ENVIRONMENTAL AND REGULATORY MATTERS

Contents

Climate and environmental impact policies continuously evolve at the state, regional and federal levels, and PSE is actively involved in these policymaking activities. This appendix summarizes the recent and evolving environmental rules and regulations that apply to PSE energy production activities.

ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Coal Combustion Residuals

On April 17, 2015, the United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash containment structures by establishing technical design, operation and maintenance, closure and post-closure care requirements for CCR landfills and surface impoundments, and corrective action requirements for any related leakage. The rule also sets out recordkeeping and reporting requirements including posting specific information related to CCR surface impoundments and landfills to a publicly-accessible website. Using information from these public websites, enforcement of the CCR rule is left entirely to citizens' lawsuits – not EPA.

Mercury and Air Toxics Standard (MATS)

The EPA published the final Mercury and Air Toxics Standard in February 2012[1] to reduce air pollution from coal and oil-fired power plants with a capacity equal to or greater than 25 megawatts. The MATS rule establishes emissions limitations at coal-fired power plants for mercury (1.2 lbs per trillion British thermal units [TBtu]), and for acid gases and certain toxic heavy metals using a particulate matter surrogate (0.03 lb per million British thermal units [MMBtu]). Coal-fired generating units had until April 2015 to comply with MATS, and they could receive up to a 1-year extension from state permitting authorities for the installation of controls if necessary.[2]

On June 29, 2015, the United States Supreme Court held that the EPA failed to consider costs when deciding whether it was "appropriate and necessary" to regulate emissions of mercury and other hazardous air pollutants from power plants. The Supreme Court's decision overturned a 2014 ruling by the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), which held that EPA's decision not to consider costs in the initial stages of the MATS rulemaking process was reasonable. The Supreme Court remanded the decision on MATS back to the D.C. Circuit for further proceedings, so the full impact is not yet known.

1/ The EPA issued the Final MATS rule April 30, 2015.
2 / Appendix K, Colstrip, describes Colstrip's compliance with the MATS rule.

The D.C. Circuit can either remand or vacate EPA's decision. Under a remand, the MATS rule would remain in effect while EPA addresses the deficiencies outlined by the Supreme Court. If the court vacated the rule, EPA would have to start the entire rulemaking process over again. EPA and environmental groups have already signaled their intent to argue for remand. The D.C. Circuit's decision is not expected for at least ten months, though industry petitioners may request expedited consideration.

Clean Water Act

Cooling Water Intake and Discharge. The EPA finalized the changes to Section 316(b) of the Clean Water Act that apply to power plant standards in May 2014. The rule requires power plants to install any one of a variety of technologies to reduce the amount of fish and other aquatic life killed by cooling water intake pipes. Environmental groups filed three separate challenges to the rule on September 2, 2014. They contend that the EPA gave utilities too much flexibility in finding a way to comply. On September 4, 2014, Entergy Corporation and the Utility Water Act Group, a coalition of 191 energy companies and three utility trade associations, filed a joint challenge on behalf of utility companies. This lawsuit is still pending before the Fourth Circuit Court of Appeals.

The rule's requirements address these potential impacts:

- Existing facilities with a design intake flow of greater than 2 million gallons per day, where more than 25 percent is used for cooling, are required to select from 9 compliance options related to impingement mortality.
- Existing facilities that withdraw at least 125 million gallons per day are required to monitor entrainment and assess the costs, benefits and other adverse environmental impacts of measures for reducing entrainment mortality. Based on these reports, the regulatory agency selects the best technology available for reducing entrainment mortality at a facility.
- New units that add electrical generation capacity at an existing facility are required to install technologies that reduce impingement and entrainment to a level equivalent to closed-cycle cooling.

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.

On September 30, 2015, the EPA finalized a rule to regulate wastewater discharges from power plants. The new rule sets limits on dissolved pollutants permitted in these discharges, and focuses on mercury, selenium, and arsenic (toxic metals previously unregulated in this context).

The finalized rule applies to all steam electric power plants, except for those smaller than 50 megawatts in production capacity, and oil-fired plants. Out of approximately 1,080 steam electric power plants in the U.S., 134 are expected to require new investments in order to comply with the regulations. The regulations will take effect in 2018, and compliance will be phased in through 2023.

Along with effluent limits on toxic metals and dissolved solids, the rule establishes zero discharge limits on pollutants in ash transport water and flue gas mercury control wastewater. Many units in the Pacific Northwest will be compliant with the rule provisions with their current controls, and therefore will not incur additional compliance costs. Colstrip is a Zero Liquid Discharge (ZLD) facility, so it will not be affected by the rule.

The Regional Haze Rule (Montana)

Adopted in 1998, the Regional Haze program is a 64-year program administered by the EPA under federal law to improve visibility. Specifically the rule is aimed at improving visibility in mandatory Class I areas (National Parks, National Forests and Wilderness Areas) and is not a health-based rule. The rule requires each state to prepare an analysis of visibility impairments to Class I areas and develop plans to eliminate man-made impairment by 2064. Major sources that began construction before 1977 (including Colstrip Units 1 & 2) must bring emission controls to Best Available Retrofit Technology (BART) standards during the initial review cycle. “Reasonable Progress” requirements call for an updated analysis of impacts every five years. It also requires states to constantly decrease haze in certain scenic areas of the country over time according to a “Glide Path.” Power plant emissions contributing to haze are evaluated in phases every 10 years and more stringent emission controls are required as needed to stay below the Glide Path.

The EPA published its Final Implementation Plan (FIP) for Colstrip, covering both the BART and Reasonable Progress requirements in September 2012, with implementation required within five years. The first phase of the Regional Haze program set emission limits for Colstrip 1 & 2 based on various emissions control technologies to bring the haze level below the Glide Path.

There were no immediate requirements for Colstrip Units 3 & 4, but Colstrip Units 1 & 2 were determined by EPA to need to upgrade pollution controls to meet new sulfur dioxide and nitrogen oxide limits. The Sierra Club filed an appeal of the FIP with the United States Court of Appeals for the Ninth Circuit on November 15, 2012, and Talen Energy also filed an appeal as the Colstrip operator. The case was heard on May 15, 2014 in Seattle, Wash., and the final decision by the Ninth Circuit was issued June 9, 2015.

On June 9, a three judge panel of the 9th Circuit Court of Appeals reviewed EPA's first phase requirements for Colstrip and found that the EPA had not adequately justified the need for two of the control technologies and remanded these two issues back to EPA for re-do. The ruling in no way affects the future planning periods for the Regional Haze program or the Glide Path. The current EPA assessment is that the state of Montana will require significant emission reductions to meet the natural visibility goal by 2064 which means that additional emission reductions will be necessary in future 10-year planning periods, beginning in the 2018-2028 period, and there is risk and uncertainty regarding potential costs.

For more information on the EPA FIP, see http://www2.epa.gov/sites/production/files/2014-02/documents/epafinalactononmontanaregionahazeplan.pdf.

For the draft Federal Implementation Plan containing EPA's analyses and cost estimates, see https://federalregister.gov/a/2012-8367.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act establishes two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation and buildings. These ambient level standards apply uniformly throughout the states.

The Clean Air Act required EPA to set NAAQS for widespread pollutants from numerous and diverse sources considered harmful to public health and the environment. EPA has set NAAQS for six "criteria" pollutants; periodic review of the standards and the science on which they are based is required.

Each time the NAAQS are revised, the states must evaluate whether any parts of the state exceed the standard (these are "non-attainment" areas). If a state contains any non-attainment areas, it must propose a plan and schedule to reduce emissions in order to achieve attainment approval by the EPA. Currently the Colstrip area of Montana is in attainment for all criteria pollutants. Reductions in Colstrip emissions for sulfur dioxide ($SO_{2)}$, nitrogen dioxide ($NO_{X)}$ and particulate matter (PM) to meet the MATS Rule and the EPA FIP are expected to keep the area in attainment with any NAAQS revisions with no further actions required. (For more information, go to http://www.epa.gov/ttn/naaqs/criteria.html.)

Ozone NAAQS in Washington State. On November 26, 2014 EPA announced a proposal to tighten the primary and secondary ozone NAAQS. EPA proposes to strengthen the ozone NAAQS by reducing the allowable level of ozone from 75 parts per billion (ppb) to a range of 65 to 70 ppb, however, EPA is taking comment on levels for the health standard as low as 60 ppb. The public has 90 days to comment on the proposal, once it is published in the Federal Register. If EPA finalizes the rule, nonattainment designations will be set by October 1, 2017. Areas in non-attainment will have 3, 6 or 9 years to meet the new standard, depending on the level of severity. If EPA finalizes a new standard by October 2017, non-attainment designations will likely be based on the three-year monitoring records from the 2014-2016 ozone seasons.

It will be the state's responsibility to develop a State Implementation Plan to meet the standards. PSE cannot predict the outcome of this matter.

Greenhouse Gas Emissions

Section 111(b) of the Clean Air Act. On January 8, 2014, the EPA issued a proposed New Source Performance Standard (NSPS) for the control of carbon dioxide (CO_2) from new power plants that burn fossil fuels under section 111(b) of the Clean Air Act. EPA first proposed a NSPS for emissions for CO_2 from new power plants in April 2012. However, after more than 2.5 million comments on the original proposal, EPA decided that a new approach was warranted and rescinded the April 2012 proposal. The EPA is proposing an emissions limit for coal-fired sources of 1,100 lb CO_2 per megawatt hour (MWh); limits for natural gas combined-cycle sources would be set at 1,000 to 1,100 lb CO_2 per MWh, depending on the size and type of unit. Under the January 8, 2014 proposal, the Agency concluded that carbon capture and storage (CCS) has been adequately demonstrated as a technology for controlling CO_2 emissions in full-scale commercial applications at coal-fired electrical generating units; however, it reached the opposite conclusion, that CCS is not adequately demonstrated, in the case of gas-fired generators. PSE submitted comments before the end of the comment period on May 9, 2014.

On August 3, 2015, EPA issued a final rule combining its New and Modified proposals into one rulemaking and making several changes. The final rule separates standards for new power plants fueled by natural gas and coal. New natural gas power plants can emit no more than 1,000 lbs of CO_2 per MWh, which is achievable with the latest combined-cycle technology. New coal power plants can emit no more than 1,400 lbs CO_2 per MWh, which is less stringent than the draft rule. This standard for coal plants would not specifically require carbon capture and storage (CCS), but CCS was reaffirmed by EPA as Best System of Emissions Reduction (BSER). These 111(b) standards are implemented by the states, but states to not have much flexibility to alter the standards set by EPA.

Section 111(d) of the Clean Air Act. On June 2, 2014, the EPA proposed draft guidelines under section 111(d) of the Clean Air Act for the control of CO_2 emissions from existing fossil fuel-fired power plants. EPA estimated the proposed guidelines, which set individual emissions targets for each state, will reduce total power sector carbon emissions 30 percent from 2005 levels by 2030. EPA is applying its "best system of emission reductions" (BSER) approach. To establish reduction targets, the EPA initially followed a four-step approach: (1) improve the heat rate of individual generating units, thereby reducing the amount of CO_2 produced per unit of electricity generated, (2) prioritize dispatch of existing (and new) natural gas combined-cycle generation over coal-fired generation, (3) account for increasing renewable generation and nuclear generation that is under construction or will have extended life, and (4) improve demand-side energy efficiency to reduce the amount of electricity generation required.

States were given the flexibility to choose the emissions reduction strategies best suited to their reduction requirements, and they can select technologies and techniques beyond those defined in BSER provided that emission reductions are verifiable and approved by EPA. Under the draft rule a state must achieve its state-specific interim goals by 2025 and its final goals by 2030. PSE filed comments on the rule on December 1, 2014, at the end of the comment period.

EPA issued a prepublication version of the final 111(d) rule on August 3, 2015 which included several changes, many of which were requested in PSE's comments. The final rule was published in the Federal Register on October 24, 2015. Specifically, EPA excluded energy efficiency from the building blocks, leaving just three building blocks (increased efficiency for coal plants, greater utilization of natural gas plants and increased renewable sources), and provided more flexibility on interim goals by phasing in the reduction of the second building block and giving states the option to set their own interim compliance glide path and pushing the start of compliance to 2022. EPA also adjusted the 2012 baseline to address hydroelectricity variability and provided specific CO_2 mass targets by year for each state.

States have broad flexibility to pick a rate-based or mass-based approach and can design compliance options and decide how to allocate credits and whether to allow trading. EPA also gave states of the option of seeking an additional time if necessary to formulate a state plan – states must submit something within one year but can request up to an additional two years for development of a state plan.

Based on the changes to the final rule, the final CO_2 goal for Montana became 26 percent more stringent and the final CO_2 goal for Washington became 35 percent less stringent. By 2030 Montana must reduce CO_2 emissions from coal plants from 20.5 million tons to 11.3 million tons, which is a 45 percent reduction in CO_2 emissions. How this will affect Colstrip cannot be determined until a state implementation plan for Montana is finalized and approved by the EPA.

STATE AND REGIONAL ACTIVITY

California Cap-and-trade Program

On December 16, 2010, the California Air Resources Board (CARB) adopted final rules to enact cap-and-trade provisions in accordance with California's Global Warming Solutions Act of 2006 (AB-32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs. The compliance obligations became binding on January 1, 2013.

AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It directs power providers to account for emissions from in-state generation and imported electricity. The regulatory approach assigns the electricity importer as the "first deliverer" of imported electricity and thus the point of regulation. Cap-and-trade regulations distinguish between "specified" and "unspecified" sources of electricity. An unspecified source means electricity generation that cannot be matched to a particular generating facility; these sources are subject to the default emission factor of 0.428 MT of CO_2e per MWh. A specified source is a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract, including any California-eligible renewable resource or an asset-owning or asset-controlling supplier. Imports from specified sources are eligible for a source-specific emission factor. To be eligible for a source-specific emission factor, imported electricity must not only come from a specified source, but any renewable energy credits associated with the electricity must be retired and verified. Imported electricity can only be assigned an emission factor lower than the default emission factor if the electricity is directly delivered, meaning the facility has a first point of interconnection with a California balancing authority or the electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous transmission path.

Washington State

In 2008, the Washington legislature recognized that climate changes posed serious threats to the economic wellbeing, public health, natural resources and the environment of the state. To limit the impacts of climate change, the legislature required that the state reduce its greenhouse gas emissions by setting limits on those emissions (RCW 70.235). The legislature also required the limits be reviewed and recommendations be made by the Department of Ecology (Ecology) using the most current global, national and regional climate science. The regulations that have been established pursuant to 70.235 to limit greenhouse gas emissions in the state are discussed in this section.

Greenhouse Gas Emissions Performance Standard. Washington state law RCW 80.80.060(4), the GHG Emissions Performance Standard (EPS), establishes a limit of 970 lbs of CO_2 emissions per MWh from new baseload generating resources, and it prohibits utilities from entering into long-term contracts of 5 years or more to acquire power from existing generating resources that exceed this standard. Contracts of less than 5 years are allowed.

This means that PSE is prohibited from building or purchasing baseload generation resources that exceed the emission performance standard. Investor-owned utilities like PSE may apply to the Washington State Utilities and Transportation Commission for exemptions based on certain reliability and cost criteria.

The law was amended in 2011. This amendment incorporated changes related to the negotiated shutdown of the TransAlta coal-fired power plant located near Centralia, Wash. The change allows TransAlta to enter into "coal transition power" contracts with Washington utilities. It exempts TransAlta and the coal transition power contracts from complying with the EPS until the dates the coal units are required to meet the EPS in 2020 (for Unit 1) and 2025 (for Unit 2).

Carbon Dioxide Mitigation Program. In 2004, the Washington state legislature passed Substitute House Bill 3141, later codified in RCW 80.70. The law requires fossil-fueled thermal power plants above 25 megawatts (MW) (net output of the electric generator) to provide mitigation for 20 percent of the CO_2 emissions it produces over a 30-year period. The mitigation requirement applies to all new power plants filing for a Site Certification Agreement or Notice of Construction after July 1, 2004. The mitigation requirement also applies to modifications of existing plants permitted by Washington's Department of Ecology or a local air quality agency that will increase power production capacity by 25 MW or more, or increase CO_2 emissions by 15 percent or more.

If mitigation is triggered, compliance must be attained through any one or a combination of these methods:

1. Paying an “Independent Qualified Organization” to verify compliance,
2. Purchasing permanent, verifiable carbon credits, or
3. Using a self-directed mitigation program.

If the third option is chosen, the mitigation program must be identified within a plan submitted as part of the permit application. Payment to a qualified organization and the cost for a self-directed mitigation program are initially limited to an amount derived by multiplying the tons of CO_2 emissions to be mitigated by $1.60.

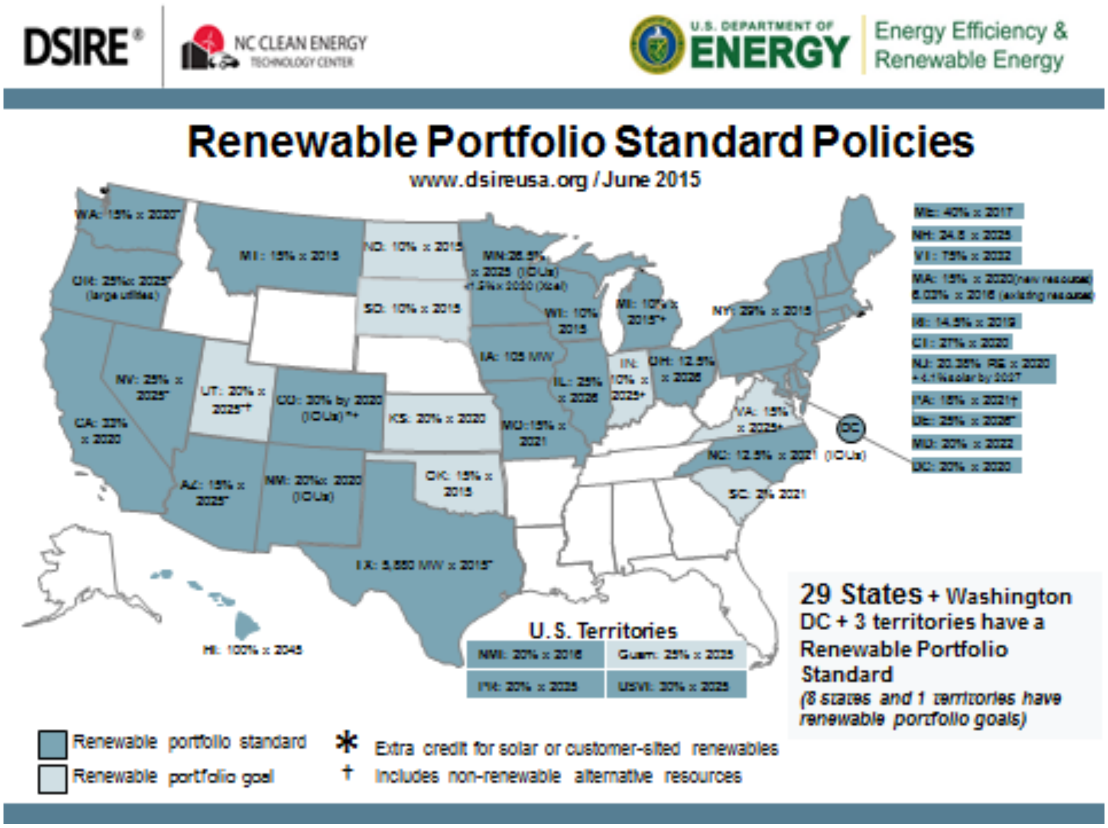
Washington Clean Air Rule. The Washington state Department of Ecology announced on September 21, 2015 a plan to promulgate a state rule to limit greenhouse gases from the state’s 35 largest emitters. Ecology officials stated that the rule would apply to facilities emitting over 100,000 tons of greenhouse gases per year, would require reductions to reach 1990 greenhouse gas emissions by 2050, and would exclude the Centralia coal fired power plant. Remaining sources reporting over 100,000 tons per year include various gasoline and other fuel sources, industrial (includes refinery processing), local gas distribution companies, power plants and waste/landfills. The agency plans to work out details in the coming months and is soliciting stakeholder input. According to EPA a formal draft rule is expected by December 2015 a final draft rule by June 2016.

Renewable Portfolio Standards (RPS)

Renewable portfolio standards require utilities to obtain a specific portion of their electricity from renewable energy resources. Of the 11 Western interconnection states, 8 have binding renewable energy targets, one has a voluntary goal, and two have no RPS in place. PSE has met Washington’s 2012 RPS requirement to meet 3 percent of load with renewable resources by 2012, and is on track to meet the RPS requirements of 9 percent by 2016 and 15 percent by 2020. RPS provisions vary widely among the different jurisdictions in the absence of a federal mandate. Differences include the specific portion of renewable resources required, the timeline to meet the requirements, the types of resources that qualify as “renewable,” the geographic location renewable resources can be sourced from, eligible commercial on-line dates and any applicable technology carve-outs (such as solar). The result is a patchwork of regulatory mandates, evolving regulations and segregated environmental markets. Managing these moving parts is complex from both a resource acquisition perspective and an environmental markets perspective.

Figure C-1, below, illustrates the wide variety of RPS requirements that exist. The table in Figure C-2 lists the current RPS requirements for each state within the Western Interconnect.[3]

Figure C-1: RPS Requirements by State



3 / *Per Figure C-2, State RPS and Eligible Technologies (as of October 2014) are drawn from the Western Interstate Energy Board's publication Exploring and Evaluating Modular Approaches to Multi-State compliance with EPA's Clean Power Plan in the West, April 29, 2015.*

Figure C-2: RPS Requirements for States in the Western Interconnect

State	RPS	Existing Renewable Generation	Eligible Renewable Energy
Arizona	20% by 2025	294 GWh	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, geothermal heat pumps, combined heat and power (CHP)/cogeneration (CHP only counts when the source fuel is an eligible RE resource), solar pool heating (commercial only), daylighting (nonresidential only), solar space cooling, solar HVAC, anaerobic digester, small hydroelectric, fuel cells using renewable fuels, geothermal direct-use, additional technologies upon approval*
California	20% by 12/31/13 25% by 12/31/16 33% by 2020 50% by 2030 (proposed)	3,350 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal electric, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels
Colorado	Investor-owned utilities (IOUs): 30% by 2020; Co-ops serving >100,000 meters: 20% by 2020; Co-ops serving <100,000 meters: 10% by 2020; Municipal utilities serving >40,000 customers: 10% by 2020	666 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, coal mine methane (if the Colorado Public Utilities Commission determines it is a GHG-neutral technology), pyrolysis of municipal solid waste (if the Commission determines it is a GHG-neutral technology), anaerobic digester, and fuel cells using renewable fuels
Idaho	None	287 GWh	N/A
Montana	15% by 2015	197 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, compressed air energy storage, battery storage, flywheel storage, pumped hydro (from eligible renewables), anaerobic digester, and fuel cells using renewable fuels
New Mexico	IOUs: 20% by 2020; Rural electric cooperatives: 10% by 2020	203 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, zero emission technology with substantial long-term production potential, anaerobic digester, and fuel cells using renewable fuels
Nevada	25% by 2025	357 GWh	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, waste tires (using microwave reduction), energy recovery processes, solar pool heating, anaerobic digestion, biodiesel, and geothermal direct use
Oregon	Large utilities: 25% by 2025; Small utilities: 10% by 2025; Smallest utilities: 5% by 2025	499 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, hydrogen, anaerobic digestion, tidal energy, wave energy, and ocean thermal
Utah	Voluntary goal: 20% by 2025	90 GWh	N/A
Washington	15% by 2020 and all cost-effective conservation	631 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, ocean thermal, and biodiesel
Wyoming	None	357 GWh	N/A

NOTE: Approved technologies are generated in the state (excluding hydro generation). In many cases, generation in one state is used for RPS compliance in a different state.

PSE must actively monitor RPS requirements throughout the Western region, because the interconnectedness of the grid and regional energy markets means that changes in one state can have a pronounced impact on the entire system. In particular, PSE pays close attention to requirements in Oregon, California, and Idaho (which currently has no RPS).

California Renewable Portfolio Standard. The size and aggressiveness of California's RPS mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

California has one of, if not *the* most aggressive RPS mandate in the nation. Senate Bill 1078 established the California RPS program in 2002. Governor Schwarzenegger sought to accelerate the standard, asking for 20 percent by 2010; this became law when he signed Senate Bill 107. In 2008, Schwarzenegger signed Executive Order S-14-08, which increased the requirement to 33 percent by 2020. Two RPS bills were passed at the end of the 2009 legislative session, however, the governor elected not to sign either. Instead, he signed Executive Order S-21-09, which allowed the California Air Resources Board (CARB), under its AB 32 authority, to adopt a regulation consistent with the 33 percent RPS target established in Executive Order S-14-08. In 2010, the CARB adopted its Renewable Electricity Standard (RES), requiring 33 percent by 2020. Legislative endorsement of this standard was achieved when Governor Jerry Brown signed Senate Bill SB 2 (1X) into law in April 2011.

SB 2 (1X) extends the original RPS goal from 20 percent of retail sales by the end of 2010 to 33 percent of retail sales by 2020 for all California independently owned utilities (IOUs), electric service providers (ESPs) and the community choice aggregators (CCAs); it also obligates publically owned utilities to meet these goals. In addition, the new law modifies many details of the program and creates portfolio content categories for RPS procurement. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) were tasked with implementing the expanded RPS. In December 2011, the CPUC issued a decision that addressed the criteria for inclusion in each of the new RPS portfolio content categories and the percentage of the annual procurement target that could be sourced from unbundled RECs. The use of unbundled renewable energy credits was capped at 25 percent of a utility's RPS requirement through December 31, 2013; this steps down to 15 percent in 2014 and 10 percent in 2017. The decision applies to contracts and ownership agreements entered into after June 1, 2010.