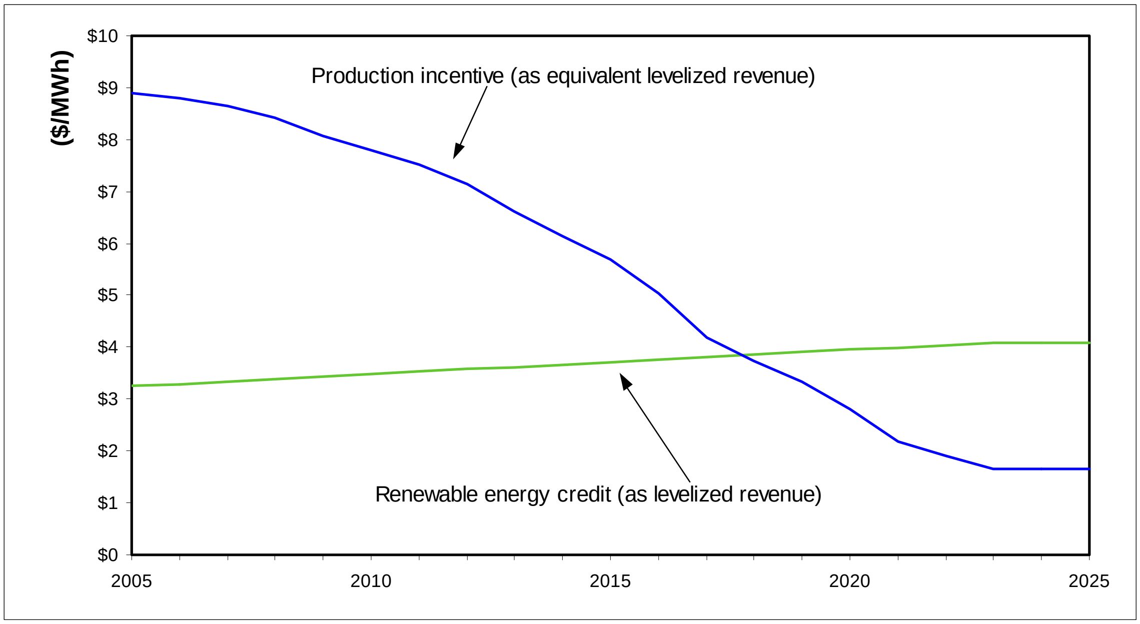

Figure C-12: Renewable energy incentives

Global Climate Change Policy

In the absence of federal initiatives, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Since 1997, Oregon has required mitigation of 17 percent of the carbon dioxide production of new power plants. Washington, in 2004 adopted CO_2 mitigation requirements for new fossil power plants exceeding 25 megawatts capacity. In Montana, the developer of the natural gas-fired Basin Creek Power Plant has agreed to mitigate CO_2 production to the Oregon requirements. California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Though it appears likely that CO_2 production from power generation facilities will be subject to increasing regulation over the period of this plan, the nature and timing of future controls is highly uncertain. For this reason, CO_2 mitigation costs were modeled in the portfolio risk analysis as a stochastic carbon tax. The probabilities and distributions used to derive the carbon tax for the portfolio analysis are described in Chapter 6. In the base case electricity price forecast, the mean annual value of the carbon tax from the portfolio risk analysis is applied to both existing and new generating resources. Unlike the portfolio analysis, the current Oregon mitigation requirements are applied to new resources developed in Washington or Oregon until this value is exceeded by the mean annual values from the portfolio analysis (Figure C-13).

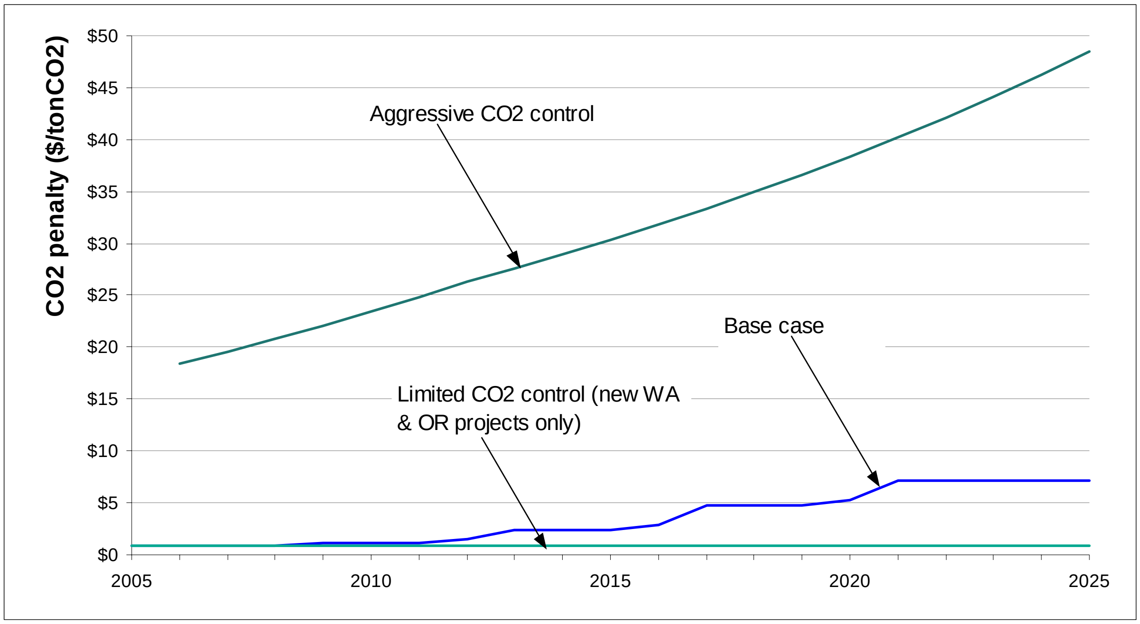

Figure C-13: CO_2 mitigation cost (as carbon tax)

Because of uncertainties regarding future CO_2 regulation, two sensitivity analyses were run. A limited CO_2 control case assumed that CO_2 mitigation continues to be required only in Oregon and Washington at a cost of $0.87 per ton CO_2 (approximately the current Oregon fixed payment option). Compared to the base case, this shifts future resource development from wind and natural gas combined-cycle plants to conventional and gasified coal (Table C-3). Additional older gas steam capacity is retired. The levelized Mid-Columbia price declines by 6 percent to $33.90 per megawatt-hour (Figure C-14). The most significant price reduction is experienced in the longer-term as the resource mix shifts from more expensive natural gas capacity to less expensive coal (Figure C-14). The additional new fossil capacity leads to a larger 2025 WECC system average CO_2 production factor of 0.576 lbCO_2/kWh, 14 percent greater than that of the base case value of 0.507 lb CO_2/kWh (Figure C-15). Cumulative WECC CO_2 production for the period 2005-25 increases by 7 percent.

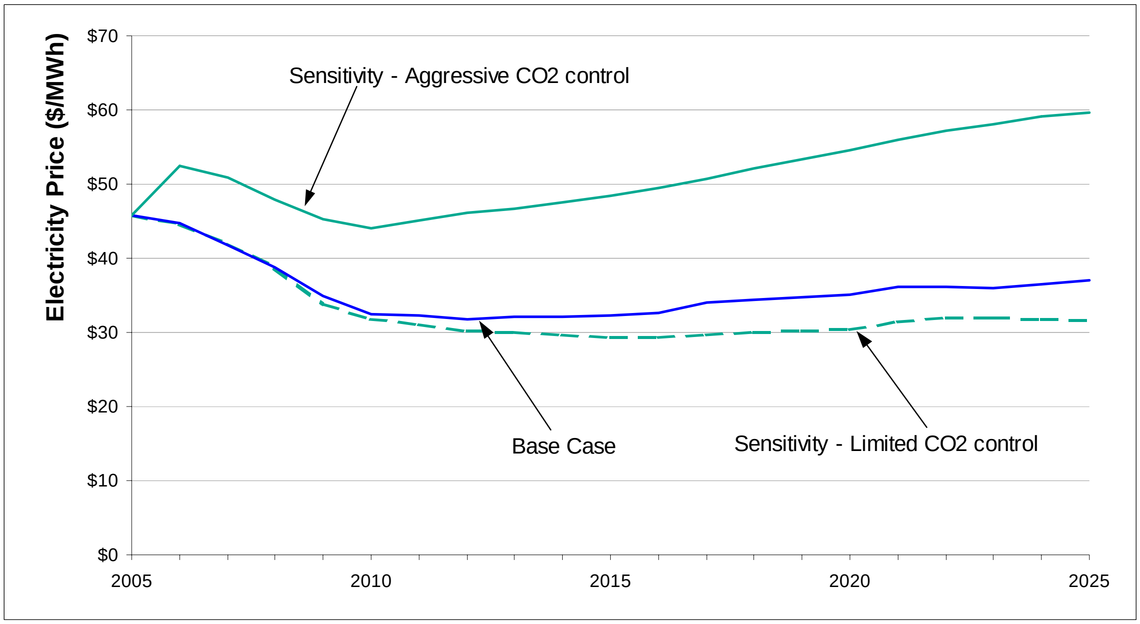

Figure C-14: Sensitivity of electricity price forecast to CO_2 mitigation cost

An aggressive CO_2 control effort was modeled by approximating the nationwide cap and trade program proposed in the McCain-Lieberman Climate Stewardship Act. McCain-Lieberman would implement capped and tradable emissions allowances for CO_2 and other greenhouse gasses. Reduction requirements would apply to large commercial, industrial and electric power sources. The proposal rejected by the Senate in a 43-55 vote in 2003 would have capped allowances at 2000 levels by 2010 and 1990 levels in 2016.

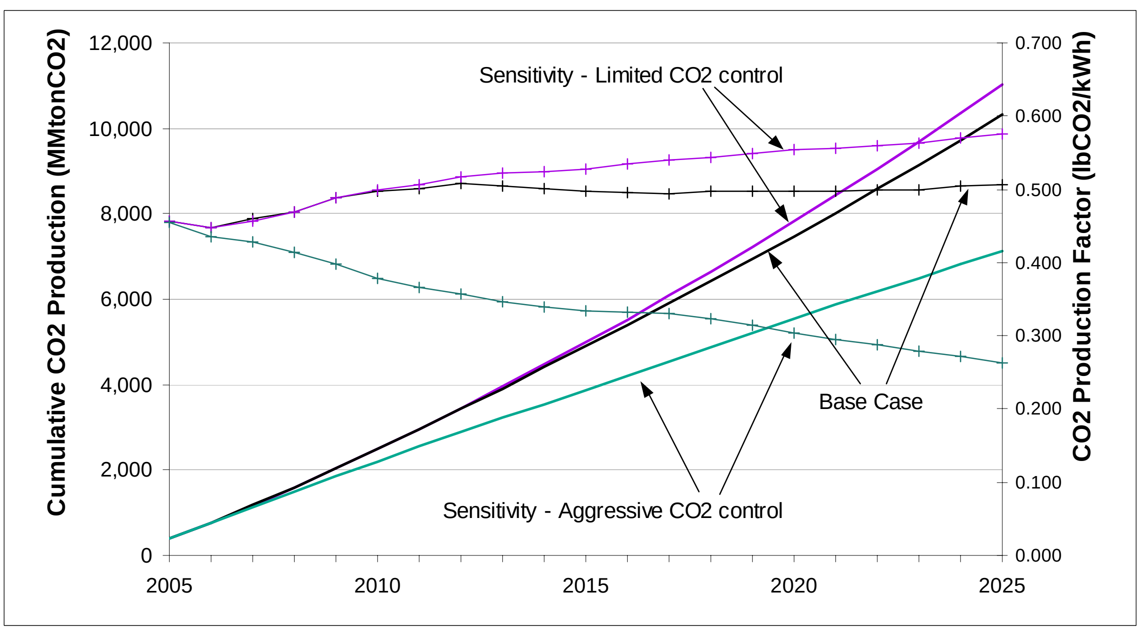

Figure C-15: Sensitivity of forecast WECC CO_2 production to CO_2 mitigation cost

The aggressive CO_2 control sensitivity case is based on the assumed enactment of federal regulation similar to the McCain-Lieberman proposal in 2006, with the year 2000 cap in effect in 2012. Model limitations require CO_2 mitigation cost to be treated as a carbon tax on fuel use rather than as a true cap and trade system. In this case, fuel carbon for existing and new projects is taxed at the equivalent of a forecast cost of CO_2 allowances required to achieve the proposed McCain-Lieberman cap[1]. The allowance costs needed to achieve the targeted reductions of the McCain-Lieberman proposal are highly uncertain but were the subject of a Massachusetts Institute of Technology (MIT) analysis[2]. The sensitivity study was based on the forecast CO_2 allowance costs of Case 5 of the MIT study, shifted back two years to coincide with the assumed 2012 Phase I implementation date. A market in banked allowances was assumed to develop on enactment in 2006 so any subsequent reduction in fuel carbon consumption is valued at an opportunity cost equivalent to the discounted forecast 2012 allowance cost. Oregon and Washington were assumed to continue their current mitigation standards at $0.87 per ton through 2006.

These assumptions result in a significant shift in the future resource mix compared to the base case. Wind and gas combined-cycle resource development is accelerated and additions of bulk solar photovoltaics appear near the end of the forecast. About 6 percent of existing coal capacity and 17 percent of existing gas steam capacity is retired over the forecast period. New coal development is entirely absent (Table C-3). The levelized forecast Mid-Columbia price is $50.10 per megawatt-hour, 38 percent higher than the base case value. Prices increase almost immediately, in 2006 because of the opportunity cost of bankable CO_2 allowances (Figure C-14). The assumed carbon tax is effective in reducing CO_2 production. The shift from coal and less efficient gas-fired capacity to wind, solar and more efficient gas capacity rapidly reduces the CO_2 production factor. The 2025 WECC system wide CO_2 production factor is 0.264 $lbCO_2/kWh$, 48 percent lower than the base case value. Cumulative CO_2 production for the WECC area for the period 2005 - 25 is reduced by 31 percent from the base case forecast.

Because this case is a sensitivity analysis rather than a scenario, the results should be used with caution. If this case were cast as a scenario, other adjustments to assumptions would have to be included. For example, natural gas prices could be expected to increase more rapidly as a result of increased development of gas-fired generating capacity. Electrical loads could be expected to moderate as a result of higher prices and additional conservation would become cost-effective. Wind resources in addition to those included in these model runs might be available, though probably at higher cost than those currently represented. New nuclear resources are not included; it is possible that new-generation modular nuclear plants might produce electricity at lower cost than the marginal resources of this case.

Price Cap

Following a year of extraordinarily high electricity prices, the FERC implemented a floating WECC wholesale trading electricity price cap in June 2001. The original cap triggered when California demand rose to within 7 percent of supply. The cap itself was set for each occurrence based on the estimated production cost of the most-expensive California plant needed to serve

[1] As a further modeling simplification, the carbon tax was applied to all WECC areas, including British Columbia, Alberta and Baja California.

[2] Massachusetts Institute of Technology. Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal. June 2003.

load. This mitigation system was revised in July 2002 to a fixed cap of $250 per megawatt-hour, effective October 2002.

The base and sensitivity cases assume continuation of the $250/MWh wholesale price cap (year 2000 dollars, escalating with inflation). This cap undercuts several of the higher cost load curtailment and demand response blocks, curtailing peak period prices and reducing generation developed to meet peak period loads.

Table C-3: Base and sensitivity case results

Case	Changes from Base	Mid-Columbia Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC coal (GW)	2025 WECC gas (GW)	2025 WECC wind & solar (GW)	2005-25 WECC CO_2 Production ($MMTCO_2$)	2025 WECC August Reserve Margin (%)	2025 PNW January L/R Balance (aMW)[3]
Base Case (Changes 2005 - 2025 shown in percent)									
Final Base	--	$36.20	$46.18	64.6 (75%)	89.7 (18%)	29.9 (570%)	10321 (154%)	11%	-14
Sensitivity Cases (Changes from base shown in percent)									
Medium-low demand forecast	NPCC Medium-low demand forecast case	$34.30 (-5 %)	$45.03 (-3%)	53.4 (-17 %)	82.0 (-9 %)	31.7 (+6 %)	9084 (-12 %)	18 %	3263
Medium-high demand forecast	NPCC Medium-high demand forecast case	$37.70 (+4 %)	$49.92 (+8 %)	74.6 (+16 %)	98.7 (+10 %)	40.0 (+10 %)	11,562 (+12 %)	6 %	-2808
Low fuel price forecast	NPCC Low fuel price forecast case	$29.80 (-18 %)	$39.47 (-15 %)	37.5 (-42 %)	114.2 (+27 %)	22.4 (-25 %)	9187 (-11 percent)	10 %	-471
High fuel price forecast	NPCC High fuel price forecast case	$39.60 (+9 %)	$57.12 (+24 %)	88.6 (+37 %)	66.1 (-26 %)	33.6 (+4 %)	11,074 (+7 %)	11 %	2356
Non-aggressive CO_2 control	$0.87/T CO_2 mitigation, WA & OR only	$33.90 (-6 %)	$46.64 (+1 %)	84.2 (+30 %)	70.2 (-22 %)	22.2 (-26 %)	11,028 (+7 %)	11 %	477
Aggressive CO_2 control	Immediate $0.87/T CO_2 offset in WA & OR Climate Stewardship Act enacted 2006, Ph I in 2012	$50.10 (+38 %)	$49.46 (+7 %)	34.5 (-47 %)	129.5 (+44 %)	44.8 (+50 %)	7126 (-31 percent)	15 %	2946

[3] Excluding demand response capability.

Appendix C1

MEMBERS OF THE GENERATING RESOURCES ADVISORY COMMITTEE

Name	Affiliation
Rob Anderson	Bonneville Power Administration
Peter Blood	Calpine Corporation
John Fazio	Northwest Power Planning Council
Stephen Fisher	Mirant Americas Energy Marketing
Mike Hoffman	Bonneville Power Administration
Clint Kalich	Avista Utilities
Eric King	Bonneville Power Administration
Jeff King	Northwest Power Planning Council
Mark Lindberg	Montana Economic Opportunity Office
Bob Looper	Summit Energy, LLC, representing State of Idaho
Jim Maloney	Eugene Water & Electric Board
Dave McClain	D.W. McClain & Associates representing Renewable Northwest Project
Alan Meyer	Weyerhaeuser Corp.
Mike Mikolaitis	Portland General Electric
Bob Neilson	Idaho National Environmental and Engineering Laboratory
Roby Roberts	PacifiCorp Power Marketing
Jim Sanders	Clark Public Utilities
David Stewart-Smith	Oregon Office of Energy
Tony Usibelli	Washington Office of Trade and Economic Development
Carl van Hoff	Energy Northwest
David Vidaver	California Energy Commission
Kevin Watkins	Pacific Northwest Generating Coop
Chris Taylor	Zilkha Renewable Energy