APPENDIX I: ENVIRONMENTAL EFFECTS OF ELECTRIC POWER PRODUCTION

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INTRODUCTION

Appendix I describes effects on the environment from the main types of generation in the Pacific Northwest that are either part of the existing power system or are likely candidates for the Seventh Power Plan's new resource strategy. The appendix also discusses regulations that exist to address these environmental effects. The appendix begins with an overview of the broadly applicable major federal environmental regulations, before providing a narrative analysis of the associated effects of the region's generating resources and the specific regulations that relate to those effects. The information in this appendix is background to inform the Council's efforts to determine and quantify where possible the environmental costs and benefits of generating resources and, more broadly, give due consideration to environmental quality and the protection and mitigation of fish and wildlife as the Council develops the plan's resource strategy. *See* Chapter 19 for a discussion of the Northwest Power Act's requirements in this regard and how the Council is complying with the Act in developing the Seventh Power Plan. *See* Chapters 3, 9, 13, 15, and 20 for specifics on generating resources and on the way in which environmental information, including compliance costs, informed the analysis of resources and the selection of the resource strategy.

SELECTED MAJOR FEDERAL ENVIRONMENTAL LAWS AND REGULATIONS

Several federal laws and regulations apply broadly to the lifecycle impacts of a variety of electricity generating resources. This section provides a brief primer of the major federal laws that arise frequently in discussing the environmental effects of electricity production. In some instances, multiple environmental laws or regulations apply to a single pollutant, waste stream or activity, in these cases, the most stringent requirements generally control. To the extent that other federal, state, or local laws or regulations impose specific requirements or restrictions on a particular generating resource and are not addressed in this section, they will be discussed in the section describing the impacts of that resource.

National Environmental Policy Act

The National Energy Policy Act of 1969 (NEPA) established a requirement that federal agencies that conduct "major federal actions significantly affecting the quality of the human environment" must prepare a statement of the environmental impact of the proposed action and consider alternatives.[1] Major federal actions are defined broadly to include official federal policies, plans, programs or permits.[2] Subject to the discretion of each federal agency, certain actions are categorically excluded

[1] https://www.law.cornell.edu/uscode/text/42/4332
[2] *Id.*

from the NEPA requirements entirely. Categorical Exclusions (CEs) are reserved for actions of a type that normally do not have the potential to cause significant environmental effects.[3] If an action is likely to have significant impacts and does not qualify for a CE, then the lead federal agency is required to prepare an Environmental Impact Statement (EIS) to assess the effects of and alternatives to the proposed action. An action that does not cause effects that are likely to rise to the level of significance requires only the preparation of an Environmental Assessment and Finding of No Significant Impact (EA/FONSI). Most agency actions fall under a CE (95 percent), with EAs representing the bulk of the remaining NEPA analyses (less than five percent). EISs represent less than one percent of NEPA analyses.[4] The process of preparing an EIS is complex and time intensive, with one report finding an average preparation time of 3.4 years.[5]

The NEPA provides for public involvement, granting interested parties the opportunity to review, comment on and challenge the adequacy of EISs and some EA/FONSIs. Procedural requirements to consider environmental effects aside, the NEPA does not require that a federal agency act to reduce the environmental impact of a proposed action.

The NEPA applies to many of the processes required to produce electricity and across a range of generating resources. Mining, drilling and logging operations that occur on federal land or obtain a federal permit are subject to the NEPA, as are many electricity and natural gas transmission projects. The construction and operation of power plants may require NEPA review as well, to the extent that generation facilities require a license from the Federal Energy Regulatory Commission or are constructed on federal lands. This is particularly true for hydroelectric facilities and renewable energy projects.

Clean Water Act

The Clean Water Act makes it illegal to discharge any pollutant into waters of the United States without first obtaining a permit. The law, originally passed in 1972, established two permitting regimes of relevance to the electric industry: the National Pollution Discharge Elimination System (NPDES) permit program administered by the Environmental Protection Agency (EPA) under § 402 of the Act,[6] and the "dredge and fill" permit program administered by both the EPA and the Army Corps of Engineers ("Corps") under § 404 of the Act.[7] Under the § 402 NPDES permitting program, the EPA or authorized state may issue a permit requiring a discharger to comply with technology-based effluent limitations for various pollutants.[8] The Act only requires a § 402 NPDES permit to the extent that the discharge is emanating from a "point source," which is defined as "any discernible,

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[3] *See, e.g.,* http://www.blm.gov/wo/st/en/prog/planning/nepa/webguide/departmental_manual/516_dm_chapter_13.print.html
[4] http://www.gao.gov/assets/670/662543.pdf at 5-6.
[5] http://journals.cambridge.org/action/displayAbstract?fromPage=online&aid=2836720
[6] https://www.law.cornell.edu/uscode/text/33/1342
[7] https://www.law.cornell.edu/uscode/text/33/1344
[8] http://www.in.gov/idem/files/rules_erb_20130213_cwa_summary.pdf at 5.

confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged."[9] The EPA may authorize states to administer the § 402 NPDES permitting program. Under this arrangement, states set effluent limitations guidelines and permit standards that permittees must comply with. The EPA administers the § 402 NPDES permitting program in states that have not been authorized. The EPA has partially or completely authorized Oregon, Washington and Montana; Idaho's § 402 NPDES permit program remains federally administered.[10] Nonpoint source pollution is not covered by the permit requirement and is typically regulated under state programs for the management of runoff. The cumulative effects of permitted discharges and nonpoint source runoff has resulted in impairment in a number of the nation's waters.[11]

Under the § 404 dredge and fill permit program, the Corps (with the environmental guidance of the EPA) may issue a permit for the disposal of dredged or fill material within wetlands or waters of the United States.[12] States may also assume authority to administer the § 404 dredge and fill permit program, however only two, Michigan and New Jersey, have done so to date.[13]

Provisions in the Clean Water Act regulate the water impacts of a variety of lifecycle stages of electricity generation, including the mining and extraction of fuel, the construction of generation facilities and associated infrastructure, and the operation of hydroelectric and steam electric power plants.

Clean Air Act

The modern Clean Air Act evolved from the Air Pollution Control Act of 1955. Under the current incarnation of the law, the EPA is responsible for establishing air quality standards and states are primarily responsible for ensuring compliance.[14] The EPA currently administers three programs of primary relevance to the electricity sector: National Ambient Air Quality Standards, National Emissions Standards for Hazardous Air Pollutants, and New Source Performance Standards.

Under § 109 of the Act, the EPA sets National Ambient Air Quality Standards (NAAQS) limiting the emission of air pollutants with the potential to endanger human health.[15] Pursuant to this requirement, the EPA has identified six "criteria" pollutants for regulation under the NAAQS, including sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone and lead.[16] Once EPA sets the NAAQS, each state is responsible for developing the procedures necessary for compliance, which are laid out in a State Implementation Plan (SIP). The SIPs are subject to EPA

[9] http://water.epa.gov/lawsregs/guidance/wetlands/sec502.cfm
[10] http://water.epa.gov/polwaste/npdes/basics/upload/State_NPDES_Prog_Auth.pdf
[11] *See* http://iaspub.epa.gov/waters10/attains_nation_cy.control?p_report_type=T
[12] http://www.in.gov/idem/files/rules_erb_20130213_cwa_summary.pdf at 6.
[13] http://water.epa.gov/type/wetlands/outreach/fact23.cfm
[14] http://fpc.state.gov/documents/organization/155015.pdf
[15] https://www.law.cornell.edu/uscode/text/42/7409
[16] http://www3.epa.gov/airquality/urbanair/

approval. New and modified sources in a state must typically obtain permits that demonstrate compliance allowable emissions limits. A region that exceeds the NAAQS for a specific pollutant is deemed a "nonattainment area," and sources within that area must meet a special compliance schedule. Compliance requirements in nonattainment areas vary depending on the level of exceedance.

In addition to the NAAQS program, the Clean Air Act established a framework to address hazardous air pollutant emissions. Under § 112 of the Act, the EPA establishes National Emissions Standards for Hazardous Air Pollutants (NESHAP) for 187 listed air toxics: first, the EPA sets technology-based Maximum Achievable Control Technology (MACT) standards that represent "maximum degree of reduction in emissions…achievable" for each pollutant, taking cost into consideration; and second, to the extent that any residual health risks remain after the implementation of MACT, the EPA sets standards to "provide an ample margin of safety to protect public health…unless the Administrator [of the EPA] determines that a more stringent standard is necessary to prevent…an adverse environmental effect." [17]

The Clean Air Act also calls for the EPA to establish technology-based New Source Performance Standards (NSPS) that apply to categories of new industrial facilities in § 111.[18] These standards set emissions limits for new major stationary sources based on the best adequately demonstrated control technology, considering cost.[19] The NSPS is applied to existing facilities pursuant to the New Source Review program to the extent that they undergo modifications.[20] The recently finalized Clean Power Plan, which restricts carbon dioxide emissions, was promulgated under the NSPS program, §§ 111(b) and (d) of the Clean Air Act.[21]

These three programs potentially regulate emissions from an array of fossil-, nuclear- and biomass-fueled electricity generating technologies. In addition, provisions of the Clean Air Act may also have implications for fuel extraction and transportation processes.

Endangered Species Act

The Endangered Species Act (ESA) was passed by Congress in 1973 with a purpose of protecting species threatened with extinction. Under the ESA, the U.S. Fish and Wildlife Service (FWS) in the Department of Interior and the fisheries agency of the National Oceanic and Atmospheric Administration in the Department of Commerce (NOAA Fisheries, also known as the National Marine Fisheries Service) are authorized to designate two classes of protected species: "endangered" species, which are those in danger of becoming extinct; and "threatened species," which are those likely to become endangered.[22] These listed species are protected against "take", which is defined

[17] https://www.law.cornell.edu/uscode/text/42/7412
[18] https://www.law.cornell.edu/uscode/text/42/7411
[19] http://fpc.state.gov/documents/organization/155015.pdf at 12
[20] *Id.*
[21] *See* http://www2.epa.gov/cleanpowerplan
[22] https://www.law.cornell.edu/uscode/text/16/1532

broadly to include "to harass, harm…wound, kill…or attempt to engage in any such conduct."[23] The take prohibition applies to "any person subject to the jurisdiction of the United States."[24] To effect the intended protections, the ESA also requires the designation of habitat critical to the conservation of the affected species. NOAA Fisheries has responsibility for anadromous fish and marine mammals; the Fish and Wildlife Service for resident fish, wildlife, and plants.

Under § 7 of the ESA, no federal agency may authorize any action likely to jeopardize the survival of any listed species or harm their critical habitat.[25] For that reason, a federal agency is required to consult with FWS or NOAA Fisheries prior to undertaking any action that may affect a listed species or critical habitat; to the extent that the proposed action is likely to adversely affect a listed species, then the agency must seek a biological opinion from the FWS or NOAA Fisheries. The FWS and NOAA Fisheries may authorize an agency to act in a manner that results in "incidental take" of a listed species, consistent with reasonable and prudent measures to minimize the take.[26]

Under § 9, no person, including private citizens, may take a listed species or harm critical habitat.[27] However, § 10 allows the FWS or NOAA Fisheries to permit take that is "incidental to… the carrying out of an otherwise lawful activity."[28] To obtain an incidental take permit, a person seeking the permit is required to prepare a habitat conservation plan that specifies the likely impact of the taking, the steps taken to minimize that impact, and the alternatives considered.[29]

The ESA impacts most types of electricity generating resources at various lifecycle stages. The best solar and wind resources often overlap with the habitat of sensitive species, implicating the ESA and causing tension between renewable energy and wildlife interests. Species and habitat may also be affected to the extent that forests are logged to provide timber as a biomass feedstock. With regards to fossil fuel-fired and nuclear generation, the mining and extraction processes may occur in areas that implicate the ESA. Finally, linear infrastructure projects such as gas pipelines and electricity transmission lines may result in adverse habitat impacts.

ENVIRONMENTAL IMPACTS OF ELECTRICITY GENERATION AND APPLICABLE REGULATIONS BY RESOURCE TYPE

The lifecycle impacts associated with electricity generation vary widely depending on the type, fuel, size and location of the resources used. The varying processes involved in producing electricity

[23] *Id*.
[24] https://www.law.cornell.edu/uscode/text/16/1538
[25] https://www.law.cornell.edu/uscode/text/16/1536
[26] *See* http://www.fws.gov/midwest/endangered/section7/section7.html
[27] https://www.law.cornell.edu/uscode/text/16/1538
[28] https://www.law.cornell.edu/uscode/text/16/1539
[29] *Id.*

mean that the profile of environmental and human health effects for each generating resource tends to be unique. The following sections discuss lifecycle impacts of each of the major generating resource types in the Pacific Northwest and in the new resource planning analysis as well as the legal and regulatory framework in place to address them.

Hydroelectricity Generation

The Northwest relies significantly on hydroelectric generation to meet electricity demand in the region, with 31 federally-owned dams[30] supplying over 40 percent of the region's electricity.[31] The Bonneville Power Administration markets the electricity produced by these dams, which together comprise the Federal Columbia River Power System.[32] Other public and privately owned dams also contribute to the region's electricity supply; all told, more than 200 hydroelectric facilities[33] generate over half of the region's power annually.

The principal environmental effects regarding hydroelectric development are generally focused on water quality impacts, hydrology impacts, erosion and sedimentation, land-use impacts, dust and noise during construction, and fish and wildlife impacts. The environmental effects associated with any one hydroelectric project are site specific and therefore can be very different when comparing projects; for example, a project that involves an existing dam or other existing water control structure will typically experience less incremental environmental impacts than a project that requires new dam construction. There are no serious air emissions or solid waste issues associated with hydroelectric development or operation.

The construction and operation of a hydroelectric project may affect water quality through thermal changes (causing wide fluctuation of stream temperatures), nitrogen supersaturation (total dissolved gas), turbidity, and oxygen depletion. A hydroelectric dam slows the movement of water in a river system, which can lead to temperature stratification and oxygen depletion in the reservoir behind the dam. Spill flows from a dam may increase the levels of total dissolved gas in the river downstream. While these water quality changes are not always adverse, they can have an effect on the aquatic environment and can prove lethal for fish and wildlife. Water quality can also affect the aesthetics of the project site.

The process of developing a hydroelectric dam permanently alters the physical hydrology—the movement and distribution of water—of the site. These changes can have significant primary and secondary effects on water quality, habitat, and fish and wildlife. The operation of a hydroelectric facility during times of maintenance, outages, or to meet peak energy demands causes fluctuations of water level in both the impoundment and the stream below. These fluctuating water levels may prohibit development of shoreline vegetation, reduce shoreline use by riparian (riverbank or

[30] https://www.bpa.gov/power/pgf/hydrpnw.shtml#introduction
[31] https://www.nwcouncil.org/history/Hydropower. The Northwest hosts over 200 hydroelectric facilities that generate around 70 percent of the region's power.
[32] https://www.bpa.gov/power/pgf/hydrpnw.shtml#introduction
[33] *See* http://www.eia.gov/state/maps.cfm

streamside) species of wildlife, and lower reproductive success of fish species that spawn near the impoundment margin. Fluctuations in rivers below dams can strand immature fish on shorelines or in shallow waters and may lead to the exposure of eggs of shoreline spawners and nests of salmonids. Storage dams tend to reduce some of the seasonal fluctuations in river flow, helping lead to a more stable riparian zone. Impounded waters can flood islands that are important breeding grounds for certain avian species.

Issues with erosion and sedimentation may occur during construction and continue long after a project is retired or removed. Changes in the sediment load and flow can affect the natural sediment equilibrium found in free flowing waters and increase water turbidity due to accretion and settling in the backwaters behind a dam. This can result in increased sediment deposits near the physical dam and decreased sediment downstream, both affecting the growth of organisms that depend on nutrients carried by the sediment. As the water levels fluctuate, erosion can occur, changing the physical environment. A lack of vegetation along the riverbank can also lead to perpetual carving away of the earth surrounding the water source.

The amount of land required for the development of a hydroelectric dam varies significantly depending on the site and project. A storage project can take up thousands of acres, while a small run-of-river project may take up less than an acre. Nonetheless, between the physical infrastructure and the equipment used for construction, land is disturbed and the surrounding environment is altered.

During construction of a hydroelectric dam, significant amounts of dust, noise, and adverse aesthetics can negatively affect the surrounding project site. Dust and equipment noise is typically limited to the construction phase, whereas the aesthetics of the site are permanently altered. Hydroelectric plant operations are relatively quiet.

Of particular concern to the Council is the potential impact of hydroelectric development on fish and wildlife. While all of the above-mentioned environmental effects can directly or indirectly impact fish and wildlife, there are specific effects that are worth mentioning. A hydroelectric dam presents a migration barrier to the passage of upstream (adult) and downstream (juvenile) anadromous and resident fish. Habitat is completely blocked by some projects in the system. At dams that allow passage, juvenile downstream migrants face the risk of mortality at each dam as a result of passage through turbines, exposure to water supersaturated with nitrogen, delay in start of migration, increased travel times, and increased predation. Filling an impoundment behind a hydroelectric dam inundates land and transforms a free-flowing river into a lake-like environment. This transition of habitat changes the composition of terrestrial and aquatic biota at the project site which may be beneficial or detrimental to wildlife. System storage operations to optimize power generation also alter flows important for the emergence, rearing, and migration of juvenile salmon and other fish, and for adult spawning.

Under the Northwest Power Act, the Council develops a program to protect, mitigate, and enhance fish and wildlife adversely affected by the development and operation of hydroelectric facilities on the Columbia and its tributaries. To address the effects from the existing system, the Council's *Columbia River Basin Fish and Wildlife Program* includes measures and objectives both to protect and increase survival of fish and wildlife within the hydrosystem and to provide compensating offsite protection and mitigation. Measures to limit the direct impact of hydroelectric development include fish screens and bypass systems, bypass spills, and fish ladders to help fish navigate through the hydroelectric dam; minimum flows, flow augmentation requirements and stable storage reservoir operations; and the installation and implementation of systems to maintain powerhouse discharge and minimize or eliminate fluctuations in water and flow levels. Offsite protection and mitigation actions include both habitat protection and improvement measures and artificial propagation facilities and strategies. Mitigation for the effects of the development of the system on wildlife has focused primarily on the offsite acquisition, improvement and protection of habitat for the affected wildlife species.

The Council develops the Fish and Wildlife Program largely on the basis of recommendations from the federal and state fish and wildlife agencies and the region's Indian tribes. The Bonneville Power Administration has an obligation under the Act to use its fund and authorities to protect, mitigate and enhance fish and wildlife in a manner consistent with the Council's Fish and Wildlife Program. All the federal agencies that manage, operate or regulate the hydroelectric facilities (Corps of Engineers, Bureau of Reclamation, and Federal Energy Regulatory Commission, as well as Bonneville) have a separate obligation under the Act to exercise their statutory responsibilities to adequately protect, mitigate and enhance fish and wildlife in a manner that provides "equitable treatment" for fish and wildlife with the other project purposes and to do so taking into account the Council's regional Fish and Wildlife Program at each stage of decisionmaking to the fullest extent practicable.

To provide guidance for future hydropower development in the region, the Council has designated approximately 44,000 miles of stream reaches as "protected areas," where hydropower development would not be appropriate because of the damage development and operation would cause to fish, wildlife, and habitat. The protected areas designations are intended to protect fish and wildlife resources,[34] send a clear signal to developers regarding the acceptability of stream reaches for hydroelectric development, provide power planning guidelines for determining the availability of new hydroelectric power, and create a comprehensive plan to provide guidance for licensing decisions made by the Federal Energy Regulatory Commission (FERC). As noted in the Council's 2014 hydropower scoping study,[35] if a prospective site is located outside a protected area, it is not automatically deemed environmentally acceptable for hydroelectric development; each project must undergo extensive environmental impact studies approved by state and federal agencies in order to proceed.

Detail on both the effects of hydroelectric production and the protection and mitigation measures to address those effects can be found in the past and current Fish and Wildlife Programs. The Council adopted its latest amendments to the *Columbia River Basin Fish and Wildlife Program* in October 2014.[36] The 2014 Fish and Wildlife Program is part of the draft Seventh Power Plan. *See* Chapter 20, as well as the discussion in Chapter 19. A number of species affected by the hydroelectric system are also listed as threatened or endangered under the federal Endangered Species Act,

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[34] Protected areas designations are based on fish and wildlife considerations only and do not reflect other river values that might affect the desirability of hydroelectric development.
[35] http://www.nwcouncil.org/energy/grac/hydro/
[36] http://www.nwcouncil.org/fw/program/2014-12/program/

including 13 distinct population segments of salmon and steelhead, Kootenai River white sturgeon, bull trout, and eulachon. The Fish and Wildlife Program includes a discussion of and links to the programs, plans, biological opinions, and other developments related to addressing the requirements of the ESA for these species, as well as a discussion as to how the ESA requirements and programs interrelate with the regional protection and mitigation program under the Northwest Power Act. The licensed issues by FERC under the Federal Power Act to the owners and operators of the non-federal hydroelectric dams on the Columbia and its tributaries include fish and wildlife protection and mitigation requirements to address the requirements of the Federal Power Act, the Northwest Power Act, and ESA.

Coal Electricity Generation

Although coal-fired power plants still produce more electricity in the US than any other resource type, coal use in the electricity sector is declining.[37] The Energy Information Administration (EIA) forecasts that coal-fired generators will produce 28 percent less electricity in 2015 than they did during coal's recent peak in 2007, a decline attributable in part to low natural gas prices and the growth of renewable energy.[38] In addition to these competitive pressures, the Environmental Protection Agency's Clean Power Plan will potentially limit coal-fired electricity generation in the future by establishing a carbon dioxide emissions reduction target of 32 percent less carbon dioxide (CO_2) from the electric industry by 2030, based on 2005 emissions levels.[39] Coal, as the most significant contributor to carbon dioxide emissions in the electric industry, stands to see the biggest impact from the policy.

However, advancements in carbon capture and sequestration (CCS) technologies may present coal with a renewed opportunity for growth in the future. The CCS process involves removing carbon dioxide from a plant's emissions and transporting it to a facility where it can be injected into deep geological formations.[40] Despite the promise of reduced CO_2 emissions, CCS technologies are too costly for widespread deployment. Including CCS technologies in the construction of a new coal plant raises the levelized cost of electricity produced by that facility by approximately 44 percent to 80 percent (depending on the type of plant), and retrofitting an existing facility is still more costly.[41] Absent a significant reduction in the cost of CCS, the electric industry's reliance on coal as a generation resource is likely to its decline. The national trend towards coal plant retirements is mirrored in the Northwest, where four of the six coal-fired power plants providing electricity to the region are slated to close in the next 10 years, and regional policymakers are considering legislation to facilitate the closure of the other two.[42] Still, because coal-fired electricity generation is expected to continue to provide power to the Northwest in the near term, and advances in CCS technologies

[37] http://www.eia.gov/forecasts/steo/images/Fig25.png
[38] http://www.eia.gov/forecasts/steo/report/coal.cfm..
[39] http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-numbers
[40] http://www.epa.gov/climatechange/ccs/
[41] http://www.c2es.org/technology/factsheet/CCS
[42] http://www.nytimes.com/2015/02/15/us/politics/bills-in-washington-state-seek-to-end-use-of-coal.html?_r=0

may make coal an attractive fuel in the future, it is important to consider the environmental consequences of these plants.

While carbon dioxide emissions represent the most visible impact from coal plants, the lifecycle environmental and human effects of coal-fired electricity generation are varied. The following sections examine the impacts associated with coal mining, processing, and transportation as well as the effects of coal plant construction and operations.

Impacts of Coal Mining, Processing, and Transportation

Coal is a sedimentary rock composed of organic matter that has been subjected to geologic heat and pressure over millions of years, a process that forms underground seams of the fuel that may be extracted either through surface or underground mining operations. Coal is typically processed at the mine site to remove impurities before transportation to a power plant. Once coal has been prepared, it is generally shipped to a power plant by train, barge or truck or pipeline.[43] Each of these stages, coal mining, processing and transportation may cause adverse environmental and human health effects.

Coal is extracted either from underground mines, which account for approximately one-third of the coal produced in the US, or surface mines, which produce about two-thirds of the domestic supply.[44] Underground mines have limited surface impacts, relying on discreet above-ground points of entry to enable miners and equipment to access the coal seam. The development of an underground mine typically involves the transportation of heavy equipment and workers to the site, which may require the construction of new roads. In addition, preparation of the site may entail drilling, blasting, excavation and pile driving. These operations often result in air impacts from fugitive dust and vehicle exhaust, as well as water impacts from altered drainage patterns and increased pollutant and sediment loads in runoff from the site. Wildlife may be affected by associated noise and human activity, as well as habitat disruption.

Underground coal mining is typically conducted by one of two methods: room-and pillar-mining, in which the miners excavate portions of the coal seam but leave pillars of coal to support the ground above, or longwall mining, in which a mechanical shearer and hydraulic roof supports are used to mine a long panel of coal in a series of slices, allowing the mined area to collapse a safe distance behind the miners and equipment. Longwall mining recovers more of the available coal than room-and-pillar operations and is generally the most cost-effective method of underground mining.[45] Subsidence of the land surface above a mine is a significant concern for both methods of underground mining, potentially damaging buildings, utility and transportation infrastructure, surface and groundwater resources, vegetation, and wildlife habitat.[46] A longwall mine is more likely to cause subsidence, because the mined area is intentionally permitted to collapse behind the shearing

[43] http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html
[44] http://www.eia.gov/coal/annual/pdf/acr.pdf
[45] http://www.bloomberg.com/news/articles/2015-08-10/the-30-year-old-trick-that-s-going-to-keep-america-s-coal-alive
[46] http://pubs.usgs.gov/circ/1983/0876/report.pdf

operation. The subsidence impacts of a longwall mine are generally more uniform and contemporaneous than subsidence resulting from a room-and-pillar mine, and are therefore easier to forecast and mitigate. Subsidence as a result of underground mining is regulated federally under the Surface Mining Control and Reclamation Act (SMCRA), which requires mine operators to adopt measures to prevent subsidence that causes material damage.[47] The Office of Surface Mining, Reclamation and Enforcement (OSMRE) issues permits for underground mines, requiring the permittee to prevent subsidence to the extent feasible, and repair or compensate for damage caused as a result of subsidence.[48] The law and associated regulations allow for planned subsidence in a predictable and controlled manner.

Underground mines also pose greater risks to mineworkers than their surface counterparts. Pulmonary diseases, including coal workers' pneumoconiosis, silicosis, and chronic obstructive pulmonary disease, are a significant concern for underground mineworkers who work in a confined area with high levels of coal dust and silica in the air.[49] Underground mineworkers are additionally faced with greater risks associated with mining accidents such as unintended collapses[50] and explosions.[51] Underground coal mining processes release methane contained within coal seams; methane is extremely flammable, toxic to humans and a greenhouse gas that contributes to climate change to the extent it is not captured.[52] Mineworker protection is regulated primarily by the Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977, as amended in 2006.[53] This law gives the MSHA the authority to promulgate safety standards, inspect mines, and investigate accidents.[54] In addition, the Department of Labor operates a program under the Black Lung Benefits Act to compensate miners and survivors of miners who suffer from or are killed by pneumoconiosis.[55]

While an underground mine causes surface impacts generally limited to the access points of the mine, a surface coal mine causes significantly more visible above-ground impacts. The two predominant methods of surface coal mining are mountaintop removal, which commonly occurs in the Appalachian coalfields, and area strip mining, which is typically employed in the Western states. Mountaintop removal mining involves the use of explosives and machinery to access coal seams beneath mountaintops.[56] The displaced rock and dirt, called "overburden," is disposed of in adjacent valleys. In addition to causing harmful effluents, mountaintop removal operations often permanently bury headwater streams with overburden and alter flow patterns in associated drainages.[57] Once

[47] https://www.law.cornell.edu/uscode/text/30/1266
[48] https://www.law.cornell.edu/cfr/text/30/817.121
[49] http://www.cdc.gov/niosh/docs/2011-172/pdfs/2011-172.pdf
[50] http://www.post-gazette.com/local/region/2015/03/08/Roof-Collapse-at-Cameron-Mine-Portal-Possible-Entrapment/stories/201503080217
[51] http://www.nytimes.com/2010/04/10/us/10westvirginia.html?pagewanted=all
[52] http://www.epa.gov/cmop/faq.html
[53] https://www.law.cornell.edu/uscode/text/30/811
[54] https://www.law.cornell.edu/uscode/text/30/813
[55] http://www.dol.gov/owcp/dcmwc/regs/compliance/blfact.htm
[56] http://www.epa.gov/region03/mtntop/
[57] *Id.*

mining operations are complete, the area is regraded and revegetated.[58] A 2002 revision of the Army Corps of Engineers' regulations revised the definition of fill material to include "overburden, slurry, or tailings or similar mining-related materials," making explicit the ability of mountaintop removal mining operations to continue valley fill practices.[59] These practices are limited to ½ an acre and 300 linear feet of stream bed loss under a general permit, but broader valley fill operations may be permitted under an individual permit. In addition to compliance with the Clean Water Act, valley fill operations require a regulatory exception from the OSMRE for surface mining activities that would disturb the land within 100 feet of a stream.[60] The current regulatory regime allows for considerable potential residual environmental effects from valley fill practices. The OSMRE has recently proposed regulations to strengthen its stream protection program,[61] but it does not appear likely that these proposed regulations would significantly alter valley fill practices.[62] After mining operations are complete, mined areas must be reclaimed pursuant to requirements in the Surface Mining and Control Act. Surface mines must typically be restored to their "approximate original contour" under the Act, however, mountaintop removal mines are exempted so long as the land is left level or gently rolling.[63] Even after reclamation, then, the character of areas subjected to mountaintop removal mining operations is significantly and permanently altered. In Appalachia, where mountaintop removal mines are frequently located in areas covered by deciduous forests that host significant biodiversity,[64] this permanent alteration of the land can represents a significant ongoing environmental impact.[65]

Area strip mining uses a similar process to mountaintop removal, in which heavy machinery is used to remove soil and rock in order to access underlying coal seams. Large scrapers remove the soils covering the area to be mined, and either stockpile the soils for later reclamation use or use them to reclaim a previously mined area.[66] The overburden beneath the soils is then leveled, blasted and removed to a spoils pile to expose the underlying coal seam. These methods of surface mining have obvious implications for vegetation, which must be removed prior to mining operations, and wildlife habitat, which relies on the natural character of the land. The affected species and degree of impact depend on the type and location of mining operation. Western strip mines are often coterminous with the habits of sensitive wildlife, such as sage grouse and mule deer. Despite the potential wildlife impacts, surface coal mining operations are not required to conduct a § 7 consultation with the Fish and Wildlife Service (FWS) under the Endangered Species Act, even where there is federal involvement in the project. This arrangement is based on the FWS's 1996 Biological Opinion on Surface Coal Mining and Reclamation, which reasoned that the environmental regulations under the

[58] *Id.*
[59] https://www.fas.org/sgp/crs/misc/RL31411.pdf at 5.
[60] http://www.gpo.gov/fdsys/pkg/CFR-2013-title30-vol3/pdf/CFR-2013-title30-vol3-sec816-57.pdf
[61] http://www.osmre.gov/programs/RCM/docs/SPRProposedRule.pdf
[62] *Id.* "…[N]othing in the proposed revisions to our excess spoil requirements would prohibit the construction of valley fills, head-of hollow fills, sidehill fills, or any type of fill other than durable rock fills."
[63] https://www.law.cornell.edu/cfr/text/30/824.11
[64] http://www.filonverde.org/images/Mountaintop_Mining_Consequences_Science1[1].pdf
[65] http://www.scientificamerican.com/article/endangered-species-coal-appalachia-mountaintop-removal/
[66] http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s09.pdf

Surface Mining Control and Reclamation Act were sufficiently protective of wildlife to find that mining activities would have no effect on listed species or critical habitat under the ESA.[67]

Surface mines may have a detrimental impact on water quality as well. Surface mining often results in acidic runoff containing harmful levels of sediment, salinity and trace metals.[68] This runoff is generally nonpoint source pollution, as such it is not regulated by the EPA.[69] Nonpoint source pollution is regulated by state management programs under the Clean Water Act, but the nonpoint waste stream is notoriously difficult to manage and these programs have yielded little improvement in water quality.[70] Many aquatic organisms, including fish species are sensitive to minor water quality changes. Sulfate present in mine runoff, for example, results in microbial production of hydrogen sulfide, which is toxic to many aquatic organisms, and selenium bioaccumulation causes deformities in certain fish species and reproductive harm to the birds that eat them.[71] Sediment adversely impacts salmonid spawning and rearing, and can reduce reservoir capacity and damage hydroelectric infrastructure. These impacts to aquatic organisms are regulated to some degree by SMCRA's environmental performance protection standards, which requires that mine operators "to the extent possible using the best technology currently available, minimize disturbances and adverse impacts of the operation on fish, wildlife, and related environmental values, and achieve enhancement of such resources where practicable."[72] The OSMRE has proposed regulations to strengthen the protections for fish and wildlife, including the restoration of native vegetation to mined areas, enhanced water quality monitoring requirements, and improved handling of acid- and toxic-forming materials.[73] The effect of these proposed regulations remain to be seen.

Air impacts associated with surface mining include the release of methane trapped within coal seams, vehicle exhaust from the use of heavy equipment, and overburden dust and coal dust aerosolized by blasting and wind erosion.[74] Coal mines emitted over 140 billion cubic feet of methane in 2012, of which surface mines were responsible for 17 percent. EPA runs a voluntary program to capture and mitigate fugitive methane emissions from both underground and surface coal mines called the Coalbed Methane Outreach Program.[75] The success of this program in reducing methane emissions is uncertain.

Surface mines, particularly mountaintop removal mines, are associated with a variety of human health impacts. In addition to significant noise levels, blasting causes vibrations that can compromise adjacent landowners' buildings and wells.[76] Dust and "flyrock" from blasting operations

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[67] http://www.fws.gov/ecological-services/es-library/pdfs/96_US_OSM.pdf
[68] http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3248525/
[69] https://www.law.cornell.edu/uscode/text/33/1329
[70] http://www.gao.gov/assets/600/591303.pdf
[71] http://www.filonverde.org/images/Mountaintop_Mining_Consequences_Science1[1].pdf
[72] https://www.law.cornell.edu/uscode/text/30/1265#FN-2
[73] https://www.law.cornell.edu/uscode/text/30/1265#FN-2
[74] http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s09.pdf
[75] http://www3.epa.gov/cmop/basic.html
[76] https://www.fas.org/sgp/crs/misc/RS21421.pdf at 4.

can travel beyond the property boundaries of the mine, settling on adjacent properties.[77] Surface mines may degrade downstream water quality, potentially causing illness in people who come in contact with the water.[78] The alteration of drainages through the practice of “valley fill” disposal of overburden increases the likelihood of flooding, impacting downstream residents.[79] Microbes metabolize the sulfate present in mining runoff into hydrogen sulfide gas, inhalation of which, in addition to producing an unpleasant “rotten egg” smell, appears to cause headaches, irritability and memory loss.[80] Ecological impairment of streams as a result of coal mining operations may increase cancer mortality for individuals living in the surrounding area.[81] A 2010 study of West Virginia residents found a correlation between rising rates of breast, respiratory and urinary cancers and the degree of stream impairment from mining activities.[82] In addition to direct human health impacts, surface mining may also result in a variety of indirect human health effects. Active surface mines occupy large areas of land and are incompatible with alternative land uses, so mining reduces recreational opportunities and causes considerable aesthetic impacts. Improper management of mine sites can lead to coal seam fires, which may smolder underground for decades.[83] Coal seam fires burn underground, releasing toxic gases through surface vents and causing subsidence. The environmental and human health effects associated with mountaintop removal mining, both real and perceived, drive down property values in nearby communities and can result in the displacement of residents and municipal infrastructure.[84] Surface mining may also adversely impact significant cultural or paleontological sites, including town cemeteries.[85] Under the OSMRE’s regulations pursuant to SMCRA, mine operators must catalogue cultural, historic and archeological resources prior to the commencement of mining activities.[86] These resources may be protected to the extent that they are eligible for listing in the National Register of Historic Sites, but exceptions to the protections may be granted by a relevant regulatory authority.[87] Communities located near surface mining operations may also encounter additional human health impacts from the processing and transportation of coal, discussed below.

Limited coal mining in the Northwest means that coal plants in the region import most of their fuel from Western coalfields or Appalachia. Wyoming is the largest coal producing state, accounting for 39 percent of US coal, followed by West Virginia at just over 11 percent.[88] The largest surface coal

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[77] *Id.*
[78] http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3226519/
[79] *Id.*
[80] *Id.*
[81] http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3226519/
[82] *Id.*
[83] http://www.portal.state.pa.us/portal/server.pt/community/centralia_mine_fire_resources/21339
[84] http://blogs.wvgazettemail.com/coaltattoo/2010/04/29/annenberg-foundation-offering-2-5-million-toward-new-marsh-fork-elementary-school/
[85] http://news.nationalgeographic.com/news/2013/09/130906-twilight-strip-mine-cemetery-west-virginia/
[86] http://www.ecfr.gov/cgi-bin/text-idx?SID=4efe39d682156fd82b3ec3ad615a8d9c&mc=true&node=se30.3.779_112&rgn=div8
[87] https://www.law.cornell.edu/uscode/text/30/1272. *See also* http://www.ecfr.gov/cgi-bin/text-idx?SID=652b47adf00515bf291385ee478048b6&mc=true&node=se36.1.60_12&rgn=div8
[88] *Id.*

mine in the US, Peabody Energy's North Antelope Rochelle Mine, covers approximately 46,000 acres in Wright, Wyoming[89] and generated over 110 million tons of coal in 2013.[90] Montana is the only state in the Northwest that hosts significant coal mining operations, producing just over 4 percent of the country's coal predominantly from the state's surface mines.[91] Most of the coal burned in the Northwest for electricity production is from the Powder River Basin in Wyoming and Montana.[92]

After coal is mined from either an underground or surface mine, it is typically processed to remove impurities before being transported to a coal plant. Coal arrives at a cleaning facility as run-of-mine coal, where it is stored in stockpiles until needed. From there, the coal is crushed and screened into fine and coarse fractions, which are subsequently conveyed to their respective cleaning processes.[93] Processing methods for fine and coarse coal are similar; typically the coal is washed with water or other fluids to allow the lighter coal particles to separate from the denser impurities such as rock, soil, and ash. The moisture must then be remove from the coal through dewatering and thermal drying.[94] Dewatering typically involves the use of screens, thickeners or cyclones to separate the water from the coal, while dewatered coal is thermally dried by exposure to hot gasses.[95] Once it is dry, the coal is ready for combustion in a coal plant. Processing generally occurs at or near the mine site to reduce transportation costs of the fuel.

The coal cleaning process raises a variety of environmental and human health concerns, primarily resulting from the water effluents associated with the cleaning process. Run-of-mine coal stockpiles may be stored outside, uncovered, which exposes them to wind and rain. Rainwater leaches contaminants from the coal, and the runoff is generally captured in a coal pile runoff pond.[96] These contaminants include metals such as copper, aluminum, nickel, and iron, as well as suspended solids. Coal pile runoff ponds are designed to settle out solids, but typically do not treat the water for metal content before discharging.[97] Effluents are also produced in the coal washing process, where much of the non-coal material removed during preparation of the coal is suspended in water and stored in tailings ponds. These ponds may contain billions of gallons of slurry, contaminated with coal particles, dirt, rock, clay and an array of metals and other pollutants.[98] Unintentional release of the coal slurry through impoundment failure[99] or an accident in transportation[100] can lead to significant damage to downstream ecological resources, property and community health. Coal waste

[89] http://www.osmre.gov/resources/reports/2012.pdf at 28.
[90] http://www.peabodyenergy.com/content/274/publications/fact-sheets/north-antelope-rochelle-mine
[91] *Id.* There is only one underground coal mine in operation in Montana.
[92] http://www.eia.gov/coal/transportationrates/archive/2010/index.cfm
[93] http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s10.pdf
[94] *Id.*
[95] *Id.*
[96] http://water.epa.gov/scitech/wastetech/guide/304m/upload/2008_09_10_guide_304m_2008_steam-detailed-200809.pdf at 3-61.
[97] *Id* at 3-62.
[98] http://www.nytimes.com/2000/12/25/us/a-torrent-of-sludge-muddies-a-town-s-future.html
[99] *Id.*
[100] http://www.wvgazettemail.com/News/201402110032

impoundments may require both a § 404 dredge and fill permit from the Corps—to the extent that the impoundment is constructed in a stream or wetland—and a § 402 NPDES permit from the EPA—to the extent that the impoundment discharges into a waterbody.[101] Even absent unintentional release, the presence of a coal slurry impoundment may cause public anxiety about the potential for a breach or water contamination in nearby communities. This public perception reduces property values and drives relocation efforts.[102] The chemicals used in coal washing may have adverse ecological and human health effects as well, to the extent that they are exposed to the environment through the washing process or accidental release from holding tanks.[103] The extent of the impacts depends on the chemicals and amount involved, although the effects of many of these chemicals are little understood until an accident occurs.[104]

In addition to water effluents, coal processing may result in particulate matter air emissions in the form of coal dust during conveyor belt pour off, stockpile construction or consumption, crushing and sorting operations, thermal drying or through wind erosion.[105] Coal dust may contribute to the health effects experienced by individuals living near mining operations.[106] Particulate emissions can be mitigated through control technology or dust suppression measures, including water wetting.[107] Fugitive dust from coal processing is regulated by the EPA under the New Source Performance Standards (NSPS) of the Clean Air Act (CAA). The standards apply to thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment, and coal storage, transfer and loading systems that process more than 200 tons of coal per day.[108] Numeric emissions standards are established for particulate matter and opacity, as well as sulfur dioxide, oxides of nitrogen and carbon monoxide emissions and are designed reflect the emissions levels achievable through the use of best demonstrated control technology.[109] The regulations also require regular monitoring and reporting.[110]

After the coal has been processed to remove impurities, it is transported to a coal fired power plant by truck, rail, barge, or pipeline. Most of the coal received by power plants is shipped by rail (72 percent), followed by barge (11 percent), truck (10 percent) and conveyor or pipeline (7 percent).[111] The primary impacts of coal transportation can include air emissions, water contamination, and noise and traffic levels.[112] Coal transportation causes two primary air impacts: coal dust release and

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[101] http://water.epa.gov/polwaste/npdes/Mining.cfm
[102] *See, e.g.* the Marsh Fork Elementary School relocation saga. http://www.wvgazettemail.com/News/201301200022. Also referenced in note 84.
[103] http://www.newyorker.com/magazine/2014/04/07/chemical-valley
[104] http://ntp.niehs.nih.gov/results/areas/wvspill/studies/index.html
[105] http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s10.pdf
[106] *See, e.g.,* http://www.scopemed.org/fulltextpdf.php?mno=20068
[107] *Id.*
[108] http://www.ecfr.gov/cgi-bin/text-idx?SID=1665e9cf519d9554e8a83ce44386e7e2&mc=true&node=sp40.7.60.y&rgn=div6
[109] http://www3.epa.gov/ttn/caaa/t1/fr_notices/cpp_nsps_fr_092509.pdf at 17.
[110] http://www.ecfr.gov/cgi-bin/text-idx?SID=1665e9cf519d9554e8a83ce44386e7e2&mc=true&node=sp40.7.60.y&rgn=div6
[111] http://www.eia.gov/coal/transportationrates/archive/2010/trend-coal.cfm#fig1
[112] http://www.che.utexas.edu/course/che359&384/lecture_notes/topic_3/Chapter4.pdf

vehicle emissions. In addition to coal dust released during the loading and unloading of coal, the act of transportation itself may cause fugitive coal dust emissions. In a 2009 testimony before the Rail Energy Transportation Advisory Committee, a railroad company executive estimated that a single railcar may lose as much as 645 pounds of coal per 400 mile trip.[113] A typical Northwest coal train may consists of five locomotives and up to 145 open-top hopper cars.[114] Truck transport of coal causes similar issues on a smaller scale. In addition to the health impacts of coal dust discussed above, landowners adjacent to loading or unloading sites and transportation routes may experience a persistent coating of coal dust around and inside their homes.[115] Water impacts from coal transportation can occur from fugitive emissions of coal dust and fuel system emissions during loading, unloading and transportation by barge.[116] Coal pipelines allow pulverized coal that has been mixed with water to flow from a coal processing facility to a power plant. The coal must be dewatered and dried prior to use, resulting in spent water that is contaminated with many of the same materials present in coal processing effluents. The spent water may be used in the cooling system of a coal-fired power plant or recycled through a return pipeline.[117] Additionally, individuals living near sites at which coal is loaded and unloaded as part of the transportation process may experience significant levels of noise, and truck or train traffic from the facility.

Both underground and surface coal mine sites are typically decommissioned and reclaimed to mitigate ongoing environmental impacts. Decommissioning and reclamation typically involves removing mining infrastructure, filling in the mine site and recontouring the land, and revegetating the area.[118] The impacts of the decommissioning and reclamation stage of a coal mining operation are primarily associated with the operation of construction equipment on the site.[119] Residual impacts may persist after a mine site has been decommissioned and reclaimed. These impacts include: altered surface or groundwater flow patterns, breach or seepage of contaminated effluent from tailings ponds, and wildlife habitat and visual impacts resulting from topographical changes to the land.[120]

If a federal agency leases land or issues a permit for proposed coal mine operations or coal-fired electricity generating facilities, the NEPA may impose procedural requirements on the project. The NEPA requires federal agencies to conduct environmental analyses of proposed actions; the scope and complexity of the analyses depends on the application of CEs to the project in addition to the significance of the environmental effects. Preparation of a full EIS, which is required when a proposed action is likely to have significant impacts, involves a considerable investment of time and resources.

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[113] http://www.scribd.com/doc/129350651/Surface-TransMinutes-9-10-09-1
[114] http://www.oregonlive.com/environment/index.ssf/2012/06/coal_clash_trains_roll_slowly.html
[115] http://newstandardnews.net/content/index.cfm/items/3141
[116] http://www.che.utexas.edu/course/che359&384/lecture_notes/topic_3/Chapter4.pdf
[117] https://www.princeton.edu/~ota/disk3/1978/7817/781706.PDF
[118] http://teeic.indianaffairs.gov/er/coal/impact/decom/index.htm
[119] *Id.*
[120] http://teeic.indianaffairs.gov/er/coal/impact/decom/index.htm

Impacts of Operating a Coal Power Plant

A coal-fired steam-electric power plant consists of coal receipt, storage, handling and preparation facilities, a furnace and steam generator, a steam turbine and condenser, an electric power generator, a switchyard, flue gas handling and emission control equipment and a closed-cycle condenser cooling system. In the Northwest, most plants use pulverized coal firing to achieve essentially complete combustion. All operate with subcritical steam pressure and temperature conditions, unlike the somewhat more efficient state-of-the-art supercritical or ultra-supercritical designs. All operational coal plants in the region use some form of closed-cycle cooling.[121] These plants normally operate as baseload units, coming down only for maintenance and seasonal economic outages.

An array of environmental and human health impacts may result from the construction, operation and decommissioning stages of a coal power plant's lifecycle. Although the construction of new coal-fired electricity generation facilities in the Northwest appears unlikely at this point in time, advancements in CCS technologies and fluctuations in fuel prices may spur coal plant development in the future. As such, an analysis of the environmental and human health impacts of the construction phase of a coal facility is important. The construction of a coal plant may result in soil erosion and associated water quality impacts during site preparation, increased air emissions related to the transportation of construction material and the operation of heavy equipment, wildlife disruption and loss of habitat, and nuisances to adjacent property owners, including increased vehicular traffic, noise and dust.[122] The production of concrete, transportation of construction materials, and operation of construction equipment all have the potential to cause air emissions.[123] Although most of these impacts are temporary, the disruption of wildlife and loss of habitat, and nuisances to adjacent landowners may persist beyond the duration of the construction phase. Under the Clean Water Act, a developer is required to obtain a § 402 NPDES permit from the EPA or authorized state for stormwater discharges that occur during construction of a coal plant.[124]

The operation phase of coal-fired electricity generation has the potential to result in significant environmental and human health impacts, notably air emissions, impacts on water quality and quantity. Atmospheric releases of an assortment pollutants are the primary environmental impact of coal-fired plants. Pollutants of concern include particulates, sulfur oxides, nitrogen oxides, mercury and other heavy metals, and carbon dioxide.[125] Direct particulate emissions from coal plants firing pulverized coal originate from incombustible constituents of coal. Most of the resulting ash settles to the bottom of the furnace and is removed for landfill or settling pond disposal, but some is entrained

[121] The Corette plant in Billings, Montana, was the only Northwest coal plant that used once-through cooling, however, Corette was retired in August, 2015.
[122] http://teeic.indianaffairs.gov/er/coal/impact/construct/index.htm
[123] *Id.*
[124] http://water.epa.gov/polwaste/npdes/stormwater/EPA-Construction-General-Permit.cfm
[125] Unless otherwise noted, the following discussion of air pollutants and controls associated with coal-fired electricity generation is derived from Environmental Protection Agency AP-42 Compilation of Air Pollutant Emission Factors, Section 1.1 Bituminous and Subbituminous Coal Combustion. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf.

in the flue gas. Plants are provided with fabric filters ("baghouses") or electrostatic precipitators to capture particulates in the flue gas. Some particulates are also captured in wet flue gas desulfurization (FGD) equipment. Particulate control technology capture efficiency ranges from 99 percent to 99.9 percent.

Particulate matter (PM) is airborne solid or liquid matter including dirt, dust, soot, smoke, and liquid droplets. Respirable particulates, or particles that capable of being inhaled, are classified as PM_{10} (less than 10 microns in diameter) and $PM_{2.5}$ (particles smaller than 2.5 microns). Particulates originate from incomplete fuel combustion and noncombustible fuel components. Secondary particulates originate from reactions of precursor compounds including nitrogen oxides or sulfur dioxide. In addition to the causes of particulate matter emissions discussed above (dust from mining, coal preparation, coal transportation, and open fuel storage), particulate matter is often a product of cooling tower drift and ash disposal operations.

Particulates can have adverse effects on health, materials, cleanliness and visibility. Respirable particles can lodge in the lungs, causing or aggravating diseases of the heart and lungs, decreased lung function, coughing, difficulty breathing and other pulmonary irritation. Fine particles are the major component of haze. Acidic derivatives of certain particulate species are a cause of acid rain, with adverse effects on surface waters, soils, and sensitive species. Acid rain and dry deposition of acidic particles can also degrade metals, stone, coatings and other materials. Particulate deposition dirties buildings and other structures causing aesthetic impacts and increasing maintenance costs. Black carbon, a form of $PM_{2.5}$ and a product of incomplete coal combustion, accelerates ice and snow melt through deposition by reducing its ability to reflect sunlight.[126]

Coal plants control particulates through exhaust gas filtration, electrostatic collection and flue gas desulfurization equipment. Particulates originating from nitrogen oxides and sulfur dioxide are controlled by regulating the release of the precursors. Dust originating from ash disposal is controlled by storing the ash under an enclosure; operating a water spray system; reducing fall distances at material drop points; using wind barriers, compaction, or vegetative covers; covering trucks transporting ash; and reducing or halting operations during high wind; among other methods.[127] The Clean Air Act regulates particulate matter is regulated as a criteria pollutant under the NAAQS.[128] The EPA has set annual and 24 hour emissions limits for PM_{10} and $PM_{2.5}$.[129] Several counties in Idaho, Montana and Oregon are categorized as "nonattainment areas" for the PM 2.5 and PM 10 NAAQS.[130] Particulate matter emissions are also regulated under the Regional Haze program, which requires states to include emissions reductions in their State Implementation Plans.[131] Reduction in emissions of particulates and precursors of haze-inducing compounds from power generation facilities is typically accomplished by installation of controls for sulfur dioxide,

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126 http://www.epa.gov/blackcarbon/effects.html. The reflectivity of a material is called its "albedo."
127 http://www.gpo.gov/fdsys/pkg/FR-2015-04-17/pdf/2015-00257.pdf at 21479.
128 http://www3.epa.gov/ttn/naaqs/criteria.html
129 *Id.*
130 http://www3.epa.gov/airquality/greenbook/ancl.html
131 http://www3.epa.gov/visibility/rhfedreg.pdf

nitrogen oxides and particulate matter. The technologies for haze control are generally similar to those required for compliance with NAAQS, although more stringent levels of control may be required. In the Northwest, the facilities at Boardman, Centralia, and North Valmy are currently in compliance with the Regional Haze Rule. Additional controls are being installed, scheduled for installation, or expected to be required in the future at the other plants in the region.[132]

Sulfur dioxide (SO_2) is formed by oxidation of sulfur compounds present in coal. Sulfur dioxide is a pungent, toxic gas, released to the atmosphere in the exhaust gas. When released to the atmosphere, hydrogen sulfide is converted to atmospheric sulfur dioxide and sulfuric acid. Sulfur dioxide irritates the respiratory system and can cause or aggravate coughing, wheezing, bronchitis, asthma and other respiratory ailments, and has been linked to cardiovascular disease.[133] Atmospheric sulfuric acid derived from sulfur dioxide emissions produces haze and is a precursor to acid rain. Acid rain adversely impacts ground and surface water quality and terrestrial and aquatic ecosystems. Sulfur dioxide impacts range from local to regional in extent. Coal steam-electric plants are potentially significant sources of sulfur dioxide. SO_2 emissions are controlled by use of low sulfur coal and post-combustion flue gas desulfurization. Various types of FGD systems are available, the most common being wet systems using alkaline slurries as an SO_2 absorbent. SO_2 removal efficiencies of 90 to 96 percent are obtainable. FGD systems also capture particulate matter, including activated carbon used to capture mercury. FGD technologies generally convert sulfur dioxide to a solid sulfur-bearing material by exposure to alkaline compounds such as lime or magnesium hydroxide. In some cases, the resulting solid byproduct has economic value, in other cases it is disposed to landfills or settling ponds. As a criteria pollutant under the Clean Air Act, sulfur dioxide is regulated under the NAAQS.[134] Sulfur dioxide is also regulated in under the Regional Haze program discussed above.[135]

Nitrogen oxides are formed by oxidation of nitrogen present in the coal and in the combustion air. Nitrogen oxides are a family of highly reactive compounds, many of which may cause adverse direct and indirect health and environmental effects. The principal nitrogen oxides of concern are nitric oxide (NO), nitrogen dioxide (NO_2) and nitrous oxide (N_2O). “NO_x” is a shorthand reference to nitrogen oxides, but may specifically refer to NO and NO_2. To the extent that they are not removed by control technologies, these compounds are entrained in plant exhaust gasses and released to the atmosphere. Nitrogen oxides can react with ammonia, moisture and other compounds to form particulate matter. Ground level ozone (a major component of smog) is formed by the reaction of nitrogen oxides and volatile organic compounds in the presence of heat and sunlight. Nitrogen oxides react with water and other compounds in the atmosphere to form a mild solution of nitric acid (HNO_3).

[132] http://www.nwcouncil.org/media/7149177/draft7p_regulatorycomplianceandcosts_042415.pdf. *See also* https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf at 123, https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/2013CoalUnitEnvironmentalAnalysis_FinalReport.PDF
[133] http://www.epa.gov/airtrends/aqtrnd95/so2.html
[134] http://www3.epa.gov/ttn/naaqs/criteria.html
[135] http://www3.epa.gov/visibility/rhfedreg.pdf

Nitrogen oxides can impact health, water quality, ecological systems and visibility. Direct nitrogen dioxide exposure can produces adverse respiratory effects including inflammation, increased symptoms of asthma and lower resistance to influenza and other respiratory diseases. Secondary particulate products of NO_x compounds can cause or aggravate emphysema, bronchitis and heart disease. NO_x-derived particulates also constrain visibility and contribute to soiling and staining of materials. Ground-level ozone can cause or aggravate chest pain, coughing, throat irritation, congestion, bronchitis, emphysema and asthma. Dry or wet deposition of atmospheric nitrogen oxides contribute to the acidification of ground and surface waters, adversely affecting terrestrial and aquatic ecosystems and can accelerate degradation of susceptible materials. On the other hand, mild nitric acid deposition can augment soil nitrogen content, with fertilization benefits to crops and forests. Nitrogen oxide impacts are typically local to regional in scope except for nitrous oxide, a powerful greenhouse gas with an extended atmospheric lifetime.

Nitrogen oxide emissions are controlled by combustor design and operating parameters ("good combustion practice"), post-combustion gas cleanup and plant operating restrictions. Fuel type (coal, oil, gas, etc.) establishes the initial concentration of fuel-bound nitrogen; coal generally having the highest nitrogen concentration and natural gas having negligible amounts. Production of nitrogen oxides from combustion air is a function of peak combustion temperature, exposure time to peak temperatures and availability of oxygen in excess of that required for complete fuel combustion. General types of combustion controls are dry controls, wet controls and catalytic combustors. Dry control technologies include reduced combustor residence time, and staged combustion. Wet combustion control technologies include steam or water injection into the combustor. Catalytic combustors are a new technology in which a catalyst is incorporated within the combustor to support combustion of a lean fuel-air mixture. The most common post-combustion nitrogen oxide control is selective catalytic reduction (SCR). In SCR unit, nitrogen oxides react with injected ammonia or urea in the presence of a catalyst to form diatomic nitrogen (N_2) and water. Because the ammonia concentration upstream of the catalyst is kept somewhat rich, some ammonia will pass the catalyst and be released to the atmosphere ("ammonia slip"). Because ammonia itself is hazardous in high concentrations and can lead to the secondary formation of ammonium sulfate and ammonium nitrate particles, ammonia slip is regulated to low levels. Other post-combustion NO_x controls include non-selective catalytic reduction and $SCONO_x$, a proprietary regenerative catalytic process that simultaneously removes NO_x, CO and volatile organic compounds (VOCs). Plant operating restrictions including limitations on number of startups, minimum load operation, overall hours of operation, warm season operation and annual fuel use may also be used to limit nitrogen oxide production. The significance of NO_x production is a function of season and geographic location. Warm weather may increase the consequences of NO_x emissions because of the accelerated conversion to ozone and haze-forming byproducts. Ozone and haze production is more significant in or near sensitive areas such as metropolitan areas or environments such as national parks where pristine visibility is important.

NO_x formation in a coal plant is suppressed by use of "low-NO_x" burners and overfire air. Low-NO_x burners minimize excess oxygen and operate at reduced flame temperatures and residence time to reduce NO_x formation. Overfire air injection promotes complete carbon combustion in the zone above the burners. All Northwest coal-fired plants are equipped with low-NO_x burners. Increasingly, coal units are being retrofitted with additional, post-combustion NO_x controls (selective catalytic reduction or selective non-catalytic reduction) to comply with regional haze regulation. Oxides of nitrogen are a criteria pollutant under the Clean Air Act, and are subject to emissions standards set by the EPA as part of the NAAQS.[136] Nitrogen oxides are also regulated under the EPA's recently revised ozone NAAQS, which, once effective, will lower the allowable the regional ground-level ozone limit from 75 parts per billion to 70.[137] All areas in the Northwest are expected to be in attainment for the revised standards.[138] The Regional Haze program, discussed above, also restricts nitrogen oxide emissions.[139]

Mercury emissions originate from naturally-occurring mercury in the coal. Airborne elemental mercury is deposited on land or water where it is transformed to methylmercury by microbial activity. Methylmercury bioaccumulates in the tissue of aquatic organisms and is concentrated through the food chain, meaning that mercury concentrations in species high in the food web may be elevated compared to the concentration of mercury in the water. Accordingly, fish-eating species and predators of fish-eating species are especially susceptible to accumulating high concentrations of methylmercury; these species include bald eagles, osprey, kingfishers, mink, and otters, among others.[140] Wildlife effects of mercury include adverse reproductive and behavioral impacts.[141] Fish consumption is the primary pathway for human exposure to mercury as well. Mercury impairs neurological and physiological development in humans. Because of their developing nervous system, fetuses and children are especially sensitive to methylmercury exposure. Higher concentrations can impair the functioning of the adult nervous system.[142]

Coal plant operators can control mercury emissions by injecting activated carbon particles into the flue gas upstream of the particulate and sulfur control equipment. The activated carbon adsorbs the mercury and is subsequently captured in the plant's electrostatic precipitators and flue gas desulfurization equipment. All Northwest coal units except the North Valmy units have been retrofitted with activated carbon injection. Other air toxins released by coal-fired plants include arsenic, chromium, nickel and acid gasses. Fabric filters or electrostatic precipitators are used to remove non-mercury toxic metals and conventional flue gas desulfurization technology will remove acid gasses.

In December 2011, the EPA issued new regulations that require existing power plants to limit emissions of mercury, arsenic, and other toxic air pollutants. Owners of coal- and oil-fired generating units greater than 25 megawatts were granted four years to modify their facilities to meet specific mercury and air toxics standards (MATS). On June 29, 2015, the Supreme Court ruled that EPA failed to consider costs in determining that its MATS rule was "necessary and appropriate," and remanded the case to the D.C. Circuit to determine whether the rule should remain in force while EPA is given an opportunity to remedy the issue or whether the rule should be vacated. As of the

[136] http://www3.epa.gov/ttn/naaqs/criteria.html
[137] http://www3.epa.gov/ozonepollution/pdfs/20151001fr.pdf
[138] http://ozoneairqualitystandards.epa.gov/OAR_OAQPS/OzoneSliderApp/index.html
[139] http://www3.epa.gov/visibility/rhfedreg.pdf
[140] http://www.epa.gov/ttn/oarpg/t3/reports/volume7.pdf at 3-3.
[141] *Id.*
[142] In popular culture, "Mad Hatter's disease" refers to the symptoms caused by exposure to mercury vapors during the processing of felt for hats.

end of September 2015, the D.C. Circuit's decision is still pending, however, owners of affected facilities have largely acted to bring their power plants into compliance with the proposed rule as a result of the drawn out judicial process and uncertainty regarding the outcome of the action.[143]

Like all fossil fuel technologies, coal-fired power plants produce carbon dioxide as a product of combustion. CO_2 is the product of complete combustion of the carbon component of fossil and biomass fuels. The high carbon to hydrogen content of coal compared to natural gas, and relatively high heat rates of coal steam electric plants result in high CO_2 emission factors compared to natural gas combined-cycle plants. Though CO_2 is naturally present in the atmosphere, the concentration of the gas has significantly increased as a result of agriculture, forest clearing and combustion of carbon-bearing fuels. Carbon dioxide is a greenhouse gas, meaning that its presence in the atmosphere traps heat and contributes to global climate change. CO_2 is the primary greenhouse gas caused by human activities, and electricity generation is the largest source of US carbon dioxide emissions.[144] A more complete discussion of the climate change impacts of carbon dioxide is provided in The Greenhouse Gas Emissions of the Northwest Electricity System section below.

Post-combustion capture of CO_2 is technically feasible, but expensive both in terms of capital cost and auxiliary energy requirements. Carbon capture and sequestration (CCS) involves separation of the CO2 component of the combustion flue gas, compression of the captured CO_2 to liquid phase, transport of the liquid to a sequestration site, injection and long-term sequestration. Sequestration options include oil and gas fields and coal deposits, deep saline aquifers and possibly flood basalt formations. The most economical of these are partially depleted oil or gas reservoirs where the CO2 is of value in enhancing further oil or gas recovery. Unfortunately, the CO_2 storage capability of depleted oil and gas fields is quite limited compared to the amount of CO2 produced by power generation. Though CCS technology currently exists, it is currently too expensive and energy intensive to be deployed for use in coal steam electric plants. Carbon dioxide emissions reductions can be achieved in coal fired steam-electric units by improving the plant heat rate, however, the efficiency improvement potential for existing steam-electric coal units is minimal.

On December 7, 2009, the EPA issued a finding that six greenhouse gases, including carbon dioxide, threaten public health and the welfare of future generations.[145] As a result of that finding, the EPA was required under the Clean Air Act to act to limit greenhouse gas emissions. The result was EPA's Carbon Pollution Standards for Existing Power Plants, also known as the "Clean Power Plan," which was finalized on August 3, 2015, but is not yet effective. The Clean Power Plan requires a 30 percent reduction in greenhouse gas emissions from the electric industry from 2005 levels by 2030.[146] The specifics of the Clean Power Plan's impact on emissions in the Northwest are

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[143] http://www.utilitydive.com/news/epa-files-with-appeals-court-to-fix-mats-states-request-its-elimination/406392/
[144] http://www.epa.gov/climatechange/ghgemissions/gases/co2.html
[145] http://www3.epa.gov/climatechange/endangerment/#action
[146] http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf

discussed below, however it is appropriate to note that these restrictions are projected to impose significant disincentives to the combustion of coal as a generating resource.[147]

In addition to air emissions, coal plant operations have the potential to generate significant water impacts, primarily as a result of cooling water withdrawals and wastewater production. At a basic level, coal-fired electricity generation facilities burn the fuel to heat water in a boiler, that causes the water to expand into steam that drives a turbine, spinning a generator that produces electricity. The steam then has to be cooled back to liquid water in a condenser.[148] Power plants may be dry-cooled, using air to condense the steam, or wet-cooled, using water to absorb the waste heat.[149] The vast majority of coal plants are wet-cooled, with only 0.5 percent of the United States' coal power plant fleet uses dry-cooling technology.[150] Condensers using wet-cooling technology may either be once-through systems, in which water is withdrawn from a nearby waterbody, passed through a condenser and discharged back to the source, or recirculating systems, in which water is withdrawn from a source, passed through a condenser, cooled and reused in the system.[151] The majority of new power plants are constructed with recirculating systems.[152] As noted above, all of the plants in the Northwest's coal fleet use recirculating cooling systems. Water withdrawals are generally regulated by state water laws.

The water impacts of a cooling system can be partly described by the amount of water that it withdraws from its source, the amount of water it consumes through evaporation, and the amount of water it discharges back into the source. Dry cooling systems have no direct water impact, because they do not require water for the condensation process. Once-through cooling requires significant water withdrawals, but results in less water consumption than recirculating cooling. As a result, once-through systems discharge a large volume of heated water back into the source waterbody. Temperature increases have the potential to damage aquatic ecosystems, including altering fish migration patterns or causing direct lethality.[153] In addition, higher water withdrawals increase the magnitude of entrainment and impingement of aquatic organisms in a coal plant's cooling water intake structure.[154] Recirculating systems, on the other hand, withdraw between 10-100 times less water than once-through systems, but consume all or nearly all of the water they withdraw.[155]

To feed both types of cooling system, a coal plant typically withdraws water from an adjacent waterbodies through a cooling water intake structure. In August 2014, the EPA promulgated new regulations "to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities for the

[147] http://www.eia.gov/analysis/requests/powerplants/cleanplan/
[148] http://www.tva.gov/power/coalart.htm
[149] http://www.eia.gov/todayinenergy/detail.cfm?id=14971
[150] *Id.*
[151] *Id.*
[152] *Id.*
[153] *See* note xxx.
[154] http://www.eia.gov/todayinenergy/detail.cfm?id=14971
[155] http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045802/pdf

withdrawal of cooling water from waters of the United States."[156] The general rule applies to existing power generation and industrial facilities withdrawing more than two million gallons per day and using at least 25 percent of withdrawn water for cooling purposes. Compliance is based on the Best Technology Available (BTA) for minimizing adverse environmental impacts. Separate standards apply to impingement mortality and entrainment. Impingement mortality standards consist of implementation of BTA, defined as any one of seven alternatives. These include closed-cycle recirculating cooling systems. Entrainment standards apply to cooling water intake structures having average intake flows of 125 million gallons per day, or more. An Entrainment Characterization Study is required for these facilities. Compliance requirements are then established on a case-by-case basis, based on the permitting agency's determination of BTA for entrainment reduction.

The new standards are implemented through the NPDES permit program under the Clean Water Act as NPDES permits are renewed. Permit renewal applications submitted after July 2018 (45 months following the effective date) will require full and complete studies. Applications due before this date may request that certain studies be submitted later on an agreed-upon schedule because of the time needed to complete the monitoring and analysis required for these studies. Interim BTA requirements must be proposed in these applications, however.

Any impingement or entrainment of a federally listed species is considered a taking under the Endangered Species Act, and will require a taking permit or Incidental Take Statement provided through a Fish and Wildlife Service or National Marine Fisheries Service biological opinion. All major Northwest coal, nuclear and gas combined-cycle generating units are equipped with closed-cycle recirculating cooling systems and are therefore likely to be in compliance with the impingement standards. Boardman is the only major thermal unit with cooling water intake exceeding 125 million gallons per day and potentially subject to entrainment standards. However, the Boardman NPDES does not expire until April 2023 so an entrainment analysis and BTA recommendations would only be required if the plant were converted to a biomass-fired facility and continued operation beyond 2020. Moreover, if the converted plant, as contemplated, operated only during peak periods, intake flows may drop below the 125 million gallon per day annual average trigger for entrainment regulation.[157]

The process of evaporative cooling concentrates naturally occurring impurities in a thermal plant's cooling system water. When concentrations become too high, they can impair the operation of the cooling system and must be discharged as "blowdown." The water in cooling systems does not mix with the water in boiler systems. Although boiler water is typically contained in a closed-loop system, it also requires periodic blowdown as the water absorbs impurities from the piping and boiler materials. Blowdown may be discharged into the original water source as an effluent, which can result in adverse ecological impacts, or it may be processed in a zero liquid discharge facility, in which the water is filtered or evaporated off and the remaining residue is disposed of.[158]

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[156] http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/
[157] http://www.nwcouncil.org/media/7149177/draft7p_regulatorycomplianceandcosts_042415.pdf
[158] http://www.powermag.com/fundamentals-of-zero-liquid-discharge-system-design/?pagenum=1

In addition to blowdown, coal plants generate wastewater as a product of coal storage, coal combustion byproducts, and the operation of pollution control equipment. Coal plants typically store 30 to 60 days' worth of coal stockpiled on site.[159] Exposure of coal piles to rainfall can produce acid leachate, which, if not contained, may contaminate surface or groundwater. The environmental effects of coal pile runoff are generally mitigated through the use of best management practices that include limiting exposure of coal piles to rainfall, stormwater diversion infrastructure, and appropriate cleanup measures for dust and debris.[160] As a result of the potential for contamination, stormwater runoff from a coal plant site may be channeled to and stored in surface impoundments used to store other wastewater, including coal combustion byproducts.

Coal combustion byproducts and waste captured by pollution control equipment may impair water quality to the extent that they are released. Nationwide, about 40 percent of coal combustion residuals are recycled for concrete, road fill and other purposes, the remainder is disposed of in landfills or impoundments. Ash is composed of the noncombustible components of coal; bottom ash is the material that settles to the bottom of the boiler, while fly ash is a fine particulate that is suspended in the boiler exhaust. Depending on the type of boiler system used, a coal plant will produce varying ratios of bottom ash to fly ash. Historically, coal plants would mix both the fly ash and bottom ash with water and transport the slurry to settling ponds,[161] however most modern facilities process fly ash separately as a saleable commodity.[162] Although there is some market demand for bottom ash as well,[163] coal plants often still dispose of it in surface impoundments or landfills on site.[164] Similarly, wet flue gas desulfurization units and other air pollution control equipment and maintenance procedures typically generate contaminated wastewater. Wet flue gas desulfurization describes the process of removing sulfur dioxide from coal plant emissions through the use of alkaline adsorbents, such as a slurry of limestone and water. One of the byproducts of the wet FGD process is synthetic gypsum, which has industrial applications,[165] however many coal plants still operate FGD waste ponds.[166] These ponds are frequently unlined, in some cases allowing wastewater to seep down through the ground toward underground aquifers.[167] The potential for contaminated discharge, breach,[168] and leaching[169] are the water-related concerns created by the presence of ash and FGD ponds. Even where the combustion byproducts are dewatered and

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[159] http://www.eia.gov/todayinenergy/detail.cfm?id=18711
[160] http://water.epa.gov/polwaste/npdes/stormwater/upload/sector_o_steamelectricpower.pdf
[161] http://www.power-eng.com/articles/print/volume-115/issue-2/features/ash-handling-options-for-coal-fired-power-plants.html
[162] Fly ash is typically sold as a component of cement or concrete products. https://www.fhwa.dot.gov/publications/research/infrastructure/pavements/97148/016.cfm
[163] https://www.fhwa.dot.gov/publications/research/infrastructure/structures/97148/cbabs1.cfm
[164] *See, e.g.,* http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/surveys2/ppl-colstrip-final.pdf, http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/surveys2/bridger-final.pdf.
[165] http://www.americangypsum.com/green/raw-material/synthetic-gypsum/
[166] http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/surveys2/bridger-final.pdf at 4-7.
[167] http://www2.epa.gov/coalash/frequent-questions-about-coal-ash-disposal-rule
[168] http://www.nytimes.com/2008/12/27/us/27sludge.html. In the Northwest, the EPA identified one of Colstrip's evaporation ponds as having a high hazard potential should the impoundment fail. http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccrs-fs/
[169] http://deq.mt.gov/mfs/ColstripSteamElectricStation/default.mcpx#Information

landfilled, they may still pose a risk of water quality impacts through leaching. Landfills for coal combustion byproducts are typically lined with a water barrier, whereon the ash and other waste is spread and compacted before being covered over top with a water barrier and topsoil. Contaminated water from these surface impoundments may contain thallium, lead, and other toxic metals that can cause significant ecological damage and human health impacts to the extent that it is released.[170] Being zero liquid discharge facilities, Colstrip, Jim Bridger, and North Valmy are not permitted to release any water to adjacent waterbodies. However, all three of these coal plants do maintain settling ponds or landfills on site, which create the potential for accidental release. Boardman and Centralia discharge water pursuant to the effluent limitation guidelines in their NPDES permits.[171]

In June 2013, the EPA proposed revisions to its effluent regulations for steam electric power generators pursuant to its authority under the Clean Water Act. The EPA issued its final rule on September 30, 2015, it will become effective 60 days after publishing in the Federal Register.[172] The revisions strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants, including mercury, arsenic, lead and selenium, from steam electric plants into surface waters, and apply to discharges associated with flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. The EPA's regulations restrict the discharge of pollutants associated with coal combustion and emissions controls from existing plants on the basis of the Best Technology Economically Achievable. The limitations vary depending on waste stream, but generally place a numeric limit on total suspended solids, and either establish a numeric limit or prohibit entirely the discharge of mercury, arsenic, selenium, nitrate and nitrite.[173] New facilities are required to meet more stringent standards, including zero-discharge requirements for fly ash and bottom ash transport water and flue gas mercury controls, and numeric standards for mercury, arsenic, selenium and total dissolved solids in other waste streams.[174] As an added benefit, the proposed regulations provide an incentive for coal plants to reduce water use in their air pollution control systems, so water withdrawals will decrease accordingly.[175] All of the Northwest's coal plants employ some, if not all, of the technologies and processes targeted by the EPA's proposed effluent limitations guidelines for steam electric generation. Based on the EPA's estimates and the fact that there are limited affected facilities in the Northwest, the region's compliance costs are not likely to be significant.[176] The EPA intends the new steam electric effluent limitations guidelines to operate in

[170] http://www.nytimes.com/2008/12/27/us/27sludge.html.
[171] Boardman: http://www.deq.state.or.us/wq/sisdata/facilityID.asp?facilityidreq=70795, Centralia: https://fortress.wa.gov/ecy/wqreports/public/WQPERMITS.document_pkg.download_document?p_document_id=14749
[172] http://www2.epa.gov/sites/production/files/2015-09/documents/steamelg_2040-af14_finalrule_preamble_2015-09-30_prepub.pdf
[173] http://www2.epa.gov/sites/production/files/2015-09/documents/steamelg_2040-af14_finalrule_preamble_2015-09-30_prepub.pdf at 18-19
[174] *Id* at 19-20
[175] *Id* at 3
[176] http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/SteamElectric_RIA_Proposed-rule_2013.pdf

conjunction with a related rule promulgated under the Resource Conservation and Recovery Act (RCRA) regulating the disposal of coal combustion residuals.

Concerns arising from groundwater contamination, blowing of contaminants into the air as dust and catastrophic impoundment failure led the EPA in June 2010 to propose regulation of the disposal of coal combustion residuals under RCRA. The EPA Administrator signed the final rule establishing technical requirements for coal combustion residuals landfills and surface impoundments on December 19, 2014 with an effective date of October 19, 2015.[177] The regulated byproducts include bottom ash, fly ash, boiler slag and flue gas desulfurization products, which have historically been exempt from federal oversight under an amendment to the RCRA. The coal combustion residuals rule establishes minimum federal criteria for both existing and new landfills, surface impoundments and expansions to existing landfills and surface impoundments. The criteria include structural integrity requirements and periodic safety inspections for surface impoundments; groundwater monitoring requirements; groundwater remediation requirements where contamination has been detected; location and design requirements for new landfills and surface impoundments; operating, record keeping and notification criteria; and, provisions regarding inactive units. The EPA anticipates that the new regulations will be implemented through revision to state Solid Waste Management Plans.

All coal plants in the Northwest will be subject to the inspection and reporting requirements of the rule. The incremental cost of these requirements is not expected to be significant. Landfill disposal is used at Boardman, Centralia and North Valmy, so it is unlikely that significant additional costs will be incurred for CCR compliance at these plants. More costly structural modifications are expected to be required at Colstrip and Jim Bridger where impoundments are used for coal combustion residuals (CCR) disposal.[178] Nationwide, it is expected that most plants using impoundment disposal will shift to dry landfill disposal.[179]

Finally, the process of coal plant decommissioning is likely to result in temporary environmental impacts. When a coal facility is retired and decommissioned, the owner must typically demolish and dispose of infrastructure, identify and abate hazardous materials, and assess the level of remediation required on the property. The decommissioning process will typically result in a temporary increase in noise and construction traffic to the site. Although toxic materials may remain on the site, a successful reclamation process should limit their exposure to the environment.

In summary, coal-fired electricity generation carries with it an array of lifecycle impacts, from land-use impact during mining to air emissions during coal plant operations. These environmental and human health concerns are largely responsible for coal’s declining fuel share in the US electricity

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[177] http://www.gpo.gov/fdsys/pkg/FR-2015-07-02/pdf/2015-15913.pdf
[178] http://www.nwcouncil.org/media/7149177/draft7p_regulatorycomplianceandcosts_042415.pdf
[179] http://www.power-eng.com/articles/print/volume-119/issue-2/features/abma-special-section/the-coal-ash-rule-how-the-epa-s-recent-ruling-will-affect-the-way-plants-manage-ccrs.html. *See, e.g.,* http://www.utilitydive.com/news/georgia-power-to-close-29-ash-ponds-to-comply-with-epa-regs/406565/

sector. Absent advances in carbon capture and sequestration technologies or other unforeseen circumstances, the Pacific Northwest is unlikely to see the development of any new coal plants.

Natural Gas-fired Electricity Generation

Natural gas is a mixture of hydrocarbon gases formed when decomposing organic matter is exposed to geologic processes. At the point of extraction, natural gas is comprised of primarily methane and typically also contains varying proportions of ethane, propane, butane and other compounds.[180] Processing removes most of the associated compounds, so natural gas at market consists almost entirely of methane.[181] Natural gas may be used as fuel to generate electricity and for direct use applications such as heating and cooking.

Natural gas combustion emits about half as much carbon dioxide as coal in relation to the energy that each produces,[182] a fact that has led some policymakers to view the fuel as a bridge to a clean energy future.[183] Perceived emissions benefits aside, advancements in natural gas extraction techniques have driven domestic production to historic levels,[184] driving down prices. These and other factors are causing a shift in the U.S. electric industry towards natural gas as generating resource over coal.[185] This trend is reflected in the Northwest, where the amount of electrical energy produced using natural gas has been growing steadily, and the electric industry is expected to further increase its reliance on natural gas as the region's coal plants are retired. The growth of natural gas as an electricity generating resource, however, carries with it its own potential impacts, including water quality and climate change concerns.

The following sections consider the lifecycle impacts of natural gas as an electricity generating resource, first addressing the effects of extraction and transportation before discussing the impacts associated with the construction, operations and decommissioning of a gas-fired power plant.

Impacts of Natural Gas Extraction, Processing and Transportation

While the combustion of natural gas is relatively clean in comparison to other fossil fuels, the processes required to bring the gas to market contribute significantly to the lifecycle environmental and human health effects of the fuel. Most concerns arise from the extraction and transportation stages of production. Extraction practices have been linked to water contamination and earthquakes, while transportation of natural gas may cause adverse land use impacts. In addition, methane emissions resulting from the leakage of natural gas at any point from drilling to end-use have the

180 http://www1.eere.energy.gov/cleancities/pdfs/hebeler_remote_gas_ngvtf_albany.pdf
181 http://naturalgas.org/naturalgas/processing-ng/
182 http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
183 See President Obama, *State of the Union*, 2014, http://www.whitehouse.gov/the-press-office/2014/01/28/president-barack-obamas-state-union-address
184 http://www.eia.gov/dnav/ng/hist/n9050us2a.htm
185 Natural gas-fired electricity generation grew by approximately 58% in the past decade, while coal-fired generation shrunk by nearly 20% during the same period. *See EIA Electricity Browser – Net generation from electricity plants for all sectors, annual*

potential to cause adverse human health and climate impacts. The following paragraphs consider the environmental effects of natural gas extraction, processing and transportation.

In simple terms, natural gas is extracted by drilling a well to access an underground gas deposit, causing the gas to be released and capturing the resulting product. Conventional wells typically involve drilling a vertical borehole to access a pocket of natural gas. The target of these wells is either “non-associated” gas, which occurs independently in reservoirs, or “associated-dissolved” gas, which occurs as a component in oil fields.[186] Conventional gas resources typically occur in sandstone or other porous formations and require only hydrodynamic pressure for extraction.[187] Unconventional wells, on the other hand, are drilled to access gas contained in less permeable substrates, including tight sands gas, shale gas and coalbed methane.[188] Advances in horizontal drilling and hydraulic fracturing (“fracking”) have contributed to a proliferation of unconventional wells in recent years, with shale gas accounting for 40 percent of domestic gas production in 2013, up from 5 percent in 2006.[189] Gas production in the Northwest is limited, with Montana being the only state in the region with significant gas reserves. Texas is the largest natural gas producer in the U.S.[190]

Depending on the type and location of the well, natural gas extraction methods have the potential to cause environmental impacts ranging from land-use concerns and induced seismicity to water quality issues and greenhouse gas emissions. Exploration is the first step required to establish a natural gas well, typically involving seismic testing and exploratory drilling. Seismic testing is conducted with a “thumper truck,” which drop metal plates from their undercarriage to shake the ground.[191] Sensors placed nearby measure the vibrations and provide data about the underlying geologic formations to the drilling company. There is some concern about the potential for the vibrations caused by seismic testing to damage infrastructure on adjacent properties, causing cracks in building foundations and collapsing wells.[192] Additionally, the operation of these thumper trucks may represent a nuisance to nearby residents, but the disruption will be limited to the duration of the testing. The use of thumper trucks may be regulated by municipal ordinance.

If sensor data indicates that there is a high probability of gas underground, gas companies generally drill an exploratory well. If gas is found during the exploratory drilling, then the well is “completed”, if not, then development is suspended.[193] Well completion is the process by which a gas well is prepared for production. In simple terms, the borehole is lined with casing strings, which are cemented in place. The casing that is inserted into the gas-bearing formation is perforated to allow gas to flow into the structure, while the casing in other parts of the well is impermeable to prevent

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186 http://pubs.usgs.gov/fs/fs-0113-01/fs-0113-01textonly.pdf
187 https://www.fas.org/sgp/crs/misc/R43148.pdf at 2.
188 *Id* at 1.
189 http://www.api.org/~/media/files/oil-and-natural-gas/natural-gas-primer/understanding-natural-gas-markets-primer-low.pdf
190 http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm
191 http://www.denverpost.com/ci_22803371/seismic-surveying-rattles-colorado-homeowners
192 *Id.*
193 http://naturalgas.org/naturalgas/extraction/

the escape of drilling fluids, fracking fluids or gas.[194] Cementing the casing strings in place serves both to keep them stable during operations and to prevent “communication” between strata. Communication occurs when, for example, fracking fluid escapes into a coal seam, or water from a brackish aquifer flows into a freshwater aquifer. A properly installed and adequately cemented casing string is unlikely to cause any long-term environmental effects, however, to the extent a casing string or cement job is compromised, a variety of impacts may result. The most significant potential impact is drinking water contamination, caused by communication between contaminated strata or well fluids and a freshwater aquifer from which well water is withdrawn.[195] This contamination may include saline water from other aquifers, methane from well leakage, or polluted surface water runoff. Additionally, the drilling process can cause freshwater aquifers to drain into the well, reducing the performance of nearby drinking water wells. This phenomenon is typically limited to the period of time between when the well is drilled, when the annular space around the well casing is cemented and when the aquifer is given sufficient time to refresh, however, improper cementing may cause the issue to persist.[196] The drilling process also produces drilling wastes and unearths cuttings that have the potential to leach contaminants into adjacent soils and water. These byproducts may contain heavy metals, petroleum related chemicals, naturally occurring radioactive materials and other substances.[197] Gas wells may also be drilled offshore, with the Gulf of Mexico producing the majority of U.S. offshore gas.[198]

Unconventional wells are designed to access gas resources in formations with small permeability, which require “stimulation” to start producing.[199] Stimulation increases the permeability of the gas-bearing formation. The most common forms of well stimulation are hydraulic fracturing using proppants, hydraulic fracturing using acid, and matrix acidizing. Both types of hydraulic fracturing describe the process of injecting fluids under significant pressure into the well to physically crack the rocks in which the gas is located. Those fractures are either held open by proppants in the fracking fluid, or etched by acid in the mixture. Matrix acidizing relies on acid etching as well, but the fluid is not pressurized to the point at which it will fracture the underlying formations. All of these forms of stimulation have the potential to adversely impact the environment and human health. Fracking requires the withdrawal of a considerable amount of water, anywhere from 1.5 to over 15 million gallons.[200] This water is mixed with other chemical ingredients to produce fracking fluid. Water withdrawals associated with fracking may cause water quantity impacts in water-constrained areas. Additionally, water quality concerns arise when fracking fluid contaminates freshwater resources, either through migration into freshwater aquifers through inadequately completed wells, or through

[194] http://naturalgas.org/naturalgas/well-completion/
[195] http://www.nytimes.com/2014/09/16/science/study-points-to-well-leaks-not-fracking-for-water-contamination.html
[196] http://news.nationalgeographic.com/2015/06/150604-fracking-EPA-water-wells-oil-gas-hydrology-poison-toxic-drinking/
[197] http://www.dep.wv.gov/pio/Documents/E05_FY_2015_2933.pdf at 2
[198] http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_r3fm_a.htm
[199] https://ccst.us/publications/2015/2015SB4-v1.pdf at 27.
[200] http://www.usgs.gov/faq/categories/10132/3824.

improper wastewater management.[201] Fracking fluid may contain diesel fuel, polycyclic aromatic hydrocarbons, methanol, formaldehyde, ethylene glycol, glycol ethers, hydrochloric acid, sodium hydroxide, and other toxic compounds.[202] Although the Safe Drinking Water Act generally regulates the injection of fluids underground, fracking is exempt from federal regulation as a result of exclusions included in the Energy Policy Act of 2005.[203] Regulation of the underground injection of fracking fluid and wastewater is left to state agencies,[204] which vary in the protections they provide. Congress has discussed repeal of the oil and gas exception to the Safe Drinking Water Act, which would provide EPA with the authority to regulate underground injection wells, but, to date, the legislature has rejected any revision.[205]

Wastewater generated in the well drilling and fracking processes is typically disposed of in underground injection wells, which have recently been linked to heightened seismic activity.[206] The Oklahoma state government, for example, attributed a five-fold increase in earthquakes of magnitude 3.0 or greater between 2013 and 2014 to the expansion of underground injection well activity in the state.[207] In recognizing the connection between underground disposal of fracking wastes and seismic activity, the Oklahoma Corporation Commission is in the process of proposing new regulations to limit the volume of wastewater that may be injected in areas susceptible to earthquakes. While Oklahoma has acted to regulate underground injection wells as a means of addressing seismic activity, the responsible regulatory authority in Texas, the Railroad Commission, rejects the conclusion that the disposal wells are causing earthquakes.[208] To the extent that fracking wastewater is discharged into surface waters, it must do so pursuant to effluent limitations in a § 402 NPDES under the Clean Water Act.

In the matrix acidizing well stimulation, mixtures of hydrochloric acid or hydrofluoric acid are injected into wells to improve permeability in sandstone and carbonate (limestone) formations.[209] Both acids are highly corrosive and exposure to either pose a significant risk to human health,[210] although the

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http://yosemite.epa.gov/opa/admpress.nsf/21b8983ffa5d0e4685257dd4006b85e2/b542d827055a839585257e5a005a796b!OpenDocument. *See also* http://www.nytimes.com/2015/05/05/science/earth/fracking-chemicals-detected-in-pennsylvania-drinking-water.html .

202 http://teeic.indianaffairs.gov/er/oilgas/activities/act/index.htm

203 http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm

204 https://www.law.cornell.edu/uscode/text/42/300h-1

205 http://www.eenews.net/stories/1060012514

206 http://www.nytimes.com/2015/04/22/us/oklahoma-acknowledges-wastewater-from-oil-and-gas-wells-as-major-cause-of-quakes.html

207 http://earthquakes.ok.gov/. The state recorded 109 magnitude 3+ earthquakes in 2013, 585 in 2014, and is on pace for 1100 in 2015. http://www.nytimes.com/2015/07/01/us/oklahoma-court-rules-homeowners-can-sue-oil-companies-over-quakes.html. For an interactive map of earthquakes and disposal well sites in Oklahoma, visit: http://earthquakes.ok.gov/what-we-know/earthquake-map/.

208 https://stateimpact.npr.org/texas/2015/09/02/texas-railroad-commission-refutes-study-linking-quakes-to-oil-and-gas-industry/

209 http://www.api.org/~/media/files/oil-and-natural-gas/hydraulic-fracturing/acidizing-oil-natural-gas-briefing-paper-v2.pdf

210 Hydrofluoric acid: http://www.cdc.gov/niosh/ipcsneng/neng0283.html. Hydrochloric acid: http://www.cdc.gov/niosh/ipcsneng/neng0163.html.

underground reaction with geological formations typically neutralizes the acidizing fluids.[211] Conventional wells may also require stimulation to the extent that the perforated casing becomes blocked or damaged.[212]

Once a gas well is producing, a "Christmas tree" is typically fitted onto the wellhead to control the flow of gas and associated fluids and to prevent blowouts.[213] The primary environmental and human health concerns that arise during the production stage of natural gas extraction are the potential for well blowouts, the production of contaminated water, and methane leakage. A blowout may occur as a result of catastrophic failure of the control equipment, causing an unregulated release of gas and associated fluids. Because the gas is toxic to humans and potentially explosive, residents living adjacent to a natural gas well blowout are typically evacuated until the well can be brought under control.[214] Blowouts are not limited to the production phase and may occur at any point during gas extraction. Contaminated water is another byproduct of natural gas production, although it is less of a problem in unconventional wells, which tend to exploit resources in tight formations. Water that is associated with hydrocarbon resources underground often arises during well operations. This waste product is called "produced water" and it may contain oil and grease, high levels of salts, naturally occurring radioactive materials, and other chemicals.[215] The U.S. oil and gas industry generates approximately 2.4 billion gallons of produced water per day.[216] This water must be properly disposed of to avoid contaminating freshwater resources. Produced water is generally disposed of in underground injection wells,[217] which have been associated with increased seismic activity. The EPA prohibits the discharge of produced water into surface waters.[218] In addition to blowouts and water impacts, the production phase of gas extraction may result in adverse climate effects as a result of methane leakage. A discussion of the greenhouse gas implications of methane and a more comprehensive consideration of the region's greenhouse gas footprint are provided below.

The natural gas produced at wells is generally to delivered market through a series of pipelines and related facilities, in a process fairly analogous to the transportation of electricity. Small diameter gathering lines collect gas produced at individual wells and deliver it to a processing facility that separates the various hydrocarbons and liquids from the methane.[219] The associated hydrocarbons and liquids are typically also marketable commodities. After processing, the methane is delivered into a large diameter natural gas transmission pipeline, which transports the gas longer distances

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[211] http://www.api.org/~/media/files/oil-and-natural-gas/hydraulic-fracturing/acidizing-oil-natural-gas-briefing-paper-v2.pdf at 5.
[212] *Id* at 26.
[213] http://extension.psu.edu/natural-resources/natural-gas/news/2012/12/the-importance-of-the-christmas-tree
[214] http://powersource.post-gazette.com/powersource/companies/2014/12/24/Utica-Shale-well-blowout-in-Ohio-brought-under-control/stories/201412240215
[215] http://aqwatec.mines.edu/produced_water/intro/pw/
[216] *Id.*
[217] https://stateimpact.npr.org/pennsylvania/tag/deep-injection-well/
[218] https://www.law.cornell.edu/cfr/text/40/435.32
[219] http://naturalgas.org/naturalgas/processing-ng/. The processing step may be bypassed if the natural gas emerging from the well is already pipeline quality. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/process.html.

and at higher volumes.[220] Compressor stations located along the transmission system maintain the pressure and flow rate of the gas. Transmission pipelines typically deliver gas to underground storage facilities before ultimate distribution to end-use customers. The most common type of underground storage facilities are depleted gas reservoirs close to consumption centers into which gas may be injected and from which it may be withdrawn as needed.[221] Other underground formations such as salt caverns and depleted water reservoirs may be used for gas storage as well. Once distribution companies receive the natural gas, it is delivered to consumers through lower volume distribution pipelines.

The primary environmental effects associated with gas transportation are wildlife impacts related to pipeline development and operations. The delivery of natural gas from wellhead to consumer typically requires the development of many miles of underground pipeline. A Nature Conservancy report estimated that each well pad requires 1.65 miles of gathering lines on average, and that gathering line rights-of-way are typically 100 feet wide.[222] The right-of-way width for transmission pipelines may be up to 200 feet.[223] The Department of Transportation calculated that there were over 1.5 million miles of gas pipelines in the U.S. in 2013.[224] To excavate the trench required to house the pipe, surface vegetation and soil must be removed. The pipe segments are then lowered into the trench, strung together and welded at the seams.[225] Soils are backfilled after installation of the pipeline, typically within ten days of the trench being cut.[226] Although the soil is replaced, the right-of-way is typically kept clear of large vegetation to allow the owner to access the pipeline for maintenance and repairs.[227] Rather than use “open-cut” trenching to cross waterbodies and roadways, pipeline developers typically use “bore crossings” to avoid disrupting the surface use.[228] The sounds and human activity involved in the construction of pipelines can disturb wildlife and the restriction of vegetation on rights-of-way have the potential to fragment habitat.[229] Rights-of-way have the potential to cut through forests and create miles of new forest edge, which may impacts many plant and animal species that require conditions found in the interior forest for survival.[230] Landscape disturbance like that caused by gas drilling and pipeline development may also promote the introduction of invasive species to a previously heterogeneous ecosystem.[231] In addition to

[220] http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/process.html
[221] *Id.*
[222] http://www.nature.org/ourinitiatives/regions/northamerica/unitedstates/pennsylvania/ng-pipelines.pdf at 3, 6.
[223] *Id* at 6.
[224] http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_01_10.html
[225] http://co.williams.com/pipeline-construction/.
[226] http://www.blm.gov/style/medialib/blm/wy/information/NEPA/pfodocs/anticline/rd-seis.Par.58090.File.dat/17app6.pdf at 6-5.
[227] *Id* at 6-9.
[228] *Id* at 6-5.
[229] http://data.iucn.org/dbtw-wpd/edocs/FR-021.pdf at 9-10.
[230] *Id* at 10-11.
[231] *Id* at 8.

wildlife impacts, pipeline development may also contribute to sedimentation of nearby surface water and altered flow patterns caused by vegetation removal and soil disruption.

Natural gas drilling and transportation projects are required to comply with the Endangered Species Act to the extent that they are likely to impact any listed species or critical habitat. A privately developed natural gas project that does not require federal involvement is generally prohibited from affecting a taking of a threatened or endangered species. However, FWS or NOAA Fisheries may permit the incidental take of listed species pursuant to an otherwise lawful activity, so long as the project developer has prepared and is acting in accordance with a habitat conservation plan.[232] Where a project is being developed on federal land, pursuant to a federal permit, or with the participation of a federal agency, then the action agency is required to consult with the FWS or NOAA Fisheries to determine if the project is likely to have adverse impacts on listed species. If the consultation process concludes with a finding that the proposed action is likely to adversely affect a listed species, then the FWS or NOAA Fisheries are required to prepare a Biological Opinion to determine whether that action is likely to jeopardize the continued existence of the species or result in adverse modification to designated critical habitat.[233] A Biological Opinion may be programmatic[234]—i.e., apply to all actions of a certain category in a specific region—or project or developer specific.[235] The process of preparing a Biological Opinion takes 135 days, 90 days for consultation and 45 days to prepare the document. If the FWS or NOAA Fisheries makes a determination of jeopardy or adverse modification in the Biological Opinion, then they will work with the action agency and the applicant to develop reasonable and prudent alternatives to the proposed action. The alternatives may adversely affect listed species, so long as they do not cause jeopardy or adverse modification to critical habitat. If take will occur as a result of the proposed action or reasonable and prudent alternatives, then the applicant is required to apply for an incidental take permit, as discussed above. Federal agencies are also required to consult with the FWS or NOAA Fisheries to the extent that the proposed action will affect a species proposed for listing.[236]

The NEPA similarly imposes procedural requirements on natural gas infrastructure development, but only to the extent that a federal agency is involved in the proposed action. If a CE applies to a proposed project, then the NEPA process is complete. Certain CEs apply to oil and gas development and pipelines on federal lands.[237] The NEPA process may likewise conclude relatively quickly and inexpensively if the action agency determines in an EA that the environmental impacts of the proposed project will be insignificant or can be mitigated to the point of insignificance. If the project is likely to cause significant environmental impacts, then the action agency is required to

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[232] *See, e.g.,* https://www.federalregister.gov/articles/2015/08/31/2015-21457/proposed-low-effect-habitat-conservation-plan-southern-california-gas-company-pipeline-1010-purisima
[233] http://www.fws.gov/endangered/what-we-do/faq.html
[234] *See, e.g.,* http://www.law.indiana.edu/publicland/files/Sample_BO_Powder_R_Basin.pdf
[235] http://www.blm.gov/style/medialib/blm/ut/vernal_fo/planning/greater_natural_buttes/record_of_decision.Par.58645.File.dat/Appendix%20D.pdf
[236] *Id.*
[237] http://www.fs.fed.us/geology/June_2010%20guidance%20Sec%20%20390%20CE.pdf

prepare a full EIS, which is a considerably lengthier and more costly process.[238] The action agency may require the developer to pay for or provide the environmental analyses for a proposed project.[239]

Being relatively poor in natural gas reserves, the Northwest imports most of its gas from Canada and adjacent states.[240] For this reason, the region is largely spared the impacts associated with natural gas production infrastructure, such as well drilling operations and gathering line development. Gas transportation infrastructure in the region is mostly limited to the transmission pipelines and associated infrastructure that bring the fuel into the Northwest and the distribution pipelines that deliver the gas to consumers.

Natural gas as a fuel source for electricity generation may have climate benefits over coal as long as lifecycle methane leakage is minimized. Consequently, a proper accounting of the climate change impacts of natural gas-fired electricity generation requires a consideration of not only the carbon dioxide emissions from gas combustion, but also fugitive methane emissions during the extraction, transportation and storage processes. The primary component of natural gas, methane, is a greenhouse gas with a global warming potential in the atmosphere of 25 times that of carbon dioxide over a 100-year period.[241] So, while natural gas may provide a net climate benefit as compared to coal, that benefit will only be realized if methane leakage remains below 3.2 percent from wellhead to power plant.[242] Faulty equipment or improper management practices may result in fugitive methane emissions at any point during the extraction, processing, transportation, storage or combustion processes. In 2009, the EPA estimated methane leakage rates in the oil and gas industry to be 2.4 percent. That estimate has been the subject of controversy, however, with some studies measuring leakage rates of over 10 percent in certain oil and gas basins.[243] According to EPA estimates, the oil and gas industry accounts for approximately 30 percent of U.S. methane emissions. The current climate calculus, then, may favor natural gas over coal, but the benefits are less distinct when emissions associated with gas extraction and delivery are taken into account.[244]

The EPA recently proposed fugitive methane emissions regulations for the oil and gas industry pursuant to its authority to set NSPS under § 111(b) of the Clean Air Act.[245] As proposed, the rule will set emissions limits for a number of categories of natural gas production facilities. Methane emissions from these facilities are currently unregulated, subject only to the EPA's voluntary Natural

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[238] *See, e.g.,* http://www.hanford.gov/files.cfm/Notice_of_Intent.pdf. The Department of Energy is in the process of preparing an EIS to develop a pipeline to supply natural gas to the Hanford site in Washington. The notice of intent to prepare an EIS was published in the Federal Register on January 23, 2012, as of early October 2015, the Draft EIS has not been released.
[239] http://www.gao.gov/assets/670/662543.pdf at 4-5.
[240] *See* http://www.eia.gov/state/maps.cfm?v=Natural%20Gas
[241] http://epa.gov/climatechange/ghgemissions/gases/ch4.html
[242] http://www.pnas.org/content/109/17/6435.full#ref-6
[243] http://www.eenews.net/stories/1060007693
[244] Complicating the equation is the fact that coal extraction also releases methane.
[245] https://www.federalregister.gov/articles/2015/09/18/2015-21023/oil-and-natural-gas-sector-emission-standards-for-new-and-modified-sources#h-22

Gas STAR program.[246] The EPA expects the rule to reduce methane emissions by up to 180,000 tons annually, in addition to limiting the emissions of volatile organic compounds and other hazardous air pollutants.[247] With this rule, the Obama Administration seeks to cut methane emissions by 40 – 45 percent of 2012 levels by 2025.[248] Although the Northwest lacks significant natural gas resources, the electricity sector in the region may be affected by these new regulations to the extent that compliance impacts fuel prices. In addition to methane emissions, natural gas production and processing facilities may emit other hazardous air pollutants regulated by the EPA's NESHAP under § 112 of the Clean Air Act.[249]

While the extraction and delivery processes contribute considerably to the lifecycle impacts of natural gas as an electricity generation resource, modern gas-fired power plants are typically efficient and low-emitting.

Impacts of Operating a Natural Gas Power Plant

Air emissions are the primary effect associated with the combustion of natural gas to generate electricity, although limited water and land-use impacts may also result from the process. The type and magnitude of these impacts depends on the generation technology used. There are three common types of natural gas-fired generation technologies, simple cycle, combined cycle and reciprocating engine, each of which utilizes a different process to produce electricity. To appreciate the environmental effects of each, it is useful to understand how each technology operates.

Simple-cycle gas turbines have been used for several decades to serve peak loads. Newer, more flexible and efficient models can also be used to follow the variable output of wind and solar resources. Because of the availability of hydropower, relatively few simple-cycle combustion turbines have been constructed in the Northwest compared to regions with a predominance of thermal-electric capacity. As wind capacity has increased, simple-cycle gas turbine plants are beginning to be constructed in the Northwest for augmenting the wind following capacity of the hydropower system. About 1800 megwatts of simple-cycle gas turbine capacity is currently in service in the Northwest, most constructed to serve peak loads. The 150 megawatts Dave Gates plant near Anaconda, Montana is the first Northwest gas turbine plant intended to provide wind following services.

A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes two) driving an electric power generator, mounted on a common frame and enclosed in an acoustic enclosure. Other major components can include fuel gas compressors, fuel oil storage facilities (if used), a switchyard, a cooling tower (intercooled turbines only), a water treatment system (intercooled units and units using water injection for NO_x control) and a control and maintenance building. Emission controls on new units include low-NO_x combustors, water injection, selective

[246] http://www.epa.gov/gasstar/
[247] *Id.*
[248] http://www3.epa.gov/airquality/oilandgas/pdfs/og_nsps_pr_081815.pdf at 35.
[249] http://www3.epa.gov/airquality/oilandgas/basic.html

catalytic reduction and oxidation catalysts. All existing simple-cycle gas turbines in the Northwest use natural gas as a primary fuel, though fuel oil is used as a backup at some plants.

Three gas turbine technologies are marketed: "Aeroderivative" turbines, based on engines developed for aircraft propulsion, are characterized by light weight, high efficiency and operational flexibility. "Frame" turbines are heavy-duty machines designed specifically for stationary applications where weight is less of concern. While rugged and reliable, frame machines tend to have lower efficiency and less operational flexibility than aeroderivative machines. Intercooled gas turbines include an intercooler between compression stages to improve thermodynamic efficiency. Intercooled machines are expressly designed for operational flexibility and high efficiency. The intercooler requires an external cooling water supply, supplied by wet or dry cooling towers.

The air emissions of principal concern from gas turbines are carbon dioxide, nitrogen oxides (NO_x), carbon monoxide and to a lesser extent volatile organic compounds.[250] Sulfur oxide emissions are of potential concern if fuel oil is used. Like all fossil fuel technologies, gas turbines produce carbon dioxide as a product of complete combustion of carbon. Carbon dioxide emission factors are a function of plant efficiency, so newer units in general, and aeroderivative and intercooled units in particular, have lower CO_2 emissions per MW than older units. Though technology for separating CO_2 from the plant exhaust is available, as a practical matter it is unlikely that CO_2 removal technology would be employed for simple-cycle gas turbines because of the relatively low carbon content of natural gas and the relatively small size and limited hours of operation of these units. Newer units are likely to comply with the CO_2 performance standards of the proposed Clean Power Plan and will continue to serve seal loads, and to an increasing extent, shaping of variable output renewable resources.

The EPA's recent Clean Power Plan rule may impact inefficient older natural gas units,[251] but the use of natural gas as a generating resource will likely continue to expand under the rule at the expense of coal.[252] One reason for this dynamic is that the EPA explicitly considered the emissions benefits of substituting coal-fired generation with natural gas in establishing the "building blocks" it used to set statewide emissions goals.[253] The final Clean Power Plan is not expected to incent natural gas electricity development to the same extent as was proposed under the draft of the rule, with the final incarnation promoting renewable energy to a larger extent.[254] After the EPA released its draft Clean Power Plan, the Energy Information Administration estimated that natural gas generation would supply the largest share of electricity in the United States in 2040 (29 percent to 27 percent renewables).[255] The regulations established in the final Clean Power Plan may alter those

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[250] The following discussion of air pollutants and controls is largely derived from Environmental Protection Agency AP-42 Compilation of Air Pollutant Emission Factors, Section 3.1 Stationary Gas Turbines.
[251] The EPA set emissions-based performance rates for natural gas fired electricity generating units at a level of 771 lbs. of carbon dioxide per megawatt hour. http://www3.epa.gov/airquality/cpptoolbox/technical-summary-for-states.pdf
[252] http://www3.epa.gov/airquality/cpp/fs-cpp-overview.pdf
[253] *Id.*
[254] http://www.eenews.net/stories/1060022944
[255] http://www.eia.gov/todayinenergy/detail.cfm?id=21392

calculations in favor of renewables in some areas of the country. Even so, the resource analysis for the Seventh Plan continues to indicate that for the Pacific Northwest, greater use of natural gas, rather than renewables, is a lower-cost path to compliance with the Clean Power Plan regulations.

Nitrogen oxide formation is controlled using low-NO_x combustors, water injection and operating hour and startup constraints. Low-NO_x combustors minimize excess oxygen and operate at reduced flame temperatures and residence time, thus reducing NO_x formation. Water injection can be used to reduce NO_x formation by lowering combustion temperatures. Additional, post combustion NO_x reduction is usually required for compliance with current regulations. Selective catalytic reduction (SCR) systems are installed for this purpose. In the past, the high exhaust temperatures of frame machines (because of lower efficiency) precluded SCR operation. Newer frame machines use ambient air injection to reduce exhaust temperatures to levels permitting use of SCR. The higher efficiency of aeroderivative and intercooled turbines produces lower exhaust gas temperatures, permitting SCR use without dilution. Because NO_x control tends to be less effective during start-up and low load operating conditions, startup and partial load operating constraints are sometimes required to meet air emission limits. The EPA regulates NO_x emissions as a criteria pollutant under the Clean Air Act. The EPA sets the NAAQS, which provide emissions standards that states are responsible for implementing. All areas in the four Northwest states are in attainment for NO_x.[256] In addition to the NAAQS, sources of NO_x emissions, including natural gas-fired electricity generating facilities, are potentially subject to regulation under the EPA's Regional Haze program[257] and ground-level ozone regulations.[258]

Carbon monoxide and unburned hydrocarbons originate from incomplete fuel combustion. CO and unburned hydrocarbon formation is reduced by "good combustion practices" (proper air/fuel ratio, temperature and residence times). Additional post-combustion reduction is usually required by current regulations. This is accomplished by an oxidation catalyst in the exhaust system. Oxidation catalysts promote complete oxidation of CO and unburned hydrocarbons to CO_2. The EPA regulates carbon monoxide under the Clean Air Act. The EPA sets emissions standards for CO as part of the NAAQS, of which states are primarily responsible for ensuring attainment.[259] All areas in the Northwest are in attainment for carbon monoxide.[260]

Simple-cycle gas turbines do not employ a steam cycle so require no condenser cooling. Intercooled turbines do require cooling of the air intercooler. This is accomplished using a circulating water system cooled by evaporative or dry mechanical draft cooling towers. Other uses of water include water injection for NO_x control and power augmentation and for inlet air evaporative cooling systems to increase power output during warm conditions. Sulfur oxide emissions from units with fuel oil firing capability are controlled by use of ultra-low sulfur fuel oil and fuel oil consumption limits.

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[256] http://www3.epa.gov/airquality/greenbook/ancl.html
[257] http://www.gpo.gov/fdsys/pkg/FR-2012-06-07/pdf/2012-13693.pdf
[258] http://www3.epa.gov/ozonepollution/pdfs/20151001fr.pdf
[259] http://www3.epa.gov/ttn/naaqs/criteria.html
[260] http://www3.epa.gov/airquality/greenbook/ancl.html

A combustion turbine combined-cycle plant consists of one or two (infrequently more) gas turbine generators, each exhausting to a heat recovery steam generator. Steam from the steam generators is supplied to a steam turbine generator and condenser. This productive use of the gas turbine exhaust energy greatly increases the efficiency of combined-cycle plants compared to coal-steam units or simple-cycle gas turbines. Other plant equipment includes natural gas compressors, a condenser cooling water system, switchyard and ancillary facilities. The heat recovery steam generators are often equipped with natural gas burners to boost the peak output of the steam turbine. Plants may be equipped with bypass exhaust dampers to allow independent operation of the gas turbines. Some plants are provided with a fuel oil system as backup to the natural gas supply. The gas turbines are usually frame units because of the larger size and higher exhaust temperatures of frame machines. About 6800 megawatts of combined-cycle capacity is in service in the Northwest and one additional plant of about 400 megawatts is under construction. Though it appears unlikely that additional combined-cycle plants will be constructed in the immediate future, additional construction is likely over the longer term, especially if the proposed federal Clean Power Plan is adopted and additional coal steam electric units are retired or redispatched to combined-cycle plants.

Environmental impacts are largely similar to those discussed previously for simple-cycle gas turbines. The emissions of principal concern are carbon dioxide, nitrogen oxides, carbon monoxide and volatile organic compounds (VOC). The high efficiency of combined cycle plants coupled with the low carbon content of natural gas results in the lowest CO_2 production rate of any fossil fuel power generating technology. Other air emissions controls are the same as used for simple-cycle gas turbines: Low-NO_x burners and SCR for NO_x control and an oxidation catalyst for CO and VOC control. Higher emission reduction factors may be required to allow the combined-cycle plant to be relatively free of operating hour and startup restrictions.

Gas-fired reciprocating engine plants are used for peak load-following and shaping the output of wind and solar variable energy resources.[261] Because of the availability of hydropower for these purposes, and the fairly recent emergence on the market of packaged plants designed for this purpose, few of these plants have been constructed in the Northwest. As wind capacity has increased, however, several reciprocating engine units have been constructed to provide additional wind plant following capability. About 305 megawatts of gas-fired reciprocating engine capacity is in service in the Northwest.[262]

A utility-scale reciprocating engine-generator consists of skid-mounted reciprocating engine coupled to an electric generator. These units can be oil or natural gas-fired and range from approximately 1.5 to 20 megawatts. For load-following and variable resource shaping, multiple (~ six to twenty) engine-generator units are grouped into a plant. The major components of a typical plant include one or two

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[261] Reciprocating engine-generators are also widely used for biogas energy recovery, remote baseload power and emergency backup purposes. These units tend to be smaller, and are fueled by biogas products and oil, respectively.

[262] Excluding biogas, emergency service and cogeneration plants. Includes Port Westward II, Basin Creek and Boulder Park.

engine halls housing the engine-generator sets, one or more wet or dry cooling towers, individual or combined exhaust stacks and a switchyard.

The advantage of reciprocating engines for load-following and variable resource shaping applications is the relatively flat heat rate curve of individual units. The multiple, independently dispatched units in a multi-unit facility provides additional flattening of the heat rate curve, allowing the plant to be operated over a wide range of output without significant loss of efficiency. Engines are available for fuel oil, natural gas or dual-fuel operation. Natural gas engines may use small amounts of fuel oil for initiating combustion.

Air emissions of concern for natural gas reciprocating engine plants are carbon dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, particulates and carbon dioxide. Engines utilizing fuel oil for compression ignition or backup purposes may also produce sulfur dioxides. As in other fossil fuel generating technologies, carbon dioxide is a fundamental product of the oxidation of fuel-bound carbon. Carbon dioxide capture and sequestration will likely remain infeasible for plants of this size; however reciprocating engine heat rates, and therefore CO_2 production, are comparable or superior to combustion turbines in similar service and are expected to comply with proposed federal CO_2 emission standards in the Clean Power Plan.

Nitrogen oxides are produced by oxidation of atmospheric nitrogen during the fuel combustion process. NO_x formation is suppressed by "low-NO_X" combustion design. Selective catalytic converters in the exhaust system for additional NO_x removal are usually needed to meet permit limits. NO_x emissions are regulated by the EPA under the Clean Air Act, as discussed above.

Carbon monoxide, volatile organic compounds and particulates originate from incomplete fuel combustion, non-combustible fuel constituents and lubricating oil carryover. These pollutants are controlled by combustion design, proper operation and maintenance, and exhaust oxidation catalysts. Ultra low sulfur distillate (ULSD) fuel is used for control of sulfur compounds. Operating hour, startup and annual fuel use limits may be imposed for additional air pollution control (pollutant emission rates are typically greater during startup conditions).

Waste heat removal is usually accomplished using closed-cycle dry or evaporative cooling. Evaporative cooling consumes water; however, the efficiency of plants using wet cooling is superior to those using dry cooling. While reciprocating engines are inherently very noisy, perimeter noise levels are controlled by acoustic enclosures and air intake and exhaust noise suppression. Solid waste production is limited to household and maintenance wastes and periodic catalyst replacement. Catalyst materials are recycled.

Though the technology is well-established, use of reciprocating engine plants for utility load and variable resource following purposes is a somewhat recent development, following significant improvement in the NO_x formation characteristics of these engines. Three reciprocating engine plants are in service in the Northwest. The Port Westward II plant was designed specifically for load and variable resource following service and is likely representative of future reciprocating engine plants constructed in the Northwest for this purpose. Port Westward II comprises twelve, 18.7 megawatt lean burn engine-generator sets. The plant will be fueled primarily by natural gas with small quantities of fuel oil injection to impart compression ignition. Engine cooling is by mechanical draft evaporative cooling towers. Nitrogen oxide control is accomplished by lean-burn combustion, selective catalytic reduction and limits on operating hours, startups and part-load operation. CO and hydrocarbon/VOC control is accomplished by good combustion design and catalytic oxidation.

In summary, the electric industry's transition towards natural gas as a generating resource has the potential reduce greenhouse gas emissions as compared to coal. Although natural gas is the cleanest burning fossil resource, a proper accounting of its lifecycle environmental and human health impacts negates some of the benefits associated with displacing coal.

Nuclear Electricity Generation

The Northwest currently hosts one operating nuclear electricity generation facility, Columbia Generating Station (CGS), located just outside Richland, Washington on the Hanford Nuclear Reservation. Placed into service in 1984, the CGS provides the region with 1,170 megawatts of electricity. The CGS is owned and operated by Energy Northwest, a consortium of 27 regional public power utilities.[263] The Bonneville Power Administration purchases and markets the output of the CGS.[264]

As a result of unfavorable economics and safety concerns, the trend over the past two decades has been toward the closure of nuclear facilities. However, the push for carbon-free electricity and federal and private investment in the development of small modular reactors (SMRs) have resulted in a reconsideration of nuclear power as a generation resource.[265] SMRs are small, factory-fabricated nuclear generators, built and installed according to standardized designs. Generally less than one third the size of traditional nuclear generators,[266] these modular units would be deployed in the quantity needed to meet electricity demand. Advocates of SMRs have not yet demonstrated that these technologies will be any cheaper or faster to construct than traditional nuclear power plants.[267] Because the distinctions between traditional nuclear power facilities and SMRs generally relate only to the generator size and methods of construction, rather than the technologies used to produce electricity, the environmental impacts are likely to differ only in magnitude. Therefore, the discussion of the environmental effects of nuclear electricity generation in this section will not distinguish between the types of facility.

Nuclear electric facilities have the potential to result in a variety of environmental effects, the most visible being human health issues caused by the release of radioactive material and adverse water use and quality impacts. However, these potential impacts evolve considerably over the lifecycle of a nuclear facility, from the extraction and processing of uranium and disposal of spent nuclear fuel, to the construction of a nuclear power plant, its operations and eventual decommissioning. This section discusses the potential impacts associated with each of these phases.

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263 http://www.energy-northwest.com/whoweare/Pages/default.aspx
264 http://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/default.aspx
265 http://www.energy-northwest.com/ourenergyprojects/smr/Pages/default.aspx
266 https://www.iaea.org/NuclearPower/SMR/.
267 http://spectrum.ieee.org/energy/nuclear/the-forgotten-history-of-small-nuclear-reactors

Impacts of Mining, Processing and Disposing of Nuclear Fuel

While the environmental impacts associated with the normal operation of a nuclear power plant are limited, the mining, processing and disposal of nuclear fuel create a variety of adverse environmental effects. Uranium, the typical fuel source for nuclear power generation, is generally mined in open pit mines or extracted through in situ leaching. Preparation of mine sites requires drilling, blasting and road construction, which may disrupt wildlife and existing land uses, in addition to potentially contaminating nearby waterbodies and groundwater. Water runoff from open pit mines may be contaminated with heavy metals and small levels of radioactive material, [268] while in situ leaching operations may also introduce drilling fluids and leaching solutions.[269] In situ leaching involves injecting a fluid (called a "lixiviant") that dissolves uranium, and then pumping that uranium-containing solution to the surface.[270] That fluid must then be processed to purify and dry the uranium from the solution.[271] The majority of operating uranium mines in the United States are in situ leaching mines.[272] Both types of uranium mining operations are required to obtain § 402 NPDES permits to discharge mine drainage, stormwater and sanitary wastewater.[273] These permits establish enforceable, facility-specific effluent limitations guidelines for the amount of each pollutant that may be discharged.

When uranium from a conventional mine arrives at a processing facility, the first step is to remove the excess material and pulverize the ore, after which a leaching agent is used to extract the uranium.[274] Once the uranium is leached from the ore, it is in contained in solution in much the same form as the product from an in-situ leaching mine. At this point, the uranium from both types of mines is concentrated from the solution into a product called "yellowcake," before undergoing a conversion process to produce uranium hexfluoride gas. The gas is purified and subjected to pressure and cooling until it solidifies for transport to an enrichment facility. There is a single commercial enrichment facility currently operating in the country, a United States Enrichment Company facility in Paducah, Kentucky. Employing a method called "gaseous diffusion", the enrichment facility processes uranium hexafluoride to increase its uranium-235 content.[275] As an isotope of the element, uranium-235 is the fissionable component of nuclear fuel. The potential impacts of concern relating to uranium processing and enrichment are chemical and radiological exposure, and accidental criticality, or an unintentional nuclear reaction, caused by the mishandling of enriched uranium.[276]

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[268] http://www.epa.gov/cleanenergy/energy-and-you/affect/nuclear.html
[269] Generic Environmental Impact Statement for In Situ Leaching Uranium Milling Facilities at 4.2-19, http://pbadupws.nrc.gov/docs/ML1509/ML15093A366.pdf.
[270] http://www.abandonedmines.gov/wbd_um.html
[271] http://www.nrc.gov/materials/uranium-recovery/extraction-methods/isl-recovery-facilities.html
[272] http://www.eia.gov/uranium/production/annual/
[273] *See, e.g.,*
[274] http://www.nrc.gov/materials/uranium-recovery/extraction-methods/conventional-mills.html
[275] http://www.nrc.gov/materials/fuel-cycle-fac/ur-enrichment.html
[276] *Id.*

Possession, use, transfer, and disposal of the milling byproduct and source material is regulated by the Nuclear Regulatory Commission (NRC).[277] The NRC imposes regulations to protect workers and the public against radiation exposure on all licensed entities involved in the mining, milling and transportation processes. The regulations require licensed entities to develop radiation protection programs to establish dose limits and limit the radiation doses of workers and members of the public.[278] While uranium produces minimal penetrating radiation, the presence of associated radium in the tailings is of greater radiological concern.[279] Accordingly, the NRC's regulations specify that uranium processing tailings should be isolated to avoid disturbance and dispersion, consolidated to avoid a proliferation of small tailings sites, and stored in a manner that limits the potential exposure of surface or ground waters.[280] The NRC also incorporates the EPA's groundwater protection standards for the disposal of hazardous wastes, which include disposal in lined surface impoundments and other site design criteria, maximum allowable groundwater pollutant levels for a variety of toxic constituents, monitoring requirements, and other standards.[281] On top of the NRC's regulations, the EPA regulates radon emissions from underground uranium mines, milling operations and disposal under the Clean Air Act NESHAP program.[282]

Uranium mining generally has sufficient federal involvement and environmental impacts to trigger the NEPA process. The NRC, as the action agency responsible for licensing uranium mines, has prepared a Generic EIS to assess the environmental effects "associated with the construction, operation, aquifer restoration, and decommissioning of an [in situ leaching] uranium recovery facility in four specified regions in the western United States."[283] Uranium mines that meet the criteria for which the GEIS applies may still be required to prepare a supplemental EIS to discuss project specific impacts. All other uranium mining projects may be required to complete a full EIS.

Although nuclear electricity generation does not directly produce any significant air pollution, the mining, processing and transportation of nuclear fuel all require energy inputs, which are typically drawn from other energy sources. Depending on the source of the energy, then, these steps may result indirectly in carbon dioxide and other emissions.[284] Even taking these emissions into account, however, the lifecycle greenhouse gas emissions of a nuclear power plant are a fraction of those produced in coal electricity generation.[285]

After a nuclear reactor consumes most of the fissile material in the uranium, the spent fuel is removed from the reactor into a spent fuel pool to cool for five to ten years.[286] Once it has

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277 http://www.nrc.gov/reading-rm/doc-collections/cfr/part020/part020-1002.html
278 http://www.nrc.gov/reading-rm/doc-collections/cfr/part020/part020-1101.html
279 http://www.nrc.gov/reading-rm/basic-ref/glossary/radium-ra.html
280 http://www.nrc.gov/reading-rm/doc-collections/cfr/part040/part040-appa.html
281 http://www.nrc.gov/reading-rm/doc-collections/cfr/part040/part040-appa.html
282 http://www2.epa.gov/radiation/radiation-regulations-and-laws#tab-2
283 http://pbadupws.nrc.gov/docs/ML1509/ML15093A359.pdf
284 Id.
285 http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Conversion-Enrichment-and-Fabrication/Uranium-Enrichment/
286 http://www.nrc.gov/waste/spent-fuel-storage/faqs.html

adequately cooled, spent nuclear fuel is removed from the pool and transferred into dry storage casks, which are typically stored on-site at a nuclear facility. The dry storage casks pose little risk to the environment or human health, barring a catastrophic disruption of the radioactive materials.[287] Dry storage casks are stored on-site indefinitely, pending the construction of a deep geological storage repository. Congress contemplated the construction of a deep geological storage facility for high level nuclear waste at Yucca Mountain in Nevada in 1987,[288] but the facility has not yet been fully developed. The Department of Energy is contractually obligated to dispose of spent nuclear fuel, and is currently paying nuclear plant operators damages for breaching that obligation.[289] The Department of Energy estimates that breach of contract damages will reach $21.4 billion by 2071, based on the assumption that the agency will begin taking possession of the spent nuclear fuel in 2021, a proposition that is far from certain.[290] It remains unclear when the federal government will develop a long-term storage solution; the Obama Administration supports permanently shuttering the Yucca Mountain site and studying alternative disposal methods for the material.[291] The environmental impacts of constructing and operating a nuclear waste repository will depend on the type and location of the facility eventually developed.

Impacts of Operating a Nuclear Power Plant

The construction phase occurs prior to fuel loading, before radioactive material is introduced to the site. The environmental impacts of building a nuclear generator are similar to those of other large construction projects, including soil erosion and associated water quality impacts during site preparation, increased air emissions related to the transportation of construction material and the operation of heavy equipment, wildlife disruption and loss of habitat, and nuisances to adjacent property owners, including increased vehicular traffic, noise and dust. Additionally, the construction of a nuclear power plant typically generates carbon dioxide and other air emissions. These emissions result from the fabrication of steel, production of concrete, transportation of construction materials, and operation of construction equipment.[292] Most of these impacts last only while the plant is being built, although some impacts—specifically wildlife disruption and loss of habitat, and nuisances to adjacent landowners—may persist beyond the duration of the construction phase. Under the Clean Water Act, a developer is required to obtain a § 402 NPDES permit from the EPA or authorized state for stormwater discharges that occur during construction.[293]

The operation phase of a nuclear power plant may result in an array of environmental and human health effects. In general terms, a nuclear plant typically uses the energy from a nuclear fission reaction to heat water, which turns a turbine that produces power. The water used in this process is

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[287] Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel at 4-98, http://pbadupws.nrc.gov/docs/ML1419/ML14196A105.pdf.
[288] https://www.law.cornell.edu/uscode/text/42/10101
[289] http://www.gao.gov/assets/670/666454.pdf.
[290] *Id.*
[291] http://www.nytimes.com/2012/01/27/science/earth/nuclear-waste-panel-urges-consent-based-approach.html
[292] http://news.bbc.co.uk/2/hi/science/nature/7371645.stm
[293] http://water.epa.gov/polwaste/npdes/stormwater/EPA-Construction-General-Permit.cfm

then condensed in a cooling process and recycled through the reactor. The cooling water used in the condenser is part of a separate system and does not come into contact with the water used in the reactor. The operation a nuclear facility does not generally release carbon dioxide or result in any other significant air pollutants, although water vapor is emitted as part of the cooling process. The CGS is a boiling water reactor and generally fits the characteristics described above.

A release of radioactive material and the associated impacts are the most visible risks attendant with the operation of a nuclear facility. There are many common types of radiation that have little to no adverse human health or environmental impacts, including cosmic radiation (sunlight), x-rays, radio waves and radar waves. Safety concerns about radiation exposure are centered on “ionizing” radiation,[294] which can harm tissue in living organisms by breaking molecular bonds and displacing electrons from atoms. The potential health impacts of radiation exposure range from an increase in the likelihood of developing cancer and DNA damage in reproductive cells, to radiation sickness and death. Radiation also has the potential to impact other living organisms, including plants and wildlife. As is the case with humans, these impacts may include increased mortality, impaired reproduction and genetic effects. The severity of the effects for humans and other living organisms depends on the type of radiation and the magnitude and duration of exposure.[295] Internal exposure to radiation may continue long after a release of radioactive materials through contamination of agricultural and forest food products.[296] The duration of the risk of exposure depends on the decay rates of the specific radionuclides released. The half-lives of radioactive elements vary considerably: radioactive iodine, for example, has a half-life of about eight days, while the half-life of radioactive cesium is 30 years.[297]

Under normal operating conditions, a nuclear facility presents minimal risk of dangerous levels of radiation exposure. The levels of exposure for a person working in or living near a properly functioning nuclear power plant typically represent a miniscule percentage of the amount of background radiation that an average person receives from naturally occurring sources.[298] While the operation of a nuclear facility may emit radioactive airborne materials, filtration systems mitigate the release of radioactive particles and gases to safe levels.[299] While the risk of an unplanned large-scale release of radioactive materials as the result of a natural disaster, accident or terrorist attack is low at any given nuclear facility, the effects of such a release may be significant. Nuclear accidents at Three Mile Island, Chernobyl, and Fukushima illustrate the array of potential harms resulting from such a release, including: health impacts to plant workers, emergency personnel and neighboring residents; long-term displacement of affected communities; and public anxiety regarding the safety of nuclear power. The NRC stresses that the risk of a significant release of radiation from a domestic nuclear plant is low, because licensed facilities employ an array safety measures to prevent such

[294] For the purposes of this section, the term “radiation” refers to ionizing radiation.
[295] http://www.world-nuclear.org/info/Safety-and-Security/Radiation-and-Health/Nuclear-Radiation-and-Health-Effects/
[296] https://www.iaea.org/sites/default/files/chernobyl.pdf at 24 - 25.
[297] http://www.scientificamerican.com/article/fukushima-water-fallout/
[298] http://www.nrc.gov/about-nrc/radiation/related-info/faq.html#8
[299] http://large.stanford.edu/courses/2012/ph241/dsouza1/docs/31404683742.pdf

accidents. Safety measures include diverse and redundant radiation barriers, internal safety systems, operator training, and routine testing and maintenance activities.[300]

The Atomic Energy Act of 1954 created the precursor to the NRC and empowered it to license and regulate civilian facilities engaged in the development and use of nuclear materials in order to “protect health and safety and minimize danger to life or property."[301] Subsequent legislation provided the EPA with the authority to establish environmental standards for protection against radiological harms. The NRC closely regulates who has access to nuclear materials,[302] the physical protection requirements for plants and material in transit,[303] and the accounting of nuclear material.[304] The EPA has established environmental standards for levels of exposure for the general public resulting from normal operations of a nuclear plant.[305] Exposure may not exceed an annual dose of more than 25 millirems to the entire body, 75 millirems to the thyroid, and 25 millirems to any organ as a result of a plant’s planned discharge of radiological material. The EPA regulations also establish limits on the discharge of a variety of radionuclides associated with nuclear power generation.[306]

The Fukushima disaster in 2011 led the NRC to review the safety of the United States nuclear power fleet. Although the NRC found that a sequence of events such as those leading to the Fukushima accident is unlikely to occur in the United States and continued operation of nuclear plants of similar design do not pose an imminent threat to public health and safety, the NRC elected to pursue upgrades to the design and operation of the nuclear power fleet to cope with external events beyond design criteria. In March 2012, the NRC issued three orders requiring operators of U.S. reactors to obtain and protect additional on- and off-site emergency equipment; install improved instrumentation for monitoring spent fuel pool water level; and improve and install emergency containment venting systems that can relieve pressure in case of a serious accident. Compliance with these orders is required by the end of 2016. The CGS is subject to all the NRC orders issued to date regarding actions in response to the Fukushima accident. Energy Northwest is in the process of implementing the measures required by the NRC orders, with a total of $53 million currently budgeted for upgrades and an additional $20.3 million included for compliance with future orders. In response to Fukushima, the NRC is also evaluating the risks associated with station blackout, fire, flooding and seismic activity, leaving open the possibility that the CGS will be subject to future compliance actions.

Nuclear power plants, including the CGS, typically withdraw a considerable amount of water from adjacent water bodies for cooling purposes. These withdrawals can impact water flows and entrain aquatic organisms, while water discharges from nuclear plants may be at higher temperatures than

[300] http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/reactor-risk.html
[301] http://www.nrc.gov/about-nrc/governing-laws.html
[302] http://www.nrc.gov/reading-rm/doc-collections/cfr/part025/
[303] http://www.nrc.gov/reading-rm/doc-collections/cfr/part073/
[304] http://www.nrc.gov/reading-rm/doc-collections/cfr/part073/
[305] http://www.ecfr.gov/cgi-bin/text-idx?SID=b7e61b2fbe3bef8fc1c93b3cdc7fa1ad&node=pt40.25.190
[306] *Id.*

the water source and contain toxic materials that dissolve into the water as it circulates through the cooling process.

Depending on the type of cooling system used, nuclear facilities have the potential to consume a significant amount of water through evaporation. Plants generally employ one of two types of cooling systems, a once-through cooling system or a recirculating cooling system. A once-through system withdraws more water than a recirculating system, but much of that water is returned to its source after use. Recirculating systems require lower withdrawals, but consume nearly twice as much water through evaporation as once-through systems.[307] Located on the Columbia River, the CGS has access to ample water quantities, but future development of small modular reactors in the region should take water use and availability into account. The CGS employs a recirculating cooling system that withdraws approximately 20 million gallons of water from the Columbia River daily, and consumes on average 13,500 gallons of water per minute (19.4 million gallons per day).[308] Energy Northwest holds surface and groundwater rights for the CGS's water requirements.[309]

A nuclear power plant's water intake structures and effluents have the potential to impact aquatic organisms, notably sensitive fish species. Nuclear power plant intake structures draw in large volumes of water to meet cooling system demands. Depending on the type of cooling system and intake structure design, these structures have the potential to entrain or impinge aquatic organisms. Designing an intake structure to meet the water requirements of the associated facility and avoid adverse impacts to aquatic organisms is a considerable and site-specific feat. In the Hanford Reach of the Columbia River, where the CGS's intake structure is located, juvenile salmonid fish (including salmon and steelhead) are the primary species of concern. Young fish may be trapped against the screens designed to exclude organisms and debris from the system (impinged), or pass through the screens and into the cooling system (entrained).[310] Impingement and entrainment may be limited through appropriate intake structure design.

As discussed with respect to coal-fired power plants, the EPA issued new cooling water intake structure regulations in August 2014, establishing new entrainment and impingement standards.[311] Because the CGS withdraws more than two million gallons per day for cooling, it is subject to the impingement mortality standards, however, the plant's closed-cycle recirculating cooling system is in compliance with the new regulations. The new entrainment standards do not apply to the CGS, because it withdraws less than the 125 million gallons per day required to trigger the standards.

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[307] http://www.nei.org/corporatesite/media/filefolder/NEI_Study_Water_June2009_v3.pdf
[308] CGS NPDES permit fact sheet, http://www.efsec.wa.gov/Columbia%20Generating%20Station/EFSEC/CGS-NPDESFactSheet-Final.pdf
[309] *See* https://fortress.wa.gov/ecy/wrx/wrx/fsvr/ecylcyfsvrxfile/WaterRights/ScanToWRTS/CRO3/pdf/CRO300003988.pdf at 4.
[310] http://www.efsec.wa.gov/Columbia%20Generating%20Station/EFSEC/20140905_Final_Dr.%20Coutant%20paper%20and%20NMFS.pdf
[311] *See* note 156

Although in compliance with the EPA's new regulations, the CGS's cooling water intake structure is subject to some controversy. The structure design dates from the late 1970s, prompting the National Marine Fisheries Service and environmental groups to recommend during the § 402 NPDES permit renewal process that the CGS modify its intake structure design to comply with modern standards of protection for aquatic organisms.[312] Washington regulators renewed the permit on September 30, 2014, against the advice of the National Marine Fisheries Service, which argued that the CGS's intake structures fail to employ BTA and represent a risk to juvenile salmon. Environmental organizations filed suit in Washington State Superior Court on Oct. 30, 2014. The environmental plaintiffs' claims include an assertion that the CGS's water intake structure does not employ BTA and should be modernized to protect juvenile salmon. The suit is pending. A resolution in favor of the plaintiffs could result in significant costs for the CGS.[313]

The water that a nuclear power plant discharges may also impact aquatic organisms. Water temperature can affect salmonid fish survival rates, either directly, through exposure to lethal temperatures, or indirectly, by stressing a fish to the point at which its fitness to survive other stressors is compromised.[314] Salmonids may experience direct lethality from water temperatures above 26°C, while temperatures of 19°C to 23°C may impede migration.[315] Once-through cooling systems have a greater potential temperature impact, because they discharge a high volume of water that has absorbed heat in the cooling process. Accordingly, most nuclear facilities that employ once-through cooling dissipate heat from the water in long discharge canals before releasing it back into the source waterbody. [316] The temperature of water discharged from recirculating systems is also elevated, but it is released in considerably lower quantities. The CGS, which employs a recirculating cooling system, discharges into the Columbia River at an average rate of 1,695 gallons per minute (2.4 million gallons per day), [317] with effluent temperatures reported over 30°C.[318] With an average low flow rate of over 23 million gallons per minute through the Hanford Reach,[319] the water that CGS releases into the Columbia River has minimal direct impact on the temperature of the receiving water. However, the cumulative impact of thermal loading on river systems from facilities like CGS and numerous other sources (including loss of shading) represents a potentially significant risk to river ecosystems.[320]

Although a recirculating system causes less temperature impact than a once-through system, a recirculating system typically generates higher levels of pollutants than a once-through system. As

[312] http://pbadupws.nrc.gov/docs/ML1409/ML14091A228.pdf
[313] http://www.tri-cityherald.com/incoming/article32204469.html
[314] http://www.nwfsc.noaa.gov/trt/wlc_viabrpt/appendix_l.pdf
[315] Id at L-5.
[316] http://www.nei.org/corporatesite/media/filefolder/NEI_Study_Water_June2009_v3.pdf at 13.
[317] Id.
[318] *See, e.g.,* Washington State Department of Ecology, Discharge Monitoring Report, Columbia Generating Station (Aug. 11, 2015), https://fortress.wa.gov/ecy/webdmrview/ViewSubmittedDMR.aspx?id=1541709.
[319] CGS NPDES permit fact sheet at 28, http://pbadupws.nrc.gov/docs/ML1407/ML14071A159.pdf.
[320] *See, e.g.,* http://iaspub.epa.gov/tmdl_waters10/attains_waterbody.control?p_list_id=OR1240483462464_0_306%2E1&p_cycle=2006&p_report_type=#tmdls

cooling water circulates and evaporates in a recirculating cooling system, the salt and mineral content of the water increases, which can compromise system efficiency. As a result, nuclear plants typically discharge this warm, salt- and mineral-laden water—called "blowdown"—back into the water source. Blowdown may contain high concentrations of impurities found in the source water, caused by the evaporative process. In addition, blowdown may include dissolved metals and a variety of additives used to treat the cooling water as recirculates through the system. Salmonids are particularly sensitive to metals, particularly copper, [321] which may be present in a recirculating system's blowdown water. Cooling water can absorb copper if it is circulated through copper-containing condenser infrastructure.[322] For that reason, The CGS recently replaced its brass condenser components with titanium parts.[323] Water in the cooling system does not come into contact with water used in the reactor, so radioactive materials are not present in a nuclear power plant's effluent stream.

The discharge of pollutants from a nuclear power plant into surface waters is regulated under the Clean Water Act § 402 NPDES permit program, which establishes plant-specific effluent limitation guidelines for flow volume, temperature, pH, turbidity, and a variety of other pollutants.[324] The Washington Energy Facility Siting and Evaluation Council (EFSEC) has delegated authority from the EPA to issue § 402 NPDES permits for energy facilities in the state.[325] The EFSEC granted Energy Northwest granted a permit renewal for the CGS on November 1, 2014.[326] The permit established an average monthly flow of 5.6 million gallons per day and a maximum daily flow of 9.4 million gallons per day. The CGS's permit also sets limits for the average monthly and maximum daily discharge of halogen, chromium, and zinc, and specifies that the facility's effluent may not include any polychlorinated biphenyl compounds or any detectable quantities of 126 priority pollutants (except chromium and zinc).[327] In addition the discharge must fall within a pH range of 6.5 to 9 standard units. Radiological material in the effluent is regulated by the NRC consistent with the standards for exposure discussed above.[328]

Decommissioning represents the final phase of a nuclear power plant's lifecycle, and may result in a variety of environmental and human health impacts. Decommissioning typically involves the removal and disposal of highly radioactive spent fuel, the demolition of structures and removal of debris, and the clean-up of contaminated soil and groundwater.[329] Decommissioning typically entails the immediate dismantling of a plant, deferred dismantling, or entombment. While immediate dismantling returns the site to an uncontaminated state the fastest, levels of radioactivity in the facility are higher than those involved in a deferred dismantling. Under a deferred dismantling,

[321] http://www.westcoast.fisheries.noaa.gov/publications/habitat/fact_sheets/stormwater_fact_sheet.pdf
[322] CGS NPDES permit fact sheet at 8.
[323] *Id.*
[324] *See* http://www.efsec.wa.gov/Columbia%20Generating%20Station/EFSEC/CGS-NPDESPermit-Final-ElectronicSignature.pdf at S-2.
[325] http://apps.leg.wa.gov/WAC/default.aspx?cite=463-76-031
[326] *Id.*
[327] *Id.*
[328] *Id* at S-1.
[329] http://www.unep.org/yearbook/2012/pdfs/UYB_2012_CH_3.pdf

demolition may not occur for 10-80 years after the closure of the facility. Entombment shields a decommissioned facility for a period of time while radiation decays, before it is ultimately dismantled. Most waste produced in decommissioning a nuclear facility is not radiologically contaminated or is minimally radioactive and may be landfilled. Intermediate level waste, such as fuel rod casings and reactor vessel parts, requires shielding and may be disposed of at shallow depths. High level nuclear wastes, such as the spent fuel stored on-site in casks or pools, requires cooling and shielding and may be reprocessed or disposed of in deep geological formations. The risk of a large scale release of radioactive material from decommissioning activities is low, however workers involved in decommissioning a nuclear facility may have heightened risks of exposure due to their interaction with the radioactive debris. The pathways for public exposure to radioactive material may arise from the demolition of structures and debris, which has the potential to release radioactive dust and gas, and the penetration of water into the disposal site, which may dissolve radioactive isotopes and transport them into the water system. These risks can be mitigated through the introduction of proper safety measures, such as protective barriers and monitoring programs. The carbon emissions impact of the decommissioning stage is typically limited to exhaust from worker and construction vehicles and transportation of waste materials.

The NRC requires a licensed facility to submit a decommissioning plan for NRC approval within 60 days of the decision to stop operating a facility.[330] The plan must include "controls and limits on procedures and equipment to protect occupational and public health and safety," among other information.[331] After decommissioning is complete, the facility owner must certify that all radiological material has been disposed of in an appropriate manner and conduct a radiation survey that demonstrates that the premises is suitable for release.[332]

In 2012, the Nuclear Regulatory Commission renewed the CGS's operating license through 2043.[333] Unless the CGS is shuttered before the expiration of its license, it will not require decommissioning for decades. Decommissioning costs typically run about 10 to 15 percent of the initial capital cost of constructing the facility, or approximately $500 million.[334]

In conclusion, the lifecycle impacts of nuclear electricity generation are different than other types of thermal generation, with limited greenhouse gas emissions, but a risk of environmental or human health impacts from radiological release. While a large-scale release of radioactive material is unlikely, the potential effects of such a release may be significant. During normal operations, the primary impacts of a nuclear power plant are land-use and water impacts associated with uranium mining, water quality and quantity effects from plant operations, and spent nuclear fuel disposal issues.

[330] http://www.nrc.gov/reading-rm/doc-collections/cfr/part072/part072-0054.html
[331] *Id.*
[332] *Id.*
[333] http://www.nrc.gov/info-finder/reactor/wash2.html
[334] http://www.unep.org/yearbook/2012/pdfs/UYB_2012_CH_3.pdf

Wind Electricity Generation

Land-based wind energy is the largest source of renewable energy in the Northwest,[335] as a result of considerable wind power development in the past decade.[336] However, the rate of new wind deployment is expected to slow in response to uncertainty regarding the future of the federal incentives—primarily the Production Tax Credit (PTC).[337] Widespread development of wind facilities has the potential to cause a variety of impacts, including harm to wildlife, plants, water and air quality, human health, and cultural and historical resources.

Wind turbines consist of several components that are manufactured using a variety of materials, primarily steel, aluminum, copper, and laminates.[338] The blades of a turbine are collectively called its rotor and are typically constructed out of laminated materials such as composites, carbon fiber or fiberglass.[339] The hub is the point of connection between the rotor and the nacelle, which sits atop the tower and houses the drivetrain and yaw drive, among other components. The hub is typically made of cast iron weighing eight to ten tons. Within the nacelle is a drivetrain that includes a generator which turns mechanical energy from a rotating shaft into electrical energy, and a yaw drive that keeps the turbine oriented into the wind.[340] The rotor and nacelle are perched atop a tower, generally between 260 to 320 feet tall, which provides the turbine with access to better wind resources.[341] The tower and the nacelle are typically constructed out of steel. The environmental impacts of the manufacturing process vary depending on the raw materials and source of energy used. These effects may include land use and water impacts from mining, and air impacts from energy generation. The transportation and assembly of turbine components also produce some air emissions concerns associated with the use of vehicles and machinery that rely on petroleum products to operate. The process of constructing wind facilities may additionally result in fugitive dust from of blasting operations, road construction, and vehicle traffic on gravel roads. Any air quality impairment from wind development, however, is likely to be minimal and temporary. According to the National Academy of Sciences, the energy payback time for a wind project, or the time it takes a generation facility to produce more energy than the energy consumed during its lifetime, can range from 0.26 to 0.39 years.[342] Wind power is among the lowest lifecycle greenhouse gas emitters of any generation technology.[343]

Wind projects have the potential to affect a variety of wildlife, including birds, bats, and non-flying animal species. Wind development in the Northwest typically occurs in sagebrush habitat,[344] which

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[335] http://acore.org/images/documents/Western_Region_Report_2014.pdf.
[336] http://energy.gov/maps/wind-farms-through-years#buttn.
[337] http://www.utilitydive.com/news/2015-looks-grim-for-wind-energy-how-will-the-industry-adapt/345786/
[338] http://www.awea.org/Resources/Content.aspx?ItemNumber=5083
[339] *Id.*
[340] *Id.*
[341] *Id.*
[342] http://www.nap.edu/read/12619/chapter/7#199 at 199-200.
[343] *Id* at 204.
[344] Compare this sagebrush habitat map: http://sagemap.wr.usgs.gov/FTP/images/fig1.1.jpg, with this wind resources map: http://www.rnp.org/sites/default/files/images/NW%20wind%20map_rgb_web.jpg

supports a variety of sensitive species.[345] This impact may occur in at least three ways: direct contact with the turbine blades, contact with areas of rapidly changing pressure near spinning turbines, and habitat disruption from the construction and operation of turbines.

Wind facilities kill an estimated 140,000 to 328,000 birds annually in the U.S., although the precise figures are subject to considerable debate.[346] Bird deaths are primarily the result of direct contact with spinning wind turbines, the tips of which can travel at speeds ranging from 150 to 200 miles per hour.[347] The average wind project reports fewer than four bird fatalities per megawatt (nameplate capacity) per year, the majority of which are songbirds.[348] Eagles and other raptors may be affected by the operation of wind facilities in and around their soaring locations, through direct contact with spinning turbine blades. Raptor mortality from wind development, however, does not appear to be as significant a concern in the Northwest as it is in California.[349] Wind developers and project owners can limit a facility's impact on raptors by engaging in a pre-development site evaluation to determine raptor abundance, siting in areas of low prey density, and mitigation measures designed to curtail turbine operation when raptors are present.[350] Environmental Impact Statements prepared in support of wind projects in the Northwest identify several special-status raptor species that may be affected by wind development including the Northern Goshawk, Ferruginous Hawk, and the Peregrine Falcon.[351]

The Bald and Golden Eagle Protection Act (BGEPA), the Migratory Bird Treaty Act (MBTA), and the Endangered Species Act (ESA) make it illegal to kill many bird species, including raptors. The Bald and Golden Eagle Protection Act, originally enacted in 1940, prohibits anyone from wounding, killing, molesting or disturbing either species without a permit.[352] The penalty for taking an eagle without a permit can be up to a $200,000 fine and imprisonment for a year. In 2013, pursuant to its authority under the BGEPA, the U.S. Fish and Wildlife Service (FWS) issued a rule extending the duration of eagle take permits from five to 30 years.[353] The longer permit insulates project developers against BGEPA liability and the potential for evolving permit requirements over time. In order to obtain an eagle take permit, wind project developers must demonstrate that eagle takes are unavoidable after the implementation of Advanced Conservation Practices (ACPs). ACPs are defined as "scientifically supportable measures that are approved by the Service and represent the best available techniques to reduce eagle disturbance and ongoing mortalities to a level where remaining take is

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345 http://www.washingtonpost.com/news/energy-environment/wp/2015/09/03/western-sagebrush-is-vanishing-and-these-10-animals-are-just-trying-to-hang-on/
346 http://www.sciencedirect.com/science/article/pii/S0006320713003522. This figure represents only a fraction of the birds killed by domestic cats, buildings, and transportation. http://www.nytimes.com/2011/03/21/science/21birds.html?_r=0.
347 http://www.aweo.org/windmodels.html.
348 http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
349 *Id.*
350 *Id.*
351 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.
352 http://www.fws.gov/midwest/MidwestBird/EaglePermits/bagepa.html
353 http://www.gpo.gov/fdsys/pkg/FR-2013-12-09/pdf/2013-29088.pdf

unavoidable."[354] After implementing ACPs and determining that take is unavoidable, permit applicants are required to develop an Eagle Conservation Plan that includes a site assessment, a site survey, a risk assessment, impact avoidance and mitigation measures, and ongoing monitoring. The FWS has issued guidelines for wind energy developers to follow in drafting Eagle Conservation Plans.

The MBTA impacts wind project development and operations by making it unlawful to "pursue, hunt, take, capture, [or] kill" over 800 migratory bird species protected by of a number of international conventions.[355] The MBTA, unlike the BGEPA, does not include a provision authorizing incidental take of protected species. Consequently, courts have traditionally interpreted the MBTA as a strict liability statute; any action that results in the death or take of a protected species is a de facto violation of the law, regardless of intent.[356] To avoid potential liability for violations of the MBTA, wind developers typically enter into handshake agreements with the FWS under which the FWS will not pursue enforcement against a developer for bird deaths as long as the developer takes steps to comply with the Land-Based Wind Energy Guidelines.[357] On the other hand, the FWS may pursue MBTA enforcement against a project owner or developer that declines to follow the Guidelines.[358] Consequently, one of the conflicts in developing a new wind project is deciding whether to dedicate the resources necessary to comply with the Guidelines and thereby limit potential liability, or build a facility without regard to the FWS's recommendations and risk potentially significant penalties.

The Guidelines provide a developer with a framework to comply with wildlife regulations associated with the MBTA, as well as the BGEPA and the ESA. Under the Guidelines, prior to construction, a developer is supposed to conduct a site evaluation, document the habitat and species present and forecast impacts of the project. During operations, the Guidelines recommend that project owners continue to monitor and estimate impacts. When risks are presented during construction or operation, a developer or project owner is encouraged to modify the project, mitigate the impacts, increase monitoring, or abandon the project.[359] Bird deaths may still occur at a wind facility that is compliant with the Land-Based Wind Energy Guidelines, although the magnitude of the deaths is likely to be limited. Several recent federal district court decisions signal a potential shift away from a

[354] https://www.law.cornell.edu/cfr/text/50/22.3
[355] http://www.fws.gov/migratorybirds/regulationspolicies/mbta/mbtandx.html
[356] *See, e.g., U.S. v. Manning*, 787 F.2d 431, 435 n.4 (8th Cir. 1986).
[357] http://www.fws.gov/ecological-services/es-library/pdfs/WEG_final.pdf. "Adherence to the Guidelines is voluntary and does not relieve any individual, company, or agency of the responsibility to comply with laws and regulations. However, if a violation occurs the Service will consider a developer's documented efforts to communicate with the Service and adhere to the Guidelines."
[358] In 2013, Duke Energy pleaded guilty to violations of the MBTA in U.S. District Court in Wyoming for the deaths of 14 golden eagles and 149 other migratory birds. The court ordered Duke Energy to pay $1 million worth in restitution, fines and community service payments, in addition to imposing a five-year probationary period. http://www.justice.gov/opa/pr/utility-company-sentenced-wyoming-killing-protected-birds-wind-projects. Similarly, in 2014, PacifiCorp entered a settlement agreement with the government to pay $2.5 million in fines for migratory bird deaths at the company's Wyoming wind facilities. http://www.rechargenews.com/wind/1387234/Buffetts-PacifiCorp-fined-2.5m-for-bird-deaths-at-Wyoming-wind-farms.
[359] *Id* at vi-vii.

strict liability interpretation of the MBTA, but Northwest courts have not yet adopted this view. [360] Although there is no incidental take permitted under the MBTA, a wind project developer may apply for a Special Purpose Utility permit that allows the collection, transportation, and temporary possession of migratory birds for avian mortality monitoring and disposal purposes.[361]

The Greater Sage Grouse is a species of particular concern, because its range coincides with prime wind resources in the region.[362] The sage grouse is primarily affected by habitat disruption resulting from wind development, because the animals tend to avoid human infrastructure.[363] The cumulative impacts of wind development in sage grouse habitat may decrease the area of that habitat to the point where survival and reproduction of the animals are in jeopardy.[364] A review of Environmental Impact Statements prepared in support of Northwest wind projects identifies other special-status bird species may be vulnerable to wind project development as well, including: the Sage Sparrow, Loggerhead Shrike, Lewis' Woodpecker and Mountain Quail.[365]

The U.S. Fish and Wildlife Service (FWS) recently elected not to list the Greater Sage Grouse as either threatened or endangered under the ESA.[366] Many policymakers from the Western states advocated to keep the sage grouse off the Endangered Species List to avoid the limitations on development that a listing entails. Although the Department of Interior declined to list the sage grouse, the Forest Service and Bureau of Land Management, the two largest landowners of sagebrush habitat, have agreed to revise their land-use plans to protect the sage grouse while permitting some development in its habitat.[367] It remains to be seen if and how the sage grouse conservation effort will impact wind development in the Northwest. Many states also operate under protective measures designed to support sage grouse populations. Other sensitive bird species may be present in areas selected for wind development in the region. With regard to these species, the project owner or developer is required to obtain an ESA incidental take permit as discussed above.

Many bat species are also affected by wind energy development, through both contact with the spinning blades and contact with areas of rapidly changing pressure caused by the turbines. Abrupt changes in pressure may cause barotrauma in bats, resulting in internal hemorrhaging that can be fatal.[368] At least one study, however, questions barotrauma as a mechanism of bat mortality.[369] Wind

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[360] In 2012, for example, the federal District Court of North Dakota dismissed misdemeanor criminal charges against three oil and gas companies for migratory bird deaths, because the conduct that resulted in the bird deaths represented a "legal, commercially useful activity," and the harm caused to protected birds was not intentional. http://www.stoel.com/federal-court-holds-that-the-migratory-bird-treaty. While that decision applied to oil and gas companies, the principle could be extended to wind project owners and developers, which similarly harm migratory birds in the process of conducting legal commercial activity.
[361] http://www.fws.gov/forms/3-200-81.pdf
[362] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18567.pdf at 2.2.
[363] *Id* at 4.1.
[364] *Id.*
[365] http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.
[366] http://www.washingtonpost.com/news/energy-environment/wp/2015/09/22/fewer-than-500000-sage-grouse-are-left-the-obama-administration-says-they-dont-merit-federal-protection/
[367] http://www.fws.gov/greatersagegrouse/findings.php
[368] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.

turbines kill an estimated 600,000 to 900,000 bats annually in the U.S. Particularly vulnerable are tree roosting species, including the Hoary Bat, the Eastern Red Bat and the Silver-haired Bat. These species are not on the Endangered Species List as threatened or endangered.[370] Risk to bats cans be reduced significantly by curtailing operation during wind speeds at which bats are active, typically below 7.8 miles per hour.[371] Other mitigation measures include feathering turbine blades to be parallel with the wind direction during periods of low wind and curtailing operation during temperatures at which bats are active.[372] Although the economic cost of doing so has not yet been quantified, wind project owners may able to reduce bat fatalities between 50 percent and 72 percent with proper mitigation.[373] Special-status bat species present near Northwest wind projects include: the Pallid Bat, Townsend's Big-eared Bat, Spotted Bat, Silver-haired Bat, Small-footed Myotis, Long-eared Myotis, Fringed Myotis, and Yuma Myotis.[374]

Other non-flying animal and plant species may be impacted by wind project development and operation, however data is limited on the extent of the impacts. The risks presented by wind projects to non-flying animals and plants include contact with vehicular traffic and construction equipment, destruction of subterranean habitat by soil compaction, animal avoidance of human activity, infrastructure and sounds, and effluent impacts on aquatic species.[375] The animal species in the Northwest that appear to exhibit particular vulnerability to wind development include antelope and mule deer, which tend to avoid human infrastructure; ground squirrels, which exhibit increased vigilance as a result of wind turbine noise; and fish and amphibians, which are sensitive to sediment load in spawning areas.[376] Special-status animal and plant species that may be affected by the development and operation of wind projects, including: the Northern Sagebrush Lizard, Pygmy Rabbit and Green-tinged Paintbrush.[377] While it seems likely that wind project development will have

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369 http://www.nrel.gov/wind/news/2013/2149.html.
370 *Id.*
371 http://www.popsci.com/blog-network/eek-squad/wind-turbines-kill-more-600000-bats-year-what-should-we-do, *see also* http://www.smithsonianmag.com/smart-news/scientists-save-bats-and-birds-from-wind-turbine-slaughter-130262849*/.*
372 http://www.batsandwind.org/pdf/Operational%20Mitigation%20Synthesis%20FINAL%20REPORT%20UPDATED.pdf.
373 *Id.*
374 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.
375 https://profile.usgs.gov/myscience/upload_folder/ci2012Dec1411215633446Wind%20energy%20and%20wildlife%20Lovich%20and%20Ennen.pdf.
376 *Id.*
377 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.

negative impacts on a variety of non-flying animals, more information is necessary to understand the scope of these impacts.

The ESA may limit wind development in regions where sensitive species are present. To the extent that a listed species or critical habitat is present at a site, a wind project developer may be required to prepare a habitat conservation plan and obtain an incidental take permit consistent with the requirements in § 10 of the ESA. In addition, federal involvement in a wind project triggers the § 7 consultation requirement.[378] Because the law allows incidental take where the permitted activity is otherwise lawful and is not likely to jeopardize the continued existence of a listed species, wind development still has the potential to affect the welfare of sensitive species to a small degree.

The NEPA environmental analysis requirements are also triggered to the extent that a wind project involves a federal entity. In 2005, the Bureau of Land Management (BLM) issued its Final Programmatic EIS for Wind Energy Development on BLM-Administered Lands in the Western United States.[379] The Programmatic EIS addressed the impacts from a proposed wind energy development program designed to expedite the construction of wind facilities on federal land. A project developers may also be required to work with federal agencies to conduct a project-specific NEPA analysis that examines the impacts associated with and alternatives to the development of a proposed facility. Because of the time and expense required to conduct a NEPA analysis, project developers may be incentive to avoid federal involvement to the extent practicable.

A wind project may have adverse impacts on water quality during its construction, operation and decommissioning phases, depending on the location of the project and its proximity to surface waters. These water quality impacts are not likely to be significant. The construction phase of wind project development typically requires the removal of vegetation, and the building of concrete foundations and access roads, all of which have the potential to alter drainage patterns, increase sediment runoff and introduce pollutants into surface waters.[380] Building access roads may require the construction of bridges or culverts to cross perennial, ephemeral and intermittent drainages.[381] Additionally, the operation of a wind project often requires the vehicular travel over gravel roads and the application of water for dust control and the use of herbicides to maintain clear access to the facilities. These measures can also contribute to sediment and contaminant runoff in proximate surface waters. Overall, the water quality impacts of wind project development and operation are minimal. To the extent that a wind project channelizes stormwater and discharges it into an adjacent waterbody, the project owner may be required to obtain a § 402 NPDES permit under the Clean Water Act.

Wind project development and operation may result in a variety of human health impacts, as well as impacts to cultural and historical resources. The human health impacts may include: viewshed and aesthetic harms, and disruption caused by noise from project construction and operation, shadow

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[378] Federal involvement includes a lease of federal land or a federal licensing requirement.
[379] http://www.windeis.anl.gov/documents/fpeis/maintext/Vol1/Vol1Complete.pdf
[380] http://teeic.indianaffairs.gov/er/wind/impact/construct/index.htm.
[381] http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf at 3-6.

flicker, and aviation safety lighting. Neighboring landowners may also simply object to the presence of wind facilities near their properties.

Viewshed and aesthetic harms are caused by the construction of wind turbines and associated infrastructure, such as roads, transmission lines and substations. Because wind projects are spread over large parcels of land, they tend to be sited in otherwise minimally developed areas. As a result of their large scale and siting in undeveloped areas, wind projects may generate complaints about the viewshed or aesthetic impacts from neighboring land-owners.[382] Noise impacts may result from the construction, operation and decommissioning phases of a wind project. In both the construction and decommissioning phases, vehicular traffic and the operation of heavy machinery may generate noise at levels that can disturb neighboring landowners. During the operation phase, a wind project consistently produces noises that are both aerodynamic—the sound of the turbine blades moving through air—and mechanical—the sound of electrical generation—which people may find disturbing.[383] Shadow flicker and aviation safety lighting may be an annoyance to nearby homeowners. Shadow flicker occurs when the sun casts the shadow of a spinning wind turbine, causing people located nearby to perceive a constant flickering. No health impacts have been scientifically tied to shadow flicker, but it may be considered a nuisance.[384] The flickering effect can be mitigated in a number of ways, including conscientious siting, vegetative buffers, window blinds for affected buildings, and curtailment during the hours of expected occurrence.[385] Aviation safety lighting, the blinking red lights atop wind turbines, may similarly be considered a nuisance for nearby landowners. No adverse health effects from exposure to these lights are evident. Some characteristics of a wind project, such as noise and shadow flicker, may represent a legitimate nuisance to adjacent landowners, but the overall human health impacts of wind development are likely minimal if proper siting and mitigation measures are taken. Many of the purported human health impacts of wind projects may be manifestations of general opposition to wind development.

Cultural and historical resource impacts of wind developments may include the physical disruption of important artifacts or sites, and the visual disruption of culturally significant areas. Of primary concern for wind developers are tribal resources, both in terms of artifacts and culturally important lands.[386] Completing a site survey of the development area early in the process and avoiding areas of potential value can minimize the physical disruption of cultural and historical resources. Similarly, visual disruption of culturally important sites can be mitigated through consultation with the potentially affected tribes and relevant state and federal agencies.

Finally, the electricity generated by the individual turbines at a wind project must be collected before delivery to a transmission system. The collector system transports the power from individual turbines to a series of local transformers and then a point of common coupling, after which a step-up

[382] http://teeic.indianaffairs.gov/er/wind/impact/construct/index.htm.
[383] *Id.*
[384] http://www.masscec.com/content/shadow-flicker.
[385] *Id.*
[386] http://www.eenews.net/stories/1059964429.

transformer increases the voltage for long-distance transmission.[387] In addition to the distance that the collector system must span to connect individual turbines, the power from the step up transformer must sometimes be delivered long distances to the transmission line. In addition, modifications may be required to the transmission system to increase capacity to accommodate more power. The infrastructure necessary to transport electricity generated by wind projects may result in environmental impacts that are discussed more fully in the Transmission section below.

In sum, a variety of environmental concerns arise during wind project development and operation; risks to plants and wildlife being the most visible issues. The risks of direct mortality for flying species and the fragmentation of sagebrush habitat are of primary concern in the Northwest. The extent of environmental damage caused by wind development depends primarily on the location and size of the project. Many of these harms, however, can be minimized through the use of appropriate mitigation measures.

Solar Electricity Generation

Solar energy is currently experiencing a period of rapid growth in the United States., as a result of declining prices for solar panels, federal and state subsidies, and growing concerns over carbon emissions.[388] This growth is occurring in the form of distributed solar energy projects, utility-scale solar photovoltaic (PV) installations, and concentrating solar facilities. PV systems are typically flat panels made of silicon, which converts sunlight directly into electricity.[389] Distributed solar refers to a small-scale solar PV installation located near the point of consumption. Sometimes referred to as rooftop solar, distributed solar facilities are often sited on the premises of an electric customer.[390] Utility-scale solar PV refers to a large-scale PV installation used to generate electricity for sale at wholesale. Utility-scale solar PV installations are typically located in more remote areas, away from electricity end-users.[391] Concentrating solar facilities use a configuration of mirrors to concentrate the sun's heat to generate electricity thermally.[392] Diffuse light conditions in the Pacific Northwest limit the potential for concentrating solar, which requires consistent direct sunlight.[393] Although the environmental impacts of solar are generally minimal, each type of solar installation poses potential environmental risks.

The production of solar PV panels requires the acquisition of raw materials, the use of toxic chemicals, the consumption of electricity, and the disposal of waste products, all of which have attendant environmental risks. In addition to silicon, which is relatively abundant and the largest component of a solar panel, the production of a PV system typically requires rare or precious metals,

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[387] http://www.windsystemsmag.com/article/detail/741/beyond-the-turbine-understanding-the-collector-system
[388] http://www.scientificamerican.com/article/solar-power-sees-unprecedented-boom-in-u-s/.
[389] http://www.nrel.gov/learning/re_photovoltaics.html
[390] http://www.seia.org/policy/distributed-solar.
[391] http://www.seia.org/policy/power-plant-development/utility-scale-solar-power.
[392] http://www.seia.org/policy/solar-technology/concentrating-solar-power.
[393] http://www.nrel.gov/csp/maps.html.

such as silver, tellurium and indium.[394] These rare metals may be mined by exploited workers and supplied from areas of conflict.[395] Although abundant, silica can cause the lung disease silicosis in workers responsible for mining the material.[396] Silica is generally mined in the form of quartz, which must be initially refined into silicon and then into polysilicon before it may be used in a solar panel.[397] The initial refining process requires the use of energy-intensive furnaces, the operation of which may result in greenhouse gas and other air emissions depending on the energy source used.[398] The energy payback time for solar panels, the amount of time it takes for panels to generate the power required during their lifecycle, typically ranges from six months to two years.[399] The second refining process produces silicon tetrachloride, a toxic chemical that produces hydrochloric acid in the presence of water. Although silicon tetrachloride may be recycled at a savings to the refining facility, some refiners dispose of the liquid as waste.[400] The polysilicon is then formed into blocks that are sliced into thin wafers, and cleaned and etched with hydrofluoric acid.[401] Hydrofluoric acid is the same extremely corrosive compound used in some types of natural gas extraction, causing damage to human tissue and bone to the extent that a person is exposed.[402] Unintentional releases of the acid can contaminate nearby water and soils. Researchers are looking into alternatives to hydrofluoric acid in the polysilicon manufacturing process. Thin-film manufacturing methods, which represent a less material- and energy intensive manner of manufacturing PV panels, may obviate the need for many of the steps described above. But thin-film technologies typically require components that contain cadmium, itself a carcinogen and genotoxin.[403] As a result, thin-film manufacturers are working on reducing or eliminating the need for cadmium in their products. The overall environmental impacts of solar panel production largely depend on the materials and processes used by the panel manufacturer.[404] The majority—58 percent—of solar panels are manufactured in China.[405] Although China's environmental standards are sometimes eyed with suspicion, they are generally seen to be improving.[406]

In addition to PV panels, a solar facility needs an inverter to convert the direct current power that the panels produce to the alternating current electricity that is the standard on the United States electricity grid. An inventory of the materials required to manufacture a solar inverter has proven

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[394] http://news.nationalgeographic.com/news/energy/2014/11/141111-solar-panel-manufacturing-sustainability-ranking/
[395] http://ngm.nationalgeographic.com/2013/10/conflict-minerals/gettleman-text
[396] http://spectrum.ieee.org/green-tech/solar/solar-energy-isnt-always-as-green-as-you-think
[397] http://spectrum.ieee.org/green-tech/solar/solar-energy-isnt-always-as-green-as-you-think
[398] *Id.*
[399] *Id.*
[400] *Id.* In 2011, China set a standard of 98.5% recycle rate for silicon tetrachloride.
[401] *Id.*
[402] *Id.*
[403] *Id.*
[404] http://www.solarscorecard.com/2014/2014-SVTC-Solar-Scorecard.pdf
[405] http://solarlove.org/wp-content/uploads/2014/10/PV-solar-cell-production-by-region.png
[406] *See, e.g.,* https://www.wilsoncenter.org/publication/making-green-green-how-improving-the-environmental-performance-supply-chains-can-be-win

difficult to track down, but the technology typically includes copper components and electronics.[407] The lifecycle environmental impacts of a solar PV project may vary depending on the materials and processes used to manufacture the associated solar inverter.

The development of solar PV facilities require an average of approximately 8 acres of land per megawatt of capacity,[408] as compared to an average of 85 acres per megawatt of capacity for wind development.[409] However, solar facilities are generally developed at a density at which the land cannot be used for other purposes, while wind turbines do not preclude other uses, such as agriculture and grazing. The Northwest has experienced limited utility-scale solar PV development,[410] but interest from developers is growing. The largest solar PV facility currently sited in the Northwest is the 40 acre, 5.7 megawatt Outback Solar Project in Christmas Valley, Oregon.[411] The development of utility-scale and distributed solar PV is expected to continue to grow in the Northwest.

As is the case with wind energy, the environmental impacts of the operation of a solar installation vary by project size, type and location. These risks include harm to vulnerable plants and wildlife, impacts on air and water quality, and impacts to human health and cultural and historical resources. Overall, however, the portfolio of environmental risks posed by solar energy appear to be similar to, but less severe than, those posed by wind.[412]

Some types of solar development have the potential impact vulnerable plant and wildlife species through habitat destruction or direct contact with facilities. Utility-scale PV and concentrating solar are the primary technologies of concern with regards to plant and wildlife impacts, because they tend to be large-scale developments in previously undeveloped areas. Distributed solar energy has minimal wildlife impacts, because it is typically sited in locations that are already developed for other uses.[413]

Habitat disruption is the primary risk to plants and wildlife posed by utility-scale solar PV.[414] The best solar resources in the Northwest are typically situated in high desert areas, so desert species are the most vulnerable to solar development. Utility-scale solar facilities typically consist of multiple rows of solar panels mounted on a concrete foundation. Once constructed, plants and wildlife are excluded from these facilities, so utility-scale PV development reduces available habitat. Solar PV development also brings with it human noise, activity and infrastructure, which may affect adjacent wildlife. Contact with increased vehicular traffic to and from the site, both during construction and

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[407] *See* http://www.clca.columbia.edu/papers/21%20EUPVSC%20-%20deWild%20et%20al%20-%20Cost%20and%20environmental%20impact%20comparison.pdf at 4.2
[408] http://spectrum.ieee.org/energywise/green-tech/solar/report-counts-up-solar-power-land-use-needs.
[409] http://www.aweo.org/windarea.html.
[410] https://openpv.nrel.gov/utility-scale.
[411] http://www.bpa.gov/news/newsroom/Pages/Twas-bright-before-Christmas.aspx.
[412] http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-of.html#.VUfpcmR4oq9.
[413] http://www1.eere.energy.gov/solar/pdfs/47927_chapter7.pdf.
[414] http://teeic.indianaffairs.gov/er/solar/impact/op/index.htm.

operation could result in additional harm to wildlife. Mitigation measures, including limiting development to disturbed areas or existing facilities, establishing protective buffers between the facility and sensitive areas, and avoiding significant activity around the facility during mating periods can limit the risk of wildlife disruption.[415]

Concentrating solar causes more troubling and visible wildlife impacts than solar PV, occasionally causing birds to ignite midair.[416] Concentrating solar facilities use mirrors to direct the sun's energy into a receiver in the form of heat, that heat is typically used to drive a steam turbine. There are four basic types of concentrating solar plant: Parabolic Trough, Compact Linear Fresnel Reflector, Power Tower and Dish-Engine.[417] Parabolic Troughs use curved mirrors to reflect the sun's energy into receiver tubes that run down the center of the trough. Compact Linear Fresnel Reflector facilities use the same principle, however the mirrors are flat, rather than curved, and arranged in a manner that mimics a trough. In Power Tower facilities, a large column serves as the receiver at the center of a field of mirrors. Dish-Engine facilities employ a parabolic dish of mirrors that direct the sun's energy into a receiver mounted in front of that dish. Bird deaths occur at some concentrating solar facilities when the animals enter the "solar flux," or the stream of concentrated solar energy created by the mirrors.[418] The dramatic nature of these bird deaths has led to sensationalistic press coverage. In some cases, the unfortunate animals are referred to as "streamers," for the trail of smoke and water vapor they release as they fall from the sky.[419] These deaths occur only at Power Tower facilities, which have much higher operating temperatures than other concentrating solar plants. Aside from bird deaths caused by contact with solar flux, concentrating solar has many of the same potential wildlife impacts due to habitat fragmentation as solar PV.

Similar to wind energy development, the potential for a solar facility to cause adverse impacts to birds and other wildlife may trigger compliance requirements under the BGEPA, MBTA and ESA. The California and Nevada regional office of the FWS drafted a template letter to provide guidance to solar developers for complying with these statutes.[420] In it, a solar developer is encouraged to work with the FWS to take measures to mitigate impact during project development and continue to adapt management practices throughout the operation of a facility to avoid take of protected species. In furtherance of these goals, a developer is encouraged to develop and adopt an avian plan and identify and implement all reasonable, prudent and effective measure to avoid killing birds and other wildlife protected under any of the three laws.[421] A solar developer is also encouraged to apply for and obtain BGEPA and ESA § 10 incidental take permits, as well as a Special Purpose Utility permit under the MBTA. As was the case with wind energy, these steps are voluntary, but project owners that comply with the FWS's guidance are less likely to face enforcement action

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[415] *Id.*
[416] http://www.popsci.com/solar-power-towers-are-vaporizing-birds.
[417] http://www.seia.org/policy/solar-technology/concentrating-solar-power.
[418] http://www.kcet.org/news/redefine/rewire/solar/concentrating-solar/scores-of-birds-killed-during-test-of-solar-project-in-nevada.html.
[419] http://www.dailymail.co.uk/sciencetech/article-2965070/Solar-farm-sets-130-birds-FIRE-Extreme-glow-power-plant-ignites-creatures-mid-air-tests.html.
[420] https://www.fws.gov/cno/images/Solar%20Letter%20template.pdf
[421] *Id.*

should a take occur.[422] While the guidance letter discussed above was issued by a FWS regional office that does not oversee the Northwest, it likely the position reflects the nationwide policy of the FWS.

Solar energy development has modest impacts on water and air quality. These impacts are primarily limited to the larger solar installations, utility-scale PV and concentrating solar. The water and air impacts of distributed solar PV appear to be minimal. Solar energy development my impact water quality to the extent that vegetation is removed and drainage patterns are altered.[423] PV systems consume water for dust control and panel cleaning, up to 395 million gallons during construction 6.8 million gallons during operation.[424] Concentrating solar facilities typically consume more than that, requiring freshwater to drive steam turbines and cool the facilities. Concentrating solar is disadvantaged in this way, because prime solar resource areas tend to overlap with water-constrained areas.[425] A solar facilities may require a § 402 NPDES permit under the Clean Water Act for stormwater discharges.

Solar energy development does not have a significant impact on air quality. Because solar power is a non-emitting resource, the construction phase of solar development is the only period in which air quality may be affected. Even then, the impacts are limited to vehicle exhaust and dust from blasting, grading and vehicular traffic.[426]

Solar energy development is unlikely to cause many human health impacts. Utility-scale PV and concentrating solar facilities require large infrastructure in remote regions and, therefore, may cause aesthetic or viewshed harms.[427] Aside from non-development of a solar facility, limited mitigation options exist for these impacts.[428] In addition, solar facilities have the potential to create glare, cause by the sun's reflection off of solar infrastructure. Glare for adjacent landowners can easily be avoided through the careful configuration of solar facilities.[429] A solar energy development's impact on cultural and historical resources may be limited through appropriate mitigation. Of particular concern in remote areas considered for solar energy development would be the removal or destruction of artifacts, and visual impacts to sacred sites and landscapes.[430] The impacts to artifacts can be mitigated through a review of known archeological sites and a comprehensive site survey. The visual impacts of solar facilities to cultural resources can be mitigated through consultation with the relevant tribes.[431]

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[422] *Id.*
[423] http://teeic.indianaffairs.gov/er/solar/impact/construct/index.htm.
[424] http://spectrum.ieee.org/green-tech/solar/solar-energy-isnt-always-as-green-as-you-think
[425] http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/Solar-Water-Use-Issues-in-Southwest.pdf.
[426] http://teeic.indianaffairs.gov/er/solar/impact/construct/index.htm.
[427] *Id.*
[428] http://www.bia.gov/cs/groups/xieed/documents/document/idc1-021617.pdf.
[429] http://www.oregon.gov/ODOT/HWY/OIPP/docs/solar_glarepotentialwl.pdf.
[430] http://teeic.indianaffairs.gov/er/solar/mitigation/index.htm.
[431] *Id.*

A solar energy project that is built on federal land or requires a federal permit or license to operate will trigger the NEPA's environmental analysis requirement. While the BLM has issued a Programmatic EIS[432] for its program to facilitate solar development on BLM-administered lands in the Southwest,[433] no similar plan exists in the Northwest. A developer seeking to build a utility-scale solar PV or concentrating solar project that requires federal involvement, then, will be required to work with the relevant federal agencies to prepare an EA or EIS.

A solar energy facility, like a wind project, may not be built with the convenience of interconnection to the transmission system in mind. For that reason, a solar project may require a considerable length of delivery infrastructure to interconnect to transmission lines. In addition, the capacity of the recipient transmission system may need to be increased to accommodate the increase in electricity. Both the construction of interconnection facilities and the expansion of the transmission system have the potential to produce environmental impacts that are more fully considered in the Transmission section below.

In conclusion, while the generation of electricity from solar facilities produces limited environmental impacts, a lifecycle assessment that includes the manufacture of components and developing necessary transmission infrastructure results in a broader accounting of environmental effects. In addition to wildlife habitat disruption associated with project construction, the effects may include environmental and human health impacts that may be outsourced to the areas where materials are mined and panels are manufactured abroad. The magnitude of the impacts caused by solar power production, however, is significantly less than those associated with fossil fuel-fired generation.

Biomass Electricity Generation

In the electricity context, biomass energy describes several types of generating resources in which fuel is burned to create steam that drives a turbine to produce power. The term biomass includes solid fuel, such as wood, wood waste and agricultural residues, as well as methane produced by the decay of organic material in landfills, sewage treatment facilities, and farming operations. These resources, while part of the energy portfolio in the Northwest, provide only modest contributions to the region's electricity sector. For this reason, this section includes a brief look at these resources and their impacts.

There is about 1,000 megawatts of installed biomass in the region. In recent years, there have been several small (on average three megawatts) animal waste and landfill gas plants developed on existing dairy farms and landfill operations. With the economic recession in the late 2000's, several of the region's paper and textile plants have shut down, reducing the supply of pulping liquor for pulp and paper biomass plants. In addition, Portland General Electric is considering converting its 660-megawatt Boardman coal-fired generation facility into a 40 to 50-megawatt biomass facility when the plant is slated to cease coal-burning operations in 2020.[434] Biomass is relatively more expensive

[432] http://solareis.anl.gov/
[433] http://blmsolar.anl.gov/sez/
[434] http://www.energybiz.com/magazine/article/288483/boardman-goes-biomass.

than other fuels, so, although it provides similar operational characteristics to coal and natural gas, the electric industry is not likely to embrace the fuel to any significant extent unless states mandate higher levels of renewable energy.[435] Direct use of biomass in applications such as home heating can also reduce electricity demand, to the extent that it supplants electric heating. While direct use of biomass does have environmental impacts, it is outside of the scope of this Appendix.

Since biomass energy refers to a diverse array of fuels and technologies, the potential environmental and human impacts that result from biomass-fueled electricity generation is varied. The primary concerns are water and land use impacts associated with feedstock production and air quality concerns relating to biomass combustion.

Feedstock refers to the organic materials that are either used directly as biomass fuels or used to produce biomass fuels. These may include round wood, woody residues, agricultural byproducts, and municipal solid waste.[436] Feedstock can be broken down into three types: primary feedstock, which includes crops grown specifically to produce biomass energy; secondary feedstock, which includes byproducts like manure, food waste, wood processing residue and pulping liquor; and tertiary feedstock, which includes municipal solid and sanitary waste, landfill gas, and urban wood waste.[437] Primary feedstock production results in the most significant environmental impacts, because it typically requires the devotion of land to agricultural purposes, as well as water and fertilizer inputs. For this reason, impacts associated with the production of primary feedstock may include: agricultural runoff in rivers and streams, habitat destruction, and human health impacts associated with pesticide use. These water quality impacts may be regulated under the Clean Water Act to the extent that the runoff is channelized, however, agricultural runoff is generally nonpoint source runoff and thus not covered by the statute.[438] Agricultural runoff contributes significantly to water quality impairment nationwide, although biomass feedstock production generates only a small fraction of agricultural runoff. Secondary and tertiary feedstocks utilize waste products for energy, and impacts relating to their production are relatively modest. The majority of the biomass used in the electricity sector is comprised of residues from the production processes associated with the pulp and paper industries, which is also the case in the Northwest.[439] Accordingly, the environmental impacts associated with the production of biomass feedstock in the regional electric industry are minimal.

The process of combusting biomass to generate electricity results in air quality and climate change impacts. The primary air emissions produced during biomass combustion include nitrogen oxides, sulfur dioxide, carbon monoxide, mercury, lead, volatile organic compounds, particulate matter, and dioxins.[440] Lifecycle emissions vary by type of biomass resource, but, in general, a biomass facility

[435] http://www.eia.gov/oiaf/analysispaper/biomass/.
[436] http://www.energy.gov/eere/bioenergy/biomass-feedstocks.
[437] http://teeic.indianaffairs.gov/er/biomass/impact/siteeval/index.htm.
[438] http://water.epa.gov/polwaste/nps/agriculture.cfm
[439] http://www.eia.gov/oiaf/analysispaper/biomass/.
[440] http://teeic.indianaffairs.gov/er/biomass/impact/op/index.htm.

emits fewer pollutants at lower levels than its fossil fuel counterparts.[441] Municipal solid waste facilities, also known as trash to energy plants, are typically associated with the emission of mercury and other heavy metals.[442] Plants that burn gas captured from landfills, manure digesters and sewage treatment produce emissions similar to natural gas-fired electricity generators. However, the capture and beneficial use of biogas as a fuel may have a net emissions benefit to the extent that it reduces methane emissions. Facilities that combust wood products emit carbon dioxide, nitrogen oxides and other pollutants. However, the process of growing trees sequesters carbon from the atmosphere, meaning that the carbon dioxide released from wood product combustion is nominally offset by the growth of new trees. According to this logic, the EPA is currently considering whether to exclude carbon emissions produced by the combustion of biogenic feedstocks from the compliance requirements under the Clean Power Plan.[443] However, there is some controversy surrounding the idea that biogenic carbon should be excluded, with opponents suggesting that such a position might lead to deforestation and a worsening of climate change.[444] The Clean Air Act generally requires compliance with emissions limitations and technology-based standards for a variety of pollutants that may result from biomass combustion. Biomass facilities are required to comply with the NAAQS, which establish emissions limits for six criteria pollutants, as well as the NESHAPS, which restrict emissions of hazardous air pollutants.

Depending on the type of biomass used, combustion may also result in water quality and quantity impacts. Biogas is a pipeline-quality methane product that may be used interchangeably with natural gas, so the water impact of using biogas as a fuel source is limited.[445] Steam electric biomass generation facilities employ boilers and cooling systems similar to coal plants. These facilities are commonly associated with solid waste and wood products, but may use a variety of solid and gaseous fuels.[446] The water impacts associated with steam electric biomass facilities are similar to those associated with coal plant operations, potentially including water withdrawals and discharges of cooling water blowdown and air pollution control equipment byproducts. A steam electric biomass facility that is discharging into surface waters must obtain a Clean Water Act § 402 NPDES permit. Biomass is commonly used in combined heat and power facilities, which utilize the waste steam after it has been used to generate electricity for industrial or heating purposes.[447]

The NEPA may impose environmental analysis requirements on the production of biomass feedstocks or the operation of an electric generation facility to the extent that a federal entity is involved.

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[441] http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-biomass-for-electricity.html#.VVJg9WR4oq8.
[442] *Id.*
[443] http://biomassmagazine.com/articles/12260/epa-releases-clean-power-plan-uncertainty-for-biomass-remains. *See also* http://www3.epa.gov/climatechange/downloads/Biogenic-CO2-Emissions-Memo-111914.pdf
[444] http://www.politico.com/magazine/story/2015/01/obama-climate-plan-threatens-us-forests-114718#ixzz3RTcr3D71
[445] http://www.afdc.energy.gov/fuels/natural_gas_renewable.html
[446] http://www3.epa.gov/chp/documents/biomass_chp_catalog_part6.pdf
[447] *Id.*

In sum, the environmental impacts of biomass vary considerably depending on the type of fuels and technologies used. Because the Northwest principally relies on wood waste, air quality and water impacts are the region's primary concern with regards to biomass-fired electricity generation. Though only a small component of the region's current energy mix, biomass may see a growing role as a generating resource as state renewable portfolio standards become more stringent, especially if the EPA elects to exclude biogenic carbon emissions from the Clean Power Plan requirements.

Geothermal Electricity Generation

Although the region boasts promising geothermal resources, the Northwest is currently home to only three geothermal electricity plants. The largest facility is 28.5 megawatt Neal Hot Springs plant, near Vale, Oregon. A smaller 3 megawatt facility is located in Paisley, Oregon.[448] Cassia County, Idaho also hosts a 13 megawatt facility called Raft River.[449] While the installed capacity of geothermal electric plants in the Northwest is minimal, the region has areas of strong potential for geothermal development.[450] Development to this point has been limited by the high cost of exploration and the general location of geothermal resources in environmentally sensitive areas.

Geothermal energy may be used to generate electricity by one of three processes: dry steam, flash steam or binary cycle. Dry steam facilities draw from underground steam resources to drive a turbine. Flash steam plants draw pressurized hot water from underground reservoirs. The water boils into steam when the pressure is decreased. Binary cycle facilities operate with water temperatures below 212 degrees Fahrenheit, using a working fluid with a low boiling point. As the working fluid is pumped through a heat exchanger in the geothermal water, the working fluid boils to form a gas that drives a turbine. Heat from geothermal resources may be used directly in certain applications, like space heating and industrial processes. The direct use of geothermal energy does not produce electricity, but may reduce overall electricity demand by displacing electric heating appliances. The development of geothermal resources for electricity generation can result in a variety of environmental and human health impacts, including harm to water quantity and quality, air quality and visual resources.

Depending on the type of system used to generate power, geothermal electricity generation facilities may use as much as 1700 to 4000 gallons of water per megawatt-hour.[451] Binary cycle plants do not consume water, because the working fluid is heated and cooled in a closed-loop system.[452] Dry steam and flash steam systems require water inputs, using steam to drive a turbine. The steam is

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[448] *Id.*
[449] http://www.energy.idaho.gov/renewableenergy/geothermal.htm.
[450] http://www.eia.gov/todayinenergy/detail.cfm?id=3970. Based on geothermal resources in the Cascade Range, Washington has the potential to produce up to 300 MW. http://www.nrel.gov/docs/fy05osti/36549.pdf. Montana has identified 15 high temperature geothermal sites for potential development. http://deq.mt.gov/energy/geothermal/sites.mcpx. Idaho is the state with the 3rd best geothermal resource in the U.S. http://www.energy.idaho.gov/renewableenergy/geothermal.htm.
[451] http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-geothermal-energy.html#.VVDYimR4oq8.
[452] http://teeic.indianaffairs.gov/er/geothermal/impact/op/index.htm.

then cooled and condensed, a process in which hot water is exposed to ambient air in cooling towers, before being reinjected into the geothermal reservoir. Some of this cooling water evaporates into the air as steam. Water that is consumed in the cooling process must be replaced with water from an outside source to prevent subsidence of the geothermal aquifer, however, this water may be non-potable.[453] The U.S. geothermal electricity generation fleet universally employs wet-recirculating cooling technologies, which constantly condense and reuse cooling water, without discharging it back into the waterway from which it was withdrawn.[454] Because geothermal facilities do not generally result in any discharges into surface waters, the Clean Water Act has limited applicability. The underground injection control regulations of the Safe Drinking Water Act, however, may impose restrictions on geothermal facility operations.[455]

The cooling process may also result in modest air quality impacts, because geothermal water tends to have high levels of dissolved minerals that are released into the air as a result of evaporation. Air emissions are only associated with dry and flash steam geothermal plants, binary cycle facilities do not produce any emissions. The primary air pollutant caused by geothermal evaporation is hydrogen sulfide, which turns into sulfur dioxide in the atmosphere.[456] Sulfur dioxide is a component of acid rain, and can cause heart and lung disease in humans.[457] However, emissions from geothermal plants generate 30 times less sulfur dioxide than coal plants per megawatt hour of electricity produced. In addition, hydrogen sulfide abatement systems can reduce these levels to levels between 0.0002 pounds per megawatt-hour for dry steam to 0.35 pounds per megawatt hour for flash steam.[458] Geothermal electric facilities are subject to the emissions limitations established under the NAAQS and NESHAPs programs of the Clean Air Act.[459]

Finally, the siting of geothermal plants is dependent on the quality of the geothermal resource. To the extent that high-quality geothermal resources are found in otherwise undeveloped or scenic areas, geothermal plants may have wildlife impacts or cause aesthetic harms. For example, many of the best sites in the Northwest lie in the Cascade Range and high desert of Eastern Oregon and Southern Idaho, areas with limited existing human infrastructure.[460] Development of geothermal resources in these areas may have an adverse impact on wildlife and aesthetic values, similar to the impacts of solar and wind development discussed above.

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453 *Id.*
454 http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html#.VVop0mR4oq8.
455 http://www.geo-energy.org/reports/Environmental%20Guide.pdf at 21.
456 http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-geothermal-energy.html#.VVpP42R4oq_.
457 *Id.*
458 http://geo-energy.org/events/Air%20Emissions%20Comparison%20and%20Externality%20Analysis_Publication.pdf.
459 http://www.geo-energy.org/reports/Environmental%20Guide.pdf at 20-21.
460 http://www.smu.edu/~/media/Site/Dedman/Academics/Programs/Geothermal%20Lab/Graphics/SMUHeatFlowMap2011_CopyrightVA0001377160_jpg.ashx?la=en.

Geothermal electric facilities sited on public land or requiring a federal permit or license to operate may be subject to environmental analysis requirements under the NEPA.

In sum, the development of geothermal resources may have modest environmental and human health impacts, but those impacts are less significant than the environmental impacts associated with fossil fuel-fired electricity generation. Although the Northwest hosts developable geothermal resources, their development does not appear to be imminent.

Electricity Storage

Energy storage systems convert electricity into a storable form of energy at one point in time and release the energy back as electricity at a later point in time. Some storage systems, such as pumped hydro and compressed air storage systems require specific geographies to operate. Battery storage systems are not geographically dependent and can be utilized at multiple locations and for a variety of applications.

Pumped Storage

Pumped storage hydroelectric projects share many of the environmental effects that hydroelectric dams do. Pumped storage projects generate electricity by moving water between two reservoirs, an upper and lower, with the ability to store energy for later use. Open-loop pumped storage systems are located directly on existing or diverted waterways, while closed loop systems recycle water from man-made reservoirs and therefore can be located anywhere. Similar to hydroelectric projects, pumped storage produces no serious air emissions or solid waste. Closed-loop systems usually undergo more extensive construction periods and have larger land footprints than hydroelectric projects, but they face the same environmental impacts.

Closed-loop systems have fewer environmental effects because they are not directly interacting with existing waterways and aquatic habitats. The initial development and construction of the two reservoirs disrupts the environment where the project is sited, causing potential erosion and effects from construction such as noise, dust, and aesthetic impacts. Water is needed to fill the reservoirs, and replacement water is brought in as needed to counteract the natural effects of evaporation and seepage.[461]

Battery Storage

Electrochemical battery technologies convert electricity to chemical potential to store, and then convert back to electricity as needed. These technologies are smaller in scale than other storage technologies and provide shorter discharge times, anywhere from a few seconds to around six hours. Battery storage systems may be especially valuable when used in combination on-site with a renewable resource such as solar PV. Battery storage systems may be an important component of

[461] http://www.hydro.org/wp-content/uploads/2012/07/NHA_PumpedStorage_071212b1.pdf

the future power system since battery technologies are rapidly improving, manufacturing is ramping, costs are expected to decline, and the technology pairs well with solar power.

Battery technologies can be more easily sited and built than other storage technologies, but have not enjoyed widespread deployment yet due to power performance, limited lifetimes, and high system cost. Conventional batteries are composed of cells which contain two electrodes - a cathode and an anode - and electrolyte in a sealed container. During discharge a reduction-oxidation reaction occurs in the cell and electrons migrate from the anode to the cathode. During recharge, the reaction is reversed through the ionization of the electrolyte. Many different combinations of electrodes and electrolytes have been developed. Three common battery storage technologies include lead-acid, sodium-sulfur, and lithium-ion.

Lead acid batteries are the most mature of the technologies. They are the low cost solution, though they suffer from short life cycles, high maintenance requirements, and toxicity. Green Mountain Power, a Vermont public utility, is currently constructing the Stafford Hill Solar Farm and micro-grid. This project will pair 2 megawatts of solar PV with 4 megawatts of lead-acid battery storage.

Lithium-ion (Li-ion) batteries are composed of a graphite negative electrode, a metal-oxide positive electrode, and organic electrolyte with dissolved lithium ions and a micro-porous polymer separator. When the battery is charging, lithium ions flow from the positive metal oxide electrode to the negative graphite electrode, and when discharging the flow of ions is reversed.

Lithium-ion battery technology has long been used in consumer electronics and electric vehicles; and is also quickly emerging as a favored choice for grid-scale storage systems in the U.S. In the Northwest, Puget Sound Energy (PSE), Portland General Electric (PGE), and the Snohomish County Public Utility District (SnoPUD) are establishing storage projects using lithium-ion battery technology. PSE’s Glacier Battery Storage Project (2 megawatts and 4.4 megawatt-hours) will serve as a backup power source, reduce system load during high demand periods, and help integrate intermittent renewable generation on the grid. The project is expected to come on-line in late 2015. PGE’s Smart Power Project (5 megawatt) is a working smart grid demonstration. It will also test the ability of battery storage to provide dispatchable backup power, provide demand response, and integrate solar power. SnoPUD is currently installing a battery storage system comprised of three lithium-ion batteries and one flow battery. The project is being developed to improve reliability and integrate variable resources.

Typically, battery storage systems are constantly monitored for high temperatures and alarms are raised if there are issues. Battery storage often contains exotic materials which require special handling during normal operations, and particularly during emergency conditions such as fire, flooding, or earthquakes.[462] Large scale storage applications are often utility-owned and operated. These systems are governed by codes and standards, including the National Electrical Safety Code®.

[462] DOE/EPRI Electricity Storage Handbook, February 2015

The environmental impacts associated with battery storage depend on the type of battery. Lead-acid batteries are the oldest form of rechargeable battery technology; often used in automobiles, boats, planes, etc. In lead-acid battery systems, the positive electrode is comprised of lead dioxide PbO_2, the negative electrode metallic lead Pb and the electrolyte sulfuric acid. Lead and sulfuric acid are considered hazardous. Contact with sulfuric acid can burn the skin and irritate the membranes of the eyes or respiratory system.[463] Lead poisoning can cause comas, convulsions, mental retardation, seizures and even death.[464] Proper disposal of the batteries at the end of their lifecycle is very important. Lead-acid batteries are the most recycled product in the world[465]. During disposal, the battery components are separated into component parts, the lead plates and grids are smelted to be used in new batteries, and the acid electrolyte is neutralized and scrubbed to remove dissolved lead[466].

Sodium-sulfur batteries (NaS) hold potential for grid services because of their lengthy discharge period (up to 6 hours). There are several installations of the technology for grid support across the world; the largest individual installation (34 megawatts) is in Northern Japan where the system is used for wind stabilization.[467] These batteries use potentially hazardous materials – including metallic sodium – which is combustible if exposed to water. These systems require air tight doubled walled stainless-steel enclosures.[468] At the end of life, the sodium, sulfur, and sulfur poly sulfide components need to be properly disposed of and/or recycled.

Flow battery systems are large scale storage systems which have a unique construction. Unlike other battery technologies, the electrolyte material is stored in tanks, external to the electrodes. During discharge and charge, electrolyte is pumped from its container into the cell to interact with the electrodes. These systems require added measures for on-site containment of electrolyte spills. These measures may require construction of dams or berms.[469] Vanadium redox flow batteries are one type of flow battery. This is a developing technology that utilizes vanadium ions. When decommissioning, the solid-ion exchange cell membranes may be highly acidic or alkaline and are toxic.[470] The liquid electrolyte may be recycled.

Lithium-ion battery systems are the fastest growing platform for stationary storage applications. These batteries are deployed in electric vehicles, plug-in hybrid electric vehicles, and for power services such as distribution grid support, frequency regulation, and solar integration. Typical anode materials include graphite and other conductive additives. Cathodes (positive electrode) are composed of metal oxides. Chemistries include lithium manganese oxide and lithium nickel cobalt manganese oxide (Li-NCM). Electrolyte solutions are composes of lithium salt and organic solvents.

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[463] California Integrated Waste Management Board, Lead-Acid Batteries – Hazards and Responsible Use, www.ciwmb.ca.gov/Publications/
[464] Ibid.
[465] DOE/EPRI Electricity Storage Handbook, February 2015
[466] Ibid.
[467] EnergyStorage.Org
[468] DOE/EPRI Electricity Storage Handbook, February 2015
[469] DOE/EPRI Electricity Storage Handbook, February 2015
[470] Ibid.

The life-cycle of a lithium battery includes:

1. Materials extraction and processing: lithium brine extracted from saline lakes in Chile comprise the largest mass input, other materials include copper, aluminum, and other metals
2. Components manufacture: electrode coatings, subsystems
3. Product Manufacture: battery cell and battery packs
4. Product Use: grid support
5. End of life: metal recovery, landfill, incineration. [471]

The choice of battery chemistry influences the resulting environmental impacts, particularly the choice of materials for the cathode.[472] The Li-NCM cathode chemistry relies on the metals cobalt and nickel. These metals have impact potential for significant toxicity. Exposure to these metal compounds in the production, processing and use of these batteries can cause adverse respiratory, pulmonary, and neurological effects.[473] There are ways to reduce these impacts, such as substituting different materials for the cathode, and recycling of metals from the batteries. There is incentive for battery recyclers to recover lithium, and nickel from used batteries since these materials have value.

Grid connected battery storage systems may play an important role in the future power system, providing such services as electric energy time shifting, peaking capacity, ancillary series, and renewable generation firming. Environmental impacts depend on the battery technology and choice of materials and battery chemistries. Recycling battery systems at the end of life is a key component to reducing the impact of battery use in the energy industry.

GREENHOUSE GAS EMISSIONS FROM THE NORTHWEST ELECTRIC INDUSTRY

The electricity sector generates more greenhouse gas than any other industry in the United States, accounting for 31 percent of all emissions.[474] Greenhouse gases, which include components and byproducts of electricity generation such as carbon dioxide, methane and nitrous oxide (among others), impact the climate by trapping heat in the atmosphere.[475] The lifespan and behavior of each of these compounds in the atmosphere varies, so their potency is expressed in terms of their Global Warming Potential (GWP).[476] The GWP reflects each gas' ability to absorb energy over a 100-year timescale. Carbon dioxide serves as the reference, and thus has a GWP of one. Methane is considerably more potent, with a GWP of 28-36, meaning that it is 28 to 36 times more potent a

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[471] United States Environmental Protection Agency, Application of Life Cycle Assessment to Nanoscale Technology: Lithium-ion Batteries for Electric Vehicles, April 2013
[472] Ibid.
[473] Ibid.
[474] http://www3.epa.gov/climatechange/ghgemissions/sources/electricity.html
[475] http://www3.epa.gov/climatechange/ghgemissions/gases.html
[476] http://www3.epa.gov/climatechange/ghgemissions/gwps.html

greenhouse gas than carbon dioxide.[477] These two gases represent the compounds of primary concern when discussing electric industry emissions. Coal plants are the most carbon intensive generating resource, producing between 214 and 228 pounds of carbon dioxide per million British thermal units (Btu) of energy. Natural gas produces nearly half as much carbon dioxide as coal at 117 pounds per Btu. Although it has carbon emissions benefits over coal, natural gas is primarily composed of methane. As discussed above, methane leakage has the potential to negate some of the climate benefits associated with natural gas.

According to estimates from the Energy Information Administration, the Northwest electric industry was responsible for 29.4 million metric tons of carbon emissions in 2012.[478] Coal-fired electricity generators were the primary source of carbon dioxide, accounting for 20.7 million metric tons. Of the four Northwest states, Montana's carbon emissions footprint was the greatest at 15.6 million metric tons.[479] The planned retirements of several of the region's coal-fired electric plants will reduce the region's carbon footprint considerably.

A legal and regulatory framework for addressing greenhouse gas emissions is starting to take shape in the United States. The EPA has recently promulgated regulations to limit carbon dioxide emissions from the electricity sector and proposed a rule to address fugitive methane emissions from the oil and gas sector. Additionally, states have enacted Renewable Portfolio Standards (RPS) to promote the development of renewable energy resources. This section will briefly discuss these policies and their impact on greenhouse gas emissions in the Northwest.

Clean Power Plan

On August 3, 2015, the EPA issued its final rule to cut carbon emissions from the electricity sector.[480] The stated goal of the Clean Power Plan is to reduce carbon dioxide emissions from the United States electric industry by 32 percent from 2005 levels by 2030. The regulations, promulgated under § 111(d) of the Clean Air Act, allow the EPA to establish state-by-state emissions targets that states have the responsibility to comply with.[481] The rule requires states to file a state implementation plan for compliance with EPA's targets, but provides states with some flexibility in selecting the means of emissions reductions, including permitting regional cooperation and emissions trading.[482] The final rule gives states until September 6, 2016 to submit final plans or requests for extension, with a final deadline no later than September 6, 2018.[483]

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[477] *Id.*
[478] http://www.eia.gov/environment/emissions/state/
[479] *Id.*
[480] http://www2.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan
[481] http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf
[482] http://www2.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan
[483] http://www2.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan

Primarily impacted by the carbon emissions requirement in the Clean Power Plan will be coal-fired electricity generation facilities, which will likely be shuttered in favor of natural gas plants.[484] Renewable energy in the region is also likely to benefit from these regulations. With abundant hydroelectric resources and four scheduled coal plant retirements in the next decade, the Clean Power Plan's impact on the generating resource mix in the Northwest is likely to be muted.

While the EPA has issued its final rule, the fate of the Clean Power Plan is uncertain. A number of states and industry groups have lined up to challenge the EPA's authority to promulgate the regulations under the Clean Air Act, and it seems likely that a protracted legal battle will ensue.[485] The ultimate impact on the Northwest electric industry will be determined by the outcome of the challenge.

Fugitive Methane Emissions

Concerns about the environmental impacts of methane emissions led the Obama Administration, on January 14, 2015, to announce plans to cut methane emissions from the oil and gas industry by 40 percent to 45 percent from 2012 levels by 2025.[486] To accomplish these reductions, the President directed the EPA to propose new methane and volatile organic compound (VOC) emissions regulations. The EPA issued its proposed rule on August 18, 2015 as part of the New Source Performance Standards program of the Clean Air Act.[487] Under the proposed rule, the EPA would establish methane emissions standards for a broad array of oil and gas extraction and transportation equipment, including well sites, compressors, pneumatic controllers, and pneumatic pumps, among others.[488] The EPA estimates that these regulations, once finalized, will reduce methane emissions by 340,000 to 400,000 tons in 2025.[489] The primary impact of these regulations on the Northwest electric industry will come from increased fuel prices that reflect the cost of compliance.

Renewable Portfolio Standards

Renewable portfolio standards (RPS) are regulatory mandates enacted by individual states to increase the development and generation of eligible renewable resources. A RPS legally obligates a qualifying retail electricity supplier to meet a specified amount of its electricity sales from the generation of renewable energy resources.[490] A RPS usually takes the form of a target that includes

[484] http://www.washingtonpost.com/news/energy-environment/wp/2015/10/14/why-natural-gas-is-catching-up-to-coal-in-powering-u-s-homes/
[485] http://www.utilitydive.com/news/colorado-will-join-legal-challenge-to-epas-clean-power-plan/404892/
[486] http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1
[487] http://www3.epa.gov/airquality/oilandgas/pdfs/og_nsps_pr_081815.pdf
[488] *Id.*
[489] *Id* at 20.
[490] Most state RPS are based on energy generated (megawatt hours) and not installed capacity (megawatts). While capacity standards also encourage renewable development, they do not necessarily lead to the generation of those developed renewable resources. Iowa and Texas are the only states with a capacity-based standard. Kansas is also unique in that its standard is based on a percentage of peak demand.

a percentage of sales that must be met by a certain date. Currently, 29 states have adopted a RPS, while an additional eight states have similar, but voluntary, renewable goals.[491] A state will pursue a RPS or goal to encourage and increase the development of renewable resources, diversify the resource portfolio mix, boost economic development, and reduce greenhouse gas emissions. There is no overarching federal RPS policy in place.

Each state has defined what an eligible renewable resource is for compliance with its RPS. These resources can come from different vintages (for example, some states allow for certain resources that were built prior to the enactment of the RPS to count towards compliance), can have minimum or maximum requirements, and can allow for a resource to count as more than one credit toward compliance (multiplier) to encourage development of that particular resource.

A megawatt hour that is generated from an eligible renewable resource is called a renewable energy credit[492] (REC) - one megawatt hour is equal to one REC. In general, power from an eligible renewable resource can be sold with and without the accompanying REC. For example, utility A can sell the power it generates from its renewable resource to utility B and sell the credit (RECs) for that generation to utility C. Power that has been stripped of its REC is known as “null” or “brown” power. Another term commonly used to describe a REC that is sold without the generation is “unbundled”; conversely the REC sold with the generation is “bundled.” RECs can be sold and traded through the REC market, which in the West is governed by the Western Renewable Energy Generation Information System (WREGIS). States have different rules concerning whether (or what percentage of) RECs must be accompanied by the generation.

In the Pacific Northwest, Montana, Washington, and Oregon adopted state renewable portfolio standards in the mid 2000’s. The RPS “targets” in the Pacific Northwest are fairly consistent with the rest of the nation. One of the biggest outliers is California, who in October 2015 revised its standard and adopted a 50 percent RPS by 2030. Each RPS is detailed and unique in its requirements, eligibilities, and allowances. Table I-1 consolidates at a high level many of the details, nuances, and unique qualities that make up the Pacific Northwest states’ RPS policies.

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http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx#sd

[491] Source: Information maintained and produced by the DSIRE. http://www.dsireusa.org/resources/detailed-summary-maps/

[492] Alternatively called a certificate.

Table I - 1: RPS in the Pacific Northwest

	Montana	Washington	Oregon
Standard	15% in 2010	15% in 2020	25% in 2025
Date of Adoption	2005	2006	2007
Sourcing Limits of Eligible Resources	Located in MT; or deliverable to MT	Located in PNW; or deliverable to WA	Located in WECC
Technology Minimums	—	—	20 MW AC Solar PV by 2020
Banking	2 years	1 year	Unlimited
Credit Multipliers	—	Distributed generation x 2; union apprenticed labor x 1.2	Solar PV x 2 (developed before 2016)

During the past several state legislative sessions in Montana, Washington and Oregon, there have been efforts to revise the state RPS. Some of these efforts seek to strengthen the targets by raising the percentage or moving the compliance dates forward, while others have the effect of weakening the RPS (for example by broadening the list of eligible resources to include certain existing resources and therefore lessening the necessity to develop new renewable resources). The following sections summarize each state's RPS as it stands today. For more detailed accounts on each state's RPS, the DSIRE website is a resource that catalogs all renewable and energy efficiency state policies.

Montana

Montana adopted the Montana Renewable Power Production and Rural Economic Development Act in 2005. Included in this policy is a renewable portfolio standard of 5 percent in 2008, 10 percent in 2010, and 15 percent in 2015 (and each year thereafter) for its investor owned utilities (IOUs) and competitive electricity suppliers serving 50 or more customers. Eligible resources must either be located in Montana or directly deliverable via existing transmission routes into Montana. A REC can be used for compliance in the year it was generated, or carried over (banked) for compliance for two subsequent years before it is retired. Failure to comply with the RPS in Montana results in a $10 per megawatt hour administrative penalty. Montana has a cost cap built into its policy that precludes the utility from having to meet the annual target if the cost of purchasing or procuring a REC is greater than 15 percent of the cost of any alternative resource.

Montana's RPS includes a provision for community renewable energy projects (CREPs), which are locally owned renewable projects less than or equal to 25 megawatts installed nameplate capacity. This requirement obligates utilities (competitive electricity suppliers are exempt) to enter into contracts with CREP projects for the REC and its associated output. For compliance years 2012 through 2014, utilities must have CREP contracts totaling at least 50 megawatts. In compliance year

2015 and each year thereafter, the CREP requirement is 75 megawatts. The purpose of the CREP requirement is to stimulate economic development within Montana, particularly in rural areas.

Washington

Washington adopted the Renewable Energy Standard by way of ballot initiative 937 in 2006. Washington's targets for renewable resources include 3 percent by 2012, 9 percent by 2016, and 15 percent by 2020 (and each year thereafter) for its utilities serving 25,000 customers or more. In addition to renewable resource requirements, Washington's standard includes separate energy efficiency targets. Eligible renewable resources can be located anywhere within the Pacific Northwest region, or delivered to Washington from outside the region on a real-time basis. For example, PacifiCorp's wind projects in Wyoming are eligible to meet RPS compliance in Washington. Washington's banking rules allow for a REC to be used within the year it was generated, or one year prior or subsequent. For example, if a REC is generated in 2015, it can be used for compliance year 2014, 2015, or 2016, and it expires in 2017. Washington allows for two multipliers in its standard. For eligible distributed generation projects less than five megawatts, the RECs generated can be multiplied by two (doubled) and if union-apprenticed labor is used in the development of an eligible renewable project, the RECs generated can be multiplied by 1.2. Failure to comply with the RPS in Washington triggers an administrative penalty of $50 per megawatt hour.

In addition to meeting the RPS by generating or procuring RECs, Washington has two alternative means of compliance. A utility is considered to be in compliance with the annual target if it has spent 4 percent of its retail revenue requirement on the incremental cost of the REC and/or if the utility experiences zero or negative load growth, it is not required to spend more than 1 percent of its retail revenue requirement on RECs.

Oregon

Oregon adopted the Renewable Portfolio Standard in 2007. Oregon defines its targets by three different utility sizes. Large utilities serving more than 3 percent of the state's load have targets of 5 percent by 2011, 15 percent by 2015, 20 percent by 2020, and 25 percent by 2025. Medium utilities serving between 1.5 percent and 3 percent of the state's load have a target of 10 percent by 2025. Finally, small utilities serving less than 1.5 percent of the state's load have a target of 5 percent by 2025. Eligible renewable resources can be located anywhere within the Western Electricity Coordinating Council (WECC) region. Oregon has the most lenient banking rules of all the Pacific Northwest states, allowing for unlimited banking that can be used indefinitely for future compliance years. The Oregon RPS has a technology carve-out, or minimum, that states that together the large utilities must procure a total of 20 megawatts (alternating current) solar photovoltaic by 2020. If the solar PV is developed by 2016, the RECs generated can be multiplied by two (doubled). Like Montana and Washington, Oregon utilizes a cost cap in its policy in which the cost of compliance cannot exceed 4 percent of the utility's annual revenue requirement.

An alternative form of compliance in Oregon is the alternative compliance payment, which is a dollar per megawatt sum that is paid in lieu of purchasing or procuring RECs. For the 2014/2015 compliance year, the alternative compliance payment was $110 per megawatt hour.[493]

REGULATORY COMPLIANCE ISSUES AFFECTING EXISTING NORTHWEST GENERATING PLANTS

Numerous federal rulemakings intended to reduce safety risks or environmental impacts of power generation have been adopted in recent years or are currently being proposed. Compliance with these rules often requires modifications to the design or operation of power generation facilities. These modifications may entail capital investment in pollution control and safety equipment and increased operating and maintenance costs. Plant performance and operational characteristics may also be affected.

Environmental Protection Agency (EPA) rulemakings with potential financial or operational impacts on existing Northwest generating units include the Regional Haze Rule, the Mercury and Air Toxics Standards for Utilities (MATS), the Coal Combustion Residuals Rule (CCR), the Cooling Water Intake Structure Rule, the Effluent Guidelines for Steam Power Generation and the proposed Carbon Pollution Standards for Existing Power Plants (Clean Power Plan). A rulemaking of considerable significance in the eastern part of the country, the Cross-state Air Pollution Rule (CSAPR) does not affect Western plants. These rulemakings primarily affect coal-fired generating units, though nuclear and gas-fired combined-cycle plants may incur some, probably minor, costs of compliance with the Cooling Water Intake Structure Rule and the Effluent Guidelines for Steam Power Generation.

A set of rulemakings in response to the severe damage to the Fukushima Dai-ichi nuclear power station resulting from the 2011 Tohuku earthquake and subsequent tsunami are being issued by the Nuclear Regulatory Commission. These rules will require additional capital investment at the region’s only nuclear facility, Columbia Generating Station.

Table I-2 summarizes the key characteristics of the major Pacific Northwest generating units potentially affected by federal regulatory compliance requirements.

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[493] http://programs.dsireusa.org/system/program/detail/2594

Table I - 2: Pacific Northwest electric generating units potentially significantly affected by recent and prospective environmental and safety rulemaking compliance requirements

Plant	Type	Location	Capacity (MW_{net})	Year of Service	Existing Air Pollution Controls and Principal Target Pollutants	Note
Boardman	Coal-steam	Boardman, OR	585	1980	New generation low-NOx burners and overfire air (NOx) Low-sulfur coal (SOx) Dry sorbent injection (SOx) Activated carbon injection (Hg) ESP (Particulates, SOx, Hg)	Scheduled to cease coal-firing by end of 2020.
Centralia (TransAlta Centralia)	Coal-steam	Centralia, WA	Unit 1 - 670 Unit 2 - 670	Unit 1 - 1973 Unit 2 - 1975	Low-NOx burners, overfire air, SNCR (NOx) Coal blending (SOx) Activated carbon injection (Hg) FGD (SOx, Hg)	One unit to retire in 2020; second unit to retire in 2025.
Colstrip	Coal-steam	Colstrip, MT	Unit 1 - 307 Unit 2 - 307 Unit 3 - 740 Unit 4 - 740	Unit 1 - 1973 Unit 2 - 1975 Unit 3 - 1976 Unit 4 - 1984	U1 & U2 Low-NOx burners (NOx) U3 & U4 Low-NOx burners w/overfire air (NOx) Bromine coal treatment (All units); Activated carbon injection (all units); FGD additive (U3 & U4) (Hg) Wet FGD (all units) (SOx, Hg)	
J. E. Corette	Coal-steam	Billings, MT	153	1968	Low-sulfur coal (SOx) Activated carbon injection (Hg) ESP (Particulates, Hg)	Scheduled to retire in August 2015
Jim Bridger	Coal-steam	Point of Rocks, WY	Unit 1 - 531 Unit 2 - 523 Unit 3 - 527 Unit 4 - 530	Unit 1 - 1974 Unit 2 - 1975 Unit 3 - 1976 Unit 4 - 1979	Low-NOx burners (NOx) SCR (NOx) ACI (Hg) Wet FGD (SOx, Hg) ESPs (Particulates)	
North Valmy	Coal-steam	North Valmy, NV	Unit 1 - 254 Unit 2 - 268	Unit 1 - 1981 Unit 2 - 1985	Low-NOx burners (NOx) Dry FGD (U2) SOx Fabric filters (Particulates)	
Columbia Generating Station	Boiling Water Reactor	Richland, WA	1,140	1984		

Regulatory Compliance Actions with Potentially Significant Effects for Existing Northwest Generating Units

The following regulatory compliance actions may have a significant effect on existing generating units in the Pacific Northwest.

National Ambient Air Quality Standards

The Clean Air Act of 1970 (subsequently amended in 1977 and 1990) requires the EPA to establish ambient air quality standards for common and widespread air pollutants. The EPA has established standards for six "criteria pollutants". These are particulate matter[494], ozone, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead. Two levels of standards are established: Primary standards, based on human health impacts and Secondary standards, based on environmental and property damage. The standards are established based on scientific evidence, and reviewed every five years.

The National Ambient Air Quality Standards (NAAQS) are attained and maintained through emission reduction strategies set forth in State Implementation Plans (SIPs). The EPA designates counties and other areas as "attainment" or "non-attainment" based on data supplied by the states. If insufficient monitoring data are available, areas may receive interim designations of "unclassifiable" (insufficient monitoring data) or "unclassifiable/attainment" (insufficient monitoring data, but expected to be in attainment). The states then develop a SIP designed to bring non-attainment areas into compliance by deadlines established by EPA. The SIPs are reviewed and approved by the EPA. The SIPs may require existing power generation facilities to install Best Available Retrofit Technology (BART) to control specific pollutants as part of the plan to bring non-attainment areas into compliance. Costs of compliance are considered in developing the implementation plans. Non-attainment areas, once brought into compliance, are designated "maintenance areas" and the SIPs must include provisions for maintaining these as attainment areas. (The general aspects of this implementation process are used for most EPA rulemakings described in this section.)

Coal-fired power generating facilities are important potential sources of "criteria pollutants," including sulfur dioxide, nitrogen oxides and particulates. Natural gas-fired power plants are potential sources of nitrogen oxides. Reduction of sulfur dioxide, nitrogen oxides and particulate emissions is accomplished by fuel selection, combustion controls and post-combustion (flue gas) cleanup. All Northwest coal and gas-fired units are currently in compliance with NAAQS.

Regional Haze Rule

Regional haze is geographically widespread impairment of atmospheric clarity, visual range or coloration. Regional haze is produced by airborne fine particulate matter and secondary products of

[494] Particulate regulations address two classes of particulates: $PM_{2.5}$ (fine, less than 2.5 microns in diameter) and PM_{10} (coarser, less than 10 microns in diameter).

nitrogen oxides, sulfur dioxide and other air pollutants. Though episodic natural events such as wildfire and dust storms may increase regional haze on a short-term basis, certain power generation and industrial facilities and motor vehicles are chronic sources of the pollutants that create regional haze.

The 1977 amendments to the Clean Air Act created a program to restore and protect visibility in national parks, wilderness areas and other visually sensitive areas. The 1990 amendments to the Clean Air Act specifically addressed regional haze and established 2007 as the deadline for states to submit implementation plans for regional haze control. The EPA adopted the Regional Haze Rule in 1999 for the purpose of improving visibility in 156 national parks and wilderness areas. The Regional Haze Rule is generally implemented through SIPs. While the majority of states opted to establish SIPs for control of regional haze, several, including Montana, opted not to prepare a regional haze SIP. In these cases, the EPA prepares a Federal Implementation Plan (FIP).

The 1999 Regional Haze Rule includes provisions for a comprehensive analysis of the regional haze state implementation plans every 10 years and a progress report every five years. Should progress in reducing regional haze not be satisfactory, installation of additional controls on electric generating units may be required.

Reduction in emissions of particulates and precursors of haze-inducing compounds from power generation facilities is typically accomplished by installation of controls for sulfur dioxide, nitrogen oxides and particulate matter. The technologies for haze control are generally similar to those required for compliance with NAAQS, although more stringent levels of control may be required.

Boardman, Centralia 1 & 2, and North Valmy 1 & 2 are currently in compliance with the Regional Haze Rule. Additional controls are being installed, or are scheduled for installation, at Colstrip 1 & 2 (2017), Bridger 1 (2022), Bridger 2 (2021), Bridger 3 (2015), and Bridger 4 (2016). The future progress provision of the Regional Haze rule is expected to require additional nitrogen oxide controls on Colstrip 3 & 4 by 2027[495]. Future control upgrades might be required on North Valmy 1 and 2, depending on future progress[496].

Mercury and Air Toxics Standards

The Mercury and Air Toxics Standards (MATS) are intended to reduce air emissions of heavy metals including mercury, arsenic, chromium, and nickel, and acid gasses including hydrochloric (HCl) and hydrofluoric acid (HF). These pollutants, released during the combustion of certain coals or oils, are known, or suspected of, causing cancer and other serious health effects.

The EPA issued the Clean Air Mercury Rule (CAMR) in March 2005 to reduce mercury emissions under a cap and trade program. However, the CAMR was vacated in February 2008 with the court finding the rule inconsistent with the Clean Air Act. In December 2011, the vacated CAMR was

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[495] Portland General Electric. 2013 Integrated Resource Plan. March 2014. P 123.
[496] Idaho Power Company. 2011 IRP Update: Coal Unit Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants. February 2013.

replaced by Final New Source Performance Standards (NSPS) for the release of mercury and other air toxics from new and existing coal and oil-fired steam-electric power plants. Updates to MATS for new plants were finalized in March 2013. Subsequent updates pertain to reporting requirements and monitoring and testing requirements relating to startup and shutdown of new coal and oil-fired power plants. The final rule sets numerical limits for release of mercury and other air toxics. Compliance requires use of maximum achievable control technology though alternative compliance measures, including a more restrictive sulfur dioxide emission limit in lieu of the hydrochloric acid limit, are allowed. The standards for existing units take effect in 2015 with a one-year extension available at state option and a second year extension available under extreme circumstances. MATS is estimated to reduce mercury emissions from coal-fired power plants by 90 percent and reduce acid gas emissions by 88 percent. The rule is also projected to reduce sulfur dioxide emissions[497].

MATS control strategies vary, depending upon coal qualities, existing pollutant control technologies, unit operating conditions, and ash disposal practices. Combinations of controls are frequently employed. Some capture of mercury occurs in wet flue gas desulfurization systems. This can be enhanced by treating the coal with a mercury oxidizing agent, but is often not sufficiently effective to meet MATS emission standards. Additional controls often consist of injection of powdered activated carbon (PAC or ACI) or proprietary non-carbon dry sorbents into the flue gas in combination with treatment of the coal with an oxidizing agent. Mercury and other heavy metals and their compounds are absorbed onto the particles which are captured by the plant's particulate control or flue gas desulfurization (FGD) system. A downside of this approach may be a reduction in the market value of fly ash (a key ingredient in concrete) as a result of increased mercury levels and heavy metal contamination.

Acid gasses are neutralized by dry injection of sorbents (DSI) such as hydrated lime into the flue gas stream with downstream capture of the particles in the plant's particulate control system.

Because of variations in coal composition and type of FGD, particulate controls and instrumentation that may already be installed on a unit, the extent of retrofit required for MATS compliance varies widely. The MATS potentially affect all power plants of 25 megawatts capacity or greater that are fired by coal, petroleum coke, or oil. Among major Northwest coal units, Boardman[498], Centralia 1 & 2[499], and North Valmy 2 are in compliance. Plants needing additional control or monitoring equipment to comply with MATS include Bridger 1 – 4 (activated carbon injection), Colstrip 1 - 4 (addition of sieve trays to the existing wet FGD systems to improve particulate capture) and North Valmy 1 (dry sorbent injection for acid gas control).

[497] U.S. Environmental Protection Agency, Final Mercury and Air Toxics Standards (MATS) for Power Plants, http://www.epa.gov/mats/actions.html; Resources for the Future. Mercury and Air Toxics Standards Analysis Deconstructed: Changing Assumptions, Changing Results. April 2013.

[498] PGE Boardman Plant Air Emissions (portlandgeneral.com). Boardman is also in compliance re: NOx and SO2 emissions

[499] SWCAA Permit No. SW98-8-R4

A federal appellate court upheld the new mercury and air toxics standards in the face of a number of challenges.[500] The U.S. Supreme Court accepted petitions for further review from the State of Michigan, the Utility Air Regulatory Group, and the National Mining Association. The U.S. Supreme Court heard oral arguments in March of 2015[501] and in June reversed the federal appellate court ruling with a 5-4 decision, finding that the EPA adopted MATS without properly considering industry compliance costs. [502] Although the ultimate fate of the MATS rule will be decided by the D.C. Circuit on remand, many utilities have already taken steps to comply with the EPA's standards.[503]

Coal Combustion Residuals

Coal combustion residuals (CCRs) include boiler bottom ash, fly ash (ash carried in the flue gas), boiler slag and products of flue gas desulfurization. As produced, these may be in dry or slurry form and contain varying concentrations of toxic substances originally present in the coal. Nationwide, about 40 percent of CCRs are recycled for concrete, road fill, and other purposes. The remainder is transferred to impoundments or dewatered and disposed in landfills, most on-site. CCRs have historically been exempt from federal regulation under an amendment to the Resource Conservation and Recovery Act (RCRA). Concerns rising from groundwater contamination, blowing of contaminants into the air as dust, and catastrophic impoundment failure led the EPA in June 2010 to propose regulation of the disposal of these materials. The EPA Administrator signed the final rule establishing technical requirements for CCR landfills and surface impoundments on December 19, 2014, with an effective date of October 19, 2015.[504].

The final rule defines CCRs as non-hazardous waste, regulated under Section 316(d) of the RCRA. The rule establishes minimum federal criteria for both existing and new CCR landfills, surface impoundments and expansions to existing landfills and surface impoundments. The criteria include structural integrity requirements and periodic safety inspections for surface impoundments; groundwater monitoring requirements; groundwater remediation requirements where contamination has been detected; location and design requirements for new CCR landfills and surface impoundments; operating, record keeping and notification criteria; and, provisions regarding inactive units. The EPA anticipates that the new CCR regulations will be implemented through revision to state Solid Waste Management Plans. The rule does not affect CCRs determined to be beneficially used or CCRs disposed in coal mines.

EPA is finalizing national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and lateral expansions. These criteria consist of location restrictions, design and operating criteria, groundwater monitoring, corrective action for existing groundwater

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[500] *White Stallion Energy Center, LLC v Environmental Protection Agency*, United States Court of Appeals for the District of Columbia, No. 12-1100 (April 15, 2014).
[501] *Michigan v EPA* No. 14-46, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-46.htm; *Utility Air Group v. EPA*, No. 14-47, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-47.htm; *National Mining Assn v. EPA*, No. 14-49, http://www.supremecourt.gov/search.aspx?filename=/docketfiles/14-49.htm.
[502] http://www.ibtimes.com/supreme-court-rules-against-epa-mercury-air-toxics-standards-us-coal-plants-1985841
[503] http://www.utilitydive.com/news/what-the-supreme-court-mats-ruling-means-for-utilities-and-the-epa-clean-po/401707/
[504] http://www.gpo.gov/fdsys/pkg/FR-2015-07-02/pdf/2015-15913.pdf

contamination, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements.[505] The rule requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances. It also requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Finally, those CCR surface impoundments that do not receive CCR after the effective date of the rule, but still contain water and CCR will be subject to all applicable regulatory requirements, unless the owner or operator of the facility dewaters and installs a final cover system on these inactive units within three years from publication of the rule.

All coal plants will be subject to the inspection and reporting requirements of the rule. The incremental cost of these requirements is not expected to be significant. Landfill disposal is used at Boardman, Centralia and North Valmy, so it is unlikely that significant additional costs will be incurred for CCR compliance at these plants.

More costly structural modifications are expected to be required at Colstrip and Jim Bridger where impoundments are used for CCR disposal. Nationwide, it is expected that most plants using impoundment disposal will shift to dry landfill disposal[506]. This will typically require the addition of dewatering equipment, slurry transportation facilities, landfill expansion and impoundment decommissioning. Puget Sound Energy (PSE), a co-owner of Colstrip 1 and 2, in its 2013 IRP estimated the costs for Colstrip to comply with the various CCR rules under consideration at the time. PSE assumed that installation of an on-site dry ash system (ash slurry dewatering system) would be required by 2018 for compliance with a Subtitle D (non-hazardous) rulemaking[507]. Portland General Electric (PGE), a co-owner of Colstrip 3 and 4, in its 2013 IRP plans on lining of the existing slurry disposal ponds by 2020.

No specific CCR compliance actions for Jim Bridger are identified in the draft PacifiCorp 2015 IRP case fact sheets[508], though all cases include the cost of meeting known and assumed compliance obligations for CCR (and other) rules. Idaho Power Company, a co-owner of Jim Bridger in its 2013 Coal Unit Investment Analysis assumed that CCR disposal at Jim Bridger would be shifted to landfills in 2014[509], though no estimate of compliance cost was provided. In 2013 the EPA completed a survey of above ground impoundments containing coal combustion residuals, rating both the hazard potential and structural integrity. The Bridger impoundments were rated as "significant"

[505] Environmental Protection Agency. Pre-Publication Version of Coal Combustion Residuals Final Rule. December 19, 2014.
[506] Power Engineering. "The Coal Ash Rule: How the EPA's recent ruling will affect the way plants manage CCRS". February 2015.
[507] At the time, CCR options under consideration included treatment as hazardous and non-hazardous material. The non-hazardous option was chosen in the final rulemaking.
[508] PacifiCorp. 2015 IRP Handout – Core Case Fact Sheets with Draft Results. November 14, 2014.
[509] Idaho Power Company. 2013 IRP Coal Study Presentation "Coal Unit Investment Analysis".

hazard and in “fair” condition[510]. The cost of structural deficiency remediation has not been reported but would be incurred irrespective of future plant operation.

The incremental O&M costs of shifting to landfill disposal are likely to be minor and not substantially affect plant dispatch.

Cooling Water Intake Structures

Water withdrawal from surface water bodies may result in the injury or death of aquatic organisms by heat, chemicals or physical stress as a result of impingement on intake screens or entrainment in the intake water. Under the authority of the Clean Water Act Section 316(b), the EPA in August 2014 concluded a multiphase rulemaking process with the publication of the National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities; Final Rule,[511] effective October 14, 2014. The purpose of the rule is “to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities for the withdrawal of cooling water from waters of the United States.”

The general rule applies to existing power generation and industrial facilities withdrawing more than two million gallons per day and using at least 25 percent of withdrawn water for cooling purposes. Compliance is based on the Best Technology Available (BTA) for minimizing adverse environmental impacts. Separate standards apply to impingement mortality and entrainment. Impingement mortality standards consist of implementation of BTA, defined as any one of seven alternatives. These include closed-cycle recirculating cooling systems. Entrainment standards apply to cooling water intake structures having average intake flows of 125 million gallons per day, or more. An Entrainment Characterization Study is required for these facilities. Compliance requirements are then established on a case-by-case basis, based on the permitting agency’s determination of BTA for entrainment reduction.

The rule will be implemented through the National Pollutant Discharge Elimination System (NPDES) permit program as NPDES permits are renewed. Permit renewal applications submitted after July 2018 (45 months following the effective date) will require full and complete studies. Applications due before this date may request that certain studies be submitted later on an agreed-upon schedule because of the time needed to complete the monitoring and analysis required for these studies. Interim BTA requirements must be proposed in these applications, however.

Any impingement or entrainment of a federally listed species is considered a taking under the Endangered Species Act, and will require a taking permit or Incidental Take Statement provided through a Fish and Wildlife Service or National Marine Fisheries Service biological opinion.

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[510] US EPA letter of August 13, 2013 to Nathan Graves Safety of Dams Engineer, Wyoming State Engineers Office.
[511] U.S. EPA, Water: Cooling Water Intakes (316b), http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/; 40 C.F.R. Parts 122 and 125

All major Northwest coal, nuclear and gas combined-cycle generating units are equipped with closed-cycle recirculating cooling systems and are therefore likely to be in compliance with the impingement standards. Boardman is the only major thermal unit with cooling water intake exceeding 125 million gallons per day and potentially subject to entrainment standards. However, the Boardman NPDES does not expire until April 2023 so an entrainment analysis and BTA recommendations would only be required if the plant were converted to a biomass-fired facility and continued operation beyond 2020. Moreover, if the converted plant, as contemplated, operated only during peak periods, intake flows may drop below the 125 MMgpd annual average trigger for entrainment regulation.

Although in compliance with the EPA's new regulations, the CGS's cooling water intake structure is subject to some controversy. The structure design dates from the late 1970s, prompting the National Marine Fisheries Service and environmental groups to recommend during the § 402 NPDES permit renewal process that the CGS modify its intake structure design to comply with modern standards of protection for aquatic organisms.[512] Washington regulators renewed the permit on September 30, 2014, against the advice of the National Marine Fisheries Service, which argued that the CGS's intake structures fail to employ BTA and represent a risk to juvenile salmon. Environmental organizations filed suit in Washington State Superior Court on Oct. 30, 2014. The environmental plaintiffs' claims include an assertion that the CGS's water intake structure does not employ BTA and should be modernized. The suit is pending. A resolution in favor of the plaintiffs could result in significant costs for the CGS.[513]

Effluent Guidelines for Steam Electric Power Generation

In June 2013, the EPA proposed revisions to its effluent regulations for steam electric power generators pursuant to its authority under the Clean Water Act. The EPA issued its final rule on September 30, 2015, which will become effective 60 days after it is published in the Federal Register.[514] The revisions strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants associated with coal-fired electricity generation, including mercury, arsenic, lead and selenium, from steam electric plants into surface waters. The region's existing coal plants are the only facilities likely to be significantly impacted by the regulations.

The EPA first adopted its regulations for steam electric power generation facilities in 1974, subsequently amending them in 1977, 1978, 1980, and most recently in 1982. In the years since they were last revised, new and shifting waste streams from coal steam-electric units have resulted in increasing levels of pollutant discharges; levels that the EPA estimates currently account for 50 percent to 60 percent of all toxic pollutants discharged into surface waters by regulated industries.[515] Those pollutants can cause harm to human life as well as fish and wildlife, and the toxic materials

[512] http://pbadupws.nrc.gov/docs/ML1409/ML14091A228.pdf
[513] http://www.tri-cityherald.com/incoming/article32204469.html
[514] http://www2.epa.gov/sites/production/files/2015-09/documents/steamelg_2040-af14_finalrule_preamble_2015-09-30_prepub.pdf
[515] Federal Register Vol. 78, No. 110, June 7, 2013 at 34435, *available at*: http://www.gpo.gov/fdsys/pkg/FR-2013-06-07/pdf/2013-10191.pdf.

can build up in sediments. Many of those discharges are the result of the installation of air pollution control technologies that utilize water for capturing and transporting air pollutants and precursors. In March 2012, the District Court of the District of Columbia approved a consent decree between the EPA and environmental organizations (Defenders of Wildlife and the Sierra Club), which obligated the EPA to take final action on steam electric effluent guidelines no later than January 31, 2014.[516] That deadline for final EPA action was extended by mutual agreement of the parties until September 30, 2015.[517]

The regulations apply to the steam electric power generating point source category, which includes thermal generators using fossil or nuclear fuels, and limits discharges associated with flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. Coal and petroleum coke-fueled generators are the most likely to be impacted by the proposed rule, because the higher volume waste streams that the rule proposes to regulate originate from flue gas pollution control systems and ash handling systems. Nuclear and gas-fired combined cycle plants may be affected to a minor degree because the rule also addresses metal cleaning and other low volume wastes that might originate from these plants. Because of the low volume of these wastes, the compliance costs for nuclear and gas combined-cycle plants are expected to be minimal.

The EPA intends that the effluent limitations guidelines regulations for steam electric generators will operate in conjunction with its coal combustion residuals (CCR) rule under the Resource Conservation and Recovery Act (RCRA). That rule regulates the disposal of fly ash, bottom ash, and flue gas desulfurization (FGD) wastes not used for beneficial purposes.

The EPA's regulations restrict the discharge of pollutants associated with coal combustion and emissions controls from existing plants on the basis of the Best Technology Economically Achievable. The limitations vary depending on waste stream, but generally place a numeric limit on total suspended solids, and either establish a numeric limit or prohibit entirely the discharge of mercury, arsenic, selenium, nitrate and nitrite.[518] New facilities are required to meet more stringent standards, including zero-discharge requirements for fly ash and bottom ash transport water and flue gas mercury controls, and numeric standards for mercury, arsenic, selenium and total dissolved solids in other waste streams.[519] As an added benefit, the proposed regulations provide an incentive for coal plants to reduce water use in their air pollution control systems, so water withdrawals will decrease accordingly.[520] Steam electric facilities are required to comply with the new regulations upon renewal of their NPDES permits. The permitting authority will determine the precise date of

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[516] Consent Decree, *Defenders of Wildlife and Sierra Club v. Lisa P. Jackson* (DC Cir. March 19, 2012), *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/consentdecree.pdf.
[517] Consent Decree Modification and Joint Stipulation, *Defenders of Wildlife and Sierra Club v. Lisa P. Jackson* (DC Cir., April 27, 2014), *available at:* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Consent-Decree-Extension-4-April-7-2014.pdf.
[518] http://www2.epa.gov/sites/production/files/2015-09/documents/steamelg_2040-af14_finalrule_preamble_2015-09-30_prepub.pdf at 18-19
[519] *Id* at 19-20
[520] *Id* at 3

compliance, but EPA's regulations require that it be as soon as possible within the next permit cycle after November 1, 2018, but before December 31, 2023.[521]

All of the Northwest's coal plants employ some, if not all, of the technologies and processes targeted by the EPA's proposed effluent limitations guidelines for steam electric generation. For example, all of the coal plants in the Northwest employ wet or wet and dry bottom ash transport handling systems, one of the regulated waste streams under the proposed rule, while only two facilities use wet flue gas desulfurization systems.[522]

Based on the EPA's estimates and the fact that there are limited affected facilities in the Northwest, the region's compliance costs are not likely to be significant.[523] J.E. Corette was retired in August 2015. Boardman and Centralia are scheduled to cease burning coal or retire in the next decade, Boardman in 2020 and Centralia in 2020 (unit one) and 2025 (unit two). Boardman's NPDES permit extends through 2023, so it will not be required to comply with the new regulations, unless it transitions to biomass and continues operations. Centralia is expected to receive a renewal of its NPDES permit in 2015, which will remain in force through 2020. For that reason, Centralia's Unit Two may be affected by the new regulations. Colstrip, Jim Bridger and North Valmy are "Zero Liquid Discharge" (ZLD) facilities and unlikely to be affected. Some of the region's gas-fired plants and the Columbia Generating Station might be affected by the provisions of the proposed regulation regarding metal cleaning waste streams. Metal cleaning wastes are a very minor waste stream, however, so compliance is unlikely to have a major financial impact.

Fukushima Upgrades

On March 11, 2011 the magnitude 9.0 Tohoku earthquake struck off the coast of the Japanese island of Honshu, the site of the six-unit Fukushima Dai-ichi nuclear power plant. Grid power was lost and units 1, 2 and 3 automatically shut down (Units 4, 5 and 6 were offline for refueling and maintenance). Emergency diesel generators supplied power to critical systems and plant conditions were stabilized. About 40 minutes following the earthquake a tsunami estimated at 46 feet in height inundated the plant, causing extensive damage and the loss of all emergency power to units 1 through 4. One diesel-generator supplying power to units 5 and 6 continued to operate, enabling these units to be maintained in safe shutdown. Steam and battery-power safety systems at Units 1, 2 and 3 failed within 24 hours. Emergency core cooling was subsequently lost and all three reactors overheated, causing fuel damage, coolant system over-pressurization and hydrogen leaks to the containment. Operators were unable to operate the containment venting systems, leading to containment over-pressurization and hydrogen explosions that destroyed the containment buildings

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[521] http://www2.epa.gov/sites/production/files/2015-09/documents/steamelg_2040-af14_finalrule_preamble_2015-09-30_prepub.pdf at 86.
[522] EPA Technical Questionnaire Database, 2010, *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/questionnaire.cfm. *See also* EPA, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA-821-R-13-002 (April 2003) at 4-22 – 4-26, *available at*: http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf
[523] http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/SteamElectric_RIA_Proposed-rule_2013.pdf

of Units 1, 2 and 4. Radioactive contamination spread over large areas requiring relocation of tens of thousands of people. The reactors were eventually stabilized but work continues to isolate the damaged reactors and radioactive contamination.

Following a review of the Fukushima events, the Nuclear Regulatory Commission (NRC) concluded that a sequence of events such as those leading to the Fukushima accident is unlikely to occur in the U.S. and continued operation of nuclear plants of similar design would not pose an imminent threat to public health and safety. However, the NRC also concluded that upgrades to the design and operation of U.S. plants are needed to cope with external events beyond design criteria. In March 2012, the NRC issued three orders requiring operators of U.S. reactors to:

- Obtain and protect additional on- and off-site emergency equipment, such as pumps, generators, batteries and fuel to support reactors in case of natural disaster and loss of off-site power (applicable to all reactor designs)
- Install improved instrumentation for monitoring the spent fuel pool water level (applicable to all reactor designs)
- Improve and install emergency containment venting systems ("reliable hardened vents[524]") that can relieve pressure in case of a serious accident (applicable to boiling water reactors (BWRs) employing Mark I or Mark II containment systems)

Plants are to be in compliance with respect to these orders by the end of 2016.

The NRC acknowledged that questions remained regarding maintaining containment integrity and limiting release of radioactive materials if the containment venting system was used during severe accident conditions. Regarding these concerns, NRC staff in November 2012 presented the Commission with four options for consideration[525]. These were: 1) reliable hardened containment vents as ordered in March 2012, 2) reliable hardened containment vents capable of reliable operation under severe accident conditions, including situations involving core damage, 3) installation of an engineered filter on the containment venting system to prevent the release of significant amounts of radioactive material following dominant severe accident sequences, and 4) performance-based confinement strategies. NRC staff recommended approval of Option 3.

In March 2013, the Commission directed staff to issue an order for modification of hardened BWR containment venting systems to be capable of reliable operation under severe accident conditions, including situations involving core damage (Option 2). The Commission also instructed staff to initiate a rulemaking regarding filtering strategies (Filtering Strategies Rulemaking) (Option 3). In

[524] "Hardened" means these vents must withstand the pressure and temperature of the steam generated early in an accident. The vents must also withstand possible fires and small explosions if they are used to release hydrogen later in an accident. The vents must be reliable enough to be operated even if the reactor loses all electrical power or if other hazardous conditions exist. (NRC at http://public-blog.nrc-gateway.gov/2012/04/24/whats-so-hardened-about-vents)

[525] Nuclear Regulatory Commission SECY-12-0157. November 26, 2012. http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2012/2012-0157scy.pdf.

June 2013, the Commission ordered the modification of hardened BWR containment venting systems to be capable of reliable operation under severe accident conditions.[526]

The filtering strategies rulemaking is in process. In recognition of a less costly alternative to filtration that may provide collateral benefits (addition of water to the containment drywell under severe accident conditions) the rulemaking has been renamed Containment Protection and Release Reduction with Mark I and II Containments (CPRR Rulemaking). A proposed rule is scheduled for December 2015 and the final rule by March 2017.

Generic estimates of the costs of certain Fukushima-related compliance actions in addition to those currently ordered have been prepared by the Nuclear Energy Institute. The capital cost of severe accident capable water injection is estimated to be $3.72 million per unit. The capital cost of containment vent filtration is estimated to range from $35.4 million (small filter) to $54.9 million (large filter). These costs include direct and indirect (engineering, project management and other indirect costs) plus a 50 percent contingency as befitting their preliminary and generic nature.[527] Incremental operating, maintenance and decommissioning costs were not estimated.

The Columbia Generating Station is a boiling water reactor employing a Mark II containment system, so is subject to all NRC orders to date regarding actions in response to the Fukushima accident. Energy Northwest is in the process of implementing the NRC March 2012 and June 2013 orders. A total of $53 million from FY 2015 through FY 2019 is budgeted to this effort[528]. The outcome of the CPRR Rulemaking is uncertain and, as noted above, the potential cost of actions resulting from this rulemaking could vary widely. Currently, Energy Northwest has included a Fukushima Filter Requirements Risk in its Management Discretion - Special Projects budget line item. This line item totals $20.3 million from FY 2016 through FY 2024[529].

Additional evaluations are being undertaken in response to the Fukushima accident including assessments of station blackout, fire, flooding and seismic risks. Possible station upgrades and other actions in response to these issues have not yet been determined.

Fugitive Methane Reduction

The electric industry is increasingly turning to natural gas as an alternative fuel source to coal,[530] at least partly for the perceived carbon emissions reduction benefits. However, the production and

[526] Nuclear Regulatory Commission. EA-13-109. Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation under Severe Accident Conditions. June 6, 2013. http://pbadupws.nrc.gov/docs/ML1314/ML13143A321.pdf

[527] Nuclear Energy Institute and Boiling Water Reactor Owners' Group. Industry Incremental Cost Estimate – External Filtration and Water Addition. NRC Public Meeting, June 18, 2014. http://pbadupws.nrc.gov/docs/ML1417/ML14170A055.pdf. Year dollars not specified.

[528] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan.

[529] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan.

[530] *See, e.g.,* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

transportation of natural gas results in the release of methane, a potent greenhouse gas with the potential to negate the climate change benefits associated with switching fuels. Concerns about the environmental impacts of methane emissions led the Obama Administration, on January 14, 2015, to announce plans to cut methane emissions from the oil and gas industry by 40 percent to 45 percent from 2012 levels by 2025.[531] To accomplish these reductions, President Obama directed the EPA to propose new methane and volatile organic compound (VOC) emissions regulations. The EPA issued its proposed rule in September 2015,[532] with final guidelines due in 2016. The rule would amend the NSPS for methane and VOC emissions for certain equipment, processes, and activities for the oil and natural gas category.

The EPA does not currently impose limits on methane emissions, instead operating a voluntary methane emissions reduction program. These new regulations will impact the Northwest electric industry by increasing the compliance costs associated with producing and transporting natural gas for the oil and gas industry, which will translate to higher fuel costs for the electric industry.

Switching from coal to natural gas as a fuel source for electricity generation may have climate benefits, as long as methane leakage is minimized. Natural gas combustion emits about half as much carbon dioxide as coal combustion in relation to the energy that each produces,[533] a fact that has led some policymakers to view the fuel as a bridge to a clean energy future.[534] However, methane, the primary component of natural gas, is a greenhouse gas with a global warming potential in the atmosphere of 25 times that of carbon dioxide over a 100-year period.[535] So, while natural gas may represent a net climate benefit as compared to coal, that benefit will only be realized if methane leakage remains below 3.2 percent from well delivery to power plant.[536]

According to EPA estimates, the oil and gas industry accounts for around 30 percent of U.S. methane emissions. In 2009, the EPA estimated methane leakage rates in the oil and gas industry to be 2.4 percent. That estimate has been the subject of controversy, however, with some studies measuring leakage rates of over 10 percent in certain oil and gas basins.[537] The current climate calculus, then, may favor natural gas over coal, but that distinction is not as clear as it seems when looking solely at carbon dioxide emissions from combustion. Complicating the equation is the fact that coal extraction also releases methane.

The EPA does not currently limit methane emissions from the oil and gas industry, instead offering a voluntary methane emissions reduction program called Natural Gas STAR.[538] The Natural Gas

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[531] http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1
[532] https://www.federalregister.gov/articles/2015/09/18/2015-21023/oil-and-natural-gas-sector-emission-standards-for-new-and-modified-sources
[533] http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
[534] See President Obama, *State of the Union*, 2014, http://www.whitehouse.gov/the-press-office/2014/01/28/president-barack-obamas-state-union-address
[535] http://epa.gov/climatechange/ghgemissions/gases/ch4.html
[536] http://www.pnas.org/content/109/17/6435.full#ref-6
[537] http://www.eenews.net/stories/1060007693
[538] http://www.epa.gov/gasstar/

STAR program provides the oil and gas industry with technical guidance, and opportunities for information sharing and technology transfer to encourage fugitive methane capture and emissions reductions. The oil and gas industry has long maintained that voluntary programs are sufficient to restrict methane emissions, because the nature of natural gas as a commodity provides the industry an economic incentive to bring it to market. The EPA's proposed methane emissions regulations will impose enforceable standards on the oil and gas industry.

The EPA plans to regulate methane and VOC emissions from new sources pursuant its authority to set New Source Performance Standards (NSPS) under Section 111(b) of the Clean Air Act (CAA).[539] The NSPS program requires certain sources of emissions to comply with standards performance consistent with the best adequately demonstrated system of emissions reductions.[540] These NSPS regulations will not affect existing oil and gas facilities. Instead, existing sources in National Ambient Air Quality Standards (NAAQS) nonattainment areas will face VOC reduction requirements pursuant to the EPA's authority under Sections 108 and 109 of the CAA.[541] The EPA classifies methane as a VOC,[542] so any requirements to reduce VOCs will necessarily also limit methane emissions.

In addition to establishing methane emissions standards, the EPA would also ramp up voluntary emissions reductions programs already in place. The EPA proposed creating a more stringent voluntary program, called Natural Gas STAR Gold, that would provide participants the opportunity to be recognized as "Gas STAR Gold" facilities in exchange for meeting certain protocols.[543]

The EPA estimates the oil and gas industry's cost of compliance to be $170 - $180 million in 2020.[544] Economic impacts for the electric industry in the short term are likely to be minimal, as existing oil and gas facilities will largely escape regulation under the EPA's proposal. As the compliance costs associated with the methane emissions regulations rise for the oil and gas industry, however, those costs will be passed along to Northwest utilities through increased fuel prices for natural gas plants. These cost increases will likely be mitigated somewhat by the fact that any captured methane leakage can be brought to market. At this point, it can be assumed that the EPA's actions on this matter will have an economic impact on the electric industry in the Northwest, but the costs associated with the proposed methane emissions regulations are not clear at this time.

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539 42 U.S.C. § 7411.
540 42 U.S.C. § 7411(a)(1).
541 42 U.S.C. §§ 7408-7409.
542 40 CFR 51.100(s)
543 http://www.epa.gov/methane/gasstar/documents/Gas_STAR_Gold_proposedframework.pdf#page=9
544 https://www.federalregister.gov/articles/2015/09/18/2015-21023/oil-and-natural-gas-sector-emission-standards-for-new-and-modified-sources#h-94.

Effects of Current and Prospective Regulatory Compliance Actions on Affected Northwest Generating Units

Table I-3 summarizes the recent and prospective compliance actions for the major Pacific Northwest generating units affected by the regulations described in the previous section. Estimates of incremental capital investment costs and fixed and variable operating and maintenance costs are provided where available.

Budget-authorization quality, or better, plant-specific cost estimates are the preferred source of compliance cost information. These, however, are not available for all compliance actions. Next-best are plant-specific feasibility or conceptual estimates. In cases where these are not located, the best available generic cost estimates have been used.

In some cases, no cost estimates appear to be available. This is either because final regulations have not yet been adopted, or have only recently been adopted and the compliance actions have not been determined, or because the compliance actions are highly plant-specific and the costs have not been released by the plant owners. In general, it appears that actions for which cost information is not available are those whose costs are expected to be relatively minor (cooling water intake modifications), or those that are remedial in nature (such as retention pond cleanup). The capital costs of the latter will have to be expended irrespective of future plant operation, so will not affect the future of the plant. Moreover, the operational costs of these measures are likely to be small, and not significantly affecting plant dispatch or going forward costs.

Uncommitted capital costs and fixed and variable costs of non-remedial compliance actions could be avoided if the plant were retired, and thus bear on decisions regarding continued plant operation. Some actions are “remedial” in nature (e.g., cleanup of contaminated groundwater) and would have to be accomplished no matter what future plant operation might be. These will normally not greatly affect decisions regarding future plant operation. Incremental variable operating costs affect the hour-to-hour economic dispatch of a plant, so bear on short-term operational decisions as well as long-term investment and retirement decisions.

Certain compliance actions increase consumption of power or steam for internal loads or otherwise affect plant performance parameters such as net output and heat rate. Little quantitative information is available regarding these effects. These effects tend to be fairly minor for most compliance actions.

The “Assumed Status of Investment” in the fourth column of Table I-3 represents the assumed status of the investment in response to the compliance action. This is an important staff assumption as it divides the estimated compliance costs by committed and near-term uncommitted costs – estimates that are fairly certain to occur and therefore included in the Regional Portfolio Model’s (RPM) existing power system and potentially affecting dispatch – and long-term uncommitted costs that are uncertain both in whether they will even occur and the accuracy of the estimates and therefore not included in the RPM at this time. This breakdown is more evident as it is carried through in summary to Table I-4, where the cost estimates included and not included in the RPM at this time are clearly identified.

The costs shown in Table I-3 and I-4 have been normalized to year 2012 dollar values and to common metrics (capital investment and fixed O&M in $/kW(net)-yr; variable O&M in $/MWh) to remain consistent with and to facilitate comparison to other costs appearing in the Seventh Power Plan work. The original sources are indicated in the footnotes.

Table I - 3: Current and prospective environmental compliance actions for major Northwest units

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
Boardman	NAAQS	In compliance (DSI and low-sulfur coal, 2014)	--	--	--	--
	Regional Haze	In compliance (LNB & MOFA, 2011); Termination of coal firing (2020)	--	--	--	--
	MATS	In compliance (ACI, 2011)	--	--	--	--
	Coal Combustion Residuals	Unknown	--	--	--	--
	Cooling Water Intakes	IMS - Probable compliance (recirculating cooling system) EMS – Evaluation probably required for continued operation as biomass unit	--	Unknown EMS cost (if converted to biomass operation)	Unknown EMS cost (if converted to biomass operation)	--
	Effluent Limitation Guidelines	Final control requirements not established	--	Expected to be minor	Expected to be minor	--
	Carbon Pollution Standards	Termination of coal firing (Dec 2020)	--	--	--	Termination of coal firing
Centralia (TransAlta Centralia) 1 & 2	NAAQS	Currently in compliance (LNB, OFA, SNCR, 2012), Coal blending, FGD, DESP)	--	--	--	--
	Regional haze	In compliance (Flex Fuel, SNCR, 2012)[546]	--	--	--	--
	MATS	In compliance (ACI, 2011)	--	--	--	--
	Coal combustion residuals	In compliance (Dry ash sold for beneficial use; balance disposed in former coal mine; wet scrubber waste treatment in compliance)	--	--	--	--

[545] Assumed status of investment for compliance actions: Committed (Obligated, Under Construction), Uncommitted (Near-term through 2022), Uncommitted (Long-term post 2022). This status is an assumption from Council staff and leads to a division of near-term and long-term costs in Table 3.
[546] Flex Fuel – Use of Powder River Basin coal and associated boiler modifications to reduce haze precursors.

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
	Cooling Water Intakes	IMS - Probable compliance (recirculating cooling system) EMS – Probable exemption (< 125 MMgpd)	--	--	--	--
	Effluent Limitation Guidelines	Final control requirements not established	--	Expected to be minor	Expected to be minor	--
	Carbon Pollution Standards	Termination of coal firing for one unit (Dec 2020) Termination of coal firing for second unit (Dec 2025)	--	--	--	Scheduled retirement
Colstrip 1&2	NAAQS	Currently in compliance	--	--	--	--
	Regional Haze	SOFA + SNCR (NOx); Lime injection (DSI) and additional scrubber vessel (SOx) (2017)	Uncommitted (Near-term)	\$254/kW[547]	Vr: \$1.49/MWh	Minor derate
	MATS	Addition of sieve trays to FGD system for enhanced particulate removal (2016)[548]	Committed	\$30/kW[549]	Fx: \$0.33/kW-yr Vr: \$0.00/MWh	Negligible
	Coal Combustion Residuals	Onsite dry ash disposal system (2018) Slurry pond lining (2020)	Dry ash: Uncommitted (Near-term) Lining: Committed	Dry ash: \$23/kW[550] Lining: \$36/kW[551]	Fx: \$1.63/kW-yr Vr: \$0.23/MWh Lining: negligible	--

547 Capital costs derived from Puget Sound Energy 2013 IRP, Appendix J – four cost scenarios, one assumes SCR installed in 2022, another in 2027. PSE quantified the total cost of SCR to all participants (owners) at \$156 million for units 1 and 2, or \$254/kW. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Appendices.pdf. O&M costs derived from Environmental Protection Agency Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan, Proposed Rule (77 Federal Register No. 77 (April 20, 2012) p. 23988 – 24101). Cost estimates submitted by PPL Montana were adopted for the final rulemaking. 2012 year \$. Fixed and variable O&M costs were not separately reported, all O&M costs normalized as variable assuming a 90% capacity factor.

548 State of Montana Department of Environmental Quality. Operating Permit Technical Review Document. Colstrip Steam Electric Station. February 9, 2015. The MT DEQ granted PPL Montana a one-year extension for MATS compliance.

549 Capital and O&M costs for upgrade to existing scrubber system from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J, Case 1 - Low Cost Colstrip 1 & 2. May 2013. PSE share is pro-rated to full capacity.

550 Capital and O&M costs for onsite dry ash disposal system from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J. May 2013. Colstrip 1 & 2 Low and Mid-cost cases (Non-hazardous CCR determination). PSE share is pro-rated to full capacity. Pond lining is assumed to have negligible effect on operating costs.

551 Capital costs for pond lining from Portland General Electric 2013 Integrated Resource Plan. March 2014 T. 7-4. Average of estimated PGE share of Colstrip 3 & 4 (\$9.8 – 12.0 MM) extrapolated to all Colstrip units and expressed as 2012 \$/kW. Cost is likely committed irrespective of future operation of Colstrip units. Pond lining assumed to have negligible effect on operating costs.

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
	Cooling Water Intakes	IMS - Probable compliance (recirculating cooling system) EMS – Probable exemption (< 125 MMgpd)	--	--	--	--
	Effluent Limitation Guidelines	Zero liquid discharge (ZLD) facility	--	--	--	--
	Carbon Pollution Standards	Heat Rate improvement, Redispatch (2020 -30)	--	Not determined at this time	Not determined at this time	Potential redispatch (reduction in capacity factor)
Colstrip 3 & 4	NAAQS	Currently in compliance	--	--	--	--
	Regional Haze	Currently in compliance; 5-year "reasonable progress" reviews will likely require SCR retrofit by 2027.	Uncommitted (Near-term)	$514/kW[552]	Fx: $0.27/kW-yr Vr: $1.00/MWh	Minor derate
	MATS	Addition of sieve trays to FGD system for enhanced particulate removal (2016)[553]	Committed	See MATS costs for Colstrip 1 & 2	See MATS costs for Colstrip 1 & 2	--
	Coal Combustion Residuals	Onsite dry ash disposal system (2018) Slurry pond lining (2020)	Dry Ash: Uncommitted (Near-term) Lining: Committed	See CCR costs for Colstrip 1 & 2	See CCR costs for Colstrip 1 & 2	--
	Cooling Water Intakes	IM - Probable compliance (recirculating cooling system) EM – Probable exemption (< 125 MMgpd)	--	--	--	--
	Effluent Limitation Guidelines	Zero liquid discharge (ZLD) facility	--	--	--	--
	Carbon Pollution Standards	Heat Rate improvement, Redispatch (2020 -30)	--	Not determined at this time	Not determined at this time	Potential redispatch (reduction in capacity factor)

552 Capital and O&M costs from Puget Sound Energy. 2013 Integrated Resource Plan, Appendix J. May 2013. Mid-cost case Colstrip 3 & 4. PSE costs pro-rated to entire unit.
553 While Colstrip Units 3 and 4 are in compliance with MATS, Units 1 and 2 are not. The compliance strategy chosen by the plant owners is to improve FGD system particulate removal for all four units by the installation of sieve trays, and comply with MATS emission requirements using weighted average emission rates from all four units. The MT DEQ granted the extension on January 5, 2015.

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
Jim Bridger 1 & 2	NAAQS	Currently in compliance	--	--	--	
	Regional Haze	SCR (Unit 1, 2022; Unit 2, 2021)	Uncommitted (Near-term)	$377/kW[554]	Fx: $0.86/kW-yr Vr: $0.41/MWh	Minor derate
	MATS	ACI + wet FGD additive + coal additive (2015)	Committed	$14/kW[555]	Fx: $0.10/kW-yr Vr: $2.80/MWh	
	Carbon Pollution Standards	Heat Rate improvement, Redispatch (Prospective, 2020 -30)	--	Not determined at this time	Not determined at this time	Potential redispatch (reduction in capacity factor)
Jim Bridger 3 & 4	NAAQS	Currently in compliance	--	--	--	
	Regional Haze	SCR (Unit 3 completion by Dec 2015; Unit 4 completion by Dec 2016) (LNB & SOFA in place 2010)	Committed	Unit 3: $326/kW Unit 4: $380/kW[556]	Assume similar to JB1.	Minor derate
	MATS	ACI wet FGD additive + coal additive (2015)	Committed	$14/kW[557]	Fx: $0.10/kW-yr Vr: $2.80/MWh	
	Carbon Pollution Standards	Heat Rate improvement, Redispatch (Prospective, 2020 -30)	--	Not determined at this time	Not determined at this time	Potential redispatch (reduction in capacity factor)
Jim Bridger (Plant)	Coal combustion residuals	Possible impoundment modifications and further shift to landfill disposal.	--	Not available	Not available	

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[554] Capital costs from Wyoming PSC estimate in letter to EPA, December 2013 - http://psc.state.wy.us/pscdocs/dwnload/ChairmansLetter-JanetMcCabe.pdf. O&M costs from CH2M-Hill (2007): BART Analysis for Jim Bridger Unit 1. Prepared by CH2M-Hill for PacifiCorp. Dec 2007. Economic Analysis Summary. T. 3-3, LNB + OFA + SCR less LNB w/OFA. Normalized to 2012 year dollars. Unit 2 costs assumed to be similar to those of Unit 1.

[555] Capital and fixed O&M costs were estimated using methodology of Table 1 of Sargent & Lundy. IPM Model - Revisions to Cost and Performance for APC Technologies, Mercury Control Cost Development Technology. March 2011. Variable O&M costs will vary depending on lost revenue and corresponding disposal cost from previously marketed fly ash rendered unsuitable for cement production and other alternative uses. The variable O&M value shown assumes 44% of fly ash was previously marketed at $30/ton and must be landfilled at $50 ton following installation of mercury control equipment.

[556] Commitment cost estimates, including AFUDC (adjusted to 100% unit shares), Section V.14 of Idaho Public Utilities Commission. Case No. IPC-E-13-16 Investment in Selective Catalytic Reduction Controls for Jim Bridger Units 3 and 4 - Idaho Power Company's Application and Direct Testimony. June 28, 2013. Normalized to 2012 $/kW (overnight cost).

[557] Capital and fixed O&M costs were estimated using methodology of Table 1 of Sargent & Lundy. IPM Model - Revisions to Cost and Performance for APC Technologies, Mercury Control Cost Development Technology. March 2011. Variable O&M costs will vary depending on lost revenue and corresponding disposal cost from previously marketed fly ash rendered unsuitable for cement production and other alternative uses. The variable O&M value shown assumes 44% of fly ash was previously marketed (US average) at $30/ton and is landfilled at $50 ton following installation of mercury control equipment.

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
	Cooling Water Intakes	IMS - Probable compliance (recirculating cooling system) EMS – Probable exemption (< 125 MMgpd)	--	--	--	
	Effluent Limitation Guidelines	Zero liquid discharge (ZLD) facility		--	--	
North Valmy 1 & 2	NAAQS	Currently in compliance	--	--	--	--
	Regional Haze	Currently in compliance. 5-year “reasonable progress” reviews may require addition of SCR and wet FGD in the future (~2025-30)	Uncommitted (Long-term)	SCR: $257/kW[558] FGD: $603/kW	Fx: $0.91/kW-yr Vr: $1.70/MWh Fx: $16.95/kW-yr Vr: $1.41/MWh	
	MATS (HCL)	Unit 1 DSI (2015)	Committed	$14/kW[559]	Fx: $1.16/kW-yr Vr: $5.83/MWh	
	Coal Combustion Residuals	Probable compliance (landfill disposal in current use)	--	--	--	--
	Cooling Water Intakes	IMS & EMS - Probable exemption (wellfield supply)	--	--	--	--
	Effluent Limitation Guidelines	Zero liquid discharge (ZLD) facility	--	--	--	
	Carbon Pollution Standards	Heat Rate improvement, Redispatch (Prospective, 2020 -30)	--	Not determined at this time	Not determined at this time	Potential redispatch (reduction in capacity factor)

558 Capital and O&M costs for SCR and FGD retrofits are from Energy Information Administration. Annual Energy Outlook 2014: Electricity Working Group Meeting. July 24, 2013. Slide 6, Average cost of environmental retrofits. Normalized to 2012 year dollars.

559 Capital cost from Application of Sierra Pacific Power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2014-2033 and Approval of its Energy Supply Plan for the period 2014-2016. Vol 11 of 16 Generation, Fuel and Purchase Power, Fuel, Renewable Narrative, and Technical Appendix. Year dollars not specified, assumed to approximate 2012 year dollars. O&M costs from Energy Information Administration. Annual Energy Outlook 2014: Electricity Working Group Meeting. July 24, 2013. Slide 6, Average cost of environmental retrofits (Dry Sorbent Injection, 100 – 299 MW unit).

Unit	Regulation	Controls or Actions; Compliance Date	Assumed Status of Investment[545]	Capital Investment	Incremental O&M Cost	Operational Impacts
Columbia Generating Station	Fukushima Upgrades (Ordered)	Mitigation strategies Spent fuel instrumentation Containment vents capable of operating under severe accident conditions	Committed	$46/kW[560]	Not available	--
	CPRR Rulemaking (In-process)	Accident- capable drywell water injection, or Containment vent filters Actions relating to station blackout, fire, flooding or seismic hazards (NRC)	Uncertain; rulemaking in process	Water injection - $3/kW Vent filters - $30 - $46/kW[561]	Not available	--
	Cooling Water Intakes	IM - Probable compliance (recirculating cooling system) EM – Probable exemption (< 125 MMgpd)	--	--	--	--
	Effluent Limitation Guidelines	Possible minor impacts	--	--	--	--

[560] Energy Northwest. Fiscal Year 2015 Columbia Generating Station Long Range Plan, adjusted to 2012 yr dollars.
[561] Assuming the Nuclear Energy Institute estimates are in 2014 year dollar values.

Costs of complying with recent and proposed environmental and safety regulations can affect the economics of existing power generation facilities in several ways. Some compliance costs, such as those associated with upgrades to existing effluent ponds are likely to be required irrespective of future plant operation. Obligated compliance costs such as these are equivalent to sunk costs and unlikely to greatly affect decisions regarding future plant operation. In contrast, high capital cost compliance actions required to be undertaken only if a plant continues in service, for example, installation of flue gas desulfurization equipment for regional haze control, can render alternative resource options such as new generation, demand side options or market purchases, more attractive than retrofit for continued operation. Compliance actions with significant variable costs such as sorbent injection for mercury control, will affect dispatch cost and thereby the extent to which the plant can compete in the power market against other power generation facilities or demand-side measures. A plant thus affected may continue to operate, though to a lesser extent than previously.

Compliance actions or combinations of compliance actions potentially affect decisions regarding future plant operation when variable costs increase to a level significantly affecting the number of hours in which a unit can economically dispatch against competing units or when avoidable going forward costs increase to levels comparable to the cost of alternative resource options. In the former case, a unit might continue to serve as an economic source of capacity. In the latter, retirement in favor of more cost-effective resource options might be a preferred course of action. The capacity as well as the energy value of an existing plant must be considered in these comparisons. Wholesale energy market prices do not include capacity value except during resource shortages. Nor do all potential new supply or demand-side resource options supply the capacity value of the coal or nuclear units most affected by recent regulatory actions.

Remaining plant life affects capital investment decisions. Most coal-fired units in the Northwest have been operating 30 to 40 years. Though coal steam-electric plants can operate for 60 years or more, and nuclear operating licenses are routinely extended to 60 years (and potentially 80 years), increasing routine maintenance costs, declining efficiency compared to newer plants, and, for coal units, exhaustion of nearby sources of fuel may limit the attractiveness of investing in compliance actions.

A final consideration is the risk to continued operation of coal units posed by climate change policy. Unlike most environmental and safety regulatory actions, the proposed compliance requirements of the Clean Power Plan are not targeted at individual units. Rather, a mix of demand and supply-side actions are proposed, including a shift of dispatch from coal to gas combined-cycle units. Also, proposed state-level climate policy in Washington and Oregon prohibiting or taxing import of electricity from coal-fired plants would further reduce the value of power from these units.

Table I-4 provides a summary of the estimated significant incremental compliance costs for the major affected Northwest generating units that was included in the RPM as part of the existing system cost. This is an important differentiation from Table I-3 because Boardman, Centralia and J.E. Corette are omitted since these units are scheduled for early retirement or cession of coal-firing.

Table I - 4: Estimated Revenue Requirements Impact of Economically Significant Compliance Actions

Units	Action	Assumed Status of Investment (from Table I-3)[562]	Capital and Cumulative[563] O&M Costs
Colstrip 1 & 2	FGD sieve trays; SOFA, SNCR, DSI, scrubber; Dry ash disposal, slurry pond lining	Committed + Uncommitted (Near-term)	Capital - $343/kW Fx O&M - $1.96/kW-yr Vr O&M - $1.72/MWh
Colstrip 3 & 4	FGD sieve trays; Dry ash disposal; Slurry pond lining; SCR	Committed + Uncommitted (Near-term)	Capital - $603/kW Fx O&M - $2.23/kW-yr Vr O&M - $1.23/MWh
Jim Bridger 1 & 2	ACI; SCR	Committed + Uncommitted (Near-term)	Capital - $391/kW Fx O&M - $0.96/kW-yr Vr O&M - $3.21/MWh
Jim Bridger 3	ACI ; SCR	Committed + Uncommitted (Near-term)	Capital - $340/kW Fx O&M - $0.96/kW-yr Vr O&M - $3.21/MWh
Jim Bridger 4	ACI ; SCR	Committed + Uncommitted (Near-term)	Capital - $394/kW Fx O&M - $0.96/kW-yr Vr O&M - $3.21/MWh
North Valmy 1 & 2	DSI (Unit 1 only; estimates have been normalized to include both units) [564]	Committed + Uncommitted (Near-term)	Capital - $6.72/kW Fx O&M - $0.56/kW-yr Vr O&M - $2.84/MWh
North Valmy 1 & 2	FGD + SCR	Uncommitted (Long-term)	Capital - $860/kW Fx O&M - $18.42/kW-yr Vr O&M - $5.95/MWh
Columbia Generating Station	Fukushima retrofits (Ordered)	Committed + Uncommitted (Near-term)	Capital - $46/kW Fx O&M – n/a Vr O&M – n/a

562 If the status of the investment is “Committed” or “Uncommitted (Near-term)”, Council staff assumed these compliance actions were fairly certain and therefore the estimates were included in the Regional Portfolio Model (RPM). If the status of the investment is “Uncommitted (Long-term)”, Council staff assumed there was too much uncertainty around both the occurrence of the compliance action and the cost estimates, so these estimates are for illustrative purposes only and were not included in the RPM at this time.

563 If the assumed status is “Uncommitted (Long-term), then the capital cost is representative of that compliance order; however the O&M costs are cumulative and include the “Committed” and “Uncommitted (Near-term)” O&M costs as well.

564 DSI is being installed on Unit 1 for reduction in acid gas emissions. The costs shown, assume that the unit 1 installation brings the entire plant into compliance and are therefore allocated to the full plant capacity.

ENVIRONMENTAL IMPACTS OF ASSOCIATED TRANSMISSION AND APPLICABLE REGULATIONS

The development and expansion of electricity transmission infrastructure is, in part, a consequence of the development of generating resources. An analysis of the environmental effects of electricity generation should also consider to some extent the environmental impacts of associated transmission development. These impacts include wildlife disruption and habitat fragmentation, modest water and air quality impacts, adverse effects on scenic and aesthetic qualities, and potential effects on cultural resources.

Transmission facilities may be developed and owned by public or private entities. In the Northwest, around 75 percent of the transmission infrastructure, over 15,000 circuit miles, is owned by the Bonneville Power Administration.[565]

The most significant impacts associated with transmission infrastructure construction and operations are the effects on wildlife and habitat. Habitat disturbance is the primary impact of transmission lines, although avian electrocution is also a concern with some transmission designs. These impacts have the potential to affect several vulnerable species in the Northwest.

Human activity may cause wildlife disturbance during the construction phase of transmission development. While some degree of disturbance is inevitable during the construction phase, developers can mitigate the impacts by avoiding construction during critical periods, such as nesting or wintering.[566] Displacement of species as a result of human activity associated with the construction phase is likely to be temporary. However, land cleared for transmission development may continue to allow increased human access in otherwise undeveloped areas after construction is complete.[567]

Transmission lines and rights-of-way may also lead to habitat fragmentation, as a result of permanent changes in the vegetation around the infrastructure. Transmission rights-of-way are maintained to keep vegetation from growing to a height that would interfere with the delivery of electricity. The Bonneville Power Administration, for example, typically limits vegetation height in rights-of-way to 10 feet tall.[568] Transmission system owners employ a variety of methods to limit vegetation growth, including manual and mechanical cutting, and the use of biological agents and herbicides.[569] This change in the vegetative structure may make rights-of-way unsuitable as habitat for some species. Habitat fragmentation causes displaced animals to seek new habitat, leading to

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[565] http://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf
[566] *Id.*
[567] http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0422-DEIS-2010.pdf.
[568] http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0285-FEIS-01-2000.pdf at 13.
[569] http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0285-FEIS-01-2000.pdf.

increased competition for resources. In addition to the removal of vegetation during construction and the maintenance of vegetation during operation, transmission development may introduce non-native or invasive species to previously undisturbed areas.[570] Mitigation measures are generally limited to avoiding transmission development in sensitive habitat.

Bird species are the most likely to be impacted by direct contact with the transmission facilities. Because transmission lines are non-insulated, a bird that establishes circuit by contacting the energized line and a grounded structure will be electrocuted.[571] Of primary concern are eagles and raptors, which have large wingspans and often nest on transmission infrastructure.[572] Avian electrocution risk can be mitigated by simply separating energized lines from grounded objects by a distance greater than the span of the birds.[573] Electrocution risk can also be mitigated by burying the lines.[574]

The species impacted by the construction and operation of transmission infrastructure include big game, birds, ground species, and sensitive plants. Big game such as mule deer, pronghorn and elk are likely to avoid areas of transmission development during the construction phase as a result of increased human activity. These impacts are not generally permanent, because human activity declines after construction is complete and transmission infrastructure does not include the installation of any fences that would impede big game behavior.[575] Birds are affected by all stages of transmission development, but the primary impacts appear to be the loss of habitat resulting from the alteration of vegetative structures within rights-of-way. Ground species are similarly affected by the alteration of habitat resulting from transmission development. Several Environmental Impact Statements prepared in support of transmission projects in the Northwest identify a familiar array of species of concern. These species include: the Greater sage grouse, Golden eagle, Ferruginous hawk, Sage sparrow, Preble's shrew, Merlin, Peregrine falcon, Loggerhead shrike, Black-tailed jackrabbit, Washington ground squirrel, Pygmy rabbit, Mule deer, Northern sagebrush lizard, and Green-tinged paintbrush.[576] The siting of a transmission project, its size, and its relation to sensitive habitat determines the precise contours of its wildlife impacts.

Wildlife impacts may be regulated by the ESA, the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act. Under the ESA, a private (or public non-federal) transmission developer is typically required to evaluate the proposed site for the presence of listed species or critical habitat. If either are present, the private developer may be required to obtain an incidental take permit from FWS or NOAA Fisheries. If the transmission developer is a federal agency, like the

570 http://teeic.indianaffairs.gov/er/transmission/impact/construct/index.htm.
571 http://www.fishwildlife.org/files/AFWA-State_agency_transmission_guide_FINAL.pdf at 15.
572 http://www.fws.gov/southwest/es/documents/R2ES/LitCited/LPC_2012/Steenhof_et_al_1993.pdf. Interestingly, transmission infrastructure may also benefit raptors by providing a nesting substrate.
573 http://www.fishwildlife.org/files/AFWA-State_agency_transmission_guide_FINAL.pdf.
574 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf at ES-11.
575 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.
576 http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0422-DEIS-2010.pdf at S-19. http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf at ES-7.

Bonneville Power Administration, compliance with the ESA requires consultation with FWS or NOAA Fisheries. If a biological assessment reveals the presence of a listed species or critical habitat, FWS or NOAA Fisheries are required to prepare a biological opinion that determines whether the proposed action is likely to jeopardize the continues existence of a listed species. If the relevant agency makes a “no jeopardy,” it may authorize the action and recommend reasonable prudent measures to avoid take. Incidental take by federal entities authorized to act by the FWS or NOAA Fisheries is permitted. A jeopardy determination by FWS or NOAA Fisheries forecloses a federal entity’s authority to act. The MBTA and BGEPA may also impose some limitations on transmission development, by requiring a transmission developer to cooperate with FWS to implement ACPs to limit impacts to eagles and mitigate migratory bird take.

The construction and operation of transmission infrastructure has modest effects on water quality and air quality impacts are limited to the construction phase. During the construction phase, the potential water quality impacts result from the removal of vegetation, excavation, grading and trenching required to prepare a site for transmission lines. These processes increase soil erosion, which leads to a rise in sediment loads in nearby waterways. Trenching and the construction of access roads may also alter drainage patterns, resulting in decreased water absorption by soil and more rapid runoff during precipitation or snowmelt.[577] Vehicular traffic during construction and maintenance may also lead to the introduction of oils and heavy metals into previously undisturbed waters. In addition, the development of transmission facilities typically requires the withdrawal of water from adjacent waterways for dust control. The operation of transmission infrastructure requires maintenance of the vegetation within transmission rights-of-way, which typically involves the application of herbicides and biological agents.[578] Rain may cause these chemicals to wash into adjacent waterways.[579] Taking steps to maintain the natural drainage patterns of a waterway, such as limiting the channelization of streams into culverts, can mitigate water quality impacts. In addition, water and sediment control measures (hay bales) can be used in trenches to limit sediment loads and slow runoff.[580]

To the extent that stormwater is channelized and discharged into adjacent surface waters during the development of a transmission project, developers must obtain a § 402 NPDES permit from the EPA. In addition, the construction of transmission infrastructure in wetlands requires a developer to seek a §404 dredge and fill permit from the Corps. The Corps has developed a Nationwide Permit that streamlines the § 404 permitting process for many activities associated the development of utility infrastructure.[581]

Transmission projects typically only cause air quality impacts during the construction phase. The construction phase of transmission development typically involves blasting and the use of heavy

577 http://teeic.indianaffairs.gov/er/transmission/impact/construct/index.htm
578 http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0285-FEIS-01-2000.pdf at 11.
579 http://teeic.indianaffairs.gov/er/transmission/impact/construct/index.htm.
580 http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0422-DEIS-2010.pdf at S-21.
581 http://www.usace.army.mil/Portals/2/docs/civilworks/nwp/2012/NWP_12_2012.pdf

machinery, resulting in exhaust from construction equipment, and fugitive dust from blasting, excavation and road construction.[582] Air impacts rarely persist beyond construction.

The construction and operation of transmission infrastructure may result in aesthetic harms, human health concerns, and the potential disruption of cultural and historical resources. Transmission lines have the potential to create new visual features in previously undeveloped areas, which may be unwelcome to adjacent landowners and people seeking natural or scenic character.[583] Project developers can mitigate these impacts to some degree by avoiding visually sensitive areas, siting transmission lines in previously disturbed areas, preserving a vegetative buffer along rights-of-way, and using non-reflective materials in building transmission infrastructure.[584] In addition to the visual impacts connected to transmission infrastructure, the operation of transmission facilities produces electric and magnetic fields. While members of the public have expressed some concern over the health impacts of these fields, scientific studies have not demonstrated any causal connection between exposure to electromagnetic fields and cancer or other disease.[585] Electromagnetic fields do have the potential to interfere with certain implantable medical devices, such as pacemakers, but the strength of an electromagnetic field decreases rapidly as distance from the source increases.[586]

The cultural and historical impacts of transmission infrastructure may include the visual or physical disturbance of important resources. Transmission lines may create a new visual feature in places of cultural or historical significance, diminishing the value of the resource for people who seek to experience it. Cultural resources may include sacred tribal lands; historical resources may include historic trails and sites. These harms can be largely mitigated using the same measures discussed in the paragraph describing aesthetic harms above. Additionally, project developers should consult with relevant tribes and state agencies regarding the locations of resources of particular value and seek to avoid disruptive development near those areas.[587] The construction of transmission infrastructure may reveal artifacts of cultural or historical significance or turn up sites of archeological importance. The potential impacts of these discoveries can be mitigated through the development of a discovery plan that outlines the appropriate steps for crewmembers to take in notifying the relevant tribes, state agencies and law enforcement.[588]

Whether developed by a federal or non-federal entity, transmission development typically includes sufficient federal involvement to trigger the NEPA's environmental analysis requirements. Depending on the scope of the impacts, project developers may be required to assist a federal agency in preparing a relatively basic EA or a significantly more comprehensive EIS. The NEPA process does

582 http://teeic.indianaffairs.gov/er/transmission/impact/construct/index.htm.
583 http://www.blm.gov/or/districts/prineville/plans/wbw_power_row/files/wbw_power_row_final_EIS.pdf.
584 http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0422-DEIS-2010.pdf at S-23.
585 http://www.niehs.nih.gov/health/materials/electric_and_magnetic_fields_associated_with_the_use_of_electric_power_questions_and_answers_english_508.pdf at 16-27.
586 http://www.niehs.nih.gov/health/topics/agents/emf/.
587 http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EIS-0422-DEIS-2010.pdf at S-23.
588 *Id.*

not impose any substantive responsibilities on transmission developers, beyond allowing public input and requiring an analysis of all reasonable alternatives.

Decisions on whether and where to site a transmission line are largely in the domain of the federal land managing agencies, if the line will be on federal land, or in state agencies designated to approve the siting of energy facilities, such as Oregon's Energy Facility Siting Council (part of the Oregon Department of Energy), if on private land. Federal land management laws and regulations, such as the Federal Land Policy and Management Act (FLPMA), the National Forest Management Act, and the Columbia River Gorge National Scenic Act, provide some measure of protection against and mitigation for environmental effects beyond the NEPA environmental analysis and the specific substantive requirements of laws such as the ESA, MBTA and BGEPA. The same is true of state energy siting and land use laws and regulations that apply to decisions by the state energy siting agencies. A complicated mix of federal and tribal laws and regulations apply to decisions to allow development of transmission lines on the lands of the Indian tribes in the Northwest.

State-federal cooperation in this area occurs in a number of ways. A key driver was a provision in FLPMA in 1976 that required federal agencies to comply with state environmental protection standards in approving right-of-ways across federal public lands for transmission lines and similar projects. Uncertainty over the precise dimensions of this obligation led to litigation the 1980s between states and, in particular, Bonneville, over the development of transmission lines, with the federal courts largely agreeing with the states about the importance of ensuring consideration of and compliance with state environmental protection regulations in approving transmission rights-of-ways.[589] Coupled with the new Northwest Power Act, and uncertainty under that Act as to the extent the regional Columbia River Basin Fish and Wildlife Program should address transmission system impacts to wildlife, led Bonneville and the Northwest states to execute cooperative agreements in the 1980s regarding transmission corridors, transmission line development, and impacts to wildlife. The agreements were intended in large part to assure the appropriate consideration and application of state environmental protections in federal transmission developments. These agreements remain in effect today. The Council has recognized these agreements as a key tool in the way the regional power system should consider, protect against and mitigate for wildlife impacts in transmission system development. It is important that implementation of the agreements and the application of state and federal environmental regulations continues and is effective in addressing impacts to wildlife and other environmental qualities.[590]

State and federal fish and wildlife agencies and Indian tribes expressed concerns during the process in 2013-14 for amending the Council's Fish and Wildlife Program over the cumulative impacts to wildlife from transmission development in the Pacific Northwest, especially in the light of the recent expansion of transmission infrastructure to support renewable energy development, especially wind

[589] *Columbia Basin Land Protection Association v. Schlesinger* (9th Cir 1981) involved the development of the Lower Monumental-Ashe transmission line in eastern Washington. *Montana v. Johnson* (9th Cir 1984), concerned the development by Bonneville of a transmission line from Townsend to Hot Springs, in northwestern Montana, associated with the building of the Colstrip coal plant.

[590] *See* 2014 Columbia River Basin Fish and Wildlife Program, Appendix S, http://www.nwcouncil.org/media/7148962/2014-12appendixs.pdf, at 283.

projects.[591] The Northwest Power Act and the fish and wildlife program and power plans developed under the Act provide a comprehensive regional protection and mitigation program to address the cumulative impacts of existing hydroelectric generating resources on fish and wildlife, as well as provide the opportunity to protect areas from further hydroelectric development and to consider the environmental effects and costs of all new generating resources in deciding which to acquire. Similar comprehensive regional laws and programs do not to exist to address the cumulative effects of and mitigate for transmission development or renewable energy development, or to provide for comprehensive and enforceable protected areas for transmission and renewable energy development. Also, the Council's power planning authority does not include planning for the development of transmission infrastructure or the ability to include in the plan enforceable provisions regarding the acquisition of or the decisions to approve transmission lines. Associated transmission development is instead part of the life-cycle costs (including environmental costs) and matters of environmental quality to be considered in analyzing and comparing the costs of new resource alternatives. See Chapter 19. It is unclear at this point whether the existing federal and state mechanisms to address environmental effects of transmission development, especially including effects to wildlife, are not adequate to address the concerns raised by the wildlife managers, and if inadequate, what can be done to improve this situation. The Council is committing, in an Action Plan item, to helping the fish and wildlife agencies and Indian tribes to work with the entities and agencies involved in developing, operating, and regulating transmission infrastructure to explore these concerns further. This investigation may also assist the Council in future power plans in considering the environmental issues raised by the transmission development associated with new resource development. And most important, avoiding the environmental impacts of transmission is another of many considerations supporting the aggressive development of cost-effective energy efficiency and demand response measures in the plan's resource strategy.

[591] *Id*., at 283, 329-30.

ACRONYMS AND ABBREVIATIONS

Acronym	**Meaning**
ACI	Activated Carbon Injection
ACP	Advanced Conservation Practices
BART	Best Available Retrofit Technology
BGEPA	Bald and Golden Eagle Protection Act
BLM	Bureau of Land Management
BPT	Best Practicable Control Technology Currently Available
BTA	Best Technology Available
CAA	Clean Air Act
CaBr2	Calcium Bromide Treatment of Coal
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CE	Categorical Exclusions
CGS	Columbia Generating Station
CO_2	Carbon Dioxide
Corps	Army Corps of Engineers
CREP	Community Renewable Energy Projects (Montana RPS)
DESP	Dual Electrostatic Precipitators
DSI	Dry Sorbent Injection
EA/FONSI	Environmental Assessment and Finding of No Significant Impact
EIA	Energy Information Administration
EIS	Environmental Impact Statements
EMS	Entrainment Mortality Standards
EPA	Environmental Protection Agency
ESA	Endangered Species Act
ESP	Electrostatic Precipitator
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FWS	Fish and Wildlife Service
GWP	Global Warming Potential
HNO_3	Nitric Acid
IMS	Impingement Mortality Standards
Li-ion	Lithium Ion
Li-NCM	Lithium Nickel Cobalt Manganese Oxide
LNB	Low NOx Burners
MATS	Mercury and Air Toxics Standards
MBTA	Migratory Bird Treaty Act
MOFA	Modified Overfire Air
MSHA	Mine Safety and Health Administration
NAAQS	National Ambient Air Quality Standards
NaS	Sodium-sulfur
NEPA	National Energy Policy Act of 1969
NESHAP	National Emissions Standards for Hazardous Air Pollutants
N_2	Diatomic Nitrogen
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide

NO_x	Shorthand reference to nitrogen oxides, but may specifically refer to NO and NO_2
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
OFA	Overfire Air
OSMRE	Office of Surface Mining, Reclamation and Enforcement
PAC	Powdered Activated Carbon
PM	Particulate Matter
PTC	Production Tax Credit
PV	Solar photovoltaic
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit/Renewable Energy Certificate
RPM	Regional Portfolio Model
RPS	Renewable Portfolio Standards
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SMCRA	Surface Mining Control and Reclamation Act
SMR	Small Modular Reactors
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
SOFA	Separated Overfire Air
ULSD	Ultra Low Sulfur Distillate
VOC	Volatile Organic Compound
WECC	Western Electricity Coordinating Council
ZLD	Zero Liquid Discharge