Environmental Matters

Contents

This appendix contains a wide range of information that relates to the environmental concerns PSE faces and seeks to address.

1. Washington State Regulatory Consideration

Energy Independence Act.

Washington is among 29 states with a renewable portfolio standard (RPS) mandate. Approved by voters in November 2006, Initiative 937 (I-937) requires utilities to acquire 15 percent of electricity from renewable resources by 2020, and undertake cost-effective energy conservation. In order to satisfy the annual RPS requirements, utilities can use eligible renewable resources, acquire renewable energy credits, or a combination of both.

In 2012, Washington state utilities will begin compliance with I-937, codified as the Energy Independence Act (Chapter 19.285 RCW). As mandated by the law, Washington's three investor-owned utilities will submit compliance reports to the Washington Utilities and Transportation Commission.

Measures to Limit and Reduce.

Revised Code of Washington (RCW) 70.235 sets the timing and targets for reducing in-state greenhouse gas (GHG) emissions. It tasks the Washington state departments of Ecology and Commerce to benchmark certain emission sources, develop reduction strategies, track progress, and report results. Both agencies have provided the governor with recommendations, and some policies have already been implemented.

The strategies cataloged by the Washington state departments of Ecology and Commerce with direct impacts on energy supply and consumption include the following:

- The Electric Utility Energy Efficiency & the Renewable Portfolio Standard provisions of Initiative-937 (Effective 2006)
- The Washington State Building Code Council Revisions of 2009
- The School Energy Efficiency Grant of 2009/2010 ($117 MM)
- The Electric Utility Emissions Performance Standard (Effective 2008)
- The High-Performance Public Buildings Act of 2005

Most notably absent from this list of strategies is a GHG emissions cap-and-trade program. Washington is a member of the Western Climate Initiative (WCI), a regional effort between states to reduce GHG emissions through a number of policies including the establishment of a cap-and-trade market. However, the Washington legislature has not yet endorsed a bill that would commit our state to the WCI's cap-and-trade program. While the governor has intended for Washington to become party to the WCI cap-and-trade program, at this point, California is the only state on track to participate when the program begins in 2012 (although the four Canadian provinces are working steadily on their cap-and-trade plans).

Emission Performance Standard. Washington's Emissions Performance Standards (EPS) (WAC 173-407, effective June 19, 2008) requires new and modified baseload electric generation to meet a greenhouse gas limit of 1,100 pounds per megawatt hour (lbs/MWh). The EPS applies to all baseload electric generation for which electric utilities enter into long-term financial commitments on or after July 1, 2008. It restricts PSE's ability to enter into contracts of five or more years when the supply is from unspecified sources, coal generation or other resources that emit above the greenhouse gas limit. PSE's portfolio screening model incorporates these limitations by restricting new coal construction. Since PSE does not model long-term contracts in the IRP, the contract clause does not affect the IRP, although it does affect the contracts that the company could enter into.

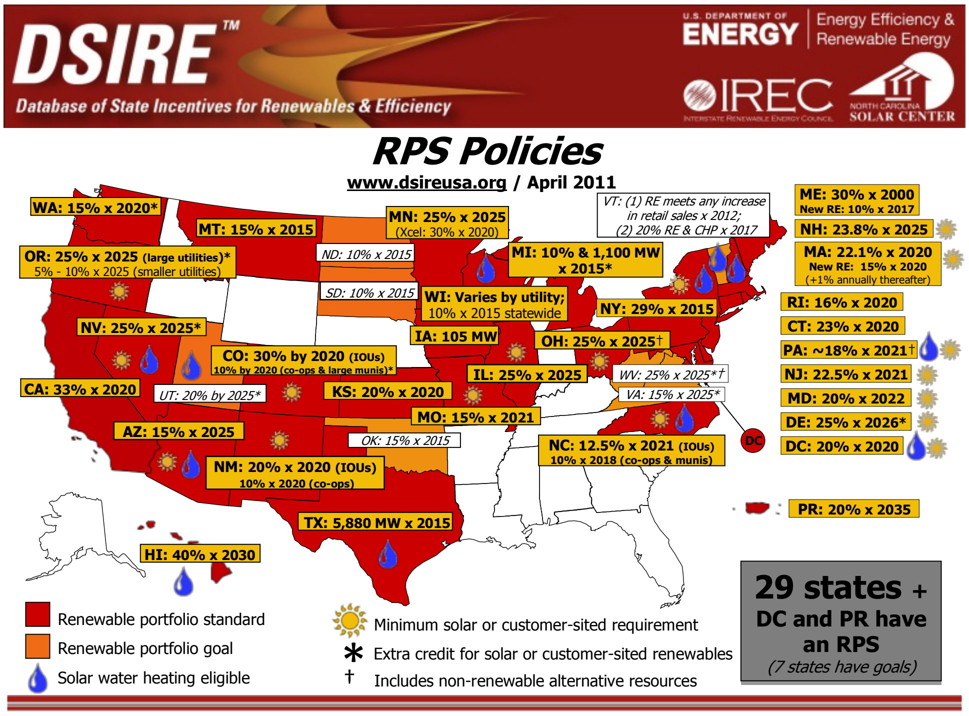
2. Regional Regulatory and Policy Issues

Washington is one of seven states and four Canadian provinces participating in the WCI. However, so far only California and New Mexico are legally committed to participate in the WCI cap-and-trade program, and New Mexico legislation is allowing a postponement of its trading commitments until more states join the partnership. Washington's involvement in the WCI was one way it planned to meet its own emissions reductions commitments set forth in Executive Order 09-05 and RCW 70.235. However, without legislative support to formally commit to the WCI cap-and-trade program, Washington's Governor, Christine Gregoire, has directed the Department of Ecology (DOE) to provide the Legislature by 2011 with recommendations for what a reductions program using statewide sector-by-sector caps would look like. Given the current budget shortfalls, it is uncertain if Washington will pursue the DOE's recommendations, or even if the legislature will ratify cap-and-trade in the WCI anytime soon.

Policy Requirements

Renewable Portfolio Standards. RPS requires utilities to obtain a specific portion of their electricity from renewable resources. Currently, 29 states, the District of Columbia and Puerto Rico have RPS mandates, and an additional seven states have renewable portfolio goals. Because there is currently no federal RPS mandate, each state RPS mandate can be unique in many ways, and variation with respect to the following is not uncommon: the specific portion of renewable resources required, a 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 (i.e. solar). The result: a patchwork of regulatory mandates, evolving regulations, and segregated environmental markets. Managing these moving parts is complex both from a resource acquisition perspective and an environmental markets perspective. Figure C-1 below illustrates the diversity of the RPS requirements in different jurisdictions.

Figure C-1
RPS Requirements by State



Pacific Northwest. In addition to the RPS mandate that PSE is subject to, we also actively monitor other RPS requirements throughout the West, as they are instrumental in shaping the market for renewable energy and Renewable Energy Credits. In particular, PSE pays close attention to the RPS requirements in Oregon and California, as well as Idaho, which currently does not have an RPS requirement. At first glance, one could observe that these state policies are distinct from one another in many ways; but as we have observed first hand, changes made to one can have a pronounced impact on the other. This can largely be attributable to the interconnected nature of the electric grid.

As an example, for nearly the past decade, the state of California has had an RPS mandate. Over the past several years, significant efforts have been made to consummate legislation requiring a 33 percent mandate by 2020. In 2011, those efforts were successful. I(In March 2011, the California House and Senate passed the 33 percent by 2020 RPS bill, and it was signed into law by Governor Jerry Brown in April 2011.)

Because of California's nearly decade long commitment to an RPS mandate and its relentless efforts to increase the state's renewable requirements, California utilities have been extremely active in acquiring renewable resources located both in and out-of-state, effectively increasing competition for renewable resources, Renewable Energy Credit products, and available transmission.

On the flip side, Idaho does not currently have an RPS mandate. Therefore, Idaho utilities are not required to purchase environmental attributes associated with the acquisition of the underlying energy, effectively bringing additional Renewable Energy Credits to the Pacific Northwest market. Should Idaho adopt an RPS mandate in the future, one would expect to see additional heightened competition for renewable resources (and thus their associated environmental attributes).

Given the market dynamics associated with an interconnected electric grid and intertwined regulatory policies, it is important to understand the policy requirements throughout the Pacific Northwest. In the current environment, however, California policy requirements are the primary driver with respect to renewable resource availability and cost, Renewable Energy Credit product availability and cost, transmission and integration.

California's Renewable Portfolio Standard.

California has one of, if not *the* most aggressive RPS mandate in the nation. Senate Bill 1078 established the California RPS program in 2002. After Governor Schwarzenegger assumed office, he called for an acceleration of the RPS, asking for 20 percent by 2010. This later became law when he signed Senate Bill 107. In 2008, Governor Schwarzenegger signed Executive Order S-14-08 to increase the RPS 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 would allow 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.

Governor Schwarzenegger's term expired December 31, 2010, without the successful legislative passage of a 33 percent by 2020 RPS bill. Governor Jerry Brown was elected and sworn into office January 2011. In March 2011, the California House and Senate passed the 33 percent by 2020 RPS bill. It was signed into law by Governor Jerry Brown in April 2011. It is not clear yet how the new RPS mandate will impact renewable resource development and acquisition, and the tradable REC market.

The California Public Utilities Commission (CPUC) has been grappling with its own policies on tradable Renewable Energy Credits (RECs) for the past several years. The policies in question include what percentage of the annual procurement target could be sourced from tradable RECs, cost limitations, the definition of REC-only transactions, and grandfathering provisions. After numerous proposed decisions, the CPUC approved a new tradable REC decision in January 2011. It is not yet clear how this new policy will impact renewable resource development and acquisition, and the tradable REC market.

California – Assembly Bill 32

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 (Assembly Bill 32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs like the WCI. California estimates that 85 percent of its total emissions will be covered under the cap-and-trade program. The program is scheduled to go into effect on January 1, 2012. The cap will be designed to reach 1990 levels by the year 2020 in two phases. Beginning in 2012, electricity generation, electricity imports and large industrial polluters must comply with the cap. Beginning in 2015, transportation fuels and all other fuel distributors will be brought into the program. The proposal includes a number of mechanisms designed to minimize the costs of reducing GHGs. Some of the mechanisms include three-year compliance periods, banking, offsets, an allowance price containment reserve, and linkage to other trading systems.

Earlier this year, lawsuits were filed against the CARB, alleging that the CARB did not adequately explore alternatives to a cap-and-trade market to regulate carbon emissions. In March 2011, the court ruled that the CARB had not sufficiently considered alternatives to the cap-and-trade initiative and that it must amend its documents to comply with the court's decision. It is not clear yet if the court's ruling will delay the implementation of the program.

3. Federal Intervention

The 111th Congress ended without enacting a major law to limit or reduce GHGs, compelling the Environmental Protection Agency (EPA) and many states to move towards utilizing existing regulatory authority under the Clean Air Act (CAA) and other laws to reduce GHG emissions. Some in Congress have been working to suspend or expel EPA's authority to proceed in this direction, but at this time those efforts have failed.

At present, EPA is issuing several new standards directed at electric generation. They include new permitting requirements for GHG emissions (Tailoring Rule), standards to improve the National Air Ambient Quality Standards (NAAQS) for smog, reductions in toxic air emissions (mercury), water discharge restrictions, and new standards for solid waste disposal (coal ash). Because many of these rules are still in development, it is difficult to assess their expected outcomes, particularly with respect to resource cost and potential retirements. Many of the rules will require retrofits at existing facilities and more stringent pollution controls for new facilities, and collectively could impact resource decision making.

With a Republican majority in the House of Representatives, it appears any attempt to move new climate change legislation in the 112th will be blocked. Hearings held in the first half of 2011 by the House Energy and Commerce Subcommittee on Energy and Power only reinforced the Republican sentiment on the issue. Likewise, many in Congress are working to prevent EPA from implementing GHG regulation (Tailoring Rule) and other regulations (described above) that would impact the utility sector. The Energy Tax Prevention Act introduced in the House and backed by Republican senators would block EPA's regulation of GHG emissions from coal plants, manufacturing facilities and other stationary sources.

Congressional resistance is leading some legislators towards clean energy legislation as a way of reducing GHG emissions indirectly. The Senate Energy and Natural Resources Committee is likely to resume work on a national renewable energy standard that passed out of the Committee in June 2009 as part of the American Clean Energy Leadership Act. That renewable energy standard would have required utilities to generate 15 percent of their total electricity from either renewable energy or energy efficiency.

Greenhouse Gas Regulation

In the absence of congressional action, EPA is addressing GHG emissions from large sources through its Tailoring Rule and through the development of New Source Performance Standards (NSPS).

The Tailoring Rule took effect on January 2, 2011 and sets permit levels for GHG emissions in two phases for power plants and other large stationary sources. The ruling intends to limit the amount of GHG emissions a facility can emit by requiring installment of best available control technology (BACT). The ruling goes into effect in phases. In Phase I, existing facilities that emit more than 100,000 tons of emissions per year are required to comply with the new BACT rules when they renew their air permits or make any major changes after January 2011. After July 2011, the second phase of the rule kicks in, requiring preconstruction permits using BACT for new projects that emit 100,000 tons of emissions per year or existing projects that make major modifications and that emit more than 75,000 tons per year. At this time, EPA has only released BACT guidance for coal technology. The agency's work to determine gas turbine BACT guidance is ongoing. Many in the industry believe BACT for natural gas technologies will focus primarily on efficiency improvements to turbine plant design and operating techniques.

On December 23, 2010, EPA entered into a settlement agreement requiring the agency to incorporate GHG emissions into the NSPS for natural gas, oil, and coal-fired electricity-generating units and petroleum refineries. The agreement requires EPA to set new emission limitation standards of performance for new and modified sources. Performance standards set by EPA will require emissions-generating units to meet a specific performance level, but do not impose a specific method by which this level must be achieved. In crafting the performance standards and emissions guidelines, EPA will take the cost and availability of control options into account. EPA is required to set performance standards at a level that has been “adequately demonstrated” by an existing technology. EPA is required to propose new power plant standards by July 26, 2011.

NAAQS for Ozone Smog and Fine Particulates

EPA is reconsidering the National Ambient Air Quality Standards (NAAQS) for ozone smog and fine particulates, although at this point that effort has been delayed another six months. In the meantime, EPA is working towards final issuance of its Clean Air

Transport Rule (CATR) to address ozone and fine particulate releases in the eastern states, where ambient standards are at risk. EPA issued a notice of data availability (NODA) on January 11, 2011 to provide information and an opportunity to comment on alternative allowance allocation approaches for potential use in the CATR. EPA is expected to propose a rule that will apply to fossil-fired electric generating units (EGUs) in 31 eastern states. Three new cap-and-trade programs – SO_2, Annual NOx, and Seasonal NOx - would be integrated into the current trading system administered by the EPA. This rule will not have direct impacts to EGUs located in the western power market.

Mercury

Under current court proceedings, the EPA is required to propose a standard that will limit the amount of toxic mercury a coal- and oil-fired power plant can emit. The proposal deadline is March 16, 2011. The standard must be finalized in rule by November 16, 2011. EPA will determine the maximum achievable control technology (MACT) emission rate limitations for coal-fired units based on coal type. EPA estimates the standards will apply to about 1,200 existing coal-fired electric generating units and will cost the electric sector $10.9 billion annually beginning in 2015.

Cooling Water Intake and Discharge

On March 28, 2011, EPA proposed a new standard under Section 316(b) of the Clean Water Act affecting the intake and discharge of cooling water at steam electric generating units that withdraw water from a body of water through cooling water intake structures. These standards will reflect the best technology available (BTA) to protect water quality from cooling water intake and discharges. This standard, known as Section 316(b), will affect all existing and new fossil steam and nuclear steam electric generating units. EPA estimates BTA will apply to 444 power plants (327 GW) at a cost of $65 billion, but because 316(b) permits are written on a case-by-case basis, the actual number of retrofits to meet compliance is difficult to estimate. Forced retrofits are expected between 2015 and 2018.

Solid Waste Disposal – Coal Ash

On October 21, 2010, EPA formally called for comment on how best to regulate coal ash residuals from electric generation units. Early in 2010, EPA proposed two regulatory options: one where coal ash is regulated as a solid waste under the Subtitle D provisions of the Resource Conservation and Recovery Act (RCRA), and one where coal ash is regulated as a hazardous waste under the Subtitle C provisions of RCRA. Subtitle C would create a comprehensive program of federally enforceable requirements for waste management and disposal. Subtitle D would give authority to the states to oversee a less stringent set of performance standards for handling and disposal. Subtitle C is the stricter of the two, as coal ash would be listed hazardous and as such would require the phase-out of wet handling and surface impoundments. Subtitle D would be less onerous, as it would allow wet handling to continue, and it would allow continued use of surface impoundments provided they are equipped with protective liners. EPA estimates over 500 surface impoundments would be affected by this ruling. The agency expects a final ruling in 2011.