Northwest Power and Conservation Council

November 1, 2007

MEMORANDUM

TO: Council Members

FROM: Terry Morlan, Jeff King, Maury Galbraith

SUBJECT: Release of Revised Electricity Price Forecast for Comment

Staff has developed a revised electricity market price forecast described in the attached paper. The purpose of this forecast is to provide current estimates of future wholesale power prices and the value of capacity for utilities and agencies that use the Council's forecasts for guidance. The forecast will also provide a cost effectiveness "bookend" to guide the initial resource assessment of for the next power plan.

The revised forecast incorporates the recently adopted assumptions about future natural gas, oil, and coal prices and the findings and conclusions of the Biennial Assessment regarding the capital costs and performance of new resources. The forecast also explores the possible effect of current renewable portfolio standards (RPS) on supplementary resource additions, market prices of electricity and the value of capacity.

The interpretation and application of the power price forecast will change because of RPS resource acquisitions and capacity additions to maintain resource adequacy. Because of these changes, staff recommends that the paper be released for public comment. The Power Committee will decide whether to request public comment on the paper. If it is to be released for public comment, we would like Council agreement for its release.

Attachment

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Northwest Power and Conservation Council

DRAFT

Interim Wholesale Power Price Forecast

November 12, 2007

Council Document 2007-XX

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This report describes an interim revision to the wholesale power price forecast of the Northwest Power and Conservation Council. This forecast incorporates revised fuel price forecasts, estimated renewable resource acquisitions in response to state renewable portfolio standards and resource acquisitions needed to maintain target resource adequacy standards. This forecast supersedes the final wholesale power price forecast of the Fifth Power Plan.

Summary of Findings

The Council's interim forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2007 through 2026, is $35.50 per megawatt-hour. This is a 9 percent reduction from the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour). Recently enacted state renewable portfolio standard (RPS) requirements are the biggest reason for the difference between these forecasts.

A comparison of the interim base case forecast and various sensitivity case forecasts is shown in the following figure.

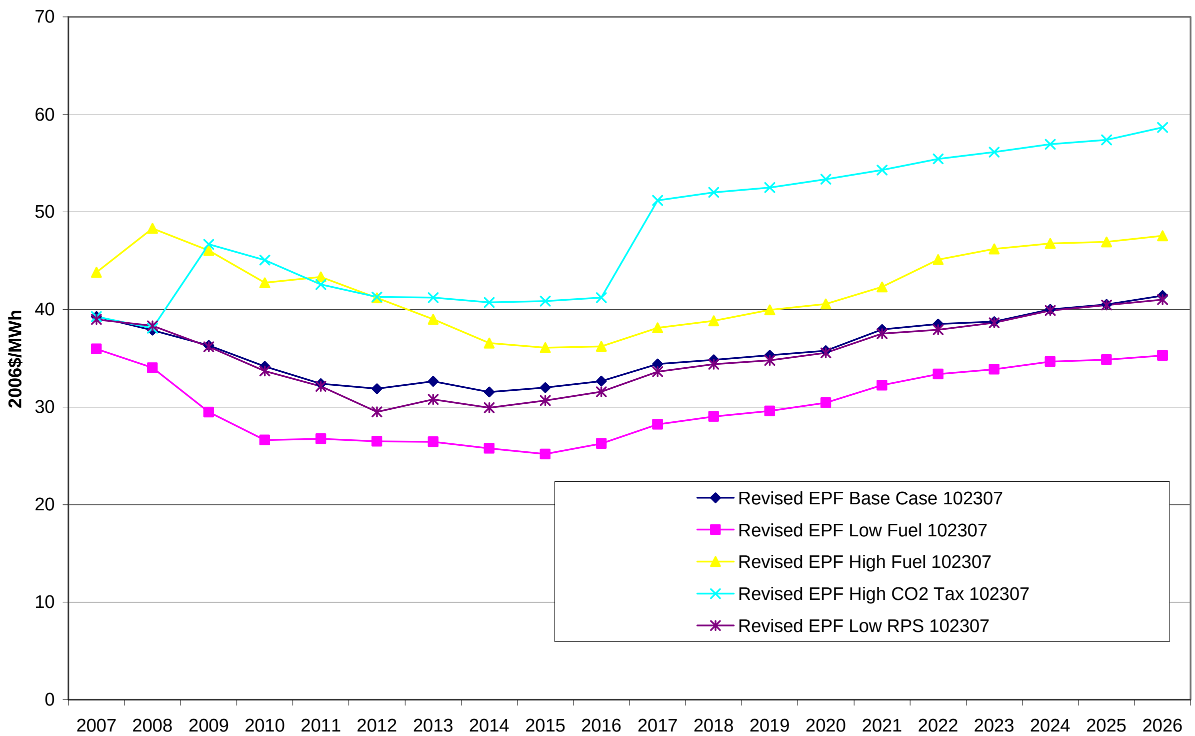

Figure 1: Interim energy price forecast base case compared to sensitivity case forecasts

The levelized Mid-Columbia price for the low fuel price case is $29.90 per megawatt-hour, 16 percent lower than the base case. The levelized Mid-Columbia price for the high fuel price case is $42.20 per megawatt-hour, 19 percent higher than the base case. The high CO_2 tax case results in a levelized price of $46.50 per megawatt-hour.

Background

The Council prepares and periodically updates a 20-year forecast of wholesale electricity prices for the Pacific Northwest. This forecast is used to establish benchmark capacity and energy costs for conservation and generating resource assessments for the Council's power plan. The forecast establishes the mean value electricity market price for the Council's portfolio risk model and for the ProCost model used by the Regional Technical Forum to assess the cost effectiveness of conservation measures. The forecasting model[1], once updated and otherwise set up for the forecast, is used to support the analysis of issues related to power system composition and operation such as the effectiveness of greenhouse gas control policies. Finally, the Council's price forecast is used by other organizations for assessing resource cost effectiveness and for other purposes.

The Council's current wholesale power price forecast was developed following completion of the Fifth Power Plan resource portfolio in late 2004. That forecast used the electricity demand and fuel price forecast of the Fifth Power Plan as well as that Plan's resource costs and "mean resource development" portfolio[2]. Significant changes potentially affecting the price forecast have occurred since the development of the final price forecast of the Fifth Power Plan. These include unforeseen rapid escalation in the construction cost of many generating resources, sustained fuel prices above the medium forecast of the Fifth Power Plan, construction of substantial amounts of wind and combined-cycle capacity during a period of regional surplus of generating capacity, adoption of ambitious renewable portfolio standards by Oregon and Washington and adoption of pilot regional energy and capacity reserve margin targets by the Resource Adequacy Forum. These changes affect future wholesale energy prices and impact the conventional use of long-term market prices as a determinant of resource cost-effectiveness. For these reasons it is desirable to revisit the wholesale price forecast prior to beginning work on the Sixth Power Plan.

The next update of the power price forecast is expected to follow development of the conservation and generating supply curves and the initial demand forecast for the Sixth Power Plan. The final Sixth Power Plan power price forecast will be prepared following development of the recommended resource portfolio.

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[1] The AURORA^{xmp} Electric Market Model, available from EPIS, Inc.

[2] The resource portfolio of the Fifth Power Plan is not deterministic but rather lays out an inventory of resources that would be developed as needed and cost-effective as the future unfolds. Except for the recommendations contained in the five-year action plan there is no single resource development schedule in the Fifth Power Plan. The mean level of resource additions, for each year and resource type observed over the 750 futures tested in the portfolio risk model was incorporated into the AURORA model for the final price forecast of the Fifth Power Plan.

Approach and assumptions

The Council uses the AURORA^{xmp} Electric Market Model to forecast wholesale electricity energy prices for the Pacific Northwest. The forecast is developed in a two-step process. First, using AURORA^{xmp} long-term resource optimization logic, a forecast of resource additions and retirements is developed. In the second step, the forecasted resource mix is then 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. A more detailed description of the Council's wholesale electricity price forecasting methodology is provided in Appendix C of the Fifth Power Plan.

The Council recently updated its AURORA^{xmp} software to version 8.4. As a result, this is the first time that the Council has implemented the capacity reserve margin capability of AURORA$^{xmp.}$. The capacity reserve margin modeling is an extension of the long-term resource optimization logic and, therefore, impacts the first-step of the Council's electricity price forecast process. Prior to this enhancement, the AURORA^{xmp} optimization logic iteratively added new resources and retired existing resources based on the resource's ability to cover its fully allocated going-forward costs at forecasted energy market prices. With the new enhancement, the AURORA^{xmp} optimization logic not only builds resources to meet target planning reserve margins, but also simultaneously produces estimates of the capacity prices needed to achieve or maintain the target reserve margin. The resulting forecast of resource additions and retirements is now co-optimized for the revenues derived from the capacity prices as well as hourly energy prices.

The Council updated many of the key inputs used in the AURORA^{xmp} model for the interim electricity price forecast. The starting point was the AURORA^{xmp} configuration used in the Council's recent CO_2 Footprint Paper. This configuration is essentially the configuration described in Appendix C to the Fifth Power Plan plus an updated inventory of existing WECC resources to reflect construction starts announced since adoption of the Fifth Power Plan in December 2004. This configuration was then updated to include coal and natural gas price forecasts from the Council's recent Revised Fuel Price Forecast, and new resource capital costs estimates from the Council's Biennial Assessment of the Fifth Power Plan. The schedule of resource additions was also updated to include renewable resources needed to fully meet state renewable portfolio standard (RPS) requirements. Finally, all of the model's financial inputs were updated to account for recent price inflation and to consistently express the 20-year time-profile of costs and revenues in constant 2006 dollars.

Coal Prices

The Council forecast the variable cost of delivered coal for each load-resource zone defined in its electricity market model. The delivered coal cost is the sum of the wholesale price of Powder River Basin (PRB) coal plus the variable cost of transporting PRB coal to each load-resource zone. The Council issued its current forecast of PRB coal prices on September 11, 2007. The variable costs of transportation are based on average transportation rates for PRB coal and average shipment distances from Wyoming to each load-resource zone.

The U.S. Energy Information Administration maintains the Coal Transportation Rate Database. The transportation rate for PRB coal shipments to electric utilities located in the Midwest census region averaged 10 mills per ton-mile for 2000-2001.[3] In order to protect the confidentiality of power producers, the average transportation rate for PRB shipments to electric utilities in the West census region was not reported. In its electricity market modeling, the Council used 9.8 mills per ton-mile as the variable transportation rate for shipping PRB coal to the load-resource zones in the West.[4]

To estimate the variable transportation cost of delivering PRB coal to each of the modeled load-resource zones in the West, the variable transportation rate is multiplied by the average rail distance between Wyoming and the load-resource zones. The Council used average rail shipments distances for shipments originating in Wyoming from the U.S. Department of Transportation and U.S. Department of Commerce 2002 Commodity Flow Survey.[5] Coal shipments comprise 98 percent of the ton-miles of rail transportation originating in Wyoming. Finally, the variable transportation cost was adjusted to reflect annual changes in the Council's forecast of diesel fuel prices.[6] The following table shows the average rail shipment distances and variable transportation costs for delivering PRB coal to western load-resource zones.

Table 1: Average Shipment Distance and Base Coal Transportation Rate by Load-Resource Zone

Load-Resource Zone		Average Rail Shipment Distance from Wyoming (Miles)	Base Transportation Rate (2006$/MMBtu)
Pacific Northwest - West	PNWW	1,263	0.69
Pacific Northwest - East	PNWE	1,009	0.55
Idaho	ID	465	0.25
Montana	MT	411	0.22
California - North	CAN	1,233	0.67
California - South	CAS	1,233	0.67
Nevada - North	NVN	896	0.49
Nevada - South	NVS	896	0.49
Wyoming	WY	138	0.08
Utah	UT	259	0.14
Colorado	CO	517	0.28
Arizona	AZ	958	0.52
New Mexico	NM	762	0.42
British Columbia	BC	1,300	0.71
Alberta	AB	900	0.49

[3] U.S. Energy Information Administration (EIA), Coal Transportation Rate Database (CTRDB), Table 2.02 Coal Field to Census Division: Average Transportation Rates, Distances, and Costs for Contract Coal Shipments to Electric Utilities, by Coal Field and Census Division, 1979, 1990, 1999, 2000, 2001.
[4] This rate reflects the 10 mill per ton-mile rate for Midwest utilities with an adjustment to remove the fixed costs associated with rail rolling stock.
[5] U.S. Department of Transportation and U.S. Department of Commerce, 2002 Economic Census, 2002 Commodity Flow Survey, Wyoming, Issued December 2004.
[6] Annual variable transportation costs are adjusted to reflect 25 percent of the annual change in the Council's diesel fuel forecast. See the Council's Revised Fuel Price Forecast, September 11, 2007.

Natural Gas Prices

Natural gas prices from the Council's recently revised fuel price forecast are used for this power price forecast. With the exception of Idaho and Montana, the assumptions used to develop load-resource area prices for AURORA are those used for the Fifth Power Plan. The approaches used to estimate Idaho and Montana natural gas prices were revised to better reflect the factors controlling gas prices in those two states.

Previously, the Idaho load-resource area price was based on the Rocky Mountain hub price adjusted for a distance-based basis differential representing transportation on the Williams Northwest pipeline serving southern Idaho. For the current forecast, Idaho natural gas prices are based on Sumas hub prices and the basis differential used for the Northwest west of Cascades load-resource area. The resulting Idaho natural gas prices are therefore identical to the Pacific Northwest West gas prices. Underlying the revised approach is the fact that the Williams Northwest pipeline levies a constant "postage stamp" rate, hence prices along the pipeline ought not to be sensitive to distance.

Montana gas prices, like those of Idaho in earlier forecasts are based on the Rockies trading hub plus a distance-based basis differential. Montana utility staff have indicated that pipeline capacity to Montana would require expansion to accommodate any significant increase in gas-fired generating capacity and that expansion would likely source Alberta gas. Hence the Montana gas price in this study is based on AECO hub prices plus a basis differential equivalent to the basis differential used for the Pacific Northwest East (PNWE) load-resource area (PNWE gas prices are also based on the AECO hub because of the Alberta origin of the PGT pipeline serving the PNWE area). The revised natural gas prices for the Northwest load-resource areas are shown in Figure 2.

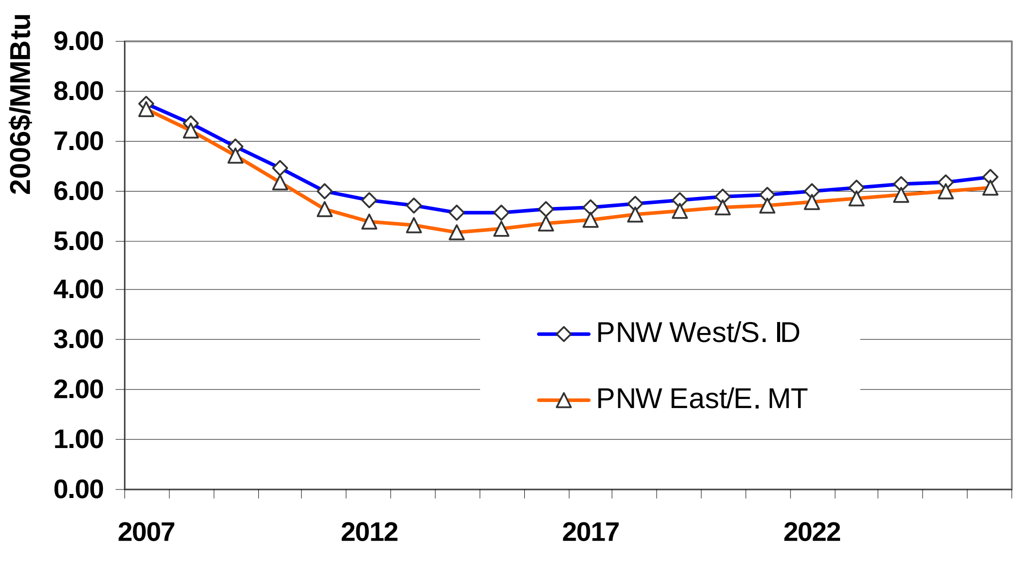

Figure 2: Delivered natural gas prices for the Pacific Northwest load-resource areas (2006$/MMBtu)

New Resource Capital Costs

Prior to adoption of the Fifth Power plan, the real capital cost of new resources had declined more or less continuously over a period of many years, driven by technology improvements, a buyer's market and a strong dollar. However, beginning in 2004 the capital cost of wind plants began to rise in real dollar terms. The Council, in its Biennial Assessment, identified a capital cost increase of 20 to 30 percent over the Fifth Power Plan base year costs for wind power. This increase was attributed to a weakening dollar, escalation in the price of commodities such as copper, steel and cement used in power plant construction and a shortage in skilled labor and specialized equipment used for construction of wind plants. The Council concluded that the observed cost increase was likely a cyclic phenomenon and that costs would likely revert to trends identified in the Fifth Plan unless the adoption of state resource portfolio standards continued to drive a seller's market in wind power. At the time, fossil generation appeared to be only moderately affected by construction cost escalation.

Power plant construction costs have continued to rise and now appear to have affected all forms of power generation. Pending the comprehensive resource assessment scheduled for development of the Sixth Power Plan, this forecast will use the resource cost assessment of the Biennial Assessment, with the exception of the cost escalation rates. With the exception of solar photovoltaics, these have been set to zero given the current uncertainty regarding future price trends. The base year (2006) resource construction costs used in this forecast are shown in Table 2 compared to the equivalent costs of the Fifth Power Plan.

Table 2: Revised capital costs for new resources (2006$/kW, 2010 service)

	Fifth Plan	Biennial Assessment
Gas turbines (Aeroderivative)	$666	$676
Gas turbines (Frame)	$416	$422
Combined-cycle	$585	$591
Pulverized coal (supercritical)	$1449	$1457
Integrated gasification combined-cycle	$1725	$1750
Solar photovoltaics	$3288	$3288
Wind power	$912	$1500

In addition to the changes in construction costs described above, the heat rates of supercritical pulverized coal and coal gasification power plants were revised as described in Appendix F of the Biennial Assessment. All new pulverized coal-fired power plants are now assumed to use supercritical technology.

State Renewable Portfolio Standards

Since adoption of the Fifth Power Plan, renewable resource portfolio standards (RPS) have been established in Colorado, Oregon and Washington. Currently, eight states within the WECC have RPS (Table 3). To model renewable portfolio standards in AURORA, assumptions must be made regarding the types of renewable resources that will be developed, and the success in achieving the targets. For the Fifth Power Plan power price forecast, RPS states were assumed to meet 75 percent of their target levels of renewable resource development. Because of much greater public concern regarding greenhouse gas control, expanded initiatives for renewable resource development, prospects for even more aggressive RPS in some states, and indications that utilities will be able to achieve the initial target levels of development in most RPS states, 100 percent achievement of RPS targets was assumed for the base case of this forecast. A sensitivity analysis assuming 75 percent achievement of RPS targets was also run. Target levels of renewable resource development and the assumptions regarding the resource mix for this study are shown in Table 3.

Table 3: Renewable portfolio standard basic targets and resource mix assumptions

	Basic Standard (load-based)	Assumed Mix
Arizona	15% by 2025	33% biomass 67% solar PV
California	20% by end of 2010	75% biomass (N. CA) 50% geothermal (S. CA) 25% solar PV (S. CA) 25% wind
Colorado	20% by 2020 (IOUs) 10% by 2020 (COUs)	33% biomass 67% wind
Montana	15% by 2015	10% biomass 90% wind
New Mexico	20% by 2020 (IOUs) 10% by 2020 (Coops)	33% biomass 67% wind
Nevada	15% by 2015	100% geothermal (N. NV) 50% geothermal (S. NV) 50% solar (S. NV)
Oregon	25% by 2025 (large utilities)	20% biomass 80% wind
Washington	15% BY 2020	15% biomass 85% wind

Planning Reserve Margin

The AURORA^{xmp} model provides the capability to perform optimized long-term system expansion studies to achieve and maintain planning reserve margin targets. The studies provide an optimized build-out of system resources and estimates of annual capacity prices needed for the marginal capacity resources to economically supply capacity to the system.

AURORA^{xmp} requires planning reserve margin targets to be based on the single highest hour of demand during the year. Reserve margin targets can be set at both the load-resource zone and operating pool level and the optimization logic can be set to either meet or exceed the target or to minimize the deviation from the target.

The Council has configured AURORA^{xmp} to simulate power plant dispatch in 18 load-resource zones that make up the WECC electric reliability area. Planning reserve margin targets are specified for two operating pools: (1) the Pacific Northwest region comprised of 6 load-resource zones; and (2) the California Independent System Operator (CA ISO) comprised of 2 load-resource zones. The remaining 10 load-resource zones were given individual reserve margin targets. For the CA ISO and 10 stand-alone zones, the planning reserve margin target was set at 15 percent. All of the planning reserve margin targets were set as minimums that are to be met or exceeded in the long-term system expansion studies.

For the Pacific Northwest region, the Council configured AURORA^{xmp} to reflect the capacity standard of the Pacific Northwest Power Supply Adequacy Forum (Adequacy Forum). The Adequacy Forum has determined that reserve margin targets of 25 percent in winter and 19 percent in summer correspond to an overall system loss-of-load probability of 5 percent.

These reserve margin targets cannot, however, be directly input into AURORA^{xmp}. The Adequacy Forum targets reflect a specific set of resource and load assumptions that cannot be easily replicated in AURORA^{xmp}. For example, the Adequacy Forum reserve margin targets are based on consideration of the highest average demand for a 50-hour peak period, while the AURORA^{xmp} targets are based on consideration of the single highest hour of demand.

For electricity price forecasting purposes, the Council converted the Adequacy Forum's multiple-hour capacity reserve margin targets to a single-hour target. Adjustments were also made to reflect consistent treatment of spot market imports, hydro conditions and flexibility, and Independent Power Producer (IPP) generation. The converted single-hour capacity reserve margin for the Northwest is 18 percent.

Conversion of the Adequacy Forum's capacity reserve margin targets does not reflect a change in adequacy standards. Both the Adequacy Forum's targets and the targets used in AURORA^{xmp} reflect an overall loss-of-load probability of 5 percent for the Northwest.

AURORA^{xmp} also provides the capability to set the contribution that each resource can make towards meeting the reserve margin target. The Council configured the model to limit the single-hour capacity contribution of Pacific Northwest hydro resources to 88 percent of nameplate capacity. The limit for wind and solar power resources was set at 15 percent of nameplate capacity.

<u>Base Case and Sensitivity Case Forecasts</u>

This interim wholesale power price forecast includes a base case forecast and several alternative cases which test the sensitivity of the base forecast to changes in input assumptions. The base case, and all of the sensitivity cases include the revised capital costs from the Biennial Assessment of the Fifth Plan. These fixed costs impact the long-term forecast of resource additions and retirements and the associated capacity prices for each of the cases.

The base case electricity price forecast uses the Council's revised medium coal and medium natural gas price forecasts and the schedule of resource additions needed to fully achieve state RPS requirements. Post- 5th Power Plan resource additions plus the schedule of RPS resource additions fully replaces the final portfolio of resource additions of the Fifth Power Plan used in prior Council configurations of AURORA[xmp]. Other base case assumptions are consistent with those used in the Fifth Power Plan.

The sensitivity analysis starts with the base case assumptions and changes a single model input. Sensitivity cases include: high and low fuel price cases, a high CO_2 tax case, and a low RPS achievement case. The low RPS achievement case assumes 75 percent achieve of state RPS targets

The CO_2 tax case uses the maximum CO_2 tax trajectory from the Fifth Plan. The following figure compares the CO_2 tax trajectories of the base case and high CO_2 tax case.

Figure 3: Base and high CO_2 tax cases

Findings

Energy price forecast

The forecast Mid-Columbia trading hub price, levelized for the period 2007 through 2026 is $35.50 per megawatt-hour. In the following figure, the current forecast is compared to the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour) and the base case of the Biennial Assessment (levelized value of $38.80 per megawatt-hour).

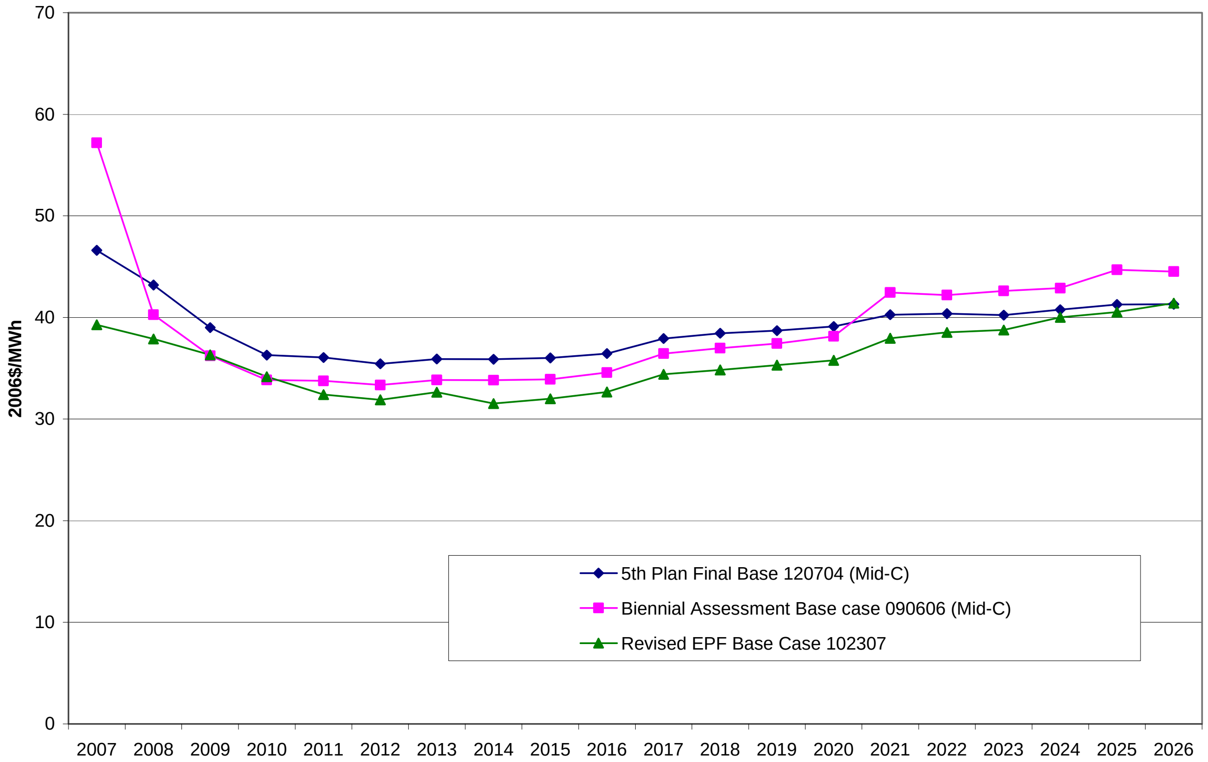

Figure 4: Interim energy price forecast base case compared to previous base case forecasts

The interim forecast prices decline from 2007 highs as new renewable resources with relatively low variable operating costs are added to the system to meet state RPS requirements.

The low variable cost of resources added to satisfy state RPS requirements are the biggest reason for the difference between the interim base forecast and the previous base forecasts. The following figure shows the annual energy output of RPS and other planned new resources for the period 2007 and 2026.

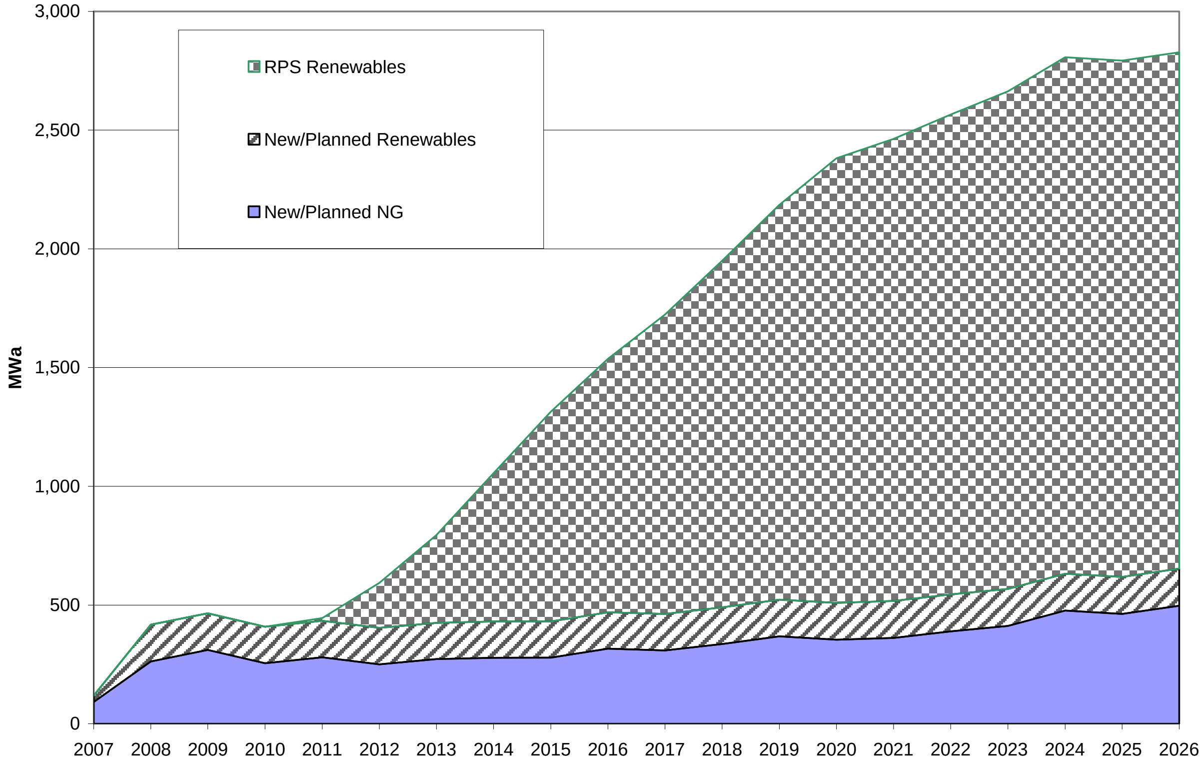

Figure 5: Forecast energy output of Pacific Northwest resource additions 2007-26

Annual average prices conceal likely episodic price excursions due to natural gas price volatility or deviations from average hydro conditions. They also conceal important seasonal and time-of-day price variation. The monthly average prices shown in the following table reveal the seasonal and time-of-day variation.

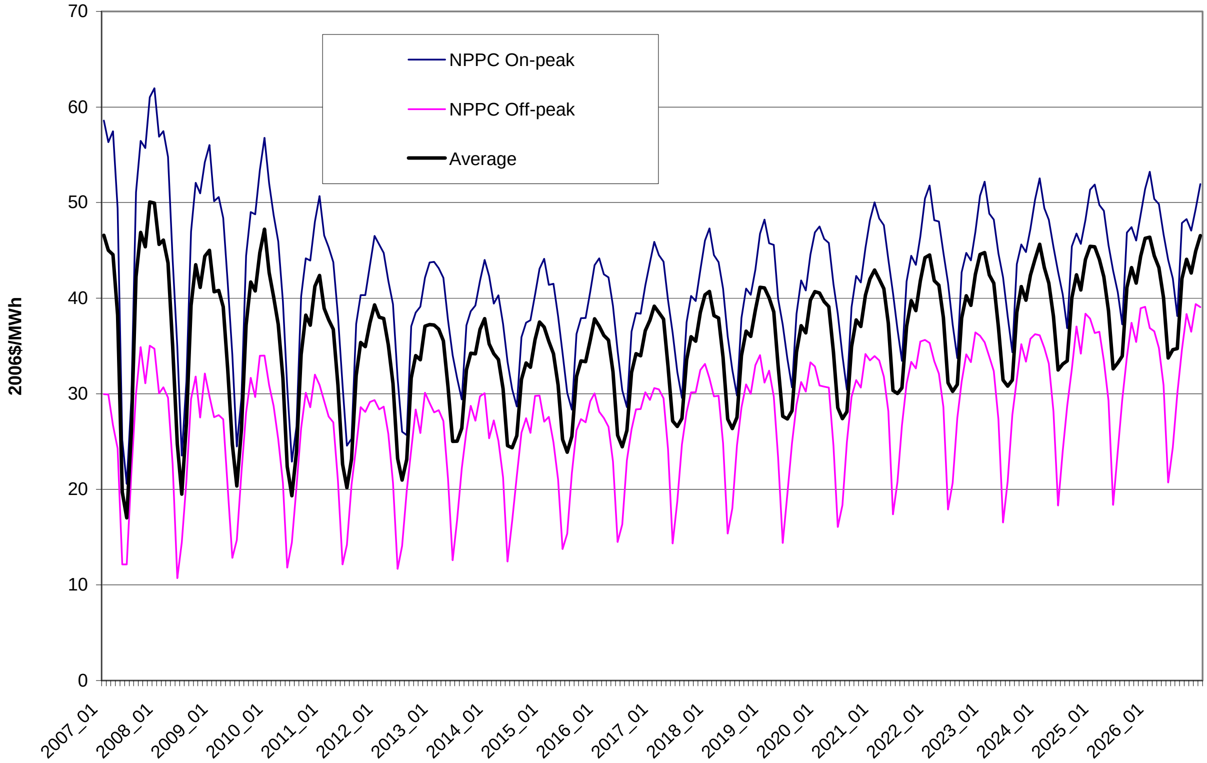

Figure 6: Forecast Mid-Columbia average monthly energy prices

The spread between on-peak and off-peak prices, which averages nearly $15 per megawatt-hour over the forecast period, appears to be larger than that experienced in recent history. The Council will continue to investigate this result and provide an explanation in the final version of this paper.

The value of power varies by time of day and day of week because the marginal power plant changes with load. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours whereas coal-fired plants with lower variable costs are frequently on the margin during nighttime and weekend low load hours. The Council and the Regional Technical Forum use four load segments for assessment of the cost-effectiveness of conservation measures - many of which are most effective at specific times of day. Figure 7 shows the levelized base case price forecast for the four load segments.

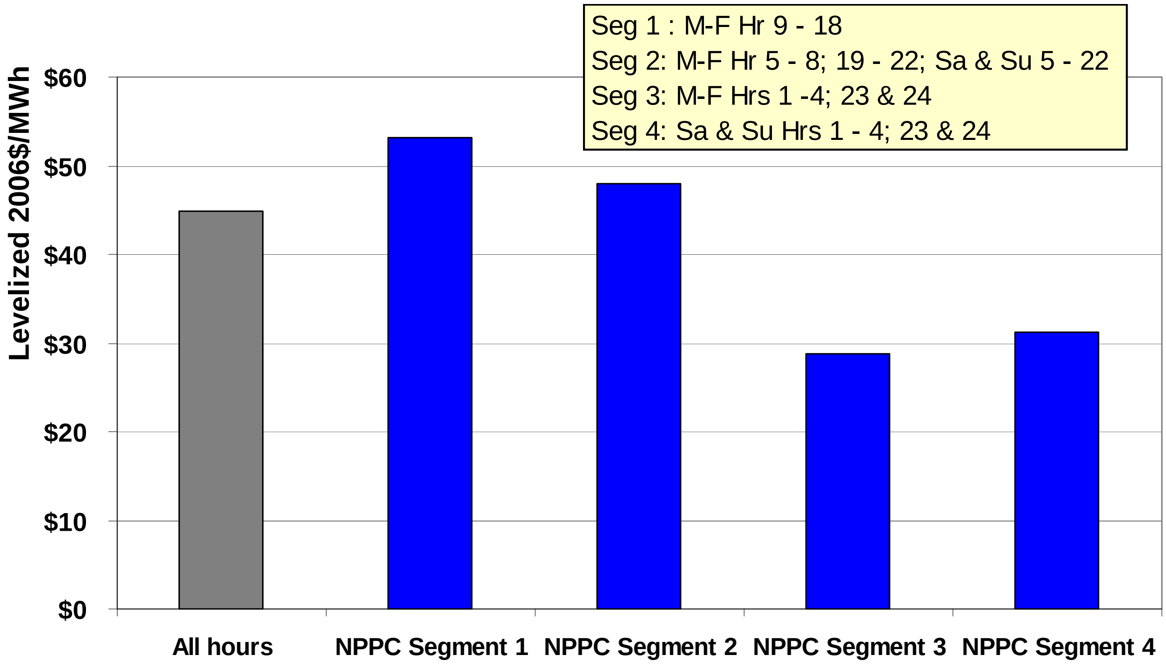

Figure 7: Forecast Mid-Columbia levelized energy prices by load segment

Sensitivities

In all of the Council's sensitivity cases the future resource mix of the Pacific Northwest is invariant with respect to forecast electricity prices. This is a direct result of the level of renewable resources being added to the system to meet state RPS requirements. This, combined with recent construction appear to satisfy all energy and capacity needs, at least on a regional basis (additional thermal capacity may eventually be needed for integration of intermittent renewable resources). The forecast annual average energy prices for the base and sensitivity cases are plotted in the following figure.

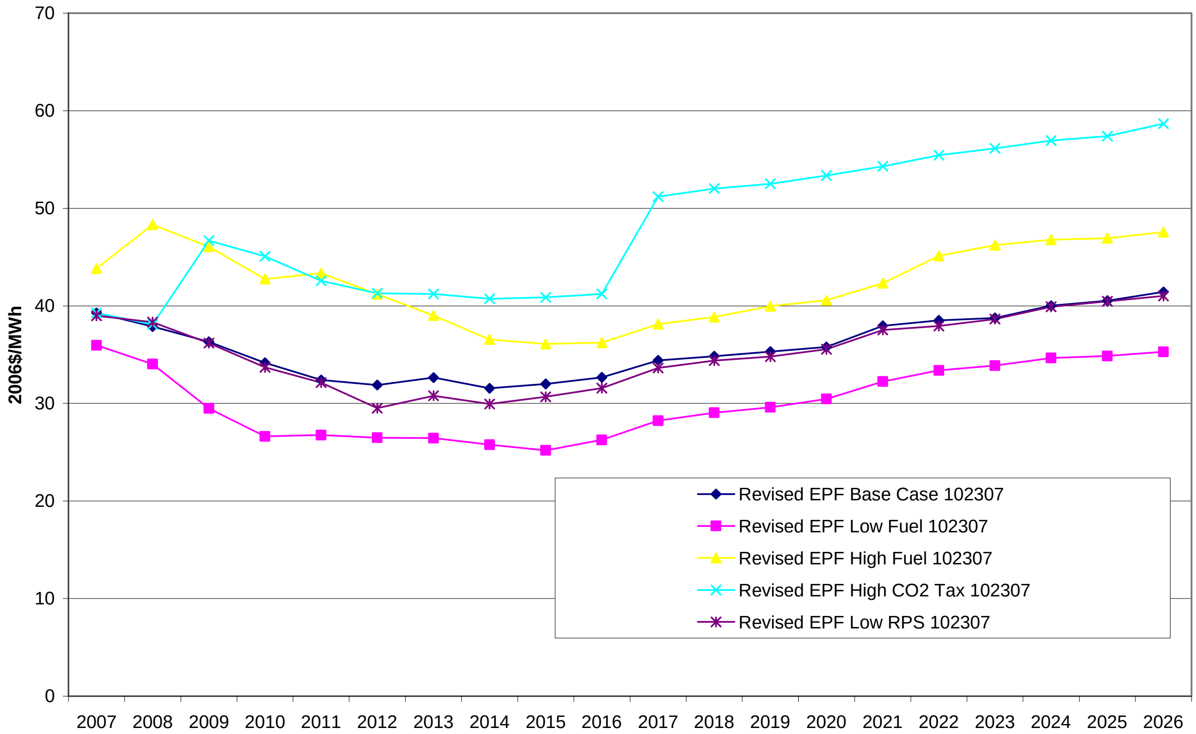

Figure 8: Interim energy price forecast base case compared to sensitivity case forecasts

The levelized Mid-Columbia price for the low fuel price case is $29.90 per megawatt-hour, 16 percent lower than the base case. The levelized Mid-Columbia price for the high fuel price case is $42.20 per megawatt-hour, 19 percent higher than the base case.

The high CO_2 tax case results in a levelized price of $46.50 per megawatt-hour.

The levelized price for the low RPS case is $34.90 per megawatt-hour. This is 2 percent lower than the base case which assumes full achievement of RPS requirements. The reason for this difference is not currently understood. The Council will continue to investigate this result and provide an explanation in the final version of this paper.

Capacity price forecast

The following figure shows the simulated annual peak-demand-hour reserve margin for the Pacific Northwest from the base case price forecast.

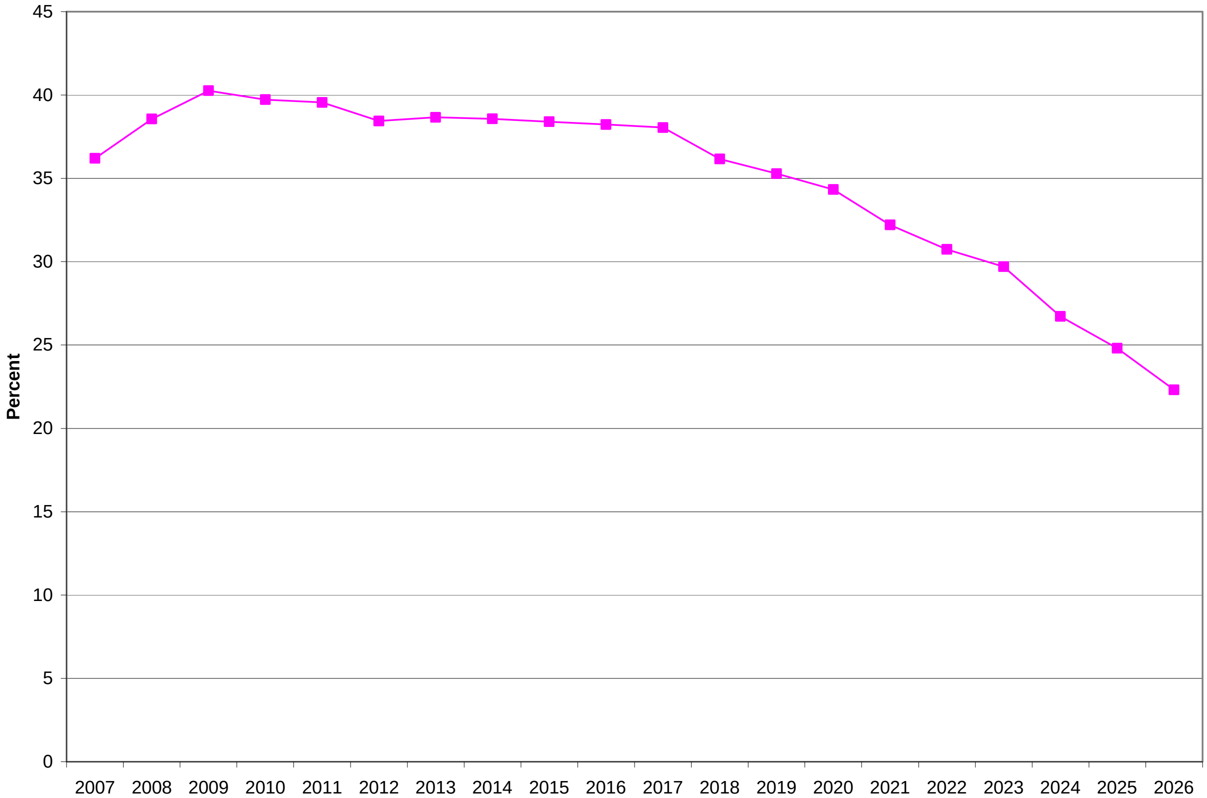

Figure 9: Forecast Pacific Northwest Annual Peak-hour Capacity Reserve Margin

The reserve margins are well above the capacity target of 18 percent for most of the planning period. This result reflects the current surplus position in the region and the addition of RPS resources over the planning period. The long-term optimization logic of AURORA^{xmp} does not add any new resources to this part of the system during the planning period.

The following chart shows the nameplate capacity of RPS resources and other new or planned resources for the period 2007 through 2026.

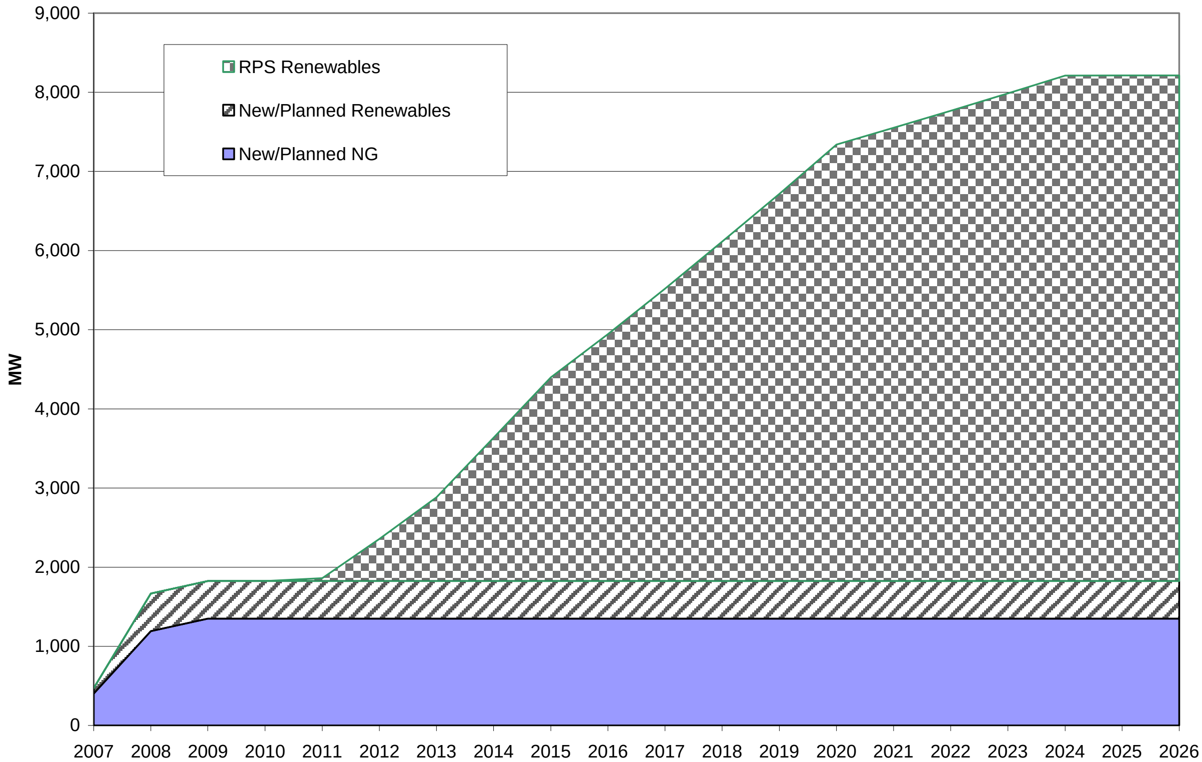

Figure 10: Forecast Nameplate Capacity of Pacific Northwest Resource Additions 2007-26

In the Council's configuration of AURORA^{xmp}, the capacity contribution of wind resources is set at 15 percent. Recent experience in the Pacific Northwest suggests that the capacity contribution of wind may be dramatically lower.

Preliminary sensitivity analysis, using a wind capacity contribution value of 5 percent, resulted in new resource development in the Pacific Northwest during the period 2027 through 2031. This is the five-year period added to the end of the forecast period to improve long-term resource optimization. The resource development consisted of 300 megawatts of new wind resources, 100 megawatts of solar resources, and 1,450 megawatts of natural gas peaking resources. The Northwest Wind Integration Forum is currently investigating the capacity value of wind. The Council will continue to analyze the impact of this capacity contribution on long-term resource development in the Sixth Power Plan.

AURORA^{xmp} not only builds resources to maintain operating pool and load-resource zone capacity reserve margin targets, it also provides estimates of the annual capacity prices needed for the marginal capacity resources to economically supply capacity to the system. The AURORA^{xmp} capacity prices represent the payment that would be necessary to allow the marginal capacity resource to recover its total costs for the operating year. In other words, the capacity prices represent the above-energy-market cost of the marginal capacity resource.

It is helpful to think of the AURORA^{xmp} capacity price calculation as occurring in a simplified progression of steps:

1) Estimate the annual operating profit and peak-hour capacity contribution for each resource in an operating pool or zone.
2) Rank the resources from most profitable to least profitable and calculate the operating pool or zone's cumulative peak-hour capacity.
3) Identify the single highest hour of demand for the operating pool or zone and add the applicable capacity reserve margin to establish the capacity target for the pool or zone.
4) Identify the least profitable resource that provides capacity to meet the capacity target on the peak-hour of the year. This is the marginal capacity resource.
5) If the marginal capacity resource has a negative operating profit for the year, then set this amount as the capacity price for the operating pool or zone. If the marginal capacity resource has a positive operating profit for the year, then set the capacity price to zero.

The capacity price is the payment amount necessary to make the marginal capacity resource whole for the operating year.

The following figure shows the estimated capacity prices for each of the load-resource zones in the Pacific Northwest region from the base case forecast. The average of the load-resource zone prices is an estimate of the overall pool prices. Capacity prices for the Northwest Power Pool are estimated to remain at zero through 2013 and then to increase to nearly $17 per kW-year by 2026.

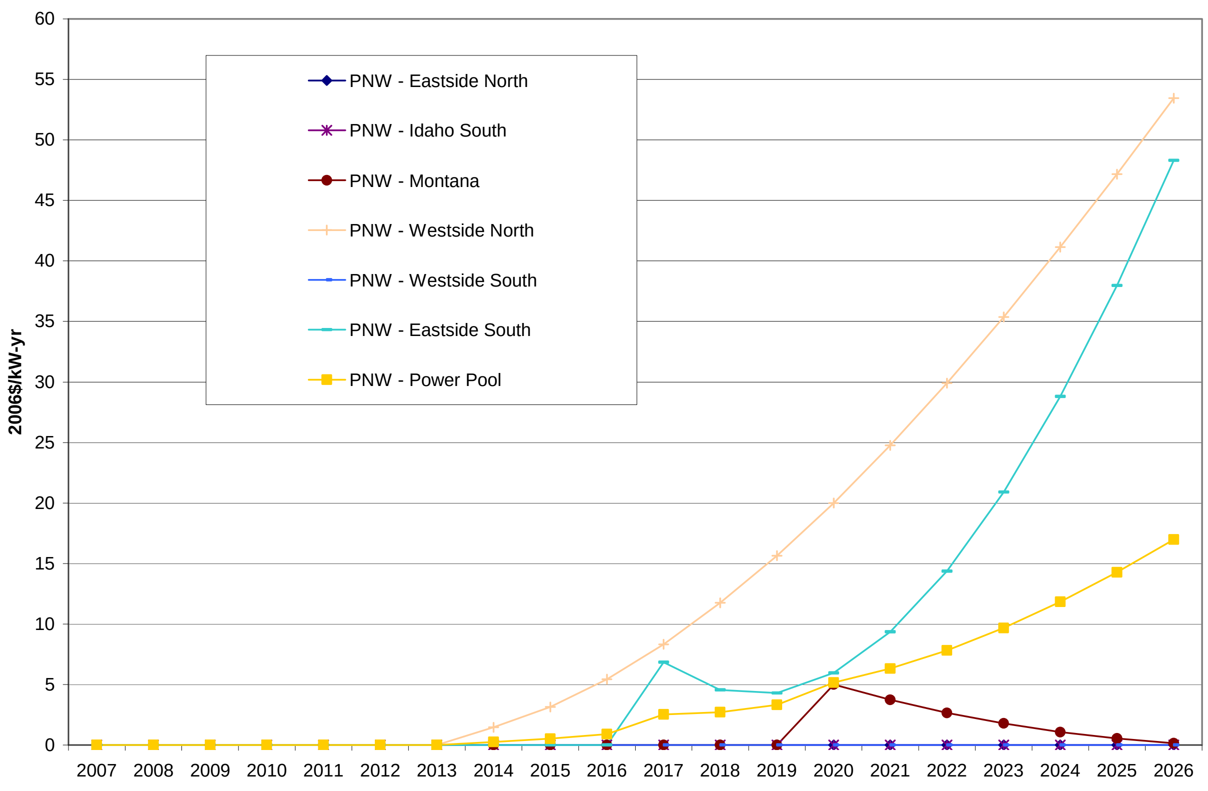

Figure 11: Interim Capacity Price Forecast for the Northwest Region

Interpretation and Recommendations

Given the current surplus load-resource balance in the Pacific Northwest and the expected addition of renewable resources to achieve state RPS requirements, the region can expect lower wholesale electricity prices in the future. Adding significant amounts of wind and other renewable resources with low variable costs to the Pacific Northwest resource mix should result in lower-cost resources clearing the market, and setting market prices, during many hours of the year. These lower market-clearing prices will not, however, reflect the capital and other fixed costs associated with bringing the RPS resources on-line. These costs will presumably need to be covered in bi-lateral contracts or through utility rate base.

The Council's interim long-term power price forecasts reflect these market fundamentals. The forecasted energy and capacity prices are insufficient to cover the total cost of the marginal qualifying RPS resource. Because of this, the conventional use of long-term market prices as a determinant of resource cost-effectiveness needs to be revisited. In the future at times when state RPS requirements are driving new resource additions, the avoidable resource will normally be the fully allocated cost of the marginal qualifying RPS resource. However, there may be periods when regulation and load-following capacity is needed to integrate wind and other intermittent renewable resources. The least-cost resource providing these services may be the marginal new resource at these times.

The fully-allocated cost of the "generic" new renewable resources assumed to be developed to meet state renewable portfolio standards in this forecast are illustrated in Figure 12. Though the fully allocated cost of generic biomass and geothermal resources are lower than that of wind, the former are typically limited in availability so wind power is expected to set the "RPS avoided cost". The costs of actual projects will, of course vary, sometimes widely from the generic resource costs used in this forecast.

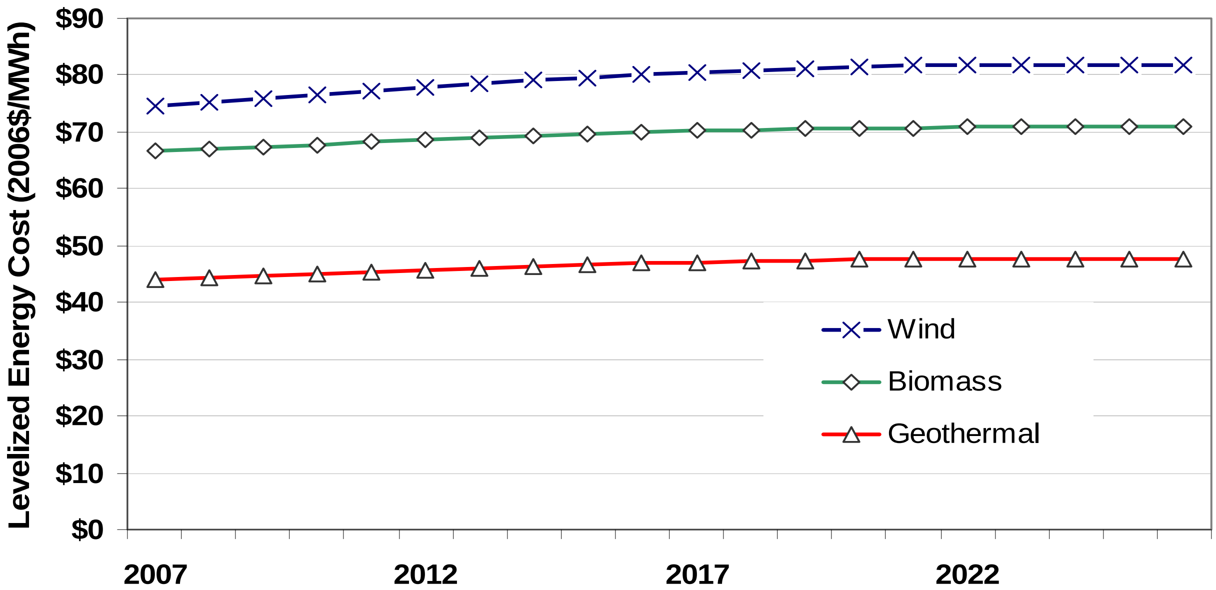

Figure 12: Annual levelized fully allocated RPS renewable resource cost (2006$/MWh)

The value of the marginal resource at times RPS requirements are satisfied, or when integration services are required is comprised of its energy market value, its capacity value, and the value of any intra-hour ancillary services it may provide. These intra-hour ancillary services, for example, regulation and load-following services, are likely to increase in value as more RPS wind resources are added to the regional resource mix.

The Council will continue to explore these issues during development of it upcoming Sixth Power Plan.

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