Renewables Portfolio Standards

A Progress Report by Utilities and Industries

January 2007

PNUCC

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PNUCC
101 SW Main, Suite 1605
Portland, OR 97204

(503) 294-1268

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Section 1. Introduction

The PNUCC Board of Directors launched an effort in the spring of 2006 to identify issues associated with designing and implementing Renewables Portfolio Standards (RPS) for Northwest utilities. A PNUCC Task Force was asked to develop information about these standards that could be provided to ratepayers, utility managers, policy makers, and elected officials, and to identify issues associated with implementing them.

The Task Force reviewed the status of standards nationally and regionally. At the time our effort began, Montana had adopted an RPS, proponents in Washington were developing an initiative for the November 2006 ballot (which was subsequently adopted), and the governor of Oregon had a group working to develop a proposal for the 2007 legislature.

This Task Force report provides a brief overview of standards, identifies and analyzes key issues, and suggests possible solutions to remedy areas of concern. The purpose is to provide an unbiased overview of utility considerations related to developing and adopting an RPS. It is not intended as a consensus utility/industry point of view. We anticipate a separate effort by individual utility managers or groups of utilities that will provide a forum for developing consensus positions on many of the key elements, both as they pertain to shaping policies in Oregon and implementing the new law in Washington.

A significant body of literature exists on RPS and the Task Force developed a bibliography, which is included at Appendix A. In addition, facts and figures about the region's electricity system provide important context for the following discussion. An overview of loads and resources is presented in Appendix B.

Renewables Standards - An Overview

At the end of 2006, Renewables Portfolio Standards had been adopted in 24 states across the nation. Most of these standards have been in place for less than five years, and it is significant that no two states share the same standards. As varied as the standards adopted in each state, are the goals and objectives they hope to achieve:

- reducing green house gas emissions
- increasing power supply fuel diversity
- encouraging development of new technologies
- assisting local rural economies
- developing a specific amount and type of resource, and
- increasing agricultural activity.

Although each state standard is different, they share common elements. At its core, each RPS requires the retail electricity provider to supply a minimum percent (target amount) of its retail load with *eligible* sources of renewable energy by a certain date, and typically, that amount increases over time. The standards may allow tradable renewable

energy credits (RECs) and/or include geographic restrictions on where the renewable resource is located. The standards usually apply to a subset of the utilities in a state, based on the number of customers served or the type of utility ownership structure. Other elements that appear in the standards are a retail rate impact test, cost cap or floor, a "long-on-resources" test, and enforcement provisions that specify off-ramps and penalties for non-compliance.

As states implement their standards and others look to develop legislation, the following elements are of particular significance: target, eligibility, and cost caps.

Target

Nearly all Renewables Portfolio Standards include a target expressed as a percent of load at a set time. For example, the Washington RPS adopted in I-937, requires utilities with more than 25,000 customers to serve 15 percent of their load with qualifying renewable resources by 2020. Oregon's governor is proposing a target that will require utilities to serve 25 percent of their load with renewable resources by the year 2025. One advantage of the percent-of-load approach is its simplicity. It is easy for the citizens to understand and is reasonably simple to monitor.

Eligibility

Every Renewables Portfolio Standard includes a definition of resources that are eligible to be considered as renewable and counted toward a utility meeting its target. No two states have exactly the same definition. Key features in determining resource eligibility are the date of construction, geographic location, fuel/technology type, credits,[1] and conservation.[2] Although some states refer to hydropower as a renewable resource, it is generally not included as eligible and does not count toward a utility's target.

In most states, the types of resources designated as eligible to meet the RPS include: hydro (where allowed, only small hydro or incremental improvements to existing plants), wind, solar, geothermal, landfill gas, wave, ocean or tidal, gas from sewage treatment facilities, bio-diesel, and biomass from animal waste or solid organic fuels from wood.

Cost Cap

Many of the states include a limit on the costs associated with implementing an RPS. In effect, these cost caps provide a way for a utility to be in compliance with the RPS on the basis of financial or cost considerations. Many utilities would find that complying with an RPS requires deviating from a least-cost integrated resource plan. The cost cap is

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[1] Renewable energy credits are also considered eligible resources in many RPS. These credits, which are acquired from other resource owners, can be used by a utility to meet its target for a particular year. This allows a utility flexibility in meeting its RPS target.

[2] Washington's new law requires a qualifying utility to "pursue all available conservation that is cost-effective, reliable, and feasible." Definitions of the terms conservation and cost-effective are included in the statute. The conservation requirement is in addition to the load-based target for renewable resources.

intended to protect end-use consumers from excessive costs and the state's economy from unintended impacts.

Status of Standards in the Pacific Northwest

State of Montana

Montana passed the first Renewables Portfolio Standard in the Pacific Northwest during the 2005 legislative session. Load-serving utilities with more than 5,000 meters are required to meet 15 percent of their retail load with qualifying renewable resources by 2015. The statute also includes interim targets of 5 percent by 2008, and 10 percent by 2010.

The Montana RPS allows the typical list of eligible renewable resources and also considers hydropower eligible, when provided by a "hydroelectric project that does not require a new appropriation, diversion, or impoundment of water and that has a nameplate rating of 10 megawatts or less."

The Montana law features a cost cap to limit the impact to retail customers. The cap relieves a utility of the obligation to acquire renewables to meet the targets if the cost of the renewable is 15 percent or more than the cost of another resource. And the Montana legislation provides for the application of renewables energy credits to meet load targets.[3]

State of Washington

Washington's RPS statute, adopted by ballot initiative (I-937) in November 2006, places new load-service and conservation requirements on all utilities serving more than 25,000 customers. It addresses both renewable resources and conservation.

The renewable resource section requires that 15 percent of a qualifying utility's load be served from renewables by 2020. There are interim targets of 3 percent by 2012 and 9 percent by 2016. Eligible resources include wind, hydro (incremental generation), ocean, solar, landfill gas, sewage gas, bio-diesel, and biomass. The law allows efficiency improvements to hydroelectric generation projects as eligible, with the exception of the Federal Columbia River Power System (FCRPS). It also includes as eligible "hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments."

The law considers a renewable resource eligible if it began operating after March 31, 1999. It places geographic restrictions on the eligibility of resources, requiring that the generating facility be located in the Pacific Northwest or that "the electricity from the

[3] The law defines the credit as "a tradable certificate of proof of 1 megawatt-hour of electricity generated by an eligible renewable resource that is tracked and verified by the commission and includes all of the environmental attributes associated with that 1 megawatt-hour unit of electricity production."

facility is delivered into Washington State on a real-time basis without shaping, storage, or integration services."[4] Extra credit is given for renewable resources that commenced operation after December 31, 2005 and in which the developer used apprenticeship programs. There is also a provision for use of renewable energy credits.

There are three exceptions to compliance with the renewable acquisition mandate. The first is for utilities that average no weather-adjusted load growth over a three-year period. These utilities are still required, however, to spend 1 percent of their annual total revenue requirement on renewable acquisitions.

The second exception addresses the failure of a utility to meet its renewable target due to events beyond its reasonable control, such as weather-related damage, mechanical failure, hydro generation variability, and strikes, lockouts or actions of government authorities that adversely affect the generation, transmission or distribution of a renewable resource under contract to a utility.

The third exception falls under the heading of resource costs. A utility would be considered in compliance with a renewable target for a given year if the utility invests 4 percent of its annual retail revenue requirement in the incremental costs of renewable resources. Incremental cost is essentially the above-market cost of renewables. It should be noted that the initiative language on this topic needs to be clarified.

Under this approach to a cost cap, Washington allows a utility to choose the type of eligible renewable resources it purchases or develops. The law does not specify that the choice be the lowest-cost resource. Utilities serving in Washington may also invest over the 4 percent cost cap if they choose.

A utility that fails to comply with its energy conservation or renewable target will pay a penalty of $50 per megawatt-hour (MWh) for any shortfall. The amount of the penalty will increase with inflation.

The conservation acquisition section of the law requires qualifying utilities to pursue cost-effective conservation. By January 1, 2010, each utility must establish a two-year achievable target that is consistent with the methodology in the Northwest Power and Conservation Council's power plan. Failure to meet the target will result in penalties. The statute does not define "achievable".

State of Oregon

Oregon's governor is proposing an ambitious standard of 25 percent of qualifying utilities' loads being served by renewable resources by the year 2025. The Oregon Renewable Energy Working Group, organized by the governor's office, has been meeting since the summer of 2006. Its objective is to develop an RPS template that will provide the basis for a new law to be enacted by the 2007 Oregon legislature.

[4] Washington Initiative 937, Section 3 (10) (a).

State of Idaho

There are presently no known discussions in Idaho regarding proposals to develop a renewables statute for that state.

Section 2. Key Issues and Potential Alternatives

The design and implementation of Renewables Portfolio Standards in the Pacific Northwest states raises issues that face policymakers throughout the country, as well as issues that are unique to the region. A major issue for the Pacific Northwest is how RPS legislation and policies treat renewable hydroelectric resources. A second is the ramifications of standards for utilities' power-purchasing relationship with the Bonneville Power Administration (BPA).

In adopting standards, Montana and Washington have considered these issues and come up with ways to approach them. The PNUCC Task Force was able to capture the experience of these states as it went about identifying issues and suggesting potential alternatives. The following discussion helps to point out ramifications of various approaches to RPS as they relate to circumstances in the Pacific Northwest. As we work toward adoption and implementation of RPS, there is a need to develop provisions and amendments that would minimize unintended consequences in the region.

Setting Renewable Resource Targets

The most common RPS target is expressed as a percent of a utility's load. This approach presents some particular challenges for the Pacific Northwest. The Washington law and what seems likely to be proposed in Oregon would require some utilities to forgo meeting their loads with BPA's lowest-price Priority Firm power (Tier 1) or to purchase renewable energy credits to make Tier 1 power eligible. (A discussion of Tier 1 power under the post-2011 BPA contracts is presented later in this report.) In addition, some utilities could be required to acquire renewable resources ahead of their customers' needs. These unintended consequences would occur when the utility's load growth falls below what it must acquire to meet the RPS target.

To further complicate matters, it is unlikely that all new resources a utility acquires will be renewable. If the RPS target is set as a percent of a utility's load, it would be applied both to load growth and to some portion of existing load.

Another key question is whether the target, defined as a percentage of a utility's total load, can be met reliably by renewable resources. The Northwest Power and Conservation Council conducted an analysis of the future availability of resources, including renewables, for its Fifth Power Plan in 2006. A table in a later section of this report provides estimates from the Council's analysis. Of particular concern in the Pacific Northwest is whether the percent-of-load target should apply to all loads or only to loads that are not now served by hydropower or other renewables.

Target as Percent-of- Load-Growth

One alternative to the percent-of-load approach would be if the RPS target is expressed in terms of meeting a percentage of load *growth*. We would avoid the problem of building resources ahead of need and/or foregoing BPA Tier 1 power. The percentage would have

to be substantially higher in this approach than in the percent-of-load approach to provide for meeting roughly the same level of regional loads with renewable resources.

For example, assume a Washington utility's current load is 80 average megawatts (MWa), and it grows to 100 MWa by 2020. In order to achieve an amount of new renewable energy that is comparable to the percent-of-load amount, the target using a percent-of-load-growth approach would need to be 75 percent (15 MWa divided by 20 MWa)). This approach would also require each utility to define a base against which to measure growth, a requirement that adds complexity to the calculation. An average of some number of previous year's load growth might be used to establish the base. This approach would also dampen potential peaks and valleys that would result were a single-year load-growth data point to be used.

Percent of Non-Renewable Load

Neither the percent-of-load nor percent-of-load-growth approach reflects the renewable nature of the hydropower resources currently serving loads in the Northwest. To recognize this, another approach would be to base the target on a percent of loads served by non-hydropower or other existing renewable resources. In other words, acknowledge the fact that 60 to 80 percent (depending on water conditions) of Northwest loads are met annually with renewable hydropower. If the goal is to reduce greenhouse gas emissions, the renewable target could be based on the load that is not met with existing, non-CO_2-emitting renewable resources, including hydropower. Once again, the percentage target would need to be recalculated if the goal were still to get an equivalent amount of load (e.g. 15 percent by 2020) served by renewables.

Include All Renewable Resources

It is common for the standards to count as eligible only resources that were built after a certain date. For example, the Washington law considers a renewable resource eligible if it began operation *after* March 31, 1999. There are other instances of geographic restrictions on the eligibility of resources. The Washington law requires the generating facility be located in the Pacific Northwest or that "the electricity from the facility is delivered into Washington State on a real-time basis without shaping, storage, or integration services."[5] While this latter restriction is likely intended to maximize the development of resources in Washington, it excludes the potential to develop the best wind generation resources in the western United States, those in Montana, since there is no transmission capacity to Washington for energy to be delivered under this requirement and the best Montana resources are on the east side of the Continental Divide.

[5] Washington Initiative 937, Section 3 (10) (a).

Treating Hydropower as a Renewable Resource

In RPS adopted across the nation, existing hydroelectric resources have uniformly been excluded as eligible renewable resources. In many instances, even recently completed or proposed incremental improvements in hydro generation have been deemed ineligible.

This exclusion fails to acknowledge that hydropower, as a generating source, is completely aligned with the commonly stated objectives of RPS proponents. Hydropower is clean and does not emit greenhouse gases. It is renewable, produced domestically, offers stable fuel costs and long-term price stability, is often local, and generally situated in rural areas. In addition, as the Federal Energy Regulatory Commission considers relicense applications for hydro projects, social and environmental concerns are being addressed and squared up with current societal values. The same can be said of the federal hydro system in the Northwest. For example, approximately $750 million is spent annually on a slate of environmental mitigation projects.

There appear to be at least a couple of explanations for the way hydropower is treated in most RPS, including the following:

- some groups view hydropower as a *suspect* resource and inconsistent with what is environmental or socially appropriate, and
- including hydropower as an eligible renewable would remove its contribution to the generating base, thereby reducing the absolute amount of new renewable resources that must be developed under a given target.

In much of the country, the treatment of hydropower as an ineligible renewable is not a significant matter and makes little difference in the amount of new renewables a utility must acquire. But in the Northwest, where hydropower serves more than half of the region's load, the question is hardly academic.

Label Hydropower as an Eligible Renewable Resource

A simple alternative would be to recognize hydropower for what it is: a renewable resource by any reasonable definition. This approach would face opposition for several potential reasons:

- labeling hydropower as a renewable would simply be distasteful to some.
- a utility with hydro generation in amounts greater than its renewable target could sell the excess at a premium in the credits market, creating a potential windfall,
- a utility that purchases hydro renewable credits could avoid having to acquire new renewables (an existing resource could displace the development of new renewable resources), and
- a utility with substantial hydro resources could itself avoid having to acquire at least some percentage of new renewables, resulting in a lower overall presence of renewables in the generation mix.

A variation on the above approach would be to include hydro as an eligible resource and increase the total RPS requirement (to a workable amount) to account for the presence of

hydro in the base. In essence, the Washington standard can more accurately be described as moving from 60 percent to 70 percent renewables and would likely have a greater impression on the public.

Exclude Load Served by Hydropower from Renewables Requirement

An alternate approach, one that steps back from the position that hydro is a renewable resource, would be to exclude utility load served by hydropower resources from the load to which an RPS percentage target is applied.

This approach avoids one aspect of the debate since hydroelectricity would not formally be referred to as an eligible renewable resource. But it provides largely the same benefit for a hydro utility (avoids having to displace an existing renewable resource with another renewable resource) as does labeling hydropower one of the eligible renewables. There are a couple of pluses that would accrue to renewables proponents in this approach:

- a utility could not sell renewable credits from its hydropower base to another utility, so no shift in costs and benefits (windfall) would occur, and
- in the absence of renewable credits from hydropower, the hydropower base of one utility could not be used to displace the renewable requirement of another utility.

Put the Northwest on Equal Footing Nationally

As Pacific Northwest states develop and adopt renewables standards, they have looked to models from other states for setting targets. Setting a high requirement, such as 10 to 30 percent, for load served by renewables might make sense in a state where 90+ percent of generation is fossil-fuel based. But in the Northwest, we already have a cleaner generating base than other states could hope to achieve for decades, at best. What, then, is the rational basis for requiring the Northwest to achieve a realized renewables penetration of at least 65 percent to 75 percent, while the remainder of the country is aiming to achieve 15 percent to 25 percent? By excluding the load served by hydro resources from a mandatory RPS target, the Northwest would still be achieving the same proportionate reduction in fossil-fuels generation as other states with similar targets.

Continue Renewables Integration Above Target, If it Makes Sense

Excluding load served by hydropower from an RPS mandate would not preclude development of new renewables in amounts greater than the target. By all means, the Northwest should aggressively develop and integrate all renewable resources that are practical, from both an electrical-system performance and least-cost standpoint It is likely in the region's long-run best interest to develop and integrate all cost-effective renewable resources as a hedge against uncertainty, and to utilize, within practical limits, the tremendous capability of federal and non-federal hydro to accomplish that. If we advocate for effective, least-cost planning to guide the development of renewables above a nominal RPS target, it would place utilities in the Northwest on the same footing proportionally as other states.

Designing Cost Caps

As explained in the introduction to this report, many renewables portfolio standards adopted across the country include a limit on implementation costs. They allow for a financial or cost comparison in considering whether a utility is in compliance with the RPS target. The cost cap protects consumers from excessive costs and the state's economy from unintended impacts. For many utilities, meeting RPS targets means a step away from least-cost resource planning, and cost caps limit the extent to which the development of renewables will affect end-use customers' retail rates.

Several statutes also include language that makes clear that while spending guidelines are often referred to as cost caps, they may, in fact, not limit (cap) the amount a utility spends to meet the standard. Rather, they provide an alternative means by which a utility may comply with the standard.

The PNUCC Task Force identified cost caps as an issue that demands substantially more discussion and analysis. A Cost Cap Work Group was tasked with preparing a summary of the cost caps in the Montana and Washington statutes. In addition, the group identified and discussed the components of cost-cap mechanisms, and made a list of the costs that should be included in any evaluation. As these elements are better understood, we expect that recommendations will be developed for consideration in the Oregon Renewable Energy Work Group, as it develops a proposal for the 2007 Oregon legislature, and for implementation of the new law in Washington. The recommendations could also serve as a model for other states as they modify their standards in the future.

Montana Law and Washington Initiative

Montana and Washington have taken significantly different approaches to limiting costs associated with implementing RPS:

- **Montana** – a utility is not obligated to take electricity from an eligible renewable resource if the cost of that resource exceeds by more than 15 percent the cost of power from an alternative resource. This is an approach similar to that taken in the Northwest Power Act giving priority to conservation by virtue of a 10 percent cost-effectiveness credit. It is worth noting that the Northwest Power Act defined a resource-priority scheme that requires all resources to be cost-effective, and gives conservation the highest priority (10 percent credit), followed by renewable resources, resources utilizing waste heat or high fuel conversion efficiency resources, and finally, "all other" resources.[6] Montana's not–to-exceed approach will, by definition, drive the resource choice to the cheapest renewable resource available, which at the present time is wind energy.
- **Washington** – a utility is considered to be in compliance each year if its spending toward meeting the renewable resource target equals 4 percent of its annual retail revenue requirement. This spending is measured as the total incremental cost difference between the delivered cost of renewable resources and delivered cost

[6] Northwest Power and Conservation Council, August 31, 2006, *Role of Renewable Resources in the Fifth Power Plan*

> of alternative conventional generation. This is not, then, the total cost of renewable resources acquired, but is instead the cost of the additional increment spent on these resources above a market or avoided-cost alternative. A utility can spend over this amount if it so chooses. The limit includes the incremental cost of generation from the renewable resource, along with the cost of renewable energy credits, or the renewable energy credits alone, whichever path the utility chooses to meet the targets.[7]

Implications of Cost Cap Structures

In addition to limiting customers' financial exposure, cost caps might also help discipline the market. The cost cap in the Montana statute, which eliminates a utility's obligation to buy a renewable resource that is more than 15 percent above the cost of an alternative, offers promise in this regard. It has been suggested, however, that the cap could have the opposite effect, namely, to give developers an incentive to increase their price to be near the 15 percent adder – to automatically increase the renewable resource cost upward to always be 15 percent more than the alternative. In either case, the Montana approach might create circumstances in which a single technology (lowest-cost resource at a given time) bids into procurement, limiting utility choice and potentially inhibiting commercialization of other technologies.

Montana utilities may have the power to remedy this issue, however, if they choose to make appropriate investments in renewables that are above the 15 percent cap. The legislation does not appear to prohibit them from making investments in resources with an incremental cost greater than 15 percent; they are just not required to do so. In addition, it does not appear the utilities would have a perpetual way to opt out if a particular resource acquisition bid exceeds the 15 percent.

Washington's new law more specifically allows a utility to choose the type of renewable resources it purchases or develops. It allows the purchase of any eligible renewable resource, while providing the opportunity to compare the aggregate cost of the incremental investments against the percent-of-revenue requirement metric. The law does not implicitly or explicitly specify the lowest-cost resource be compared against the cost cap. The law is explicit that utilities serving in Washington may invest over the 4 percent cost cap if they so choose.

Consider Key Components of Cost Caps

The cost cap element of a renewables portfolio standard should incorporate the following attributes:

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[7] There is considerable reason for concern over how this provision is interpreted since the initiative does not spell out the specific accounting methods to be used. The initiative language is also silent on how to amortize large capital expenditures typically associated with renewable projects. This lack of direction could mean that each utility can make its own decision or it could mean that the rules have yet to be determined. Another issue to be determined is whether the 4 percent is meant to compound, since the increase in those costs will have the effect of raising the retail revenue requirement.

- understandable
- simple to implement
- transparent
- durable and adaptable over time, and
- acceptable to consumers.

There are dozens of considerations in developing cost caps for RPS. The issues in the following list were identified by the Work Group as key to developing a workable cost cap.

Renewable Resource Cost-Effectiveness Test. The Montana statute allows for a cost-effectiveness test for each renewable resource acquisition (no requirement to purchase if renewable costs 15 percent or more than the alternative). Presumably, this cost comparison is done prior to a utility's decision to acquire a resource. The statute is silent on the next steps if the cost cap is exceeded in any one resource acquisition process.

Limit on Cumulative RPS Cost. The Washington statute includes an annual limit on the costs of implementing RPS. Resource costs associated with complying with the standard are measured against a utility's total retail revenue requirement. The Washington law appears to use the actual revenue requirement, which changes through time. There are likely ways to reduce some of the volatility this creates for utilities as they endeavor to stay in compliance.[8]

Limit on Resource Portfolio. Another approach to a cost cap is basing the cap on the overall cost of the resource portfolio a utility is considering to meet its future load obligation. This method would combine the Montana and Washington approaches and include both a resource cost-effectiveness test (i.e., no individual renewable resource would cost more than a set percent of the alternative) and a total incremental portfolio cost test. In other words, the total of all incremental costs of renewable resources would not exceed a certain value.

Method of Cost Comparison. Utilities traditionally use several methods to compare costs of new generating resources: net present value or levelized per-unit costs (either real or nominal). The Washington statute suggests using a levelized delivered cost in calculating the incremental cost of renewables as compared to alternatives; the Montana law mentions the use of per-kilowatt-hour cost without specifying the metric for the per-unit cost.

Comparability of Costs. The Montana and Washington laws refer to a comparison of costs between renewable and alternative (non-renewable) resources. It is crucial for a

[8] One approach could be to use rolling averages of annual revenue requirement. Another suggestion is to use only the costs of generation included in the revenue requirement (exclude customer service, distribution, and transmission costs) for the calculation. Excluding these other cost elements, however, may be inconsistent with including incremental integration and transmission costs for renewables, which in many cases are higher than for non-eligible conventional resources. Another alternative would be to base the limit on the utility's annual revenue requirement in some base year, such as the date of the enactment of the statute, and index to inflation in future years.

utility to properly compare the cost of resource choices. This should be done using the approaches utilities apply in developing integrated resource plans. To compare both cost and value of resources per MWh, utilities would need to make analytical adjustments so the renewable resources and the alternatives have the same operating characteristics. Key factors to be considered in such a comparison include:

- operating life expectancy
- temporal shape of generation – seasonal, monthly, hourly
- ability to shape to utility's real-time load
- capacity factor, and
- predictability.

Resource Costs to Include in Comparison. The levelized delivered cost for a proposed renewable or a non-renewable alternative is typically calculated as follows: the estimated levelized cost in dollars per MWh for energy from the resource, spread over the life of the project, and delivered to the utility's distribution network. In order to make a valid comparison, the cost estimates must include substantially similar data in terms of whether the resource is firm, its heavy and light-load hour characteristics, and seasonality. Cost factors to be considered should include, but not be limited to, the following:

- capital (including financing) and operating costs
- fuel costs
- quantifiable environmental externalities
- royalty or land-right payments
- incentives or other payments from state /federal governments
- transmission integration[9]
- regulation[10]
- load following[11]
- portfolio costs[12]
- opportunity cost associated with using existing resources to integrate a new resource, if these costs are not reflected in the system and/or load-following costs described above, and
- capacity cost (i.e., if new resources are predominantly wind, additional dispatchable, capacity resources will eventually be needed to assure reliability).

R&D and Dry-Hole Costs. Utilities often incur research and demonstration costs in developing renewable resources. They can put dollars toward commercializing a non-

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[9] Costs associated with substation and feeder lines required to connect output of the generating resource into the high-voltage transmission system; transmission losses; and upgrades and expansions to the transmission system required to transfer the energy to loads.

[10] Costs associated with following real-time changes in system balance, usually provided by power plants on Automatic Generation Control.

[11] Costs of balancing loads/resources over periods beyond the real-time changes associated with regulation.

[12] Utilities often perform portfolio or system analyses that include their current power-supply system and prospective new resources. This portfolio analysis estimates the total system cost associated with building and operating a new resource, as well as the costs of the existing system. Comparing the system cost of a renewable resource scenario with the system cost of an alternative resource provides a comprehensive estimate of the total incremental cost of the renewable.

commercial renewable or toward gaining efficiency improvements from commercial renewables. In addition, a utility may incur dry-hole costs, dollars expended toward developing a renewable project that due to various circumstances never results in commercial operation.[13] The Washington statute is silent on whether these costs may be included in calculating the cost cap.

Renewable Energy Credits. Costs associated with purchasing renewable energy credits are included in cost cap calculations.

Voluntary Utility Green-Power Programs. Some utilities offer programs in which customers choose to have some or all of their energy needs met by a renewable resource. In general, the option requires the customer to pay an additional per-unit cost for the renewable power. The Montana statute excludes the use of renewable energy credits sold through voluntary utility green-power programs in determining compliance. Section 4(f) of the Washington statute also disallows "eligible renewable resources or renewable energy credits obtained for and used in an optional pricing program, such as the program established in RCW 19.29A.090." Excluding the use of credits acquired through green-power initiatives will likely diminish customer participation in these utility-run programs. In Washington, however, this program is required by law. States that adopt RPS should consider whether to drop the mandatory green-power option for utilities subject to the new standards.

Planned or Actual Costs. The calculations to assess and apply the cost cap could be based on either planning or actual values. For example, planning costs would be used when the utility acquires the renewable resource, (i.e., the incremental levelized per-unit cost, or net-present value, of the renewable would be compared with the cost of the alternative at the time of acquisition). This difference could become part of the resource cost-effectiveness limit (Montana) or the limit on cumulative total costs (Washington). The use of actual costs would require detailed accounting in which a utility could have to estimate what its revenue requirement would have been if it had acquired the alternative resource instead of the renewable.

Eligible Existing Renewables. A cost cap should consider the treatment of existing eligible renewables. While the Washington statute dictates that renewable resources are eligible if they began operation after March 31, 1999, it is silent on how the incremental costs of these resources would be treated in the cost cap calculation.

Energy Efficiency Costs. A cost cap calculation should address the treatment of costs associated with energy efficiency.

Rolling Averages for Cumulative Limits. If the RPS has a cumulative cost cap, an additional consideration is whether it should it be based on a rolling average of revenue requirements, or a single annual value.

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[13] The California Energy Commission chartered a study that concluded as many as 20 to 30 percent of proposed renewable projects may ultimately fall into this category, despite the best efforts of the purchasing utilities to bring them on line.

Certifying Entity. A key question in setting up the cost cap is the agency that will be designated to review and certify that a utility's spending is in compliance. For investor-owned utilities, it is likely that state utility commissions would make the certification. For consumer-owned utilities, it would likely be the governing body/board of commissioners. The Washington statute envisions that consumer-owned utilities self-certify (that the cost cap has been reached and exercised), with a review by the state auditor for public utility districts and an independent auditor for co-ops. As part of their regular annual audit, the reviewers would provide a report indicating whether the utility complied with the RPS, similar to what they provide for compliance with other laws.

Allowing Grace Period or Alternative Compliance; Penalties

The Washington statute includes a compliance timeline to act as a grace period. This is an important element for structuring an RPS, along with the imposition of any financial penalties if a utility fails to comply with the RPS. Consideration should be given to other incentives that might be available if a financial penalty is not imposed. The Washington law imposes an administrative penalty of $50/ MWh for any shortfall in meeting the RPS.

A concept being discussed in Oregon is an "alternative compliance payment." In lieu of acquiring either a renewable resource or a renewable energy credit, a utility would have the option of making a payment in dollars per MWh to meet its target. One idea under discussion is to dedicate the funds collected through such payments to an entity that would use them to develop renewable resources. The per-MWh payment could be indexed to the market price of a renewable energy credit or to BPA's Tier 2 renewable product. (Extensive discussion of the relationship of RPS to BPA's Tier 1 and Tier 2 products is provided later in this report.) An alternative compliance mechanism would appear to achieve the same result as a penalty, but with a more positive connotation.

Calibrating with Other Mandates

Oregon law requires customers of investor-owned utilities to fund, through a public-purpose charge equal to 3 percent of the utility's revenues, new cost-effective local energy conservation, market transformation efforts, the above-market costs of new renewable energy resources, and low-income weatherization. An RPS for Oregon should address the overlap and interaction between any proposed new standards and SB1149, the law under which the public-purpose charge was levied. The requirement in Washington that utilities offer a green-power option is a similar instance in which some calibration among mandates may be needed.

Integrating Wind Resources into the System

A discussion of issues related to integrating wind resources into the system is key to drawing a complete picture of renewables development in the Pacific Northwest. Wind generation makes up the preponderance of renewables nationally and in the region. At this time, 93 percent of all capacity and 85 percent of all energy from renewables

(excluding hydropower) across the nation comes from wind generation. As utilities continue to develop wind and other intermittent resources to meet RPS, three critical issues must be addressed: 1) adequate transmission capacity, 2) availability of integration services, and 3) development of additional capacity resources to back up intermittent wind generation.

Transmission Capacity

Interconnecting new generating resources can be challenging from a transmission perspective – even for resources with more traditional generating characteristics (e.g. dispatchable and high capacity factor). One utility that recently solicited proposals for renewable resources, reports that while respondents were required to include transmission from the resource to the utility's system as part of their proposal, only one of 22 respondents was able to do so.

In his presentation to the Oregon Renewable Energy Working Group, Ryan Wiser recently noted that transmission bottlenecks are a hindrance to renewables development in several other states at present.[14] And this situation exists even at a relatively low level of renewables penetration in the market.

Of particular interest in the Northwest is the wind potential in Montana. The potential in that state is roughly ten times that in Idaho, Washington, and Oregon combined. But there simply does not presently exist the transmission capability (or the firming resources) to take advantage of this potential. The transmission bottleneck notwithstanding, the Washington law allows raw wind energy to be brought in from outside the state only if the generating facility is located in the region, and eastern Montana is not part of the region as defined by Initiative-937. Importing large amounts of wind generation on a dynamic basis has its own set of issues. Montana's NorthWestern Energy does not have the resources to integrate the wind generation already on its system and has had to purchase ancillary services for this specific purpose.

Existing Transmission Capability

Several groups have formed to evaluate the impact of large-scale wind development on transmission and back-up resources in the Pacific Northwest and the Western Interconnect. The Western Electricity Coordinating Council (WECC) has a committee, the Power Pool's Northwest Transmission Assessment Committee (NTAC) has established a task force, and BPA has joined with the Northwest Power and Conservation Council in a special project to evaluate these issues. Several utilities have formed internal teams to conduct their own evaluations.

The region also needs to understand more clearly the ramifications for the integration of wind resources of the Open Access Transmission Tariff and new OATT interconnection requirements on transmission owners.

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[14] Ryan H. Wiser, 2006. State RPS Policies: Experiences and Lessons Learned. Presented to the Oregon Renewable Energy Working Group, May 31, 2006.

Investment in New Transmission

The region already needs substantial new transmission investment. It is not well understood at this point how much the large-scale development of wind resources will increase the amount of transmission investment that must be made, where it will occur, and how long it will take to construct.

At present, BPA is making transmission investments to facilitate the interconnection of new wind resources. But even these recent transmission additions do not address the need for a broad regional look at the investments needed to ensure an orderly integration of new wind developments. Such an evaluation is especially important since the lead time for siting transmission is often much greater than that for permitting and developing generating resources.

Integration Services

There appears to be broadly divergent views among stakeholders in the Northwest about the wind-integration capability of the Federal Columbia River Power System. At present, BPA has suspended development of new wind-integration services. This move is pending BPA's internal assessment of the cost and capability of the power and transmission systems to integrate wind. This assessment is particularly important in light of restrictions related to fish recovery that have been imposed on river operations. BPA's assessment of the wind-integration capability of the FCRPS and the resulting price for required services is likely to be a critical factor in determining the overall cost of wind resource development in the Northwest, as it is being driven by existing and expected RPS.

As mentioned earlier, BPA has joined with the Council to develop a Northwest Wind Integration Action Plan. This effort has the potential to identify key constraints in the FCRPS that will affect what is intended to be the expansive development of wind resources in the region. Just as importantly, the study could begin to identify costs of removing these constraints, which will further understanding in the region about the full cost of continuing to expand wind resources.

According to the BPA/Council work plan,[15] this study will start with a review of previous and current analyses, as well as a review of how other regions have approached the challenges of large-scale wind integration. The next phase will identify individual and cooperative operational strategies related to control-area reliability and system flexibility. This is intended to help manage the integration of planned wind development (2,000-4,000 MW) in a least-cost fashion. The last phase of the study will identify longer-term options and costs related to transmission planning and expansion. It will also include the flexibility augmentation and wind forecasting likely to be required to maximize the development of the region's cost-effective wind potential (6,000+ MW).

[15] Northwest Wind Integration Action Plan, Revised Work Plan V 3.0, August 17, 2006

Contemplating Effects on Utility Resource Planning

The following discussion does not consider the cost of complying with RPS. It seeks instead to examine variables that will determine the effect RPS will have on different utilities as they plan for resources.

The largest variables for utilities in Washington relate to the interaction of conservation acquisition and load growth. A utility that projects 1.5 percent annual load growth could see its loads grow by 21 percent by the year 2020, when the RPS target is 15 percent of load. Accelerated conservation acquisition could, however, act to dampen load growth, which could result in a utility over building resources. For instance, a 1 percent annual load growth would lead to 14 percent total load growth during the period the utility is obligated to acquire renewables to serve 15 percent of its load.

A slower-growing, full-requirements public power utility will face the most difficult circumstance under the Washington law. At .5 percent annual average load growth, its loads will grow by 6.6 percent while it is under an obligation to acquire all cost-effective conservation and meet 15 percent of its load from new renewables. A similar situation would occur if a moderate-growing utility loses a large industrial customer. Even with no load growth, the utility would still be obligated to meet its conservation target and spend an additional 1 percent of its annual revenue requirement for renewable resource acquisition.

A utility that now has resources in excess of its current needs faces a similar challenge. It is still obligated to acquire all cost-effective conservation and renewable resources regardless of its actual need for resources to serve load.

Utilities that have purchased renewables or have increased the efficiency of hydropower projects since 1999 will have a head start in meeting the Washington RPS. The RPS does not provide a similar opportunity for utility customers of BPA to gain any benefit from efficiency improvements to the FCRPS. A question may arise over who has the rights to efficiency improvements when a hydro project is owned by one utility and part of its output is contracted to other utilities. And a utility that has a successful voluntary green-power rate tariff cannot count the beneficial results of that tariff towards meeting the RPS target.

Fast-growing utilities or utilities that face losing resources due to expiring contracts may find the RPS easier to accommodate as part of a portfolio of new resource acquisitions. Even fast-growing utilities, however, could face challenges if they start out with a large hydro base, federal or utility owned. Layering an intermittent renewable resource, such as wind, over a variable hydro base might not provide adequate resource reliability without the acquisition of other dispatchable resources.

Considering Rate Impacts for BPA's Public Customers

Post-2011 Tiered Rates

BPA is nearing the end of its Regional Dialogue with customers and other stakeholders. The goal of this process is to define BPA's obligation to serve the loads and load growth of its public customers when their current power-sales contracts expire on September 30, 2011. By law, BPA serves the load and load growth of public customers that request such service. Currently, BPA serves this load at a melded power rate, with load growth priced the same rate as service to existing load.

One of the objectives of the Regional Dialogue is to move BPA to a future where its existing public-power load, less customer resources, will be served at rates that reflect the underlying costs of the existing FCRPS (Tier 1). Load growth will be served at the incremental cost of service (Tier 2). The region is poised to adopt this tiered construct under which customers will receive an allocation of low-cost Tier 1 power (90 percent hydro, 10 percent nuclear) based on their load in 2010. A customer's right to Tier 1 power (or its net requirements as of 2012) will be extremely valuable, since the cost of the existing system, which is primarily hydro, is considerably lower than the cost of new resources. This is particularly true in view of the potential for a carbon-constrained future.

Relationship Between RPS and Tier 1

Most RPS targets are expressed as a percent of load at a specified time. In states where resources are largely thermal, it's likely that establishing renewables targets in this way is appropriate. But in the Pacific Northwest, this percent-of-load approach could lead to situations in which a utility is forced to divest low-cost Tier 1 power or purchase higher-cost renewable energy credits to meet an RPS target. Some utility loads, given a conservation mandate such as in I-937, will not grow sufficiently for the utility to meet the RPS target, even if *all* load growth is served with eligible renewable resources.

Evaluation Scenario. The following evaluation of RPS and Tier 1 assumes BPA's public-power customers are served entirely by Tier 1 power in 2012. It also assumes that all load growth is served on the margin (at Tier 2). Assuming a 1.25 percent annual load-growth rate, the Tier 1 annual energy load of these utilities is forecast to be 7,364 MWa in 2012. This would result in the following circumstances:

- Under the Oregon proposal, by 2025, the public power load on BPA will be 8,655 MWa and 2,164 MWa of that load will have to be served by renewables.
- Under the Washington law, by 2020, the public power load on BPA will be 8,133 MWa, and 1,220 MWa of that load will have to be served by renewables
- If all of BPA's Tier 2 purchases and all of the load-growth purchases of the utilities beyond Tier 1 were renewables, they would meet only a portion of the requirement on the region's public utilities to purchase renewable resources. For example, assuming a load-growth rate of 1.25 percent per year under the Washington standard, load growth would be about 10 percent from 2012 to 2020,

and the RPS requirement is 15 percent of the total by 2020. Under the Oregon proposal, load growth would be about 18 percent from 2012 to 2025 and the RPS requirement is 25 percent by 2025.

- As a result, as the region's public utilities move to meet the RPS, they will have to divest themselves of Tier 1 power in order to incorporate renewables purchases (since BPA hydropower is not deemed an eligible renewable) into their portfolios. The Tier 1 power would then presumably be available to BPA as surplus for sale to other customers. Alternatively, the utilities would have to purchase renewable energy credits in addition to Tier 1 resources, adding substantially to their cost of power.
- Inland Power and Light, a utility in Washington, currently has a load on BPA of 83 MWa (2004). The utility's load is forecast to be 89 MWa in 2012 and 99 MWa in 2020. Faced with the Washington RPS of 15 percent by 2020, Inland will have to reduce its low-cost Tier 1 purchases by 5 MWa in order to meet its requirement to purchase 15 MWa of renewables by 2020. This reduction in Inland's Tier 1 allocation will cost each of its customers about $50 per year, possibly much more.
- The results would be more dramatic for Oregon utilities under the likely proposal. Central Lincoln PUD has a current load on BPA of 145 MWa (2004). The PUD's load is forecast to be 157 MWa in 2012 and 188 MWa in 2025. Faced with an Oregon standard of 25 percent by 2025, Central Lincoln would have to reduce its low-cost Tier 1 purchase by 15 MWa in order to meet its requirement to purchase 47 MWa of renewables by 2025.
- These analyses assume each utility's entire load growth is served by eligible renewable resources. Accomplishing this could be problematic, however, for reasons other than cost. There may not be an adequate supply of renewables in the market, yet utilities may wish to make market purchases to serve load growth which could mean a shorter-term contract commitment with BPA and/or other providers.

The Washington statute specifies that both resources and renewable energy credits to meet the RPS targets must come from renewables in the Pacific Northwest. The regional market for available renewable energy credits will likely be small to non-existent (leading to very high prices for those that are available).

By definition, renewable energy credits are only created when the resource generates electricity. And since most utilities will be meeting their own load growth with renewable resources (and must retain the associated credits for RPS compliance) such credits may be difficult or impossible to obtain in the Pacific Northwest market. This will no doubt be the case if Oregon takes the same approach as Washington to a Pacific Northwest resource requirement and renewable energy credits.

Rate Impacts With This Approach

BPA's resource base is 90 percent renewable hydropower. Divesting a low-cost renewable resource or adding costs to that low-cost renewable resource through

renewable energy credit purchases in order to comply with an RPS target will likely be seen as illogical and unacceptable to utility customers.

Customer rates would rise as a result of the cost difference between new renewables and the existing hydro base, which is estimated at 30 to 40 mills per kWh. It is also likely the market price for scarce renewable energy credits in the region will rise and eventually exceed the penalty for non-compliance, which in Washington is $50 /MWh. Unless this possibility is addressed, utilities could have an economic incentive to divest when the cost of renewable energy credits reaches the 30 to 40-mill cost differential, leaving aside the complexity that would be created.

Similarly, financial benefits to investor-owned utility customers would be reduced because the proxy priority-firm rate that BPA uses in making that calculation would increase.

Potential Alternatives

In implementing the new Washington statute and shaping the Oregon proposal, there are ways to mitigate the unintended impact of foregoing Tier 1 purchases from BPA to meet the RPS. These could include the following:

- Provide a more clearly defined cost cap limiting the rate impact of the standard in Washington and that proposed in Oregon. Note that the Washington initiative has both a cost cap and a temporary and potentially meaningless exemption for non-growing utilities. This latter non-growth cap needs to be clarified.
- Include provisions for both states that prohibit any need to divest Tier 1 power or to purchase renewable energy credits to make any Tier 1 power eligible under RPS.
- Base the RPS on a percentage of load growth triggered when new resources are needed and include meaningful cost caps.
- Eliminate all loads served by hydropower resources from the percent-of-load calculation required for compliance with the RPS target.
- Allow pooling of Tier 1 purchases.[16]
- Achieve a declaration that all of the region's hydropower (including the FCRPS) is eligible as a renewable resource.
- Provide that loads served by hydropower resources are not included in the calculation.
- Lower the RPS percentage targets or extend the target further out in time.
- Provide an explicit provision related to Tier 1 purchases that protect them from any renewable mandate.

[16]BPA has said it will not allow pooling.

- Provide an allowance for conservation as part of the RPS goal.
- Provide an allowance for federal hydro efficiency gains as eligible new renewable resources.
- Use green tags to meet the requirement (in Washington statute).

Additional Topics Regarding BPA's Role and RPS

In addition to the topics explored in the above discussion, the relationship between BPA and its utility customers gives rise to numerous questions with regard to implementing RPS. Among them are the following:

- Will BPA have the ability to provide firming for renewables as loads grow and flow-related fish and wildlife requirements remain the same or increase?
- Will BPA have the ability to provide physical transmission assets for renewables, using its federal borrowing authority, third party financing, and/or developer financing?
- Will BPA have the ability to provide transmission services for renewables; what types of transmission services will be available (conditional firm)?
- Will customers be able to use General Transfer Agreements to bring non-federal renewable resources into their systems to meet RPS?
- What will BPA's role be in renewables development? In part, BPA's view is expressed in language from the BPA Power Business Line (Regional Dialogue Concept Paper issued September 2005, p. 41).[17] This role does not appear to have changed in the Regional Dialogue proposal.

  It is worth noting that even if Tier 2 power were acquired only from renewables, meeting load growth alone through Tier 2 renewables would not be sufficient to meet the targets. Presumably BPA will continue to offer a conservation discount

[17] "Tier 1 renewable resource spending would be focused on specific, measurable facilitation and R&D activities, with explicit identified costs to be included in Tier 1 rates. The value of these expenditures would not fluctuate with natural gas prices or other variables. Facilitation and R&D activities may include: providing marketing services for customer-owned renewable generation and developing new variants of wind integration services; exploring alternatives to direct financing to reduce the cost of transmission upgrades for renewable projects; providing grants to offset upfront costs of new customer-sponsored renewable R&D projects; directing R&D projects that support the long-term growth of the regional renewables market, such as wind and solar monitoring; and, other suitable R&D initiatives. Evaluation criteria for prioritizing new spending activities would be developed as part of the Long-Term Regional Dialogue discussion, but should be based on maximizing the amount of new renewable generation built in the region per dollar of facilitation spending.

The Tier 2 renewable resource product would be developed in a manner consistent with other proposed BPA policies and practices on Tier 2 products. BPA proposes to work proactively with customers and others to help ensure economies of scale in new project development in order to help secure cost-effective renewable resources for Tier 2 service."

for conservation activities taken on at the individual utility and for a conservation acquisition program (funding conservation at the utility level). How will this effect the amount of renewable resource output that a utility needs to buy under the RPS?

- Presumably as load is reduced through conservation, the amount of renewable resource that needs to be purchased is reduced. I-937 included language on this topic.[18]

  It is not clear how this compliance mechanism would work. For example, what happens if a customer's load subsequently grows; will it then have to achieve the RPS, and at what level in what timeframe?

Evaluating the Region's Renewable Energy Supply

As the RPS discussion in the Pacific Northwest continues, one issue that must be considered is the amount of energy the region can reasonably expect to integrate cost-effectively from new renewable energy sources. The Council, in its Fifth Power Plan, identified the generating resources available for future development in the Northwest.

Chapter 5 of the plan described two groups of generating resources and technologies: "**major** future potential" and "**moderate** potential." The Council included the major resources in its portfolio analysis. The moderate resources were considered to play a more limited role in meeting future power needs because of higher costs, limited supply, or limited need for the services they provide. Wind is the only renewable power supply identified in the major potential category. Biomass, geothermal and solar technologies were included in the moderate category.

[18] **"**A qualifying utility shall be considered in compliance with an annual (RPS) target in (a) of this subsection if: (i) The utility's weather-adjusted load for the previous three years on average did not increase over that time period… and (iii) the utility invested at least one percent of its total annual retail revenue requirement that year on eligible renewable resources, renewable energy credits, or a combination of both."

The table below summarizes the quantities and estimated costs for both major and moderate potential renewables technologies. By the Council's estimates, wind has the potential of providing about 1,800 MWa of energy. Biomass, geothermal, and solar might contribute another 2,000 to 3,000 MWa. Based on *actual* developers' responses to Northwest utility renewable Request for Proposals, the PNUCC Task Force views this latter forecast for non-wind resources as completely unrealistic.

	Capacity (MW)	Annual Energy (MWa)	Cost ($/MWh) (2000$)
Wind			
West of Continental Divide	5,000	1,500	$42-53
"committed"	1,000	300	
Biomass			
pulp,paper,efficiency		280	$23
animal manure		50	$56
landfill		100-200	$45
wood residue		1,000-1,700	$54-65
Geothermal		200-400?	
Solar			
PV		No Limit	$250
Total		**3,500-4,500**	

Assessing Cumulative Effects of RPS

In light of the Council's analysis of the availability of renewables, it is important to consider the overall impact of Renewables Portfolio Standards in the region. The PNUCC Task Force made the following estimate of the combined effect of the existing and potential RPS in the four Pacific Northwest states. Each of the state's energy forecasts includes required amounts of annual energy to be produced by renewable energy resources at future times. Using the load forecast published in PNUCC's 2006 *Northwest Regional Forecast,* the Task Force estimated the amount of total renewable resources that would need to be developed to meet these standards during the next 20 years.

The following table provides details of the estimate by state and as a regional total. No requirement for the state of Idaho was included.

Annual Energy (MWa)	2006-07	2010-11	2015-16	2020-21	2025-26
Idaho					
Load	3,688	3,964	4,182	4,481	4,798
Montana (Regional Act					
Load	634	658	696	733	772
Target - RPPRED Act 2005		10%	15%	15%	15%
Renewables Required	-	66	104	110	116
Oregon					
Load	6,083	6,460	6,953	7,489	8,067
Governor's Target	-	6%	13%	19%	25%
Renewables Required	-	359	869	1,456	2,017
Washington					
Load	10,908	11,488	11,974	12,611	13,282
Target - Initiative 937	-	-	9%	15%	15%
Renewables Required	-	-	1,078	1,892	1,992
Region					
Firm Load	21,312	22,570	23,805	25,314	26,919
Renewables Required	-	425	2,051	3,458	4,125

This analysis suggests that in less than **20 years**:

- Approximately 4,000 MWa of renewable energy would need to be acquired from renewables facilities in the Northwest to meet RPS in Oregon, Washington and Montana.
- If all of that new renewable energy were to be produced from wind turbines, approximately 12,000 MW of capacity would need to be built. This is twice the capacity the Council has estimated as potentially available in the region.
- Approximately 75 percent of all load growth would be met with new renewable power supplies. This assumes the region's load grows by about 5,600 MWa, or about 1.2 percent per year.
- In Oregon, all load growth would need to be met with new renewables, and very close to 100% for Washington.

Looking out **10 years**, the analysis projects that:

- Approximately 2,000 MWa of new renewable energy would need to be acquired from renewables facilities to meet the RPS.
- In essence, all the wind energy potential identified in the Council's Fifth Power Plan would need to be built and integrated in this time frame.
- All load growth in Oregon and Washington would have to be met with new renewable energy sources to meet the RPS.

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Appendix B: Facts and Figures on Loads/Resources

A critical element of developing and implementing Renewables Portfolio Standards successfully in the Pacific Northwest is to understand the existing and forecast mixture of energy demand, as well as the supply to meet that demand. What follows are a few facts and figures about the Northwest's power supply and demand picture. The data reflected in this section is from PNUCC's May 2006 *Northwest Regional Forecast*, an annual compilation of utility load and resource information. The region discussed in this section is the geographic area defined in the Northwest Power Act: the states of Idaho, Oregon, Washington, and western Montana.

Firm Load

The Northwest currently has an annual firm energy load of approximately 21,000 MWa, with projections to grow at about 1.3 percent or about 275 MWa per year. That translates into a current demand for energy of about 3,600 MWa in Idaho, 6,000 MWa in Oregon, 11,000 MWa in Washington, and 600 MWa in western Montana. In addition to firm regional retail load, Northwest utilities currently have firm contractual obligations to deliver about 800 MWa of energy to entities outside the Pacific Northwest.

Firm Resources

On the resource side of the equation, the region meets this energy load predominately (70 percent) with hydropower (assumes average water). The hydropower output can vary dramatically from year to year because of the variation in snow pack and rain. Under a condition of low water, regional hydro power energy would be about 12,000 MWa, increasing to about 20,000 MWa in the highest water condition. The average energy supplied is about 15,600 MWa.

In addition, the region's loads are met with about 1,300 MWa of gas-fired combustion turbines, 1,200 MWa of cogeneration (mostly gas fired), 3,300 MWa of coal, 1,000 MWa of nuclear, and about 600 MWa of renewables, which includes solar, landfill gas, biomass, wind, and wood waste. In addition, there are several large-scale wind farms and a 500 kW solar project in various stages of development.

Surplus/Deficit

Traditionally, Northwest utilities have evaluated the regional energy supply/demand picture using a simple comparison of expected firm loads to expected firm resources. The firm hydropower capability is based on low water conditions. By this measure, the region is currently slightly deficit, with a projection of a need to build or acquire new power supply during the next five to 10 years. These projections are updated annually.

On a parallel track, the Council and BPA have been developing standards for regional resource adequacy, both for energy and capacity. The adopted energy standard indicates that the region as a whole is currently 3,000 to 4,000 MWa surplus. The Council and BPA are still developing winter and summer capacity standards.