Exhibit F

Montana Department of Environmental Quality's Final Environmental Impact Statement for Bull Mountain Development Company, LLC's Roundup Power Project (Jan. 2002)

State of Montana
Department of Environmental Quality
Permitting and Compliance Division January 2003

Roundup Power Project

Final Environmental Impact Statement

Montana Department of
ENVIRONMENTAL QUALITY

Judy Martz, Governor

P.O. Box 200901 • Helena, MT 59620-0901 • (406) 444-2544 • Website: www.deq.state.mt.us

January 2003

Dear Reader:

Enclosed is the Final Environmental Impact Statement (EIS) for the proposed Roundup Power Project. The Final EIS adopts the Draft EIS as a part of the final, responds to public comments, and provides substantive changes, which amend the Draft EIS in response to public comments.

About 100 copies of the Draft EIS were distributed in November 2002 for a 30-day comment period. During the comment period, the Department of Environmental Quality (DEQ) held a public hearing in Roundup to receive oral and written comments on the Draft EIS. In addition to oral testimony, DEQ received 80 letters, about 500 post cards, and more than 1200 e-mails commenting on the Draft EIS. All comments were reviewed and considered in preparing the Final EIS. Comments that provided new data, questioned facts or analysis, or raised questions or issues bearing directly on the alternatives or environmental analysis have been given responses in this Final EIS. Comments expressing personal opinions were considered but have received no direct response.

DEQ has selected the Proposed Action as modified by the Landfill Alternative as the preferred alternative. The final decision will be made in the Record of Decision that will be released no sooner than 15 days from the issuance of this Final EIS.

DEQ appreciates the public's involvement in preparing this Final EIS. Additional copies are available upon request while the supply lasts. The Draft and Final EISs are also posted on DEQ's web site at www.deq.state.mt.us. A copy of the Record of Decision will be sent to everyone who receives the Final EIS.

Sincerely,

Jan P. Sensibaugh

Jan P. Sensibaugh
Director

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CHAPTER 1
INTRODUCTION

This Final Environmental Impact Statement (FEIS), prepared by the Montana Department of Environmental Quality (DEQ), adopts the Roundup Power Project Draft EIS (DEIS), November 18, 2002, as the FEIS with modifications contained in this document.

The FEIS contains a summary of major conclusions and supporting information from the DEIS including the agency's recommendation (Section 2.0), a list of all sources of written and oral comments received during the public comment period on the DEIS (Section 3.0), the agency's responses to substantive comments which includes a summary of the comments received and disposition of the issues involved (Section 4.0), and a description of modifications and corrected errors to the DEIS (Section 5.0). The decision to issue or deny an Air Quality permit for the Roundup Power Project (Project) and rationale for this decision will be included in the Record of Decision (ROD) to be made public no sooner than 15 days after the FEIS release to the public.

1.1 Public Participation

One of the prime objectives under Montana Environmental Policy Act (MEPA) is to involve the public through each step of the decision-making process. This is accomplished by (1) seeking preliminary comments on the purpose and benefits for the pending action and potential issues of concern, (2) requesting and evaluating public comments about the environmental review, and (3) informing the public of the final decision and the justification for that decision in the form of a Record of Decision after review of the FEIS.

The DEIS was issued for public comment November 18, 2002. To seek comments from the public on the DEIS, the DEQ conducted a public hearing on Thursday, December 5, 2002 in Roundup, Montana.

The location for the meeting was selected based on the area likely to experience the greatest impacts from the Project.

During the 30-day public comment period for the DEIS, comments were also submitted to the DEQ in writing. All substantive comments received during the public comment period have been reproduced with DEQ responses in Section 4.0 of this FEIS. Sources of public comments are listed in Section 3.0 with associated comment identification numbers.

CHAPTER 2
SUMMARY

This summary presents a condensed version of information contained in the DEIS for the Project with modifications subsequent to the public comment period. Two alternatives to components of the Proposed Action, in addition to a No-Action Alternative were analyzed in the DEIS. If interested in more detailed information, please refer to the DEIS. The FEIS and the DEIS can be obtained from the DEQ web site at http://www.deq.state.mt.us or, while supplies last, by contacting:

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2.1 The MEPA Process for the Roundup Power Project

The Project is a proposed coal-fired electric generation plant located on private property about 35 miles north of Billings and 13 miles south-southeast of Roundup, Montana. A map of the Project Area is shown in Figure 2-1. The Bull Mountain Development Company (Proponent) submitted an application for an air quality permit to the DEQ on January 14, 2002. The application, which had to meet the requirements of the Clean Air Act of Montana (75-2-101 et seq., MCA and ARM 17.8.701 et seq.), was found to be adequate on July 22, 2002. This started a mandatory 180-day time frame for the environmental review under the MEPA. The purpose of the Proposed Action is to permit activities that provide additional electricity to meet increasing demand for power within the western United States.

Procedures governing the EIS analysis process in Montana are defined in administrative rules implementing the MEPA. This law requires an EIS to be prepared if any action taken by the State of Montana may significantly affect the quality of the human environment (as defined in MEPA). The EIS was written to meet the requirements of MEPA and the administrative rules implementing MEPA.

The Montana DEQ is the lead agency and is responsible for completing an EIS before issuing the Final Air Quality Permit (75-1-201, MCA).

The scope of the EIS includes actions, alternatives, and analyses necessary for the DEQ to make decisions regarding permits or approvals for the Proponent to construct and operate the Project. Permitting decisions will be based on the environmental effects and consequences relative to legal standards as documented in the EIS, along with other information presented during agency decision-making processes.

2.2 Proposed Action

The Proponent has submitted an application to the DEQ for an air quality permit. The Project is designed to be a mine-mouth generating facility using coal from the existing Bull Mountains Mine (Mine) adjacent to the Project. To meet its coal supply needs, the Project Proponent has entered into contractual agreements with the Mine to purchase approximately 2.7 million tons of coal per year. Coal would be delivered from the Mine to the Generation Plant by a 4,000-foot-conveyor system.

The Project would be built specifically to burn coal. The mine-mouth fuel source of the Project is intended to provide stable pricing and reliability for base load power assisting utilities in more reliably serving industrial, commercial, and residential customers.

Two electric generating units, each with a pulverized coal-fired boiler and a steam turbine generator, are proposed. Each unit would be designed to generate a nominal 390 megawatts (MW) gross (350MW net) electrical capacity year-round on a 24-hour-per-day basis, except during planned maintenance periods and occasional repair outages when one unit would normally remain operating. Four to six groundwater wells, approximately 8,500 feet deep, are proposed as the Project's water supply.

A new 161 kilovolt (kV) transmission system (i.e., three circuits), approximately 28.2 miles long, would be built from the Generation Plant to NorthWestern Energy's Broadview Substation, interconnecting with the northwest transmission network. Power generated by this facility would be sold to all classes of electricity consumers (residential, municipal, cooperative, commercial, and industrial customers). The route for the transmission lines would be within or immediately adjacent to the Mine's rail corridor.

Air pollution emissions, wastewater discharges, solid waste disposal, and other significant aspects of the Project would comply with applicable permits and environmental requirements.

2.3 Issues of Concern

Before preparation of the DEIS, DEQ invited the participation of affected federal, state, and local government agencies, Indian tribes, the Project sponsors, and interested persons and groups to discuss issues, concerns, and opportunities, and to help identify the scope of the DEIS. During this scoping process DEQ also identified possible alternatives to the Project.

On April 4, 2002, a public scoping meeting was held by the DEQ in the City of Roundup to identify issues and concerns. Comments were also accepted by mail. In addition, the Project Proponent has sought public participation by making three presentations to the Legislature's Transition Advisory Committee, by participating in the Governor's Conference on Economic Development on March 7, 2002, in Billings, and by making a presentation to the executive board of the Big Sky Economic Development Authority in Billings.

The issues of concern raised during the public and agency scoping process include:

Socioeconomic Effects

- Impacts on schools, law enforcement, and other public services due to in-migration of Generation Plant workers.
- Changes in social setting and attitudes due to in-migration of Generation Plant workers, impacts associated with increased traffic, and infrastructure impacts.

Air Quality

- Impacts due to pollution emissions during Generation Plant operation.
- Global climate impacts due to greenhouse gas emissions during Generation Plant operation.
- Cumulative visibility impacts.

Water Resources

- Impacts on surface water or groundwater quality due to solid waste disposal and other Generation Plant activities.
- Impacts on groundwater levels and supplies due to withdrawals during Generation Plant operation.

Noise

- Disturbance of nearby residents by noise from Generation Plant construction and operation.

Infrastructure

- Adequacy of existing transmission system to carry the Generation Plant output.

DEQ Regulatory Actions and Response

- Evaluation/regulation for combined impacts of the Generation Plant and other industrial developments in the region
- Monitoring of the Generation Plant construction process, including depth of groundwater wells, and response to Generation Plant emissions exceedances of permitted levels
- Accidents during Generation Plant operations and issues involving the proposed landfill

2.4 Alternatives Considered and Eliminated

The Project Proponent identified numerous alternatives to the Project, including:

- Fuel Sources

- Water Supplies
- Cooling Systems
- Combustion Systems
- Solid Waste Systems
- Wastewater Discharge Systems
- Emission Control Systems
- Generation Sites

The alternatives described in this section were eliminated from further consideration because they did not meet the stated purpose for the Project or were found to be economically unreasonable. A summary comparison of the alternatives considered and eliminated is provided in Table 2-1.

2.5 Alternatives Analyzed in Detail in the DEIS

There are two alternatives to components of the Project:

- Landfill Alternative – Alternative to in-mine waste disposal from the Generation Plant.
- 230kV Transmission System – Alternative transmission voltage for interconnection into the transmission grid of the western United States at Broadview Substation.

In addition, a No-Action Alternative was analyzed in detail.

Landfill Alternative

Over the life of the Project, construction and operation of additional landfill cells on the Generation Plant site is proposed as an alternative to moving most of the solid waste to the Mine for disposal. The landfill would be a state-of-the-art facility designed with two cells, providing 60 acres for solid waste storage. The disposal area would be lined for the protection of groundwater and provided with a leachate collection system not to exceed 10 acres to remove leachate and storm water that collects on top of the lining.

230kV Transmission System Alternative

Each generating unit would be designed to generate nominally 390MW gross (350MW net) electrical capacity year round on a 24-hour per day basis. As an alternative to the three circuits of 161kV transmission lines from the Generation Plant to the Broadview Substation, two single-circuit 230kV lines on wood pole H-frame structures in the same corridor as the Project would be constructed. This would require a different transformer and associated equipment to support connection to a higher voltage transmission line. Equipment and construction would be similar to the 161kV Transmission System. Constructing the 230kV Transmission System Alternative would need a certificate under the Montana Major Facility Siting Act.

NorthWestern Energy's Broadview Substation is connected to the transmission grid in the northwest and coordinated by the Western Electricity Coordinating Council (WECC). Improvements are planned for the system to allow approximately 500MW to flow west towards Bonneville Power Administration's (BPA) Garrison Substation and approximately 200MW to flow south to PacifiCorp's Yellowtail Substation. Both transmission providers will perform studies to identify necessary upgrades to support this flow.

No-Action Alternative

Under the No-Action alternative, the Generation Plant and the 161kV Transmission System to the Broadview Substation would not be constructed. The State of Montana would not issue the Final Air Permit for the Project. The purpose and need for the Project would not be met under the No-Action Alternative.

2.6 Expected Impacts From the Alternatives

Affected Environment

The Project would be located approximately 35 miles north of Billings and 13 miles south-southeast of the City of Roundup. The affected environment considered for the Generation Plant Study Area encompassed all of the land in Section 15, Township 6 North, Range 26 East in Musselshell County, Montana. Approximately 208 acres would be devoted to the Generation Plant. The Landfill Alternative would occupy an additional 70 acres of land adjacent to the Generation Plant. The proposed Transmission System and 230kV Alternative would be approximately 28 miles in length, crossing Musselshell and Yellowstone Counties from the Generation Plant to Broadview Substation to the west.

The air quality in the Project Study Area (Generation Plant and Transmission System) is well within the applicable ambient air quality standards for all criteria pollutants. The Generation Plant would be located along the crest of the drainage divide between the Musselshell and Yellowstone rivers. There are no surface water bodies within the Generation Plant Study Area. There are two main aquifers: the shallow sandstone aquifers and the Madison aquifer, which is the proposed water source for the Project.

From on-site soils and vegetation surveys, it has been determined that there are no identified wetland resources within the Generation Plant Study Area. No federal or state-listed plant or wildlife species of concern are known to occur within the vicinity of the Project. The Bull Mountains surrounding the Project support a good diversity of wildlife. Many of these species, particularly non-game species, could occur at least seasonally on or adjacent to the Project site.

A total of 65 cultural resources have been identified within the area of potential effect for the Project. Overall, the Project site contains visual resources such as Signal Mountain and the Bull Mountains. Foothills, ephemeral drainages, riparian vegetation, annual grasslands, and large expanses of ponderosa pine influence the natural visual setting. Human built features include: U.S. Highway 87, dispersed rural residential housing and agricultural fields along with grazing areas. No BLM or U.S. Forest Service (FS) lands occur within or near the Project site.

Environmental Consequences

Where potential impacts to a resource were identified, an evaluation was conducted to determine if one or more actions would be effective in avoiding or reducing (e.g. intensity and/or duration) the potential impact.

Proposed Action

The Project was assessed for compliance with Montana Ambient Air Quality Standards (MAAQS) and the National Ambient Air Quality Standards (NAAQS), and Prevention of Significant Deterioration (PSD) increment levels as part of the air resources analysis. The area of impact included surrounding Class I areas (Yellowstone National Park, UL Bend Wilderness Area, North Absaroka Wilderness Area, and Northern Cheyenne Indian Reservation). The Project, by itself, was above the PSD modeling significance levels.

The Generation Plant would directly impact approximately 208 acres of mostly grass/shrubland habitat with some ponderosa pine. Due to the widespread, common nature of this habitat, and because no federally-listed threatened and endangered species are known to occur in these areas, the loss to wildlife habitat, cattle grazing and agricultural practices would result in a low impact to these resources.

Impacts to groundwater from in-mine storage of waste is unknown. More studies would be required to assess impacts. Zero discharge would cause low impacts on groundwater resources from wastewater ponds and a solid waste landfill.

Soil erosion impacts would be low due to control of runoff from the Generation Plant.

Archaeological sites within three miles of the Generation Plant site would be impacted, of which eight are considered visually sensitive. The Generation Plant chimneys would visually impact residents and travelers.

Full economic benefits realized from implementation of the Project may include tax benefits to Musselshell County and the State of Montana. Jobs would also be a benefit during construction and during the life of the Project.

Portions of a 28.2-mile long and 300-foot wide right-of-way would result in ground disturbance caused by transmission structures and access roads associated with the Project. The transmission right-of-way would remain available for wildlife habitat, cattle grazing and agricultural practices. Due to the widespread, common nature of this habitat, and because no federally-listed threatened and endangered species are known to occur in these areas, the loss to wildlife habitat, cattle grazing and agricultural practices would result in a low impact to these resources.

If cultural or paleontological resources are discovered during Project construction and cannot be avoided, recovery of these resources would ensure no irreversible and irretrievable loss to cultural resources. Visual impacts would occur at road crossings and from scattered residences along the transmission line corridor.

The Project operations would result in the consumption of approximately 8,000 tons of coal per day from the adjacent Mine, which would be irreversibly replaced by the generation of electricity. The loss of these coal reserves would be offset by the benefit of electricity generation by the Project.

Landfill Alternative

Approximately 70 additional acres would be disturbed to develop the waste disposal landfill and associated ditches and access road. Impacts would be similar to Proposed Action with minor soil erosion caused by the transport of waste from the Generation Plant to the expanded landfill site.

The Landfill Alternative would have no impacts on threatened and endangered species. The expansion of the landfill would be more noticeable than the Proposed Action, but would result in only low visual resource impacts. As with the Proposed Action, socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and long-term jobs from operation and maintenance of the facility.

230kV Transmission System Alternative

The 230kV alternative would require fewer circuits and larger conductors, taller poles but wider spans between poles, and different hardware than a lower voltage system to transport the Project's 750MW. During construction, existing roads would be used where feasible but some new roads and upgrades to existing roads would likely be needed. Ground disturbance on the right-of-way would result in permanent loss of acreage for the pole footings and any new access roads. Temporary disturbance at work areas could be returned to pre-project use following construction. No impacts would result to threatened and endangered species.

As with the Proposed Action, socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and improved transmission infrastructure.

Visual impacts would occur at road crossings and from scattered residences along the transmission line corridor.

Cumulative Impacts

Cumulative impacts result from the incremental impact of the Project when added to other past and present actions and future actions under state review.

Residential and Commercial Development

Currently residential and commercial developments are few in the Generation Plant and Transmission System study areas and surrounding Musselshell and Yellowstone counties. Eight rural residences are located within a mile of the Generation Plant. The City of Roundup, located approximately 13 miles to the north of the Generation Plant, is the closest urban development.

According to county records, no new residential developments are currently planned for these study areas. However, given the amount of recent residential development, and the amount of land in these study areas that is subdivided, it is reasonable to assume that a small level of development would occur in the future.

The nearest commercial establishment is the Brandin' Iron Saloon, which is located along U.S. Route 87, approximately two miles north-northwest of the Project study area. A convenience store and a log furniture store are proposed along U.S Route 87, approximately two miles northwest of the Project study area. Other plans for the area include a recreational vehicle park and golf course.

Industrial Development

The PM Mine, an underground coal mining operation, was located partially in Section 14, east of the Project study area. The PM Mine ceased operation in the 1990s, but the Bull Mountains Mine No. 1 plans to resume mining of the same area. No new coal mines or other industrial developments are known to be proposed for the Generation Plant or Transmission System study areas.

Infrastructure Development

Roads

Portions of U.S. Route 87 between Roundup and Billings were upgraded during the 1990s. The only known proposed future upgrades are the construction of acceleration-deceleration lanes where Old Divide Road (the proposed access road to the Generation Plant and associated facilities) intersects Route 87.

Transmission

The major backbone of the Montana transmission system is the two 500kV lines that run east to west across the state and through the Broadview Substation (the Project connection point). The 500kV lines connect to the BPA system at Garrison Substation, west of Broadview Substation. Additionally, 230kV transmission connects Broadview Substation to the PacifiCorp system at Yellowtail Substation southwest of the Transmission System Study Area.

According to BPA, major transmission improvements to the BPA system are planned. These improvements would include substation upgrades and transmission line additions between Montana and the Pacific Northwest.

The transmission lines from the Project would be inside or immediately adjacent to the existing railroad right-of-way for the Mine railroad to Broadview Substation, where the lines would connect to the NorthWestern Energy system. No additional land would be disturbed.

2.7 Agency-Preferred Alternative

The DEQ Preferred Alternative is the Proposed Action, with the addition of the Landfill Alternative for long-term solid waste disposal instead of long-term disposal in the Mine. In this alternative, solid waste would be stored in landfill cells adjacent to the Generation Plant site for the life of the Project.

The alternative of disposing waste in the off-site landfill is preferred over the Proposed Action of long-term disposal of waste in the adjacent Mine, because it would result in the least impacts to environmental resources. The uncertainties associated with in-mine storage of waste make the Proposed Action a higher risk for causing impacts and possible contamination to soils, water bearing geological zones, and groundwater resources. In comparison, the use of lined and monitored landfill cells would minimize the risk of these impacts in the future. More information is needed to fully understand impacts from in-mine storage. Therefore, the Landfill Alternative is preferred.

With the construction and operation of the Proposed Action or the two alternatives (i.e., Landfill and 230kV Transmission), all resource areas, with the exception of fisheries, would experience some adverse environmental impacts (refer to Table 2-2). Impacts that would result to vegetation and wildlife would include the loss of approximately 208 acres of grass/shrubland habitat for the Proposed Action or the action alternatives. However, this habitat is common and widespread in this portion of Montana, so impacts would be low. No federally-listed or state sensitive species are known to exist in the Project study areas.

Air quality impacts were not a factor in selecting the Preferred Alternative, as impacts would not be measurably different under the Proposed Action or with selection of either of the action alternatives. Air resources were identified as having the highest Project-related impacts with most impacts ranging from low to moderate. A high impact to three Class 1 Areas (i.e., Yellowstone National Park, North Absaroka Wilderness Area, and Northern Cheyenne Reservation) was identified from Project operations impairing visibility in these areas during specific periods of time each year.

Finally, the socioeconomic benefits of preferring the Proposed Action and the Landfill Alternative (i.e., the Preferred Alternative), as well as the benefits of adding the base load generation at this location and using the proposed fuel source, would outweigh the potential environmental consequences of constructing and operating the Project as the Preferred Alternative.

DEQ's preference for this alternative could change in response to public comments on the DEIS, new information, or analysis completed as part of this FEIS.

Recommended Mitigation

Mitigation measures cannot be required by DEQ without a request from the Project Proponent that they be placed in a permit (75-1-201(5)(a) and (5)(b), MCA). The Project Proponent may request that any or all of the mitigation measures that pertain to expected impacts from their proposed activities be placed in the permits. In those instances when the Proponent chooses not to include a mitigation measure in a state permit, the Project Proponent may decide to perform the proposed mitigation voluntarily.

Construction and Maintenance Access

CM-1 All construction vehicle movement outside the 300 foot-wide easement would normally be restricted to predesignated access as negotiated with the landowner, contractor-acquired access, or public roads. Construction activities for the transmission lines would be restricted to and confined within the predefined limits.

CM-2 Roads would be built at right angles to the streams and drainages to the extent practicable.

CM-3 Culverts or rock crossings would be installed where needed.

CM-4 Existing roads would be utilized for construction where feasible.

CM-5 No paint or permanent discoloring agents would be applied to rocks or vegetation to indicate limits of survey or construction activity.

CM-6 Prior to construction, all supervisory construction personnel would be instructed on the protection of important cultural, paleontological, and ecological resources.

Air Quality

AQ-1 Suggested design and operation mitigation measures include

- Coal cleaning and/or coal preparation
- NOx control
- Carbon sequestration, such as planting trees

Earth Resources

ER-1 A Landfill Management Plan would be developed to address potential environmental impacts from proposed waste disposal.

Water Resources

WTR-1 Alternate water supplies may be necessary for a small number of wells that are proven to be directly influenced by reduction of recharge due to the plant construction.

WTR-2 Installation of groundwater monitoring wells in the vicinity of the landfill area would serve to identify groundwater impacts from leachate releases. Groundwater monitoring wells should be installed prior to startup of landfill operation in order to establish baseline conditions. A minimum of three groundwater monitoring wells would be required to characterize groundwater quality and flow direction beneath the landfill area.

Waste and Cleanup

WC-1 No equipment would be refueled or greased within 100 feet of a wetland or perennial stream. In addition, fuels, oils, lubricants, herbicides, or other potentially hazardous materials would not be stored within 300 feet of a wetland or perennial stream.

WC-2 A spill prevention plan would be developed that addresses containment and cleanup of spills affecting surface waters.

Botanical Resources and Wetlands

BW-1 Existing vegetation would only be cleared from areas scheduled for immediate construction work and only for the width needed for active construction activities.

BW-2 All reseeding mixtures used for reclamation would be certified weed-free.

BW-3 Effective soil erosion control and reseeding of disturbed areas not required for permanent access for the transmission line would be implemented to encourage revegetation.

BW-4 Transmission line structures would be located to span streams and drainages.

Wildlife Resources

WR-1 Harassment of wildlife would not be permitted at any time during Project construction activities.

WR-2 Construction timing would be altered in specific identified areas where sharp-tailed and sage grouse leks are identified.

WR-3 Install raptor diverters on transmission structures in specific identified locations to discourage raptor roosting and potential raptor predation on certain terrestrial species (e.g., sage grouse on strutting grounds).

Cultural Resources

CR-1 Each cultural resource potentially affected by the proposed action should be more completely documented and evaluated so that a formal determination of National Register eligibility can be made by the State Historical Preservation Office (SHPO).

CR-2 An assessment of effects should be performed if a cultural resource is determined eligible to the National Register.

CR-3 Adverse effects should be avoided by Project redesign, if feasible, if a considerable cultural resource would be affected by ground disturbance.

CR-4 Appropriate mitigations measures, including data recovery, should be implemented following consultation with the Montana SHPO, Native American tribes, and other interested parties if a National Register-eligible resource cannot be avoided through Project redesign.

Visual Resources

VR-1 No paint or permanent discoloring agents would be applied to rocks or vegetation to indicate limits of survey or construction activity.

VR-2 Wood poles or dulled metal surfaces would be used for the transmission line to reduce visual contrast.

VR-3 In construction areas where ground disturbance would be substantial or where recontouring would be required, surface restoration would occur as required by the landowner. The method of restoration could consist of loosening the soil surface, replacing rocks or plants removed during transmission line construction, reseeding, mulching, installing cross drains for erosion control, placing water bars in the road, and filling unnecessary ditches.

VR-4 To minimize ground disturbance over the transmission line route and/or reduce scarring (visual contrast) of the landscape, the alignment of any new access roads or cross-country route would follow the landform contours in designated areas where practicable.

VR-5 Non-specular conductors would be used to reduce visual contrast.

VR-6 Where possible the edges of clearings in forested lands or tree groves would be feathered to avoid abrupt, straight lines.

VR-7 Baffled strobe lights would be installed on Project chimneys to direct light upward rather than outward if strobe lighting is determined to be required by the Federal Aviation Administration (FAA).

Noise

N-1 Careful evaluation of specifications and design selection of typical low-noise design options, equipment specifications, building and wall designs, and enclosure constructions would be made during the design process to ensure that the Generation Plant noise is not excessive.

N-2 The Proponent would implement noise control measures at the Generation Plant, such as silencers for decreasing noise generated during boiler steam blowout for plant start-up and maintenance.

N-3 If measured noise levels exceed L_{dn} 55 dBA at the sensitive receptors, then additional noise control measures would be installed, as necessary, to avoid adverse impacts on the sensitive receptors.

Land Use and Safety

LS-1 Existing improvements, such as fences and gates, would be repaired or replaced to their condition prior to disturbance or as agreed to with the landowner, if they are damaged or destroyed by transmission line construction activities.

LS-2 Temporary gates would be installed only with the permission of the landowner and would be restored to original condition prior to disturbance following transmission line construction.

LS-3 All existing roads would be left in a condition equal to or better than their condition prior to the construction of the transmission line.

LS-4 All new access not required for operations and maintenance of the transmission line would be closed using the most effective and least environmentally damaging methods appropriate to that area with concurrence of the landowner.

LS-5 The Project would comply with any FAA requirements regarding public safety.

LS-6 Warning signs and flag-persons would be used at all roadway crossings during transmission line construction for all state, federal, county, and local roads and highways.

LS-7 To prevent problems with livestock during the transmission line construction, all fences and gates would remain closed at all times throughout construction unless specified otherwise by the agency manager or landowner.

LS-8 The Proponent and the construction contractors would coordinate activities with property owners to ensure continued access across the transmission line right-of-way for the use of property by the property owner.

LS-9 Harassment of livestock would not be permitted at any time during Project construction activities.

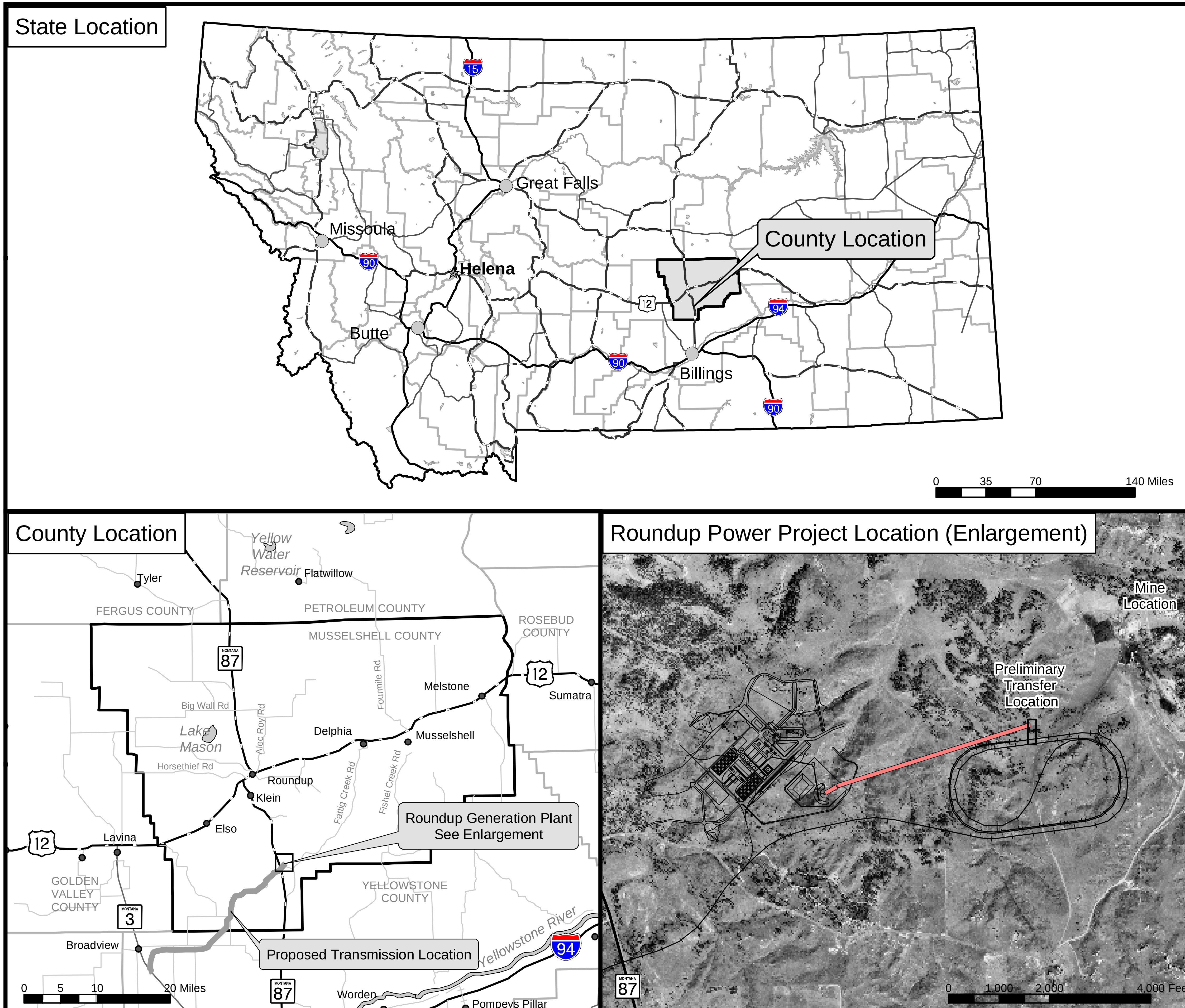

Figure 2-1

Vicinity Map

Roundup Power Project FEIS

Legend

- Preliminary Transfer Location
- Towns
- Cities
- State Capital
- Conveyor Location
- Proposed Transmission
- Interstate Highway
- U.S. Highway
- State Highway
- County Road
- Proposed Railroad
- County Line
- Lake / Stream

Montana Department of Environmental Quality

POWER ENGINEERS

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Table 2-1 Summary of Alternatives Considered But Eliminated

Screening Criteria	Energy Sources & Conveyance					Power Plant Processes									Waste Stream Treatment & Disposal					
	Alternative Fuel Sources					Alternative Water Sources			Cooling Systems	Alternative Combustion Systems				Generation Sites	Alternative Pollution Control and Solid Waste Treatment			Alternative Solid Waste Disposal Methods		
	Lower Sulfur Coal	Synthetic Fuels (e.g., shale oil, tar sands, etc.)	Coal Bed Methane	Gases	Fuel Cells	Yellowstone River	Musselshell River	Shallow Aquifers	Wet Cooling	Stoker	IGCC	Alternative Boiler Types	Gas Turbines / Combined Cycle		Ash & Wet FGD	Wet FGD	Separate Bottom Ash from Waste	Waste Rock Landfill	Off-Site Landfill for Life of Project	On-Site Landfill for Life of Project
Technical	Technically feasible, however coal-fired powerplants are designed to burn specific coal. Therefore, not technically feasible using the current design.	Technically feasible, but would not be feasible under current design. It is doubtful that the source could not solely support proposed load	Technically feasible, but would not be feasible under current design. Source may not be available as fuel supply after 2008	Technically feasible, but not feasible under the current design. There are many gas facilities planned throughout the country competing for limited supplies of gas.	Techically feasible, however not feasible under current design and for this size facility. Design is totally different and tied to gas or hydrogen.	Technically feasible - a pipeline could be constructed and water rights may be available.	Technically feasible, although there is not likely enough water consistently available from the Musselshell to make it a reasonable alternative water source.	Technically feasible, although not enough water is likely available from the shallow acquifer to make it aq reasonable water source.	Technically feasible, although this would increase the amount of water needed and would result in additional water resource impacts.	Technically feasible, but not practical economically.	Technically feasible.	Cyclone and CFB boilers would be used to burn higher sulfur coal and use smaller boilers. Three CFB units would be needed. Solid waste would increase.	Technically feasible in one of many different configurations being used around the country.	Other sites are not feasible in order to utilize Bull Mountain coal.	Dewatering and treating.	Waste streams would have to be separated and treated	Process would include keeping bottom ash separate from the fly ash and flu gas wastes. Disposal would be segregated.	Would need to modify Waste Rock Repository to accommodate and isolate Ash Lens	Would require additional permits.	Would likely be difficult to accommodate waste disposal on-site for the life of the project due to limited space available.
Logistics	Cost would be much higher to transport coal from other mines.	There are no conveyances available for fuel supply.	There are no conveyances available for fuel supply.	There are no conveyances available for fuel supply.	There are no conveyances available for fuel supply.	Require pipelines, pump stations, and easements	Require pipelines, pump stations, and easements	Would require additional wells. Wouldldrawdown local wells in the area	Would require different design and increase water use.	Would require completely new facility design. This system would burn more coal for same MW output.	Would require completely new facilty design.	Would require completely new facility design. This system would burn more coal for same MW output.	Would require completely new facility design. No gas lines are within the area that could supply the fuel requirements. Facility would burn more gas for same MW output.	The handling logistics of transporting coal to another site would make the plan uneconomical and therefore infeasible.	Would require adding slurry pipeline and pumps.	Would require adding slurry pipeline and pumps.	Would not affect air emissions. Would require separate handling and segregated disposal, thus increasing costs.	Would need to truck at least 20 loads of ash to waste rock area per day.	TSDF construction.	TSDF construction.
Economics	Ecomonics of the facility dependent upon an abundant supply of coal in the immediate vicinity as a mine-mouth project	Ecomonics of the facility rely upon an abundant supply in the immediate vicinity, of which there are none.	Ecomonics of the facility rely upon an abundant supply in the immediate vicinity, of which there are none.	Ecomonics of the facility rely upon an abundant supply in the immediate vicinity, of which there are none.	Ecomonics of the facility are infeasible and cost prohibitive.	Would be much more expensive and would likely result in the costs being prohibitive.	Would be more expensive due to conveyance costs. Also, insufficient supplies of water would be available.	May or may not be more expensive, but supply is not likely to be sufficient.	Cost of additional water could increase costs.	More reasonable cost s but could not meet the expected outputs	No data, but costs per MW output would be expected to substantially increase.	No cost analyses were performed for these types of designs.	No cost analyses were performed for these types of designs	Other generation sites would not be as cost effective as a mine-mouth concept, and would therefore be infeasible.	Most economical, but water supply is an issue for this project.	Most economical, but water supply is an issue for this project.	Additional handling and segregated disposal would likely be somewhat more expensive.	Assume costs are similar or somewhat higher because of additional logistics to coordinate waste rock and solid waste disposal.	Would be more expensive because of handling and transportation costs.	Would likely be more expensive for special design and handling to accommodate the solid waste on-site in limited space.
Regulatory Considerations	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No regulations.	Would require water right acquistion.	Would require water right acquisition (e.g., purchase from irrigators).	Would require water right acquistion. Also, insufficient supplies would likely be available on a consistent basis.	Fugitive PM10 emissions from wet cooling towers would have to be calculated and included in modeling analysis.	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	No expected changes in regulation except that new emission rates would have to be calculated and modeled	Regulatory requirements could be somewhat different to accommodate transport of coal and water.	Air permit would need to be modified.	Air permit would need to be modified.	Solid waste permit would need to be modified to accommodate logistics and handling with waste rock.	Would have to modify permit to accommodate this type of disposal.	TSDF permit.	Would have to permit expanded facility to accommodate off-site disposal.
Potential Resource Impacts	Similar to Proposed Action	Similar to Proposed Action	Similar to Proposed Action	Similar to Proposed Action	Water Resource impacts. Air impacts would be minimized or eliminated.	Additional impacts to water resources, fisheries, and other resources from a pipeline.	Additional impacts to water resources, fisheries, and other resources from a pipeline.	Would likely result in impacts to wetlands and water resources, and could affect well production in the area.	Additional impacts to water quality and quantity.	Additional air, solids and water resource impacts would likely result.	Additional air, solids and water resource impacts would likely result.	Air emissions would likely be higher and solid wastes would be increased.	Similar to Proposed Action after air quality mitigation.	More impacts would result to air quality because of transportation costs for the fuel.	Solid waste treatment would be more difficult and would result in more impacts to water quality and quantity.	Solid waste treatment would be more difficult and would result in more impacts to water quality and quantity.	Likely would result in similar impacts as the Proposed Action.	Would increase size of Waste Rock Repository	Could aggravate exposure to groundwater impacts	Solid waste off-site would result in slightly higher environmental impacts, although waste stream not expected to have measurable effect on groundwater resources.
Reasonable/ Feasible	Not reasonable because of fuel transportation costs, increased cost of logistics, and would not meet the purpose and need for the Proposed Action.	Not economically feasible and would not meet the stated purpose and need for the Proposed Action.	Not economically feasible and would not meet the stated purpose and need for the Proposed Action.	Not economically feasible and would not meet the stated purpose and need for the Proposed Action.	Not economically feasible and would not meet the stated purpose and need for the Proposed Action.	Not reasonable because increased costs of pipeline and treatment would make the project infeasible.	Not reasonable because of increased costs of pipeline and treatment, and insufficient water supplies available.	Not reasonable because of insufficient water supplies available.	Common design, but increase in water usage would result in higher construction and operation costs and increased water resources impacts. Alternative is not reasonable.	Not reasonable because increased costs would make the project infeasible, thus not meeting the stated purpose and need.	Not reasonable because increased costs would make the project infeasible, thus not meeting the stated purpose and need.	Not reasonable because these boiler types are designed for different fuel not available at this location.	Not reasonable because turbines are designed for different fuel and since adequate supplies of gas are not available, this alternative is not feasible.	Would not reasonably meet the purpose and need for the Proposed Action because increased costs would make the project infeasible.	Not reasonable since this technology would require additional water and would result in higher impacts to water resources.	Not reasonable since this technology would require additional water and would result in higher impacts to water resources.	Additional handling and segregated disposal would likely be somewhat more expensive, and was eliminated from further consideration because of increased costs and handling with no benefit.	Not a reasonable alternative because additional logistics and costs with no benefit, and is considered and eliminated.	Is not reasonable because increased costs would result in no benefit.	Not reasonable because of space limitations.

		Table 2-2 Alternatives Comparison Summary					
		Proposed Action	Waste Disposal Alternatives		Transmission System Alternatives		No Action
			Proposed Action - Waste Disposal in Mine After 10 Years	Alternative - Expand Landfill After 10 Years (Preferred Alternative)	Proposed Action - 3 Circuits of 161kV Transmission	Alternative - Double Circuit 230kV Transmission Line	
		Roundup Power Project, as proposed	More information would be required for in-mine storage of waste ash with long-wall coal mining method.	Designed same as Proposed Action landfill; 3 times larger landfill area	161kV would require more circuits, shorter poles and shorter spans between poles than a higher voltage system to transport 750MW	230kV would require fewer circuits and larger conductors, taller poles but wider spans between poles, and different hardware than a lower voltage system to transport 750MW	Generation facility would not be constructed or operated. Transmission System and Waste Storage proposed action or alternatives would not be constructed and operated.
Resource Impacts	Ground Disturbance	208 acres of ground disturbance.	208 acres of ground disturbance	Additional ~70 acres would be disturbed to develop the waste disposal landfill and the road	Use existing roads; would need some new roads and upgrades to existing roads pending railroad spur construction; Ground disturbance on right-of-way (300 feet x 28 miles) for structures and access roads; most disturbance temporary.	Use existing roads; would need some new roads and upgrades to existing roads pending railroad spur construction; fewer circuits than lower voltage would require less labor and materials; Ground disturbance on right-of-way (300 feet x 28 miles) for structures and access roads; most disturbance temporary; Less ground disturbance because of fewer	Ground disturbance resulting from constructing and operating the generating facility and transmission lines would not occur.
	Water Resource	Impacts to ground water from in-mine storage of waste unknown; more studies would be required to assess impacts; zero discharge minimizes impacts on ground water resources from wastewater ponds and solid waste landfill	Impacts unknown and will require additional investigation, however could include elevated concentrations of TDS and metals and impacts to spring and well production.	Similar to Proposed Action.	Impacts would occur from access road construction, maintenance activities, and clearing of right-of-way, structure and work areas. Crosses several ephemeral drainages. No perennial streams crossed. Crosses the Hay Basin lakebed.	Similar to Proposed Action.	Water Resource impacts resulting from construction and operation of the generating facility and transmission lines would not occur.
	Earth Resources	Soil erosion impacts would be minimal due to control of runoff from the generation site.	Minor soil erosion would result from transport of waste from generating facility to mine site.	Minor soil erosion would result from transport of waste from generating facility to expanded landfill site.	Minor displacement of earth materials. Direct impacts to soils from access roads, and clearing of right-of-way, structure locations and work areas.	Similar to the Proposed Action; slightly less because of fewer expected structures.	Earth Resource impacts resulting from construction and operation of the generating facility and transmission lines would not occur.
	Biological and Wetland	Loss of ~207 acres of grass/shrubland for wildlife habitat, grazing and agriculture; no impacts to T&E species	No impacts to T&E species	Expanding the landfill would result in additional ~70 acres habitat loss. No impacts to T&E species	No impacts to T&E species	No impacts to T&E species	Biological impacts resulting from construction and operation of the generating facility and transmission lines would not occur.
	Cultural Resource	Archaeological site within the plant site would be impacted. 51 cultural resources within 3 miles of the 574-foot chimneys, of which 8 are considered visually sensitive.	Solid waste disposal haul road and conveyor belt could potentially affect a prehistoric lithic scatter.	Could have greater impacts than Proposed Action due to greater ground disturbance.	Three cultural resources identified within or near transmission route.	Similar to the Proposed Action, however the potential to disturb undiscovered resources may be slightly lower due to increased span length.	Cultural Resource impacts resulting from construction and operation of the generating facility and transmission lines would not occur.
	Visual	Visual impacts to residents and travelers from chimneys.	Low to non-identifiable impacts.	The expansion of the landfill would be more noticeable than the Proposed Action, but would result in only low visual resource impacts.	Visual impacts at road crossings and from scattered residences resulting from transmission lines.	Similar to the Proposed Action - Visual impacts at road crossings and from scattered residences resulting from transmission lines.	Visual impacts of constructing and operating the generating facility and transmission lines would not occur.
	Land Use	Conversion of currently available grazing and agricultural land to heavy industrial use. Recreation use at the plant site would be permanently lost.	Conversion of currently available grazing and agricultural land to heavy industrial use. Recreation use would be permanently lost.	Similar to the Proposed Action.	Crossing of non-irrigated cropland, livestock grazing land, and CRP land.	Similar to the Proposed Action.	Existing land uses would continue. No impacts to land uses from the generating facility and transmission lines would occur.
	Socioeconomic Benefits	Full economic benefits realized from implementation of the Proposed Action, including tax benefits to Musselshell County and the State of Montana, jobs created during construction and during the life of the project to operate and maintain the generating facility and to mine the coal.	Socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and long-term jobs from operation and maintenance of the facility.	Similar to the Proposed Waste Disposal - Socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and long-term jobs from operation and maintenance of the facility.	Socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and long-term jobs from operation and maintenance of the facility.	Similar to the Proposed Transmission Line System - Socioeconomic benefits would result from construction jobs, taxes for government agencies and social services, and long-term jobs from operation and maintenance of the facility.	Musselshell County and the State of Montana would not gain the tax benefits, jobs, and other socioeconomic benefits from operating the generation facility and transmission line, and would not gain the jobs and economic benefits from operating the Bull Mountain Mine to support the fuel needs of the generating facility.

CHAPTER 3
SOURCES OF DEIS COMMENTS

Table 3-1 Comments from Local, State and Federal Agencies and Tribes

Comment Source	Comment Numbers
Local, State and Federal Agencies and Tribes (Refer to Appendix A for agency and Tribe letters)	
Alan Olson – Representative State House of Representatives	8, 106
Charles E. Matthews Process Manager, Network Planning Bonneville Power Administration	142, 143
Dan Martin, Planner Program & Policy Analysis Bureau Rail, Transit & planning Division Montana Department of Transportation	102, 103
Don Codding Air Resource Division Nation Park Service	1, 2, 3, 4, 5, 12, 13, 19, 33, 39, 79, 80
Geri Small, President Northern Cheyenne Tribe Administration	14, 18, 32, 42, 51, 87, 88
James E. Reno, Commissioner Yellowstone County Commissioners	31, 93
Kirby Danielson Subdivision & Planning Musselshell County	94, 95, 96, 97, 98, 99, 100, 101
Richard R. Long U.S. EPA Region VIII	24, 25, 30, 37, 38, 47, 48, 49, 50, 53, 61, 62, 63, 64, 65, 66, 67
Stan Wilmoth, Ph.D. State Archaeologist/Deputy, SHPO State Historic Preservation Office	108, 109, 110, 111

Table 3-2 Comments from Private Citizens and Organizations

Comment Source	Comment Numbers *These comments are summarized from repeated topics.
Private Citizens and Organizations	
Al Mills	Thank you for your remarks
Alan W. Bridwell	17*
Alen Stoll	Thank you for your remarks
Anita Joessmann	Thank you for your remarks
Anne G. Charter, BMLOA Chair Bull Mountain Landowners Association	23, 46, 60
Ann Haggett	85*
Barbara Arms	91, 105
Barbara Yoder	17*
Berklee B. Cudmore	Thank you for your remarks
Beslanowitch	138
Bette Lowery	57
Beverly M. and Robert C. Falsted	Thank you for your remarks
Bob Stocker	Thank you for your remarks
Bonnie E. Miller	17*
Carissa Hill	Thank you for your remarks
Carol Guzman-Aspevig & Clyde Aspevig	Thank you for your remarks
Carrie Atiyeh Kowalski Environmental Defense	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140
Cecil Deming	Thank you for your remarks
Chancie Myers	Thank you for your remarks
Charlotte Trolinger	17*, 85*, 107*
Christine Caramanica	Thank you for your remarks
Christopher Lish	6, 107*
Conrad E. Wickstrom	17*
Curtis & Los Cannell	7
Curtis Hahn	17*
Danny F. Siemers	Thank you for your remarks
Dean Ruscoe	107*

Comment Source	Comment Numbers *These comments are summarized from repeated topics.
Private Citizens and Organizations	
Delores A. Poe	17*
Dennis Campbell	Thank you for your remarks
Dennis O'Reilly	Thank you for your remarks
Don Seyfert	Thank you for your remarks
Donna Luehrmann	17*
EJ Harpham	Thank you for your remarks
Elaine Rippey	Thank you for your remarks
Elizabeth Miles	Thank you for your remarks
Elizabeth Robinson	17*
Ellen Pfister	29, 43, 118, 119, 121
Emily Metzgar	17*
Eric Guidry Energy Project Staff Attorney Land and Water Fund of the Rockies	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140
Eran Holmes	Thank you for your remarks
Fred Bardelli	Thank you for your remarks
G. Todd Baugh	Thank you for your remarks
Garrett Sawyer	17*
Gavin Kramer	Thank you for your remarks
George Holton	Thank you for your remarks
Gray Harris	27
Gregory Wilhelmi	Thank you for your remarks
Group of Citizens of Montana: Patricia Borneman; Sandy Shull; Bruce H. Kershaw; Neil L. Perry; Brian Cooper; John R. Wulsin; Thomas G. Keith; Bill Borneman; Brenda Lochinton; Colette Strizils; Stanley A. Derensing; Irene N. Lee; Joseph Walden	107*
Harry Hardy	17*
Henry Dykema	17*
Herb Fobes	Thank you for your remarks
Hope Sieck Associate Program Director Greater Yellowstone Coalition	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133

Comment Source	Comment Numbers *These comments are summarized from repeated topics.
Private Citizens and Organizations	
Greater Yellowstone Coalition	134, 135, 136, 137, 139, 140
J. McKiely	Thank you for your remarks
James Barnett	Thank you for your remarks
James D. Greene & Martha A. Vogt	85*
James H. Meyers	Thank you for your remarks
Jean Vaira	Thank you for your remarks
Jeffrey J. Smith	Thank you for your remarks
Jerry Fraser	9, 92
Jim & Marge O'Toole	122, 133, 141
Jim Emerson	Thank you for your remarks
Jim Mckowin	Thank you for your remarks
Joan Ryshavy	Thank you for your remarks
Joanne Bernard	Thank you for your remarks
Jocelyn G. Elson-Riggins, Ph.D.	17*
Joel G. Vignere	107*
John and Kathy Pritchard	Thank you for your remarks
John C. Hain	Thank you for your remarks
John L. Delano	Thank you for your remarks
Jonathan Lotz	17*
Judy Reed	Thank you for your remarks
Julie Bolcer	Thank you for your remarks
Kathie A. Bailey	Thank you for your remarks
Kelly Corley Yellowstone Valley Citizen's Council	11, 17*, 23, 24, 31, 37, 61, 133, 135, 137
Kenneth M. Nevel	17*
Kip Gjerde	28, 112
Kip Drobish Raven Ridge Farm	Thank you for your remarks
Laine McNeil	Thank you for your remarks
Lavinia and Frank Reno	Thank you for your remarks
Lisa Discoe	85*
Lori Henderson	85*

Comment Source	**Comment Numbers** *These comments are summarized from repeated topics.
Private Citizens and Organizations	
Lorraine Kuntz	17*
Mack Cole	Thank you for your remarks
Margaret J. Leverton	Thank you for your remarks
Marian Lacklen	Thank you for your remarks
Mark E. Juedman	85*
Marshal Compton	17*, 107*
Martin S. Cohen	Thank you for your remarks
Mary Brower	Thank you for your remarks
Michael Ford	85*
Mike Eiselein	Thank you for your remarks
Mike Lulay	Thank you for your remarks
Mike May	17*
Mike Yochim	Thank you for your remarks
Mr. & Mrs. Donald D. Snow	17*
Mr. Donald G. Knauss	Thank you for your remarks
Ms. Linda M Bonacci	Thank you for your remarks
Ms. Sue Dickenson	85*
Nick Golder	Thank you for your remarks
Patrick Judge Energy Policy Director MEIC	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140
Paul Edwards	Thank you for your remarks
Paul S. Kent & Bill Kent	85*
Peter Zadis	17*, 107*
Philip F. Richmond	Thank you for your remarks
Ramona Clark	17*
Robert Oset	Thank you for your remarks
Roberta Frasca	Thank you for your remarks
Roger and Susan Sherman	107*
Ronni E. O'Neil	85*
Sara Toubman	85*

Comment Source	Comment Numbers *These comments are summarized from repeated topics.
Private Citizens and Organizations	
Shirley Wolters	Thank you for your remarks
Sonja Indreland	Thank you for your remarks
Stan Everson	Thank you for your remarks
Steve and Judy Bayless	Thank you for your remarks
Steve Marquardt	107*
Terry Prichard & Nancy Mertz	17*
Terry Ross (CEED) Center for Energy & Economic Development	15
Tom McKerlick	Thank you for your remarks
Tony Jewett Senior Director, Northern Rockies Region National Parks Conservation Association	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140
Vern O Rich	Thank you for your remarks
Vickie Patton Senior Attorney Environmental Defense	10, 11, 16, 22, 26, 36, 40, 41, 44, 45, 54, 52, 55, 59, 91, 82, 83, 84, 85*, 107*, 113, 114, 115, 116, 117, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140
Wade Sikorski, Ph.D.	56
Wendy Malmid	107*
Wilbur Wood	17*, 34, 35, 58, 85*, 86
William B. Hall	17*

Table 3-3 Comments from Project Proponent

Project Proponent - Thank you for your remarks	
Steven T. Wade Browning, Kaleczyc, Berry & Hoven, P.C. Bull Mountain Development Corp., LLC	20, 21, 68, 68, 70, 71, 72, 73, 74, 75, 76, 77, 78, 89, 90, 104

Table 3-4 Comments from Roundup Power Project Public Hearing

Oral Testimony from Public Hearing Dec 5, 2002 - Thank you for your remarks	
Alan Evans	Kelly Gebhardt
Bart Erickson	Mack Cole
Charles Heath	Michael Lange
Don Codding	Monty Sealey
Gary Mjolsness	Paul Tarmann
Gregory Wilhelm	Philip Richmond
Herb Fobes	Ray Frasca
Joe Dickey	Victor De Maio
John Ligget	

Table 3-5 Comments from Draft Permit Comment Period

Publics and Agencies who commented on Draft Air Permit prior to DEIS	
Wilbur Wood	34, 35, 58, 86
Beslanowitch	138
Eric Guidry Energy Project Staff Attorney Land and Water Fund of the Rockies	52, 59, 81-83, 139-140
Vicki Patton Environmental Defense	52, 59, 81-83, 139-140
Patrick Judge Energy Policy Director MEIC	52, 59, 81-83, 139-140
Steven T. Wade Browning, Kaleczyc, Berry & Hoven, P.C. Bull Mountain Development Corp., LLC	68-78
Don Codding Air Resource Division Nation Park Service	19, 33, 39, 79-80
Geri Small, President Northern Cheyenne Tribe Administration	18, 32, 51

Table 3-6 Comments from Private Citizens via Email

Private Citizens sent via E-mail - Thank you for your remarks		
Adam de Yong	Adam Hill	Adam Miller
Adam Savett	Adriana Francois	Alan Seegert
Alanna Louin	Alex Herrera	Alexandra Miles
Alexia Dorsch	Alexis Kenyon	Alice Bartholomew
Alice Benham	Alice Neuhauser	Alison McDowell
Allen Altman	Allen Church	Allison Shurr
Amanda Petel	Amanda Poverchuk	Amie Osowski
Amy Brzeczek	Amy Corley	Amy R. Prisco
Amy Schneider	Ana Velasco	Andrea Diephuis
Andrew Freeman	Andrew H. Card, Jr.	Andy Lynn
Angela Burbage	Angela Hemingway	Angela Jackson
Angela Thompson	Angie Grosland	Angus Morrison
Ann Hamilton & Ron Stirling	Ann Marie Kotlik	Ann R. Jacobson
Annemarie Fitzell	Annette Hagerty	Annette Johnson
Anthony DiLemme	Anthony Donnici	Anthony Nieter
Antony DiGiovanni	Archbishop Sergius	Art Zernis
Audna Lang	August & Judith Mirabella	Azel Beckner
Barbara A. McClain	Barbara Erb	Barbara Hayward
Barbara Schaeffer	Barbara Yoder	Barre Simmons
Barry Allison	BC Hall	Becky Maller
Becky Russell	Benjamin Coulter	Benjamin Daniel
Berklee B. Cudmore	Bernie Sierelson	Bert Smith
Beth Brown	Bethani Goste	Betsy Robinson
Betty Abel	Betty J. Van Wicklen	Betty Jean Herner
Betty Lowery	Betty Martin	Betty Stephens
Beverly Ackerman	Beverly Drucker	Billie Whittaker
Bob Knapp	Bob Thompson	Bonnie New
Brad Hutcheson	Brain Stewart	Brandy Hinkle
Brenda Lehman	Brenda Planchon	Brent Rowley
Brian Bockhahn	Brian Coan	Brian Lutenegger
Brian Scott	Brian Thomas	Bridgit Roeth
Brooke Livingston	Bruce Acciavatti	Bruce K. Mafarlane

Private Citizens sent via E-mail - Thank you for your remarks		
Bryan Roosien	Bryan Strickland	Bud Corely
Burt Culver	C. B. Pearson	Caitlin O'Reilly
Candace Dias	Carissa Hill	Carl Clark
Carla Burgess	Carla Winterbottom	Carlos Moreno
Carlton Swisher	Carol Blumenthal	Carol Liberatore
Carol Linning	Carol Oster	Carol Pridgeon
Carol Sulanke	Carolyn Bourassa	Carolyn Ganus
Carolyn Miller	Carolyn Mullin	Carrie Atiyeh Kowalski
Casper Nicca	Catherine Knollmeyer	Cathy Arnett
Cathy Burleson	Cedar Stanistreet	Celeste Shitama
Celine Nahas	Chad Fordham	Charlene Root
Charles Ferris	Charlotte Alexandre	Charmaine Oakley
Cheri Downen	Cheryl Owens	Cheryl Thacker
Chris Henderson	Chris Norbury	Chris Palmer
Christina Wilkins	Christopher Lish	Christopher Lukachko
Christopher Mull	Christy Carosella	Christy George
CJ Dupont	Claire Langone	Claire Mikalson
Clarissa Confer	Clark Andelin	Clark Andelin
Clyde Everton	Clyde Remmers	Colette Corwin
Connie Adamski	Connie Boitano	Conrad E. Wickstrom
Constance Chambers	Constance L. Everitt	Corinne Ebinger
Courtney Gartin	Craig Beach	Craig Colistra
Craig Conn	Crystal Booth	Cyndi Torelli
Cynthia Ortiz	Cyrstal Cain	D Scott
D.A.A195 Randall	Dale & Sheree Kesler	Dan and Janet Blair
Dana Palka	Dana Steeples	Dana Suechting
Dana Wullenwaber	Daniel Hawley	Danny Dillow
Darlene Wolf	Dave Easterday	Dave Trochlell
David & Diane Sonneville	David & Nike Stevens	David Anderson
David Byman	David DesRochers	David Koltz
David Lien	David Mills	David Nuckols
David Roederer	David Smith	David Thompson
David Wick	David Wright	David Yingling
Dawn Powell	Dean Griffin	Dean Ruscoe

Private Citizens sent via E-mail - Thank you for your remarks		
Deanna Gerwin	Deanna Wenstrup	Deb Klein
Debbie Feldman	Debbie Gibbs-Halm	Debra Burns
Debra Havill	Debra Lakin	Della Prevele
Delores A. Poe	Demelza Costa	Denise DeGeare
Dennis B. Wolfe	Dennis O'Reilly	Diana Allard
Diana Dexter	Diana Wallace	Diana Wittenbreder
Diane Grinde	Diane Hargreaves	Diane Hert
Diane Lucas	Diane Pratzner	Dianne Beal
Dianne Brehmer	Dianne Patterson	Dick Paull
Dolores C. Pino, Esq.	Don & Pat Griffith	Don Anderson
Don Blanton	Don Renninger	Don Shepler
Don Steinke	Donna Calvao	Donna Cooper
Donna Deutsch	Dora Anderson	Doris Dickens
Dorothy A. Roux	Dorothy Buchholz	Dorothy Hanes
Dottie Moseley	Doug Hilborn	Douglas Adolphsen
Douglas Bushey	Douglas Harmsen	Douglas Murray
Duke Sharp	Edward Petcavage	Eileen Cox
Eileen Levin	Eileen Perry	Eileen Smith
EJ Harpham	Elaine Fischer	Eleanor Burian-Mohr
Eliet Brookes	Elinore Krell	Elizabeth Case
Elizabeth Dodd	Elizabeth May	Elizabeth Miles
Elizabeth Mullen	Elizabeth Olsson	Elizabeth Petersen
Ellen Kolasky	Ellen Mongolis	Elora Gabriel
Elvira Floran-Bernier	Elynor Little Wolf	Emily Johnson
Emily Oesterling	Emily Young	Eric Dec
Eric Holm	Eric Krueger	Eric Speed
Erica Lee	Erich Pessl	Erik Schultz
Erin Zell	Ero Lippold	Esther Cover
Ethan Finkelstein	Eugene Kiver	Frances Cone
Franchezska Zamora	Franco Delucchi	Frank Cassell
Frank McNeely	Frans de Calonne	Fred J. Goebel
Fritz Clark	Fritz Wittenburg	Gail Harmon
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Sharon Jabs	Sharon Morris	Shaun & ReNae Gardner
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Sherry Taylor	Sherryn Frigon	Shidepoke
Shirley Davis	Sienna Wagner	Sister Philothea
Skye Swan	Sonja Hannon	Sonja Indreland
Stacey Forrester	Stacey Perfetto	Staci Bekker
Stacy Bruno Lovra	Stacy Clark	Stefanie Collins
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Weldon H Jackson	Wendi Patrick	Wendy Gardner
Wendy Largent	Wendy Porter	Wendy Powers
Wesley Hamilton	Weyman Culp	WhiteWolf Woman
William B. Hall	William Brent	William Hancammon
William Hermann	William Koenig	William L. Herzberg
William Waters	Wood Lee	Yochanan Zakai
Yvonne Londres	Zach Feris	Zoe Hope

CHAPTER 4
COMMENTS AND RESPONSES ON THE DEIS

Air Visibility

1. A significant reduction in visibility would hinder the benefits and enjoyment of visitors to Yellowstone National Park and UL Bend WA . . . Visibility impacts from the RPP alone would cause a significant change in extinction that would hinder the benefits and enjoyment of visitors to Yellowstone National Park and UL Bend WA on the days those impacts occur. The emissions from RPP would significantly contribute to the more frequent and severe cumulative visibility impacts that occur at both Yellowstone National Park and UL Bend WA.

   Response:

   DEQ agrees that a significant reduction in visibility would be unacceptable. However, the question remains as to whether or not the Project would cause a significant reduction in visibility. Currently, DEQ is analyzing the case-by-case analysis of the days of impact, the FLAG guidance document, and the applicable federal and state rules to determine whether or not the Project may cause or contribute to an adverse impact to Class I areas. A case-by-case analysis was submitted by the Project Proponent to more closely analyze the days that the model predicted an impact. The analysis takes into consideration the actual weather occurrences for the days that indicate visibility impacts greater than 5%. By rule, the Department may not issue a final air quality permit if impairment may result. However, DEQ may issue a final air quality permit if DEQ determines that the visibility analysis does not demonstrate that an adverse impact on visibility will result. DEQ's final decision on the visibility issue will be described in the ROD and will affect DEQ's decision to either issue or deny the Project a final air quality permit.

2. RPP and the MT DEQ have raised the issue as to whether RPP's contribution to the adverse cumulative visibility impacts are "significant" A review of the modeling outputs for the 1990 RPP-only and for the 1990 cumulative visibility impacts was done by the NPS/FWS (National Park Service/US Fish and Wildlife Service) to examine this issue. The results demonstrate that RPP's contributions on days in which the cumulative impacts exceed 10% at Yellowstone National Park and UL Bend WA are indeed significant. For instance, on Day #15 at receptor #33, the cumulative change in extinction is 12.24%. On that same day and at the same receptor, the change in extinction caused by RPP alone is 6.77% or 55% of the total cumulative visibility impact. On Day #16 at receptor #33, the cumulative change in extinction is 14.32%. The extinction caused by RPP alone on this date and receptor is 6.33%, representing 44% of the cumulative visibility impact. Similarly, for UL Bend WA on day #46 at receptor #351, RPP's contribution was 8.41% of the total 29.18% change in extinction (29%). Our review of both the 1990 and 1992 results shows many additional instances when RPP represents a significant percentage of a cumulative

change in extinction that is greater than 10% change in extinction at Yellowstone National Park and UL Bend WA.

Response:

See response to Comment #1.

3. This determination must be made on a case-by-case basis taking into account the geographic extent intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Class I area, and (2) the frequency and timing of natural conditions that reduce visibility.

Response:

See response to Comment #1.

4. The Administrative Rules of Montana also give a similar definition, stating that "adverse impact on visibility means visibility impairment which the department determines does or is likely to interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within a federal Class I area.

Response:

See response to Comment #1.

5. With respect to the relationship of visibility impact and time of visitor use of the Class I areas, Yellowstone National Park and UL Bend WA are both open to visitor use 24 hours a day, year-round. Thus visitation can and does occur at any time. There were nearly three million recreational visits to Yellowstone National Park during 2001. For many visitors this is a once-in-a-lifetime experience, and the NPS and FWS are greatly concerned that the experience of each and every visitor not be interfered with by adverse visibility impairment on any day(s) in which visitation occurs. Regarding natural conditions that reduce visibility, RPP has stated that the 1990 impact that is greater than 10% occurs during a snowstorm and that a park visitor 1) would not be out in the elements to view the scenery with any expectation of seeing vast distances and 2) the natural background impairment of the snowstorm would far outweigh the impact of RPP (October 21, 2002, letter to D. Walsh, MT DEQ, from J.W. Dickey). This argument is flawed because it assumes that the snowstorm would be occurring throughout the entire 1.1 million hectare area of Yellowstone National Park, and would affect all visitors present in the park at that time. Further, it is unlikely that this weather condition would persist throughout the entire period that is modeled.

Response:

The FLAG document describes that the determination on visibility impact should take into consideration, on a case-by-case basis, the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Class I area, and (2) the frequency and timing of the natural conditions that reduce visibility. DEQ will take this guidance statement into consideration when determining the magnitude of the Project impact on visibility.

6. The National Park Service modeled visibility impacts for the park, which as a Class I airshed is supposed to have the cleanest air in the nation. Their analysis of the cumulative effect of Roundup with other nearby polluting sources demonstrates a reduction of over 10 percent visibility on 24 days annually–an enormous number in the scope of impacts within Class I airsheds. The Billings Gazette recently reported the National Park Service, U.S. Fish and Wildlife Service, and U.S. Forest Service have expressed concern about the potential for pollution from the plant causing visibility problems at Yellowstone National Park, UL Bend National Wildlife Refuge in north-central Montana, and in the North Absaroka Wilderness Area.

   Response:

   The FLMs have expressed great concern with impacts from the Project at the Class I areas. DEQ takes the NPS concerns seriously; however, a case-by-case analysis of the days that indicated visibility impacts greater than 5% from the Project indicates that the severity of the initial modeling results may have been overestimated. DEQ has yet to determine if the Project may cause or contribute to an adverse impact at any of the Class I areas and is currently analyzing the case-by-case analysis submitted to DEQ by the Project Proponent. See response to Comment #1 for further information.

7. According to the National Parks Conservation Association, the cumulative effect of the Roundup Power Project along with other nearby sources of pollution demonstrates a reduction of over 10% visibility on 24 days annually. Additionally, the cumulative impacts to visibility at Yellowstone National Park from the proposed Roundup Power Project and other nearby sources is 39 days greater than the five percent reduction and 24 days greater than the 10 percent reduction. Because of the nearby Class I air sheds, including Yellowstone National Park, we feel this is unacceptable and must be addressed.

   Response:

   See responses to Comments #1 and #6.

8. As for the visibility concerns of the Federal Land Managers addressed on pages 4-103 and Appendix B-4, B-7, I have to question why the Federal Land Managers's would include air quality data from sources that no longer exist such as the Anaconda Smelter.

   Response:

   Such a question is more appropriately answered by the FLMs. However, DEQ intends to make a determination on the appropriate scenario for conducting the cumulative visibility analysis (as the analyses are described in Appendix B of the DEIS). The decision made by DEQ will be consistent with the applicable air quality rules.

9. The Cumulative Visibility Analysis results should not be based upon emission data of major sources, with no decrease adjustment, from the PSD baseline data of 1975. Either a more recent baseline year should be used or both increase and decrease adjustments should be included. The modeling assesses air quality impacts by doing a "cumulative" visibility analysis. If one or more of the major sources no longer exists,

their emissions should not be included in the baseline, because of the effect on "cumulative" results. The visibility analysis would likely not show nearly as many days of 5% or more Class I exceedences.

Response:

See response to Comment #8.

10. Roundup will have an adverse impact on visibility at Yellowstone National Park, and the UL Bend WA and North Absaroka Wilderness Areas. The state may not issue the air quality permit until these adverse effects are addressed. Montana has a Legal Duty to Consider the Cumulative Visibility Effects of Roundup in Conjunction with Other Emitting and Expected Pollution Sources.

Response:

See responses to Comments #1 and #6.

11. The Federal Land Managers' Modeling Analysis Documents Roundup's Adverse Visibility Impact, and Roundup's Alternative Visibility Analysis Reproduced Under DEIS Scenario Nos. 1 and 3 Are Seriously Flawed.

Response:

DEQ does not believe that any of the three visibility modeling scenarios are necessarily flawed. The FLAG document does not recommend a specific modeling protocol to determine the cumulative visibility impacts; therefore, the three different scenarios were examined. Each if the three scenarios has its own merits. Also see response to Comment # 6.

12. The Federal Land Managers finding of an adverse impact is based upon a demonstration that the current or predicted deterioration of air quality will diminish the area's national significance, impair the structure and functioning of the area's ecosystem, or impair the quality of the visitor experience in the area. Modeling results presented in the RPP PSD application and in the DEIS (based on 1990 data) show one day exceeding a 10% change in extinction and seven days greater than 5% change in visibility extinction at Yellowstone National Park. Four days exceed a 5% change in extinction at UL Bend WA. Further modeling by RPP and NPS/FWS using 1992 data show two days at Yellowstone National Park and four days at UL Bend WA exceeding a 10% change in extinction. Thirteen and sixteen days exceed 5% change in extinction at Yellowstone National Park and UL Bend WA, respectively. The results of the cumulative visibility analysis (both 1990 and 1992 data) indicate that the RPP would be a significant contributing source to adverse visibility impacts at Yellowstone National Park and UL Bend WA. The values represented in all analyses (whether RPP-only or cumulative) predict impacts that would be perceptible to visitors at Yellowstone National Park and UL Bend WA, and would violate two of the three adverse impact criteria cited above (i.e., impair the visitor's experience and diminish the area's national significance).

Response:

The analysis conducted up to the issuance of the DEIS did not include a specific case-by-case analysis of the days of impact shown by CALPUFF. Since the DEIS, the Project Proponent has submitted a case-by-case analysis of the days in question. See responses to Comments #1 and #6.

13. The NPS and FWS have concluded that Roundup Power Project alone would cause an adverse impact to visibility at Yellowstone National Park and UL Bend WA, and contribute significantly to a cumulative adverse impact on visibility at Yellowstone National Park and UL Bend WA. This finding is clearly supported by language found in the Clean Air Act, Code of Federal Regulations, Administrative Rules of Montana and in the enabling legislation that established Yellowstone National Park. Therefore, we ask that the MT DEQ not grant a final PSD permit to RPP until our adverse impact concerns are adequately addressed.

Response:

See responses to Comments #1 and #6.

14. . . . The tribe believes, too, that up to date modeling with current sources be done to show the cumulative effects that impact the Northern Cheyenne Reservations.

Response:

Up-to-date modeling was performed to determine the impacts to the Northern Cheyenne lands. The results are contained in Appendix B of the DEIS.

15. In this case, the applicant and the Department have demonstrated compliance with all of the applicable NAAQS and PSD increments. The NPS/FWS have not demonstrated that the proposed facility will have an adverse impact on an AQRV. Further, no Federal Land Managers demonstration has been submitted that provides proof not merely of a speculative risk of harm, but of demonstrable harm to an AQRV caused by the pollution from the proposed new source. In the absence of utilizing that lawful and available approach, the NPS/FWS should not be allowed to require continuous assessments and studies using questionable, non-peer reviewed and non-regulatory criteria such as those contained in the FLAG documents.

Response:

See responses to Comments #1 and #6.

16. MDEQ did not examine mitigating Roundup's adverse impacts on Class I areas through emission offsets at Colstrip or Other Area Pollution Sources as recommend by EPA.

Response:

DEQ has yet to determine whether or not the Project may cause or contribute to adverse impacts on visibility in the surrounding Class I areas. DEQ does not have the authority in this permitting action to require emission offsets at Colstrip Units 3 and 4, which were permitted by the EPA, or other area pollution sources. If there is a problem with other emission sources, the appropriate course of action would be for the FLMs to certify visibility

impairment. By certifying such impairment to EPA, other programs could be used to rectify problems created by existing sources.

17. ...I am particularly concerned about the impact of this proposed power plant on the air quality around Yellowstone National Park, a Class I airshed.

Response:

The Project would not cause or contribute to a violation of any ambient air quality standard in or near Yellowstone National Park. However, DEQ is analyzing whether the Project may cause or contribute to an adverse impact on visibility within Yellowstone. See response to Comment #1.

18. Visibility is another issue that needs to be addressed (on the Northern Cheyenne Reservation). Nitrogen dioxide greatly impairs visibility with the brown haze associated with it.

Response:

The visibility impacts from the proposed Project on the Northern Cheyenne lands were presented in the DEIS. Case-by-case factors may also influence the days of modeled impact for the Northern Cheyenne lands. The Project Proponent was required to conduct Class I visibility modeling for the nearby mandatory federal Class I areas, as required by Montana's rules. Since the Northern Cheyenne Reservation is not a mandatory federal Class I area, the Class I visibility modeling was not required as part of the New Source Review permitting process. However, as part of the EIS process, the Project Proponent was required to address impacts from the Project and cumulative impacts of the Project with other nearby sources on the Northern Cheyenne Reservation. The modeled impacts on the Northern Cheyenne lands were presented for informational purposes, but according to the regulations, cannot be used to accept or reject a permit application or to dictate permit conditions.

19. A cumulative analysis of visibility impacts is necessary.

Response:

A cumulative Class I visibility analysis was submitted to DEQ and the FLMs. The analysis was discussed by the FLMs, DEQ, and the Proponent. The information from this analysis has been included in the EIS.

20. Although the coal-fired power plant emissions would be higher from an existing plant, or roughly the same from a new plant at another location, additional emissions would result from the transportation necessary to ship the coal to its user. Additional emissions would result from the diesel-powered trains hauling the coal out of Montana. Pollutants from rail transport have been estimated for the approximately 214 trains per year that would be necessary to haul the 2.7 million tons of coal out of state. We have estimated that exporting the coal to the Montana border then burning it at a similar new facility would result in total criteria pollutants of 111% of the Project's total pollutants, and NOx emissions. Similar emission increases would occur for all other emission products.

Response:

The DEIS did not evaluate the impacts of burning Bull Mountain coal in other locations or for other projects. The objective of this Project is to combust the Bull Mountain coal at the Project facility, not at another facility. Conducting an analysis of the impacts from combusting coal at another location is outside the scope of this Project. The impacts from transporting coal to other areas were assessed in the Bull Mountain EIS (1992).

21. The visibility analysis results for Roundup Power Project impacts (Table 4-10) showed nine days of greater than 5% impact in Yellowstone National Park, based on CALPUFF modeling using 1990 meteorological data. Review of IMPROVE monitoring data from Yellowstone for 1990 (direct measurement of light extinction), which was used to determine the background conditions in the CALPUFF model, reveals that on six of the nine specific days for which Roundup impacts were predicted, 12 or more hours of visibility data were considered "invalid" by the NPS due to occurrence of precipitation and/or very high relative humidity. On two additional >5% impact days, six or more hours of data were considered to be invalid because of natural meteorological conditions. The invalid days included the day of highest predicted impact, when 18 of the 24 hours reported precipitation. Similar results were found for 1992 CALPUFF modeling results; out of 15 days of modeled 5% or greater impact, actual Yellowstone visibility was considered to be impacted by natural conditions for nine or more hours on 12 days. These comparisons support the assertion that actual impacts to visibility will not occur on most of the days of model-predicted visibility degradation. . . .

Response:

See responses to Comments #1 and #6.

Modeling

22. The modeling analysis for Roundup is technically flawed. Roundup Failed to Include All Appropriate Sources in its Class I Modeling Analyses for Increments and Visibility Impacts Such as the Massive Oil and Gas Development Planned for Montana and Wyoming, and the YELP Facility. Roundup did not include all appropriate sources in its Class I modeling analysis for increments and visibility impacts. It appears that the modeling analysis did not consider the massive oil and gas development planned for Montana and Wyoming. Roundup also failed to include SO_2 emissions from the Yellowstone Energy Limited Partnership (YELP) facility and other sources listed in Table B-1 of Appendix B. Specifically, Table B-1 lists the increment consuming SO_2 emissions of the YELP facility as zero, as well as for "Williston Basin, EB" and "Colorado Inter., EB."

Response:

DEQ does not agree that the modeling analysis is technically flawed. The Proponent did in fact include all of the increment-consuming sources in its Class I Modeling Analyses for Increments and Visibility. The YELP facility does not consume increment. When YELP was permitted, SO_2 offsets were obtained

from the Billings Exxon Refinery. Also, the Williston Basin, EB and Colorado Inter, EB facilities are compressor stations with negligible SO_2 emissions. Thus, DEQ believes all increment-consuming sources have been appropriately included in the analyses.

While it is correct that the modeling analysis did not consider the massive oil and gas development planned for Montana and Wyoming, it would not have been appropriate to require analyses based on future development that may or may not occur. The Coal Bed Methane programmatic EIS under the BLM's lead has included emissions from the proposed Project along with other recently permitted facilities. The Project Proponent is not required to include speculative development plans in their modeling analysis.

23. The EIS should include a detailed discussion of power plant air pollution's impact on human health and agricultural productivity. It should also include an economic analysis of the value of full enforcement of "Best Available Control Technology (BACT)" requirements.

Response:

The EIS does include an analysis on human health by showing that the ambient impacts from the Project's air emissions would be below the National Ambient Air Quality Standards (NAAQS) and the Montana Ambient Air Quality Standards (MAAQS). The NAAQS/MAAQS are set at levels that are intended to protect human health and the environment, with a margin of safety. The AQRV analysis in the EIS shows the impacts from air emissions (gaseous and trace metals) on sensitive species of plants, animals and soils. (See Section 4.2 of DEIS.)

The BACT analysis that was provided by the Proponent in the air quality permit application and reviewed by DEQ includes an economic evaluation of all proposed pollution control equipment. The Proponent has included additional economic evaluations in response to requests by DEQ for additional information needed for BACT determinations. For instances where the top control technology was proposed and selected, a cost per ton of reduction was not necessarily figured because it did not factor into the BACT decision.

All final BACT determinations summarized in the DEIS were completed using the top-down method outlined in the EPA New Source Review Manual. This method uses economic evaluations, collateral environmental damage assessments, and other appropriate criteria for determining BACT.

24. a) In the draft EIS, cumulative modeled impacts predict that the 3-hour and 24-hour SO2 Class I increments are exceeded in the NCIR Class I area (see Table B-2 of the draft EIS). Under our stated policies, if the Project's modeled contribution is significant, then it would appear that the permit should not be issued without further control or offsets. See 40 CFR 51.166(k); pages C.52 and C.53 of EPA's October 1990 New Source Review Workshop Manual; EPA's July 5, 1998Memorandum from Gerald A. Emison, Director, OAQPS, to Thomas J. Maslany, entitled: "Air Quality Analysis for Prevention of Significant Deterioration (PSD)."

b) Presently, our regulations establish no set values for significant impacts on Class I increment, and to our knowledge, the Montana SIP does not establish values for significance for such impacts either. In concluding in the draft EIS that the Roundup Project would not be a significant contributor to increment exceedances in the NCIR Class I area, it appears that the State has assumed that Class I significance levels EPA proposed in 1996 as part of the NSR reforms proposal (published in the Federal Register on July 23, 1996 - 61 FR 38250) are appropriate. It would be helpful if you could confirm that this is the approach you are using and your basis for concluding that these values represent an appropriate significance threshold for evaluating impacts on Class I increment.

Response:

a) The predicted 3-hour and 24-hour SO2 Class I increments are exceeded in the NCIR Class I area as a result of Colstrip Units 3 and 4. The Project does not cause or contribute to a violation of the Class I increments. As stated on page C.52 of EPA's October 1990 New Source Review Workshop Manual, "The source will not be considered to cause or contribute to a violation if its own impact is not significant at any violating receptor at the time of each predicted violation." The Project Proponent has made this demonstration through the cumulative Class I increment analysis.

b) DEQ has not established any set values for significant impacts on Class I increment nor does the Montana SIP establish values for significant impact. By policy, DEQ uses the 40 CFR 51, Appendix S, values to determine significance (i.e., whether sources locating in unclassifiable areas would cause or contribute to a violation). Because the Project emissions would be above the Appendix S significance levels, a cumulative Class I increment analysis was performed to ensure that the Class I increments would not be violated as a result of the Project. The modeling showed that the Project would not cause or contribute to any Class I increment violation. The EPA-proposed, but not adopted, PSD significance levels are 4% of the Class I increments.

25 In addition, we note that the modeled values for the Project are just under the significance levels for Class I increment used in the draft EIS. Under the circumstances, we believe it is important to carefully verify these modeled values and to correct any deficiencies in the modeling. For example, it appears that the predicted increment exceedances were based on the CALPUFF model being used for all sources near and far to the Class I area. This is not the correct regulatory approach for sources near the Class I area. Rather, the correct regulatory modeling approach would be to use CALPUFF for sources greater than 50 kilometers from the Class I area and ISC for sources less than 50 kilometers from the Class I area. Also, as we describe in greater detail elsewhere in this letter, it appears you may have underestimated emissions from the auxiliary boilers and other sources in your modeling, and we are unable to determine whether modeled values for the main boilers represent worst-case emissions on a 3-hour and 24-hour basis.

Response:

DEQ believes the correct approach for modeling all sources was used. While Colstrip Units 3 and 4 and Rocky Mountain Power are within 50 km of the Class

I areas, all of the other sources are not, including the Project. It was concluded that the cumulative impact modeling results would be most valid if all modeling was performed with the same model, rather than mixing model results from two different models. Therefore, CALPUFF was the model of choice. Furthermore, DEQ already knows the violations on the NCIR border occur by modeling only Colstrip Units 3 and 4 using the ISC model. DEQ believes using CALPUFF is the correct approach.

26. The air quality permit for Roundup must be denied unless the source mitigates the violations of the SO_2 increment at the Northern Cheyenne Class I area.

Response:

See response to Comment #16.

27. The draft EIS admits that estimated SO_2 impacts for the Project "exceed PSD modeling significance levels" (p. 4-15), and estimated cumulative impacts "are above the PSD modeling significance levels" (p. 4-101). The conclusion that no impacts would be felt further than 8.1 miles away from the project is hogwash:

Response:

The DEIS did not state that no impacts would occur further away than 8.1 miles. Table 4-9 states that the radius of impact for the PSD modeling significance level of 5 $\mu g/m^3$ extends to 8.1 miles from the facility. Table 4-9 lists the distance, in miles, to the farthest point (i.e., receptor) at which the radius of impact level of 5 $\mu g/m^3$ for the 24-hour averaging period is reached.

28. While I could reasonably live with 'Low' impact severity, I can not accept 'Moderate' and 'High' impact severities to Montana's air resources as indicated on Table 4-18. The project needs to be reformulated such that all impact severities are 'Low'. The resulting alternative should then be adopted as the DEQ Preferred Alternative.

Response:

Table 4-18 was developed to summarize the potential impacts to air resources from the proposed action and the alternatives. Impact severity was defined as Low, Moderate and High. Low impacts indicated that the Project's modeled emissions were below screening thresholds, while Moderate indicated that the modeled emissions were above the screening thresholds. High indicated that the modeled emissions were near the standards. The standards were not exceeded in any case but the impact severity table was developed to show how close the modeled emissions were to the ambient standards or Class I/II increments. DEQ does not have the authority to deny an air quality permit based upon emissions that would be within lawful limits.

29. According to the EIS, there is an area 8.5 miles in radius from the RPP that will suffer a higher deposition of pollutants. See Exhibit "B" attached hereto. I would like to see a lot more detailed discussion of what we who live within that radius or own land within it can expect as affects to us.

Response:

The 8.1-mile reference is used to identify how far the radius of impact for the PSD modeling significance level of 5 μg/m3 for a 24-hour period extends from the facility. People living within the area or owning land will be impacted by the Project to some degree. However, the modeling has demonstrated that all ambient standards would be met. The ambient standards are set to be protective of human health and the environment.

30. In Table 5-7 (page 50 of the permit application) and Table 4-38 (page 4-99 of the draft EIS), it does not appear that the flare emission limits from the Billings/Laurel sources were considered in the NAAQS/MAAQS modeling; the limits shown appear to be only the limits from the Billings/Laurel SO_2 State Implementation plan (SIP). The flare limits must be considered in the NAAQS/MAAQS modeling.

Response:

The flare emissions were erroneously left out of the model. These limits are 150 lb/3-hr each for Montana Sulphur, Exxon, Cenex, and Conoco. Because the flare limits for Billings/Laurel are not included in the SIP submitted to EPA but are state-only enforceable limits, they were inadvertently left out of the model. The emissions entered into the model were 33,311 lb/3-hr; thus, the total emissions were underestimated by 600 lb/3-hr or 1.8%. However, this fact makes little difference in the final outcome of the modeling. For instance the 1-hour high-second-high modeled concentration is 480 μg/m^3, the background concentration is 41.6 μg/m^3 for a total concentration of 522 μg/m^3. Assuming the modeled results were scaled to account for this omission the difference would be negligible at less than 3 μg/m^3. The one-hour MAAQS is 1300 μg/m^3.

31. The predominant wind direction for this region is from the Southwest. The possible decrease in visibility to Yellowstone National Park is misrepresented.

Response:

Even though the predominant wind direction is from the southwest, visibility impacts are calculated on a 24-hour average. Therefore, the predominant wind direction has little effect when calculating maximum daily visibility impacts. As long as the wind direction is toward Yellowstone National Park during any 24-hr period (i.e., midnight to midnight), visibility impacts can occur at Yellowstone National Park.

32. The Northern Cheyenne Indian Reservation is a redesignated Class I airshed. According to our wind data the prevailing winds are from the northwest. There are over twenty years of air quality data on the reservation. The site of the power plant is approximately 100 miles to the northwest of the reservation. Any impacts from this source, such as sulfur dioxide and nitrogen dioxide, would impact the increment concerning the Class I status.

Response:

The Proponent conducted air-modeling analyses to identify the potential impacts from the Project on the air quality at the Northern Cheyenne Reservation. The analyses were conducted to identify the potential impacts at

the Northern Cheyenne boundary. DEQ has used the information to describe potential impacts in the DEIS.

33. A cumulative SO_2 increment analysis is necessary.

Response:

A cumulative Class I SO_2 increment analysis has been submitted and discussed by the Federal Land Managers, DEQ, and the Proponent. The information from this analysis has been included in the DEIS.

34. We already have a local problem when one considers cumulative effects from emissions from the nearby petroleum and other refineries in Laurel, Billings, and Lockwood, just 35 miles to the south.

Response:

The applicable air quality rules and regulations require that the Proponent consider emissions from other sources in the modeling analyses. The Proponent conducted the analyses (including other emitting sources as appropriate), and DEQ reviewed the analyses to determine the accuracy and adequacy of the modeling that were conducted. Based on the modeling impacts from the Project and other nearby sources, the proposed Project would comply with the applicable air quality rules, regulations, and standards as required for permit issuance.

35. The Department needs to consider the cumulative effects (from all of the new and proposed power plants in Montana) of carbon dioxide and other greenhouse gases and pollutants and particulates that are inevitably released into Montana skies.

Response:

Only emissions from the recently permitted Rocky Mountain Generation facility were included in the cumulative modeling analysis. Other recently permitted sources, such as Montana First Megawatts Plant, Silver Bow Generation Plant, and Thompson River Cogeneration Plant, were not included in the cumulative modeling analysis because they are all located at distances greater than 200 km from the Project. DEQ determined that the impacts from sources this far away would not be significant. Furthermore, carbon dioxide and other greenhouse gases are not regulated air pollutants under the federal or state regulations, so cumulative effects from carbon dioxide were not analyzed.

Short-Term Emission Rates

36. Roundup Failed to Model Maximum Short-Term Emission Rates for SO_2.

Response:

Maximum short-term emission rates for SO_2 were modeled for all short-term modeling analyses (i.e., ambient standards, PSD increments, and AQRV). DEQ will include short-term SO_2 emission limits in the final air quality permit, if one is issued. All final decisions will be provided in the ROD.

37. Currently the draft permit only contains SO_2 emission limitations on a 30-day rolling average. This approach may be acceptable only if modeling for protection of the short-term NAAQS and PSD increments was based on worst-case hourly SO_2 emissions, rather than on the 30-day emission limitations in the draft permit. Based on the information we've received, we cannot tell whether worst-case hourly conditions were modeled. Table 4-8 (page 4-13) of the draft EIS indicates the hourly lb/hr limits and annual lb/hr limits were modeled. The document does not clearly explain what the hourly lb/hr limits are based on; there are no such limits in the draft permit. For example, are these levels based on the source's maximum potential to emit?

    At a minimum, we believe that the permit action should either establish short-term emission limits in the permit itself, or justify that worst-case hourly SO_2 emission limits have been modeled for protection of short-term NAAQS and PSD increments. Our preference would be that the permit itself include the worst-case modeled hourly SO_2 emission limits, in addition to the 30-day BACT limits.

    Response:

    See response to Comment #36.

38. The NO_x emission limits in the draft permit are expressed on a rolling 30-day average, but we do not see this as an issue for protection of NAAQS and PSD increments, because of the NO_x NAAQS and increment are annual averages. However, we do support the comment that the National Park Services made in its August 27, 2002 letter to Dan Walsh, that an equivalent 24-hour limit be set for NO_x to control short-term impacts upon visibility.

    Response:

    Maximum short-term emission rates for NOx were modeled for all short-term modeling analyses (i.e., ambient standards, PSD increments, and AQRV). DEQ will include short-term NOx emission limits in the final air quality permit, if one is issued.

39. The Preliminary Determination on Permit Application does not set a limit on boiler heat input (except for tons of coal per year), nor are there any short-term emission limits for various pollutants. There are no limits at all for H_2SO_4. The lack of short-term (e.g., 3-hr and 24-hr) limits is especially problematic because the applicant has proposed to "overfire" the boilers for short periods, thus resulting in abnormally high emissions. These higher emission rates increase the possibility that AQRVs at Yellowstone NP and UL Bend WA could be adversely impacted. Therefore, we ask that MT DEQ include short-term limits for all pollutants in the final permit. It is also important that these rates correspond to those modeled in the air quality permit impact analysis.

    Response:

    Maximum short-term emission rates for SO_2 were modeled for all short-term modeling analyses (i.e., ambient standards, PSD increments, and AQRV). DEQ will include short-term SO_2 and NOx emission limits in the final air quality

permit, if one is issued. DEQ will review the need to include a limit on boiler heat input.

DEQ is currently discussing the applicability of an H_2SO_4 limit. If DEQ decides to establish a limit for H_2SO_4, the limit will be included in the final air quality permit, if one is issued. Such a decision will be based upon what other recently permitted similar sources have been required to do.

Meteorological Data

40. Use of Billings Meteorological Data Without Consideration of Local Data Is Technically Flawed.

Response:

The Proponent consulted with DEQ prior to conducting any modeling. DEQ agreed that Billings' meteorological data would be considered representative. The EPA New Source Review workshop manual states that site-specific meteorological data is preferred for air quality modeling analyses if one or more years of quality assured data are available. However, if at least one year of site-specific data is not available, five years of meteorological data from the nearest National Weather Service station can be used in the modeling analysis.

41. Roundup Failed to Use the Most Recent Five Years of Meteorological Data.

Response:

The Proponent used five years of surface meteorological data (1987-1991) collected at the Billings International Airport National Weather Station and the corresponding upper air data collected at the Great Falls International Airport National Weather Station. These five years of data represent the most readily available processed data and were approved by DEQ.

42. Page 4-5, 4.2.1: Paragraph number 4 and 5: Acid rain has been known to form miles downwind of a coal fired power plant. We have over twenty years of met data on the Northern Cheyenne Reservation. The prevailing winds are from the west, northwest and north, therefore the reservation would be impacted from RPP.

Response:

Although not performed for the Northern Cheyenne Indian Reservation, acid deposition from nitrogen and sulfur compounds was calculated for the UL Bend WA, Yellowstone National Park, North Absaroka WA, and numerous areas in the Beartooth Wilderness near Yellowstone National Park. Only the receptor at the UL Bend WA showed acid deposition slightly above the Data Analysis Thresholds (DAT) established by the Federal Land Managers. (See Table 4.12 of the DEIS.) The data supplied in the DEIS indicates that the acid deposition from the Project, which includes wet "acid rain" and dry deposition, would not greatly impact the Northern Cheyenne Indian Reservation.

43. A little more recent weather data is in order for both Billings and RPP. See Exhibit "A-1" for an indicator map of where pollution from the RPP will enter the Yellowstone Valley according to the Mine wind rose.

Response:

Even if more recent weather data or onsite data (assuming it is PSD modeling-worthy) are used in the PSD modeling analysis, maximum 3-hour and 24-hour impact values will probably not significantly change. Annual impacts based on a different predominant wind direction will shift with the wind direction, but the annual model-predicted impacts in the Yellowstone Valley are quite low and shifts in predominant wind directions will not cause significantly larger impacts in the Yellowstone Valley.

Best Available Control Technology (BACT)

44. Federal and state clean air laws, and MEPA require Montana to consider available methods - including IGCC - to lower airborne contaminants from Roundup. IGCC is available and must be considered in the BACT Analysis.

Response:

DEQ has followed all federal regulations, state regulations, and EPA-recommended guidance in the evaluation of BACT. Even though evaluating other types of power facilities is out of scope for a BACT analysis, DEQ has examined IGCC facilities. Based on information submitted by the Project Proponent and research by DEQ, DEQ determined that IGCC is not a viable option for the Project.

45 The proposed SO_2 and PM emission limits for Roundup fail to meet Wyoming's recent BACT determination for the WYGEN 2 facility.

Response:

When the draft air quality permit and DEIS were issued, the WYGEN 2 facility had not yet been permitted. Now that WYGEN2 has been permitted, DEQ will consider the determination made for WYGEN2 in the BACT determination. The final determinations on this issue will be described in the ROD and in a final air quality permit, if one is issued.

46. Montana should follow the lead of other states by rejecting the applicants' pulverized coal plant design and directing them to evaluate an Integrated Gasification Combined Cycle alternative under the "Best Available Control Technology (BACT) national standard.

Response:

See response to Comment #44.

47. The draft permit specifies 0.015 lb/MMBtu as BACT, based on use of a baghouse. We believe 0.012 lb/MMBtu or lower should be specified as BACT. A BACT determination of 0.012 was recently made by the Wyoming DEQ for the WYGEN2 project, a 500MW PC-fired boiler to be constructed by Black Hills Corporation. Wyoming’s determination was based on use of a baghouse with membrane-type bags (e.g., Gortex).

Response:

See response to Comment #45.

48. BACT in terms of lb/MMBtu. The draft permit specifies 0.12 lb/MMBtu (on a 30-day rolling average) as BACT, based on use of a dry SO_2 scrubber and assuming 94% control efficiency and worst-case coal sulfur content (equivalent to 1.90 lb/MMBtu as the scrubber inlet). We [EPA] believe a much tighter lb/MMBtu limit should be specified as BACT, for the following reasons: . . .

Response:

DEQ has followed all federal regulations and state regulations in the evaluation of BACT. DEQ is continuing to analyze other recently permitted similar sources as part of the ultimate BACT determination. The final BACT determination will be consistent with the applicable air quality rules. DEQ's final decision will be described in the ROD.

49. BACT in terms of control efficiency. A minimum required SO_2 scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO_2 emissions are minimized at all times, regardless of the sulfur content in the coal. Because of the severe visibility impacts identified by the Federal land manager, we believe the permit should specify scrubber efficiency in the range of 94% to 96% (on a 30-day rolling average), with compliance to be demonstrated via SO_2, CEMS at the scrubber inlet and outlet. We note that 40CFR 60.47a(b)(I) already requires inlet and outlet CEMS. We consider 96% efficiency achievable based in part on BACT determinations by other states (mentioned above), and on vendor literature from Babcock and Wilcox (a manufacturer of large PC-fired boilers and control equipment; see www.babcock.com), which indicates that even higher SO_2 control efficiencies of 96% to 98% can be achieved with dry scrubbers, even where low-sulfur western coal is used.

Response:

DEQ is continuing to review the BACT analysis. Emission control efficiency requirements are typically not the result of BACT analyses. However, DEQ will review this suggestion in the context of the BACT determination. The final BACT determination will be consistent with the applicable air quality rules and recently permitted similar sources. The visibility impacts identified by the FLMs are a separate issue than BACT. The visibility issue cannot be used to establish the BACT determination. See response to Comment #48.

50. The draft permit specifies 0.07 lb/MMBtu (on a 30-day rolling average) as BACT, based on combined use of low- NO_x burners (LNB), selective catalytic reduction (SCR) at 80% control efficiency, and overfire air (OFA). The Montana DEQ's discussion of available control technologies of NO_x fails to mention ultra-low- NO_x, burners (ULNB). Vendor literature from Babcock and Wilcox (see www.babcock.com) indicates that the ULNB, in conjunction with 90% efficient SCR, could achieve NO_x emission rates in the range of 0.015 to 0.025 lb/MMBtu.

Response:

DEQ has followed all federal regulations and state regulations in the evaluation of BACT. DEQ is continuing to review the NOx BACT analysis. DEQ's final decisions will be described in the ROD.

51. It is very important that BACT be implement in the operation of RPP.

Response:

DEQ has reviewed the BACT analysis that was submitted by the Proponent. In addition, DEQ has 1) researched other BACT determinations made throughout the nation, 2) reviewed current BACT proposals in other areas, and 3) discussed BACT proposals with other state and federal agencies. As required by rule, the BACT determinations were made taking into consideration energy, environmental, and economic impacts and other costs. Based upon this BACT review, DEQ determined that the BACT conditions contained in the Preliminary Determination were appropriate. Since the issuance of the preliminary determination, other BACT determinations have been made. DEQ is currently reviewing the BACT determinations. The final BACT determinations will be discussed in the ROD.

52. BACT Determination

a. MTDEQ's Preliminary Determination for the Roundup Power Project Fails to Satisfy the Core Requirements of a BACT Determination

Response:

DEQ disagrees with the assertion that the preliminary determination fails to satisfy the core requirements of a BACT analysis. DEQ believes that the analysis conducted for the preliminary determination completely satisfies the core requirements of a BACT analysis.

b. IGCC is a Well-Established Technology with Significant Emission Reductions Benefits that must be Considered as Part of the BACT Analysis.

Response:

The governing air quality regulations and supporting policy/guidance make it clear that BACT determinations are not a basis for redefining a project. Requiring the Proponent to install IGCC as part of the BACT determination would clearly redefine the Project. The appropriate control technologies were analyzed for the Project.

c. Circulating Fluidized Bed Combustion is a Well-Established Technology with Significant Emissions Reductions Benefits that Must be Considered as Part of the BACT Analysis

Response:

The administrative record shows that DEQ not only considered circulating fluidized bed (CFB) boilers, but DEQ requested more information on this issue from the Proponent. Based on information submitted by the Proponent to DEQ and research by DEQ, DEQ determined that CFB boilers did not constitute BACT.

d. The Proposed SO_2 Emission Limitation Does Not Reflect BACT

Response:

DEQ is continuing to review the SO_2 BACT determination. Additional BACT information has become available since the preliminary determination was issued. DEQ's final BACT determination will be described in the ROD.

e. The BACT Analysis Fails to Adequately Consider Circulating Dry Scrubber Technology

Response:

Circulating Dry Scrubber (CDS) technology was adequately analyzed as part of the SO_2 BACT analysis. The Project's initial air quality permit application included an evaluation of the CDS technology. DEQ requested more information on CDS technology from the Proponent. Based on this information and DEQ research, DEQ determined that CDS technology does not constitute BACT

f. The Draft Permit Fails to Impose an Emission Limitation Representative of BACT for Sulfuric Acid Mist

Response:

DEQ is currently considering a sulfuric acid mist limit for the Project. Any final decisions will be included in the final air quality permit, if one is issued.

g. The Proposed PM_{10} Emission Limit Does Not Reflect BACT.

Response:

DEQ is currently considering revising the PM_{10} emission limit for the Project. Any final decisions will be included in the final air quality permit, if one is issued.

h. MTDEQ Has Failed to Specify a Visible Emission Limitation Representative of BACT

Response:

DEQ does not believe a 5% opacity limit is necessary or constitutes BACT. The definition of BACT in the state regulations allows the establishment of a visible emission limit in lieu of an emission limit if necessary. The definition does not indicate that a visible emission limit must be established as part of the BACT determination. The opacity limit of 20% will remain in the final air quality permit, if one is issued.

Maximum Achievable Control Technology (MACT)

53. The project is subject to case-by-case MACT pursuant to section 122(g) of the Clean Air Act. However, Montana DEQ did not establish case-by-case MACT limits or follow the procedures specified in the Administrative Rules of Montana (ARM)) 17.8.342 or 40 CFR §63.43(c) Review options, (f) Administrative procedures for

review of the Notice of MACT Approval (g) Notice of MACT Approval and (h) Opportunity for public comment on the Notice of the MACT Approval.1

Response:

DEQ concurs that the Project is subject to case-by-case MACT requirements under state and federal regulations. The procedures for completing a case-by-case MACT given in ARM 17.8.342 and 40 CFR 63.43 will be followed in completing a MACT determination (notice of approval or disapproval) prior to beginning actual construction of the Project or in conjunction with issuance of the final air quality pre-construction permit.

54. MDEQ must establish emission limitations for mercury and other HAPS to be discharged from the Roundup Power Plant as required by federal and state law.

Response:

DEQ is responsible for implementing requirements for control of hazardous air pollutants (HAPs) from new major sources of HAPs, as described in the response to Comment #53. ARM 17.8.342 stipulates that a new major source of HAPs must obtain a notice of MACT (maximum achievable control technology) approval prior to beginning actual construction. The MACT determination for newly constructed major sources is governed by requirements in 40 CFR 63.43; the determination results in a MACT emission limitation or requirement which shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source.

A specific design, equipment, work practice or operational standard, or a combination thereof may be substituted for an emissions limit if DEQ specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Federal Clean Air Act [40 CFR 63.43(d)(3)].

55. Mercury has serious, adverse impacts on public health and the environment. MDEQ must establish rigorous Hg emission limitations for Roundup to ensure protection of public health and the environment.

Response:

See response to Comment #54.

56. An increase in mercury exposure across all of southeastern Montana is unacceptable to me.

Response:

See response to Comment #54.

57. What of mercury byproducts?

Response:

When coal is burned in a boiler, mercury is converted to elemental mercury vapor (Hg0) in the high temperature regions of combustion devices. As the flue gas cools, Hg0 is oxidized to ionic mercury (Hg++). In coal-fired combustors, Hg0 may be oxidized to mercuric oxide (HgO), mercuric sulfate ($HgSO_4$),

mercuric chloride ($Hg Cl_2$), or some other mercury compound (EPA-600/R-00-083). Hg0, $Hg Cl_2$, and HgO can adhere to porous solids such as fly ash, powdered activated carbon, and calcium-based acid gas sorbents for subsequent collection in a particulate matter control device.

Once in the atmosphere, mercury exists in either the elemental vapor or ionic form (EPA-600/R-00-083). Most of the mercury in the atmosphere is elemental mercury vapor and inorganic mercury; most of the mercury in water, soil, plants and animals is inorganic and organic mercury (primarily methylmercury) (EPA-823-F-01-011).

Methylmercury is the most common organic form of mercury and is easily absorbed into the living tissue of aquatic organisms and is not easily eliminated. Therefore, it accumulates in predators. The degree to which mercury is transformed into methylmercury and transferred up the food chain through bioaccumulation depends on many site-specific factors (such as water chemistry and the complexity of the food web) through processes that are not completely understood (EPA–823-F-01-001). Methylmercury is highly toxic to mammals, including people, and causes a number of adverse effects. EPA has established a criterion of 0.3 mg methylmercury/kg in fish tissue that should not be exceeded to protect the health of consumers of noncommercial freshwater/estuarine fish. EPA has developed a quantitative model relating air deposition of mercury to accumulation of methylmercury in fish. EPA is also developing procedures to translate methylmercury concentrations in fish to total mercury concentrations in ambient surface water.

58. Mercury emissions were not addressed at all.

Response:

See response to Comment #57.

59. The draft Roundup permit fails to include MACT emission limitations.

1. Roundup's Permit Application Fails to Adequately Address Case-By-Case MACT Application Requirements

Response:

See response to Comment #53.

2. The Mercury MACT Emission Limit for Roundup Should Be Based on Ninety Percent Reduction Achievable with Activated Carbon Injection

Response:

See responses to Comments #53 and #54.

Draft Air Quality Permitting Issues

60. The EIS and air pollution permitting process should be suspended pending demonstration by the applicant of serious intention to commence construction with 12 months of permitting.

Response:

Federal PSD regulations state that a facility must commence construction within 18 months of the final permit being issued or BACT would have to be reevaluated before construction can commence. Currently, the Preliminary Determination of the Project air quality permit states that the Project Proponent must commence construction within 3 years. However, DEQ may change this requirement to 18 months. Any final decisions will be in the ROD, and if issued, the final air quality permit.

61. EPA has not approved into the SIP the de minimis permitting provisions mentions in section II.C.2. We believe section II.C.2 should be removed from the permit.

Response:

State regulations allow for de minimis changes. The regulations apply to sources applying for an air quality permit in Montana.

62. The draft permit only requires a stack test once every five years for NOx and SO_2 emissions from the auxiliary boilers. We do not believe this is adequate to demonstrate continuous compliance with the emission limitations in lbs/hr. For SO_2, the permit should also require record keeping for sulfur content in the fuel oil burned, the quantity of fuel oil burned per hour, and the resulting SO_2 emission rate in lb/hr. For NOx, the permit should require annual stack tests, unless test results are sufficiently below the emission limitation that test frequency can be reduced to once every five years.

Response:

DEQ is examining the testing schedules and record keeping requirements contained in the draft air quality permit. DEQ's internal testing guidance and the use of CEMS will affect the ultimate decision on testing frequency. DEQ's final decisions will be discussed in the ROD and in the final air quality permit, if issued.

63. We have several questions with respect to the PM_{10}, SOx and NOx emission calculations on pages 23 and 24 of the draft permit and the provisions in sections II.A.13 through 17 and 19.

1) First, section II.A.16 limits diesel consumption of the two auxiliary boilers to 5,438,400 gallons per rolling 12-month period and section II.A.17 limits the combined hours of operation of the two auxiliary boilers to 3,300 hours per rolling 12-month period. If you divide total oil consumed by total hours of operation (5,438,400/3,300) you would consume 1,648 gallons/hr. Yet the calculations on pages 23 and 24 assume that 823 gals/hr of oil are used. The calculations on pages 23 and 24 of the draft permit and the emission calculations for the auxiliary boilers in Appendix B2 of the permit application seem to imply that the fuel oil consumption for auxiliary boilers will be around 2,766,000 or 2,716,000 gallons year, respectively. We question whether the limit in section II.A.16 was developed in error. If not, we question why 823 gal/hr was used in calculations on pages 23 and 24.

2) Second, the limit in section II.A.13 is not consistent with the calculations on pages 23 and 24 of the draft permit. The calculations in the draft permit indicated that emissions would be 64.61 lbs of SO_2/yr, yet section II.A.13 has a limit of 6.46 lbs of SO_2/hr. It appears that the limit in section II.A.13 is incorrect. The permit application also appears to indicate that 6.47 lbs of SO_2/hr was used in the permit modeling.

3) Third, the limit in section II.A.19 is not consistent with the calculations on pages 23 and 24 of the permit. Section II.A.19 indicates that the sulfur content of the No. 2 fuel oil used in the auxiliary boilers shall not exceed 0.05%, yet the calculations on pages 23 and 24 indicate that the sulfur content on the fuel oil is 0.5%. Perry's Chemical Engineer's Handbook indicates that No. 2 fuel oil contains 0.5% sulfur (see 1984 edition, pages 9-10 to 9-???). We question whether the limit in section II.A.19 is correct. We also believe that section II.A.19 should be rewritten to make it clear that only No. 2 fuel oil or better can be burned in the auxiliary boilers. Finally, we note that the permit limit for sulfur content in fuel oil needs to be at least as stringent as the 1 lb of sulfur per mmBTU fired limit required by ARM 17.8.322(4).

Response:

The request for corrections to the Preliminary Determination of the Project air quality permit will be examined by DEQ. If warranted, the changes will be made in the final air quality permit, if issued.

64. Section III.H of the permit indicates that construction must begin within 3 years of permit issuance and proceed with due diligence until the project is completed or the permit revoked. We believe this is an unreasonably long period of time before construction must begin. BACT could change considerably in three years; accordingly, our PSD regulations (40 CFR 52.21(r)(2)) provide:

Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

Response:

See response to Comment #60.

65. Although the Montana SIP does not appear to contain an equivalent provision, it does contain ARM 17.8.819, "Control Technology Review," which corresponds to our 40 CFR 51.166(j). Subsection (4) of ARM 17.8.819 provides that for phased construction projects, the determination of BACT must be reviewed and modified as appropriate "at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of BACT for the source."

This makes clear the maximum length of time a BACT determination should be considered valid is 18 months, and although the Roundup Project has not been labeled a phased construction project, we believe the permit must include a term, consistent with ARM 17.8.819(4), requiring review of and potential revision to BACT if construction does not begin within 18 months. In the alternative, the permit should be revised to require that construction begin within 18 months.

Response:

See response to Comment #60.

66. The draft permit does not provide a method for monitoring compliance with the VOC emission limit in section II.A.10.

Response:

State regulations do not require preconstruction permits to have monitoring compliance plans for all regulated air pollutants; however, the Title V operating permit, if issued, will address VOC methods for monitoring compliance.

67. The draft permit does not indicate how the DEQ determined that the 10 to 12-year-old PM-10 ambient data represent the year preceding the receipt of the application. We believe the DEQ should provide an explanation as to why the data represents the year preceding the receipt of the application, or require that ambient PM-10 data be collected that represents such timeframe.

Response:

The Project Proponent consulted with DEQ prior to submitting the air quality permit application. Since there have been no significant additional sources constructed or operating in the Project area since the PM_{10} data were collected, DEQ agreed that 12-year old PM_{10} ambient data represented baseline ambient data and was appropriate to use as ambient pre-monitoring data.

68. The Preliminary Determination cover letter correctly describes the total generating capacity of the two main boilers as "nominal 180-megawatt (MW)." However, several locations in the Permit and the Permit Analysis refer to each boiler simply as a "390-MW PC Boiler." Part 1.A of the Permit Analysis refers to " Two steam turbine-generators rated at 390-megawatt (MMW) gross electrical output each." To avoid confusion and to maintain consistency, it would be best to insert the word "nominal" at each of these locations, or simply refer to each "main boiler." As shown in the spreadsheets included in Appendix B of the permit application, each of the main boilers is capable of generating more than 390 MW when operating in the "valves wide open and 5% overpressure" mode.

Response:

DEQ agrees with this comment and will update the final air quality permit if one is issued.

69. In Section I.B, the plant location is described as "just east of Old Divide Road." It should say "north."

Response:

DEQ agrees with this comment and will update the final air quality permit, if one is issued.

70. In Section II.A, Condition 5 abbreviates “million British Thermal Units” as “mmBtu.” However, all other parts of the Permit Analysis use “MMBtu.” To avoid confusion, “MMBtu” should be used in Condition 5.

Response:

DEQ agrees with this comment and will update the final air quality permit, if one is issued

71. In Section II.A, Conditions 6 through 10 provide lb/hr emission limits for the main boilers, but the values were calculated using 3,737 MMBtu/hr, which is the maximum annual average heat input. As shown in the permit application and explained in our response to DEQ’s 2/27/02 request for additional information, each boiler will be capable of operating at 4,013 MMBtu/hr (in the “valves wide open and 5% overpressure” mode). Since the boilers probably will operate in this mode for some periods of time, the lb/hr emission limits should be based on 4,013 MMBtu/hr. The correct values are shown in bold font below. In addition, we have added tons/yr emission limits based on the maximum annual heat input (3,737 MMBtu/hr x 8,760 hr/year = 32,736,120 MMBtu)….

Response:

DEQ agrees that the short-term emission limits should be based upon 4013 MMBtu/hr. DEQ will update the final air quality permit to use this value, if the air permit is issued.

72. In Section II.A, Condition 16 limits the combined diesel oil consumption of the two auxiliary boilers to “5,438,400 gallons per rolling 12-month period.” The correct value should be “2,719,200” gallons (based on 824 gallons/hr and 3,300 hours/year total for both boilers).

Response:

DEQ agrees with this comment and will update the final air quality permit, if one is issued.

73. In Section II.B, Conditions 1, 2, and 3 require that emission testing of each main boiler “shall continue on an annual basis” after completion of the initial compliance tests. Annual emission testing is unnecessary for NOX and SO_2, because these pollutants will be continuously monitored. In addition, we believe the standard period of emission testing is every 5 years. We recommend changing Conditions 1, 2, and 3 to require emission testing every 5 years or as requested by the Department after successful completion of the initial compliance tests.

Response:

DEQ is examining the testing schedules and record keeping requirements contained in the draft air quality permit. DEQ’s internal testing guidance and

the use of CEMS will affect the ultimate decision on testing frequency. DEQ's final decisions will be discussed in the ROD and the final air quality permit, if one is issued.

74. In Section II.D, Condition 2 requires continuous emission monitoring in accordance with several regulations, including 40 CFR Part 60, Subpart Db. This reference is not correct. For the Roundup project, only the auxiliary boilers are subject to Subpart Db, and the auxiliary boilers are not required to have (and will not have) continuous emission monitors.

Response:

The intention of this permit condition is to identify the subparts that apply to units at the facility, not to impose a condition that is not already required by the New Source Performance Standards (NSPS). DEQ will add text to the final air quality permit, if one is issued, to clarify the intention of the permit condition.

75. In Part II.C, the third and fourth paragraphs under Item 7 say that "Roundup Power is an affected facility" under 40 CFR 60, Subpart Da and Subpart Db. These paragraphs should be revised to clarify that only the main boilers are affected facilities under Subpart Da (which defines an "affected facility" as a steam generating unit that is used to generate electricity) and only the auxiliary boilers are affected facilities under Subpart Db (which defines an "affected facility" as a steam generating unit that is not subject to Subpart Da).

Response:

DEQ will add language to the final air quality permit, if one is issued, to clarify the applicability of the NSPS subparts (Subpart Da and Subpart Db) to the Project.

76. In Part II.C, the fifth paragraph under Item 7 says that "Roundup Power is an affected facility" under 40 CFR Part 60, Subpart Y. This paragraph should be revised to clarify that only the coal handling equipment is an affected facility under Subpart Y.

Response:

DEQ will add language to the final air quality permit, if one is issued, to clarify the applicability of the NSPS Subpart Y to the Project.

77. In Part II.H, Item 2.a contains a list of pollutants for which Roundup has a PTE greater than 100 tons/year. Carbon monoxide (CO) should be added to this list, and VOCs should be deleted.

Response:

DEQ agrees with this comment and will update the final air quality permit, if one is issued.

78. In Part IV, several numerical values in the "emissions inventory" are incorrect… correct values are shown in bold font below….

Response:

DEQ will review the emission inventory and update the inventory as appropriate for the final permit, should a final permit be issued.

79. We appreciate MT DEQ's concern regarding collateral impacts of wet (versus dry) scrubbing. However, given the need to further reduce SO_2 emissions due to their impact upon Yellowstone NP and UL Bend WA, we believe that wet scrubbing (with addition of a wet ESP to control acid mist) should remain a viable option. Even if the dry scrubber option becomes the final determination for this project, we believe that dry scrubbing technology can achieve lower emission than the 0.12 lb/mmBtu rate proposed.

Response:

DEQ still believes that, upon consideration of the collateral environmental impacts (arid region and need for deep water wells), the appropriate BACT determination is the dry scrubber that was required in the preliminary determination. However, DEQ is still considering the ultimate BACT determination. DEQ's final decision will be described in the ROD.

80. We (NPS) continue to believe that the RPP has the potential to create adverse impacts to visibility at Yellowstone NP and UL Bend WA, if allowed to operate under the conditions outlined in the Preliminary Determination on Permit Application. We (NPS) reiterate the need to reduce emissions from the proposed Roundup facility, in order to reduce or eliminate potential impacts to AQRVs at Yellowstone NP and UL Bend WA.

Response:

See responses to Comments #1 - #19.

81. Roundup failed to conduct one year of preapplication ambient monitoring.

Response:

Based upon the results of the ambient SO_2 monitoring conducted by the Proponent, DEQ determined that 4 months of monitoring was adequate to establish the background SO_2 concentrations in the area. However, DEQ expects that the Proponent will collect one year of data. Because the Proponent satisfied state requirements, DEQ has no authority to require the Proponent to collect additional ambient SO_2 data. Therefore, the permit does not contain a condition requiring the Proponent to collect the additional ambient SO_2 data. Furthermore, based on internal DEQ guidance, the Proponent is not subject to preconstruction permit monitoring requirements.

DEQ accepted the PM_{10} data collected by the mine as satisfying the pre-application monitoring requirements for PM_{10}.

82. Key conditions of the draft permit fail to comply with federal and state regulations.

 1. Condition II.D.1 fails to require continuous inlet and outlet SO_2 monitoring pursuant to the requirement of 40 CFR § 60.47a(b)(1).

Response:

The Project is subject to the provisions of the applicable New Source Performance Standards (NSPS). Because Condition II.D.1 of the permit does not reiterate the provisions of a particular NSPS does not void the requirements of the particular NSPS.

2. Condition III.H of the draft construction permit provides that construction must begin within three years of permit issuance. This is in direct conflict with ARM 17.8.731 of the EPA-approved SIP which states that the permit may contain a provision that the permit will expire unless construction is commenced by the date specified in the permit *which in no event may be less than one year after the permit is issued*. Thus, the permit must include a condition that it will expire if construction is not commenced within one year of issuance of the permit, and no extension for commencing construction should be granted without a reanalysis of best available control technology (BACT).

Response:

The rule cited in the comment does not state that the permit shall expire if construction has not commenced within 1 year. One year is the minimum time that DEQ may identify for construction to commence. DEQ does not believe that a 1-year time frame is appropriate in this case.

However, DEQ is currently considering revising the preliminary determination to reflect that if the facility does not commence construction within 18 months of permit issuance, a new BACT analysis will be required before construction can commence. Any final decisions will be reflected in the final air quality permit, if one is issued. See response to Comment #60.

3. Condition II.C.2 of the permit is based on a state provision in ARM 17.8.705(1)(r) that allows for "*de minimis* exemptions" from construction permitting requirements which have not yet been approved by EPA as part of the SIP. Thus, this provision must be deleted from the construction permit, or this permit will allow violations of the EPA-approved SIP. Instead, a provision must be added requiring *any* change that would increase potential emissions of the source to require a construction permit from the MTDEQ prior to commencement of construction on the change.

Response:

See response to Comment #61.

4. The permit must state the maximum hourly capacity of the boilers as a condition of the permit, since it was relied on in determining the short-term emissions rates for the air quality modeling analysis.

Response:

DEQ does not believe that a permit condition is necessary regarding the maximum hourly capacity of the boilers. Furthermore, monitoring compliance with such a condition would be extremely difficult. DEQ believes that the other conditions in the permit will protect the analyses done for the permit

application. However, DEQ will take this suggestion into consideration for the final permit application decision.

83. The permit fails to include a practically enforceable emission limit for VOCs.

Response:

See response to Comment #66.

Greenhouse Gases

84 Carbon sequestration is a viable measure that should be seriously considered to mitigate the harmful GHG discharges from Roundup.

Response:

No existing federal or state regulations require the mitigation (e.g., carbon sequestration) of GHG discharges from the Project . Therefore, DEQ has no authority to mandate GHG mitigation.

85. ...This plant will significantly increase Montana's contribution to the problem of global warming by releasing 8.2 million tons of carbon dioxide per year. Any increase - particularly an increase of that magnitude - is unacceptable, particularly when alternative sources of energy are available....

Response:

See response to Comment #84

86. Carbon dioxide did not appear to be addressed by the power plant information.

Response:

See response to Comment #84. Carbon dioxide was, however, discussed in the DEIS. Please see page 4-20 of the DEIS for the Greenhouse Gas Estimates.

Draft EIS Issues

87. Page 3-4, 3.2.3: Add, "The town of Lame Deer, MT, PM_{10} non-attainment area, is located (down wind) southeast of RPP.

Response:

Comment has been noted, and the sentence will be added to that paragraph.

88. Page 4-16, 4.2.1: Paragraph number 2: change the last sentence to read: "The closest federal non-mandatory Class I area is the Northern Cheyenne Reservation (NCR), located 130 (81miles) km southeast of the site."

Response:

Comment has been noted and the sentence will be edited to read as the comment states. Also, similar language will be used in other areas in the DEIS where the Northern Cheyenne Indian Reservation is stated (e.g., Page 3.9, Section 3.3.2: Paragraph number 3).

89. Table 4-6 should be corrected to state "482 lb/hr SO_2, 24-hour basis" instead of 448.4.

Response:

Comment noted. Document will reflect this change

90. Page 4-17, 1st Full paragraph. It should be explained that the 10% change calculation is relative to the Federal Land Manager's pristine background values for Class I areas in the Western United States.

Response:

Comment noted. Document will reflect this change

Land Use / Socioeconomics

91. . . . proposed direction of the railroad associated with the Power Project.. . .Old Divide Road, on the northern most end is .9 to 1.0 mile from the road to the house, Cole road. Cole Road is not labeled, in spite of the fact that there is mention of 8 residences, nearby....". Exactly how near is very cryptically avoided.. . . Simply enough, the project report, (draft), could easily have included the state mile markers, but again, this minimal information is not included.

Response:

Road will be labeled.

92. On page 3-77, under Social Well-being, it is states "Roundup residents tend to favor new coal development, whereas the ranchers and Bull Mountain "mini-farmers" are perceived by Roundup residents to oppose it." Residents from the Bull Mountains have showed up in substantial numbers to support this proposed project at the Roundup Scoping Session and other public meetings related to the proposed project and the EIS. That perceived opposition has mostly disappeared.

Response:

During the public hearing on the DEIS held December 5, 2002, in Roundup, 15 of the 17 persons giving oral testimony (ranging from legislators to private citizens) supported the Project. The other two persons had reservations but were not totally opposed to the Project.

93. Lack of full consideration for the Positive economic impact the project would have to this region

Response:

Analysis of the Census Bureau’s reports from the 1992 and 1997 Censuses of Government (“Local Government Finances for Individual County Areas by State: 1991-92 and 1996-97”) show a general deterioration in fiscal health for the county and other local jurisdictions of Musselshell County. After converting account balances to constant value dollars and dividing by the respective years’ populations, per capita levels of revenues from county sources (mainly property taxes) and expenditures on most public services declined in real terms. On the revenue side, transfers from the federal and state governments slightly offset

declines in locally-generated revenues, leading to a 7.3% increase in real per capita total revenues between FY 1992 and FY 1997 – this despite a 16.2% decrease in locally-generated taxes and other revenues over the five-year period. Expenditures in all categories except education declined in per capita terms, most in double-digit percentages. Per capita educational expenditures increased by only 2.3%.

The general downturn in the national economy since 1999-2000 undoubtedly has affected fiscal conditions in Montana and Musselshell County. Documentation of the extent of the impact from the U.S. Census Bureau will not be available until the 2002 Census of Governments has been compiled and published. But it is safe to say that the ability of local governments to meet demands for services has been severely constrained by limitations on local revenue sources. The lack of a strong economic base in Musselshell County is the primary factor, which would be significantly alleviated by the construction and operation of the Project and Bull Mountain Mine.

94. Once tax revenues increase, we can deal with these issues appropriately. When you couple the impact of the mine construction and power plant construction, we will have some significant impact quickly and these will be before new revenues begin. Since paragraph 4.12.1 rightfully acknowledges the perspective of both projects, the rest of the document should do so also.

Response:

This is a cash flow issue. Under state law (15-24-3005, MCA), local governmental units and school districts have the authority to impose an in-lieu-of-tax impact fee on new electrical generation projects located within their jurisdictions to compensate for the 10-year exemption from property taxes granted to qualifying facilities as of May 2001 (15-24-3001 and –3002, MCA). Affected local jurisdictions can share a fee not exceeding 0.75% of the Project's construction cost during the first two years of construction, rising to 1.0% (maximum) in the subsequent four years, and then declining to no more than 0.8% over the final four years. On that basis, the projected $440 million cost of the Project would yield a maximum of $38.5 million in impact fees over the first 10 years of the Project (after which local property taxes would become applicable). Refer to Table 4-1, below.

Table 4-1 Local Electrical Generation Facility Impact Fee for Local Governmental Units and School Districts

Year	Impact Fee Basis (%)	Annual Impact Fee ($ million)
1	0.75%	$3.300
2	0.75%	$3.300
3	1.00%	$4.400
4	1.00%	$4.400
5	1.00%	$4.400
6	1.00%	$4.400

Year	Impact Fee Basis (%)	Annual Impact Fee ($ million)
7	0.80%	$3.520
8	0.80%	$3.520
9	0.80%	$3.520
10	0.80%	$3.520
	Total Fee (maximum)	**$38.280**

Total Projected Construction Cost ($ 440 million)

Source: Montana Code Annotated Sec. 15-24-3001, et seq.

These revenues would help to mitigate the additional costs of local public services arising from constructing and operating the power plant over the first 10 years.

95. Page 3-75, section on health and safety. The sections on law enforcement and fire were not coordinated with the proper department officials, . . .

Response:

The following contacts were made with Musselshell County authorities Rosalie Mercardo, dispatcher; Mark Shoup, Highway Patrol; and Chuck Poulos commissary manager; personal communication, January 22, 2002. Gary Thomas, City Hall; personal communication, January 22, 2002. Ron Solberg, Director of Ambulance Services; personal communication, January 22, 2002.

96. This affects the conclusions in section 4.12.8 because of incomplete information. The County Sheriff, and County Fire Chief who chairs the County Fire Council, were not consulted.

Response:

See response #95.

97. Paragraph 4.1.1, page 4-1 discusses mitigation that may be required and mitigation that may be recommended as a condition for permitting. The draft EIS does not make any recommendations for any matter related to emergency services, nor does it discuss who or how these services are to be provided. The assumption seems to be that the county can absorb these impacts. They are not negligible during the construction phase due to lack of funding, and they will be significant to law, fire, ambulance, and roads. If mitigation of these cannot be required, they must be stridently sought by us.

Response:

Plant constructors and operators would be responsible for providing standard on-site fire protection and first aid for worker injuries. This Project would during construction however, increase the need for emergency services due to an increase in personnel and traffic on site. Because these services are paid for through local taxes, mitigation would not be required.

98. Paragraph 4.12.6, page 4-91. There is no mention of impacts to county and local roads during the construction phases of the mine or power plants.

Response:

Average daily traffic volumes on U.S. Route 87 in the vicinity of Old Divide Road are moderate. According to the Montana Department of Transportation, ADT levels between the Yellowstone County line and the town of Klein averaged 2,322 vehicles per day in 1999 (latest data available), dropping to 1,627 VPD north of Roundup. East-west traffic levels on U.S. Route 12 averaged 509 VPD east of Roundup and 2,930 VPD west of town. No data were available for county-maintained roads, but levels on Old Divide Road are believed to be low, since it mainly serves rural residents. Construction traffic for the Project and Bull Mountain Mine would add to traffic levels in the vicinity of the Project, but in view of the close proximity of the Projects to where Old Divide Road joins U.S. Route 87, it is unlikely that local residents would be much affected by Project-related traffic. Traffic management measures like lane striping and shoulder widening would probably suffice.

99. Paragraph 4.12.8, page 4-93. Musselshell County has had and continues to have a high crime rate associated with our poor economic conditions. The data used to suggest a low crime rate for 1999 was a known aberration due to faulty reporting. A short time prior to 1999 we had the highest crime in the state, and using 1999 data misrepresents our current crime statistics.

Response:

Crime rates can be correlated to poverty. Because the Project is expected to increase employment and provide a specific economic boost, however, the crime rate more likely would be reduced. Because the Project would increase the population in the county, this could place additional requirements on emergency services and law enforcement; however the improved economic conditions resulting from the new payrolls and Project procurement spending should significantly improve local economic conditions, which should help reduce crimes.

Plant constructors and operators would be responsible for providing standard on-site fire protection and first aid for worker injuries. This Project would during construction however, increase the need for emergency services due to an increase in personnel and traffic on site. Because these services are paid for through local taxes, mitigation would not be required.

100. The consultation section does not list any consultation with local officials. Nowhere in the document was Disaster and Emergency Services referenced or consulted.

Response:

See response to Comment #96.

101. In the reference section, land use portion, county subdivisions and planning is the source for the facts-at-a-glance document.

Response:

Comment noted. Reference section will reflect the following source of the facts-at-a-glance document, Musselshell County, Montana County Subdivisions and Planning.

102. The meaning or intent of the third sentence in the first paragraph on page 3-74 that begins "The Montana Department of Transportation does not attempt to justify. . ." is not clear. A better explanation of what is intended should be provided or the sentence deleted.

Response:

Sentence will be removed.

103. In the second paragraph on page 3-74 US Route 87 and US Route 12 are referred to as SR 87 and SR 12. If this SR is identifying the roadways as "State Routes" it is incorrect. They are both US Routes.

Response:

Comment noted. Document will reflect these changes.

104. Section 4.12.4 is confusing. While the property tax amount, $26.4 million seems correct, the tax is over a larger base than $440 million. It should also be pointed out that in previous discussions with Musselshell County, a number of services not currently in place will need to be either created or procured (i.e. fire/emergency services, road improvements, etc.). The Project has discussed these with the County and has offered to advance pay some tax payments if these funds are used for the above purposes.

Response:

DEQ concurs with this comment. The Project Proponent has agreed to advance pay some tax payments. This will help alleviate the cash flow issues addressed in comments 93 and 94.

Groundwater

105. What if my well drains into this so-called Madison aquifer, and when the mining operations use thousands of gallons of that water, my water is lost to the deeper level? Will I be faced with "proving I had water before the mine opened, or proving it is the mine's fault that my source is gone?"

Response:

Local users probably obtain water from wells screened in the Fort Union Formation. The Project will obtain water from the Madison Formation. Based on the hydrogeologic properties of the strata between the Fort Union Formation and the Madison Aquifer, which is approximately 7,900 feet deep at the site, it is unlikely that the two aquifers are connected. These two aquifer systems are separated by thousands of feet of silt and clay that act as confining layers. These confining layers inhibit the movement of water between the aquifers. In addition, available data indicate a strong upward vertical gradient in the Madison Aquifer. The vertical gradient in the Madison Aquifer causes water

levels in wells drilled into this limestone formation to rise thousands of feet above the upper contact of the formation at 7,900 feet below the ground surface. The proposed pumping rates for water used by the mine from the Madison Aquifer should not affect the upward vertical gradient. The combination of a strong upward vertical gradient and confining layers separating the aquifers make it virtually impossible for the water resource in the Fort Union Formation to be lost to the Madison Aquifer.

106. Potential impacts to residents in the area from withdrawal of water from Madison formation would be virtually non-existent with a properly constructed well casing program. Casing, cemented back to surface, set through reasonably accessible ground water zones would protect the various aquifers in the Tongue River member of the Fort Union Formation from contamination, either from Madison Formation water due to artesian flow or contamination due to communication from other water sands or coal seams. Additional casing would be run to approximate total well depth and cemented, not necessarily to surface, to protect not only the well bore, but also to prevent mixing of other aquifers. Generally, this is standard practice in wells such as these.

Response:

Thank you for your comment.

Merchant Plant

107. . . . This permit should be denied on other grounds as well. Being classified a "merchant plant" by the state will make it exempt from regulation by the Public Services Commission, which assures that all the power will be sent out of state, rather than servicing the needs of Montanans. . . .

Response:

The Project Proponent has stated that the proposed Project is not a merchant power plant. The Project Proponent intends to market shares of ownership of the Project to utilities that will want to own its electrical output. The owners of the Project will determine where they market the power, and the owners and the market economy will determine the price for the power. Nothing more specific is available, and to make more specific statements would be speculative.

Cultural

108. p. 1-7 It is at this point incorrect to state that the SHPO is reviewing the project under section 106 of the NHPA as no responsible federal agency is identified. SHPO normally consults with DEQ or other state agencies under the Montana Antiquities Act and/or MEPA.

Response:

In Table 1-1, under Permit/Approval, the Montana State Historic Preservation Office provides consultation; there is no permit. Also, under Authority, the

reference to the National Historic Preservation Act should be changed to the Montana Antiquities Act; Montana Environmental Policy Act.

109. p. 2-40 Again reference to section 106 of the NHPA is misleading unless this becomes a federal undertaking. We agree with generic mitigation of impacts to cultural resources as proposed under CR-1, -2, -3 and -4 (however we find the reference to section 106 technically misleading).

Response:

Under CR-2, "in accordance with Section 106 of the NHPA" will be deleted.

110. p. 4-52 Again, since we have not seen the cultural resource reports we are unable to comment other than to agree that areas not inventoried (i.e., groundwater well/pipeline, disposal haul road and conveyor routes) may contain important unknown cultural resources.

Response:

Various consultants performed the cultural resource inventories used for describing the affected environment. All reports referenced in the Draft EIS and inventory forms for all known cultural resources are in the files of the Montana SHPO. No additional systematic surveys and no additional site recording were performed in preparing the Draft EIS.

111. Whether or not we are requested to provide comment on specific site significance, effects or mitigation we believe it would be appropriate that the cultural resource reports prepared for this project be submitted to our office for inclusion in the statewide inventory; see M.C.A.22-3-423.

Response:

See response # 110

Purpose & Need

112. The report states on Page 2-21, that "the potential purchasers of electricity generated by the Project are power distributors (i.e., utilities) and commercial owners in Montana and the western United States." By adding an explanation of the loads anticipated to be served along with the energy & capacity to be supplied to each will not only make the purpose and need more clear but will also aid the reader in understanding the need for and financial feasibility of the transmission line, which is also unclear.

Response:

The Project owners are in the north portion of the Western Electricity Coordinating Council. Each is an equity owner of their share as a base load component of their generation supply mix. Each has identified their generation needs for 2006 and beyond and the Project is intended to be an integral part of their supply portfolio.

Their generation needs are the result of a combination of load growth and cancellation or reduction of existing contracts. Each may also have other generation projects to make up the remaining portion of their supply portfolio. However, the Project is a low cost project and is intended to provide a reliable base load component to each of the owners.

Data from the Pacific Northwest Utilities Conference Committee's (PNUCC) regional forecast in November 2002 show a regional shortfall of just over 4000 MW in 2005-6 and 4738 MW in 2006-7. The Project is intended to serve some of the utilities represented in this study. A similar situation exists for all other utilities in the north portion of the Western Electricity Coordinating Council. The PNUCC has 55 public and private utility and direct served industry members.

The Bonneville Power Administration has notified numerous utilities and direct served industrial customers of cancellations or reductions in existing contracts. Bonneville Power Administration has also notified customers that it will expect utilities to make their own arrangements for load growth rather than Bonneville Power Administration buying power on the market or arranging for power contracts to serve those utilities.

113. The Roundup Power Plant will produce energy that the state of Montana does not in fact demand. In establishing the need for the plant, MDEQ makes no mention of Montana-specific supply and demand statistics. By comparison, the Energy Subcommittee of the interim legislative Environmental Quality Council recently released its report, "Understanding Electricity in Montana" (December 2002) that documents the actual power generation supply and demand data in Montana. According to the data tables contained in that report (and prepared by MDEQ), it appears that Montana has little, if any, need for additional power generation. Table E6 indicates that in the year 2000, Montana consumed a total of 14,569 million kilowatt hours of electricity, which is equivalent to 1663 aMW. Table E2 indicates that Montana produces, on average, 3,177 aMW. In other words, Montana already produces nearly twice as much electricity as it consumes. While it is true that much of that power is owned by out-of-state utilities and the federal government, it is also true that many Montana utilities have significant access to (and contracts for) federal power at extremely competitive preference rates. In the absence of the formal "needs analysis" formerly required by the Major Facility Siting Act, MDEQ lacks a reasoned basis for asserting a need for this facility -- especially a state or local need.

Response:

DEQ agrees that there may not be a need for the Project. The owners of the Project have indicated that they can market much of the output of the Project within Montana, that the cost of the power will be competitive, and that transmission would be available in the future to sell additional capacity to out-of-state customers. It will be up to the ultimate owners of the Project to use the Project's capacity within their service territory or sell some of that capacity into the open marketplace. The provisions of the DEIS that discuss the need for the Project should have been stated in terms of the potential benefits of the Project. Those provisions have been stricken and replaced in the FEIS. While the Project may provide needed generation for in-state and out of-state consumers, and may

result in more competition and lower prices, the owners of the Project would determine where they market the power, and the owners and the market economy will determine the price for that power.

114. Even if Montana's load did increase 260 MW, recently permitted facilities such as NorthWestern (150 MW), Hardin (113 MW), Basin Creek (96 MW), and Thompson River Cogen (13 MW) could easily meet any such need.

Response:

This may be correct. However, it cannot be assumed that any particular plant, especially a recently permitted plant, will be on line at any given time. Across the country permitted projects have been put on hold or cancelled.

115. The DEIS suggests that there are continuing, new electrical generation needs in light of the retirement of aging units. But if the power from this facility is in fact meant to serve as replacement power from existing Montana generators, the Final EIS should include a decommissioning timeline for those facilities.

Response:

DEQ agrees that any timeline for decommissioning of aging power generation facilities is speculative. The DEIS should have stated that power generated by the Project could help meet any increased demand resulting from any retirement of older generating units that may occur in the future.

116. To the extent that this facility is meant to serve a regional or national need as opposed to a Montana need, MDEQ should address the results of recent 2002 studies by RAND and by the Tellus Institute. The Tellus report projected an increase in regional demand of 5,830 aMW (from 21,345 aMW in the year 2000 to 27,742 aMW in 2020). The report concluded that the region could meet all of this new demand (as well as some replacement power) with a combination of cost-effective conservation (3,542 aMW) and new, cost-competitive wind, biomass, and geothermal resources (9,954 aMW). These resources have no direct emissions of air pollutants, and provide the benchmark for comparison when speaking of "clean" resources. The transition to a clean energy future does not, and cannot imply the use of traditional coal-based power generation. MDEQ's characterization of the Roundup power plant as "clean" generation simply cannot be taken seriously.

Response:

DEQ agrees that conservation and alternative energy sources could meet some or all of the projected increase in power demand and would provide air quality benefits compared to a new efficient coal-fired plant. However, Project would meet the requirements of the Clean Air Act, and would utilize state of the art emission reduction technology.

117. We are also concerned that MDEQ unreasonably overestimates demand growth in justifying this facility. Load growth projections contained in section 1.3 of the DEIS seem wildly over-exaggerated. That we would see a 30% increase in demand (from 120,000 MW in 2001 to 165,000 MW in 2010) does not comport with either historical trends or other forecasting sources. For example, the Northwest Power

Planning Council's "Medium Case Consumption Forecast" estimates a 13.7% increase over a similar period - from 20,442 aMW in 2000 to 23,234 aMW in 2010. DEQ should also take into consideration the large, already-permitted fleet of power plants that came as a response to the 2000-2001 power crisis. Predictions of future supply shortages, when they are made, are not based on an absence of permitted power plants, but rather on the financing and other economic challenges these plants face.

Response:

DEQ disagrees that the sources cited in the DEIS are not legitimate. The historical peak demand for the 2001 calendar year was 125,000 MW. The data sited encompasses the entire Western Electricity Coordinating Council (WECC). This data reflects the coordinated plans of the WECC organization as of January 1, 2002. DEQ does agree that the Project faces other challenges if the Project is permitted, including financing and economics.

Ash/Waste

118. The proponents of RPP have proposed an interesting fly ash disposal solution. DEQ is correct in preferring the plant site storage alternative. However, what happens when the 30 years are up? The life of the plant is estimated at 40 years on page 4.20. That would indicate a need for fly ash disposal for at least 40 years.

Response:

The fly ash storage facility plan specifies design of on-site storage for 10 years capacity in two cells. The preferred alternative specifies design of additional cells for placement of fly ash waste for the anticipated life of the plant, an additional 30 years.

119. Does DEQ have the authority to make RPP accept DEQ's preferred alternative for waste disposal? If so, under what law or regulation?

Response:

DEQ prefers this alternative because DEQ believes that it would cause less environmental impact; however, DEQ does not have the authority to require the Project Proponent to accept alternative waste disposal. The Project Proponent would have to voluntarily implement that option.

Visual Impacts

120. On page 4-60, the report indicates that the visual impacts of the two 574-foot Project chimneys and the 250-foot high boiler buildings which sit on top of a major drainage divide are 'moderate'. I believe that the impacts are going to be much more severe than 'moderate', e.g., the infrastructure, strobes and hot exhaust gases will stick out of the landscape like Rudolph's nose and will destroy much of what tourists come here for.

Response:

The proposed Generation Plant is sited atop a drainage divide for two intermittent creeks (Rehder and Halfbreed Creeks) in the area (see section 3.3, Water Resources in DEIS). Rolling hills, foothills and mountains surround the proposed Generation Plant site. Refer to figure 2-1 to see the neighboring Bull Mountain buttes that surround the proposed Generation Plant site. Clear, unobstructed views of the Project facilities would be limited only to the local area as discussed on pages 3-43 and 4-60 of the DEIS.

The visual impacts were considered moderate overall because views of the Project would occur to some degree in the middle ground distance zone, while most Project views would occur in background distance zone. Refer to tables 4-23 and 4-24 in the DEIS for the impact assessment process followed by a discussion thereafter on impact levels.

Scenic views that attract tourists occur approximately 116 miles to the southwest at Yellowstone National Park. Scenic highways generally do not occur in the Project study area and therefore the number of tourists focused on scenic views in or near the Project study area would be expected to be low. Recreational near the proposed Generation Plant site includes dispersed outdoor activities such as hunting and horseback riding (see page 3-57 of DEIS). These activities are not generally dependant upon pristine landscapes or areas of high scenic quality. In addition, for these recreational pursuits to occur, landowner permission must first occur, as most land near the Proposed Generation plant is privately owned. The nearest public recreation facilities (including a golf course, tennis courts, and swimming pool) are within the City of Roundup, more than 13 miles from the proposed Generation Plant, (see pages 3-57 and 3-58 of the DEIS).

121. From the top of Dunn Mountains are visible the Little Wolf Mountains, the Wolf Mountains, the Big Horn Mountains, The Pryor Mountains, the Beartooth Mountains, the Crazy Mountains, and the Snowy Mountains. I suspect that if RPP operates, we will say goodbye to the Wolfs and the Little Wolfs, It is a lovely view.

Response:

There is no conclusive evidence to suggest that the view would be lost. The top of the proposed Generation Plant chimneys would not obstruct any views from Dunn Mountain. The Little Wolf Mountains and the Wolf Mountains would both remain visible from Dunn Mountain if the Project were constructed. The top of the Project's chimneys would occur approximately 181 feet below the elevation found at the top of Dunn Mountain. The Project would also be located approximately 4.25 miles away from Dunn Mountain. Any viewpoints located on Dunn Mountain are not developed and do not contain residences, public roads, or parks. Any views of the Project from Dunn Mountain would occur from dispersed recreationists while on horseback or hunting, refer to section 3.11, Land Use in the DEIS.

Atmospheric haze that may occur as a result of the Project that would be seen from viewpoints nearby (Dunn Mountain) would not occur any higher than opacity limits set forth in the air quality permit. Since there were no Class I PSD areas or integral vistas within 50 km per Montana State regulations, a plume blight analysis was not performed nor statutorily required, refer to section 3.2, Air Resources in the DEIS.

Vegetation

122. Statements on Pp. 4-39 (see 4.5.2) concerning p.pine are incomplete.

Response:

This is covered on page 4-19 & 20; Section 4.22.

Fish & Wildlife

123. "The states, territories, and Native American tribes have primary responsibility for protecting residents from the health risks of eating Mercury contaminated fish and wildlife."

Response:

There is no conclusive evidence that the Project would have mercury emissions with serious, adverse impacts on public health and the environment. Mercury deposition has always occurred naturally within the regions streams, lakes, rivers and the human body is able to adapt to the mercury found in the natural environment. Much of the mercury in Northwestern fish originates from natural deposits in rocks and soils, with some influence from historic mining practices (Oregon's Fish Advisories for Methylmercury).

Mercury releases from power plants may influence the amount of methylmercury in freshwater fish living in some U.S. lakes and streams. Health risks from power plants depend largely on how much those plants influence the amount of methylmercury in fish that people eat. In several case studies sponsored by EPRI, independent researchers found that the amount of methylmercury in lake fish that might come from nearby power plants was well below the amount that EPA says people may take into their bodies without harming their health (Colorado Mining Association, Health Risk Profiles-Mercury). At freshwater lakes and rivers known to be contaminated with mercury, many states post "fish advisories" telling fishermen how many and which kinds of fish their families can safely eat.

Role of the Project Proponent in Preparing the DEIS

124. Finally, as a general comment, we strongly object to the State allowing the company to write major portions of its own environmental review. The language found in Section 1.3.1, for example, is taken nearly verbatim from the language submitted by the company in its "EIS Support Document" submitted in May of 2002.

Response:

Your comment is noted. DEQ can use any legitimate source of information that might be available when preparing an EIS. This information often includes that provided by the Proponent, especially information contained in the permit application.

Montana Constitution

125. The Roundup Power Project does not comply with the Montana state constitution. We believe similar issues are raised with the permitting of this facility, which poses even greater adverse environmental impacts than earlier proposals. To address this core legal responsibility, MDEQ must explain whether the justification quoted above is meant to satisfy the "compelling state interest" test. If so, we respectfully request specific information as to what formula the Department has devised to determine an acceptable tradeoff between environmental degradation and economic benefit.

Response:

District Court Judge Jeffrey Sherlock recently rejected the argument of the Montana Environmental Information Center (MEIC) that DEQ was required to deny an air quality permit for another proposed power plant based upon the Constitutional right to a clean and healthful environment, even though the plant would comply with applicable air quality statutes and rules. Judge Sherlock ruled that DEQ is required to faithfully execute the air quality statutes and rules of Montana, unless it has been demonstrated that those laws are unconstitutional. MEIC has not demonstrated this.

Article IX, Section 1(2), of the Montana Constitution, provides that the Montana Legislature shall provide for the administration and enforcement of the duty of the state and each person to maintain and improve a clean and healthful environment. Article IX, Section 1(3) further provides that the Legislature shall provide adequate remedies for the protection of the environment. The Montana Legislature has provided for protection of the state's environment through acts such as the Clean Air Act of Montana. Under Montana law, acts of the Legislature are presumed to be constitutional, and a person challenging the constitutionality of a legislative act has the burden of proving beyond a reasonable doubt that the act is unconstitutional. Unless determined in court to be unconstitutional, DEQ must presume that the Clean Air Act meets constitutional requirements and must implement that act in response to an application for an air quality permit. If DEQ determines that the application for an air quality permit for the Project demonstrates that the Project can be expected to meet the air quality standards adopted by administrative rule under the Clean Air Act, the Montana Constitution does not provide a legal basis for DEQ to base its decision on the permit, instead, upon the suggested balancing of environmental degradation and economic benefit.

The Clean Air Act does not provide DEQ with authority to deny an air quality permit when the proposed Project can be expected to comply with air quality requirements. Further, Section 75-1-201(5)(a), MCA, of the Montana Environmental Policy Act (MEPA), expressly prohibits DEQ denying or conditioning a permit based upon DEQ's review of the application under MEPA. Consideration of environmental impacts beyond review for compliance with applicable requirements and consideration of the economic benefits of a proposed Project are MEPA considerations that, by law, DEQ may not rely upon in making its decision on the permit application.

126. That MDEQ is unable to require mitigation to "avoid, reduce, or eliminate potential impacts" makes the consideration of Montana's Constitutional duty "to maintain and improve a clean and healthful environment" even more relevant. If the Department cannot require sufficient mitigation of impacts including, but not limited to, those identified in the DEIS to fulfill this Constitutional duty, than it must instead select the No-Action alternative.

Response:

DEQ has authority to require mitigation measures necessary to ensure compliance with the air quality standards adopted under the Clean Air Act of Montana. These measures become enforceable conditions of any air quality permit that is issued. As discussed above in the response to Comment No. 125, DEQ is prohibited by law from imposing requirements beyond those needed to comply with the standards adopted under the Clean Air Act. Impacts unrelated to compliance with air quality requirements do not provide legal authority to select the "no action" alternative.

Alternative Fuel

127. For the purposes of this document, the Final EIS should at a minimum acknowledge the risk associated with the proposed design in light of future environmental regulation. The EIS should also note the drawback of a proposal that would decrease the diversity of Montana's energy mix.

Response:

The Project would meet the requirements of the Clean Air Act and all relevant, applicable and appropriate requirements. Several energy alternatives were evaluated and the Proposed Action was determined to provide a balance of a solid, reliable, and economically feasible energy source for Montana.

128. The DEIS must also thoroughly evaluate the use of lower sulfur coal including coal blending to satisfy BACT and MEPA requirements.

Response:

The DEIS considered and dismissed further evaluation of other coal and other fuel sources. DEQ believes that the analysis is adequate. Refer to page 2-42, Section 2.3.1, of the DEIS. All conditions are satisfied.

Alternative Technologies

129. Integrated Gasification Combined Cycle's (IGCC) Environmental Performance is Superior to other Technologies for Generating Electricity from Coal.

Response:

Comments were adequately addressed on page 2-45 Section 2.3.4.

130. IGCC is Economically Competitive with other Technologies for Generating Electricity from Coal.

Response:

See Response #129.

131. IGCC is Not Redefining the Source.

Response:

It is redefining the facility and is out of scope both for an in-depth BACT and EIS analysis.

132. MDEQ Failed to Consider Cost-effective Energy Efficiency and Renewable Energy Alternatives.

Response:

The DEIS identified reasonable alternatives to key elements of the Proposed Action, as well as a wide range of other alternatives. DEQ believes the DEIS adequately identified, treated, evaluated, and compared alternatives.

Alternatives / Mitigation

133. The DEIS fails to examine all viable alternatives and mitigation strategies.

Response:

The DEIS identified reasonable alternatives to key elements of the Proposed Action, as well as a wide range of other alternatives. DEQ believes the DEIS adequately identified, treated, evaluated, and compared alternatives. DEQ believes that reasonable mitigation strategies were identified, and is limited by Montana statute from imposing mitigation other than is required under permits issued by the State of Montana.

Alternative Voltages

134. The proposed alternative for transmission is flawed. The use of a 161 kV transmission lines to transmit 750 MW simply does not conform to best engineering practices.

Response:

Both the 161kV and 230kV transmission systems were shown to accommodate the transmission of 750MW of power. Environmental impacts would be very similar with either system.

135. Throughout the DEIS, MDEQ refers to major improvements that are planned to the BPA transmission system (including both "substation upgrades and transmission line additions between Montana and the Pacific Northwest"). Pages ES-4 and 2-21 describe plans to upgrade the transmission systems to allow an additional 500 MW to flow west toward the Garrison Substation, and an additional 200 MW to flow south toward PacifiCorp's Yellowtail Substation. Yet much more information is needed to completely understand such developments.

Response:

DEQ agrees that additional work may be required on the transmission system to accommodate the capacity requirements of the Project. However, at this time there is not enough known about how much capacity would be required on any particular transmission system because DEQ is not aware that there are any contracts in place for power transactions.

136. To ensure a meaningful public process, MDEQ must provide more specific information regarding these proposals, and documentation as to where additional information can be found. There are a number of critical questions that are not addressed. In particular, when will the additional transmission capacity be available? Who will pay for it? What guarantee is there that Roundup will acquire contract rights to that additional capacity (with other already-permitted proposals ahead in the queue)? Will these upgrades alone be sufficient to allow for the transmission of power to major out-of-state load centers to the west and the south (or are additional upgrades needed to actually move the power out-of-state)?

Response:

DEQ is not aware of a specific date that the transmission capacity would become available. The specific transmission paths needed would depend on the contracts that the Project Proponent would be able to negotiate with potential purchasers of power. This is dependent on the Project being approved and cannot be predetermined. Transmission line improvements would be paid for by those parties benefiting from any specific improvements that may be required. If the Project Proponent or its contract partners are capable of paying for the improvements, this would be implied as the guarantee of transmission access regardless of the queue. Since there is no way to predict the transmission improvements that might be required until the contracts are signed, and again, this would be pursued by the owner if the Project is approved.

Eminent Domain

137. "Eminent domain seizures could be at risk of court challenges if a landowner were to convince the court the public purposes of the line were speculative."

Response:

Transmission owners, who would have the right of eminent domain, would likely provide transmission access.

Miscellaneous Issues

138. Please note our concerns about the Bull Mountain Power Plant and mine. The effect on the fragile environment previously impaired by the loss of forest in a 1984 fire and years of drought would seem risky to us. Health issues relating to emissions are extremely important to us.

Response:

In both cases (the mine and the power plant), DEQ required that the applicant conduct analyses to make sure that the air emissions from the proposed sources

would not cause or contribute to concentrations of criteria pollutants that would exceed the NAAQS or the MAAQS. These standards were established at levels that are protective of human health and the environment. The governing rules and regulations for permitting sources of air emissions require that the source conduct certain analyses. Based upon the results of the analyses, DEQ determines whether the proposed source would comply with the governing rules, regulations, and standards.

139. MTDEQ's Permit Proceeding Violates Core PSD Requirements by Precluding Meaningful Public Participation

Response:

The public comment period for the Project was not severely limited. In fact, the opportunity for public comment for the Project initial permit application was quite long. The Proponent submitted the air quality permit application in January of 2002. The public could begin reviewing and commenting on the permit application starting at the date of the submittal. After DEQ's review of that permit application and subsequent deficiency notices and responses, DEQ issued a preliminary determination on August 12, 2002. DEQ initially requested that the comments on the PD be submitted by August 27, 2002. The PD was also attached to the DEIS. Comments on the DEIS were due by December 18, 2002. Based upon these dates, the public had approximately 8 months to comment on the permit application prior to issuance of the PD and approximately 4 months to comment on the PD.

140. MTDEQ Has Failed to Comply With the Public Review Procedures of the EPA-Approved SIP

Response:

The PD for a permit can be issued prior to issuance of a DEIS. In fact, such an approach actually allows the public more time to review the document than if DEQ were to withhold the PD until issuance of the DEIS.

141. Why is this EIS not being done by an appropriate Federal agency under NEPA instead of the Montana DEQ?

Response:

No federal agency has jurisdiction, and no federal permits are needed. DEQ is the sole permitting authority, so the EIS was prepared pursuant to MEPA.

142. On the Roundup Power Project DEIS is in Section 2.4.2, 230kV Transmission System Alternative, page 2-53, second paragraph. The last sentence states, "Studies performed by both transmission providers have identified upgrades that are proposed and underway to support this flow." I suggest the following alternative. "Studies will be performed by both transmission providers to identify necessary upgrades to support this flow."

Response:

Comment noted. The document will reflect this change.

143. In the section titled Infrastructure Development, Transmission, Page 4-98, second paragraph. This paragraph states, “According to BPA, major transmission improvements to the BPA system are planned. These improvements would include substation upgrades and transmission line additions between Montana and the Pacific Northwest.” I suggest the following alternative. “BPAT has a current project to increase the West-of-Hatwai cutplane capacity in Washington. However, this does not provide increased capacity from Montana to the Northwest. In order to provide service to the Roundup Power Project major facility additions will be required. This could potentially include substation upgrades and/or transmission line additions. Studies will be done in queue order based on BPAT’s long-term transmission request queue to determine the improvements needed.”

Response:

Comment noted. The document will reflect this change.

CHAPTER 5 MODIFICATIONS AND CORRECTIONS TO THE DEIS

Page ES-1, Change heading “Purpose and Need for the Action” to “Benefits of the Action.”

Page ES-1, replace the last paragraph beginning “The primary needs for the Project…” with the following paragraph:

> The primary purposes of the Project are to serve population growth and load growth and provide new base load electrical generation. Population and electrical demand growth, together with the retirement of older, less efficient electrical generating units, has created a demand for new and cleaner generation sources. The Project would fill a portion of this demand.

Page ES-2, replace the 1st paragraph beginning “The Project would be built specifically …” with the following paragraph:

> The Project would be built specifically to burn coal. The mine-mouth fuel source of the Project is intended to provide stable pricing and reliability for base load power assisting utilities in more reliably serving industrial, commercial, and residential customers.

Page ES-2, replace the 2nd paragraph beginning “The Project would also increase …” with the following paragraph:

> The Project would increase the opportunity for competition in the regional energy market by increasing the total amount of electricity that could be transmitted reliably within the grid. Competition in the power marketplace is a means in a market economy to keep power pricing in line with customer demand. According to the Proponent, some of the electricity could be consumed by industrial, commercial, and residential customers in Montana. NorthWestern Energy currently is evaluating the interconnection of the Project with their transmission system at the Broadview Substation.

Page ES-5, delete the 1st paragraph beginning “Finally, the socioeconomic benefits…”

Page 1-1, Section 1.3, change heading “Purpose and Need for the Action” to “Benefits of the Action.”

Page 1-2, 1st paragraph, change 1st sentence to “The Project would provide a new source of electricity in a region where energy supplies may not be keeping up with the growth of demand.”

Page 1-2, end of 1st paragraph, change last two sentences to: “That population and electrical demand growth, together with any retirement of older, less efficient, electrical generating units could require the continued development of new generation sources, along with energy conservation. The Project would fill a portion of need for additional generation.”

Page 1-2, 2nd paragraph, change last 2 sentences to “While the demand for electricity has weakened somewhat since the economic downturn starting in late 2000, the demand for power may continue its upward trend following economic recovery. This Project fits into the expected future economic growth and need for new sources of economical power."

Page 1-5, 1st paragraph, change 2nd sentence to "The mine-mouth fuel source of the Project could provide stable pricing and reliability for base load power that may be needed by the utilities to reliably serve industrial, commercial, and residential customers."

Page 1-5, Section 1.3.1, 1st paragraph, change 1st sentence to "A benefit of the Project could be a stable, reliable, low-cost supply of electricity in a region that has had uncertain supply and prices in recent years."

Page 1-5, Section 1.3.1, 3rd paragraph, change 2nd sentence to "Montana would receive the investment, the tax-base increases, and the jobs that would be created by the construction, long-term operation of the facility, and the support systems and economic development."

Page 1-7, Section 1.4, Table 1-1, delete "Section 106 of the National Historic Preservation Act" under the Permit/Approval heading. Under Authority heading, change "National Historic Preservation Act" to "Montana Antiquities Act and Montana Environmental Policy Act."

Page 2-40, Section 2.2.5, Cultural Resources subsection, CR-2, delete the phrase "in accordance with Section 106 of the NHPA."

Page 2-53, Section 2.4.2, second paragraph, replace the sentence beginning "Studies performed by both transmission providers…" with "Studies will be performed by both transmission providers to identify necessary upgrades to support this flow."

Page 2-55, delete 3rd full paragraph "Finally, the socioeconomic benefits…"

Page 3-4, Section 3.2.3, add the following sentence after the last sentence: "The town of Lame Deer, MT, a non-attainment area for PM_{10}, is located southeast (downwind) of the Project."

Page 3-55, Figure 3-7 Land Use, add label for Cole Road. See attached map at the end of this section.

Page 3-74, Transportation subsection, first paragraph, delete the third sentence that begins "The Montana Department of Transportation does not attempt to justify. . ."

Page 3-74, Transportation subsection, second paragraph and bulleted text, change SR 87 and SR 12 to US Route 87 and US Route 12, respectively.

Page 4-10, Section 4.2.2, Table 4-6, replace the Proposed Emission Limit for SO_2 of "448.4 (30-day rolling average)" with "482 lb/hr (24-hour basis)".

Page 4-16, Section 4.2.1, paragraph number 2, replace the last sentence to read: "The closest federal non-mandatory Class I area is the Northern Cheyenne Reservation (NCR), located 130 (81miles) km southeast of the site."

Page 4-17, 1st Full paragraph, add the following sentence to the end of that paragraph: "The 10% change calculation is relative to the FLM's pristine background values for Class I areas in the Western United States."

Page 4-98, Infrastructure Development Section, second paragraph, replace the paragraph beginning, “According to BPA, major transmission improvements...” with the following paragraph:

> BPA has a current project to increase capacity in Washington. However, this does not provide increased capacity from Montana to the Northwest. In order to provide service to the Roundup Power Project major facility additions will be required. This could potentially include substation upgrades and/or transmission line additions. Studies will be done in queue order based on BPA’s long-term transmission request queue to determine the improvements needed.

Page 7-2, Air Resources Section, add the following references:

Dickey, J. W. Bull Mountain Development Co., LLC. 2002. Letter to Mr. Dan Walsh at MDEQ, December 30, 2002.

Lorenzen, Diane, Lorenzen Engineering, Inc. 2002. Memo to Dan Walsh at MDEQ, November 21, 2002.

Manson, Craig, Assistant Secretary for Fish and Wildlife, U.S. Fish and Wildlife Service, United States Department of the Interior. 2002. Letter to Ms. Jan Sensibaugh, Director of MDEQ, December 18, 2002.

Page 7-9, Land Use Section, Change author of Fact Sheet: Facts At-A-Glance to “Musselshell County, Montana County Subdivisions and Planning.”

Page 8-2, add the following acronym and definitions:

> **CALPUFF –** modeling system proposed by the EPA as the refined modeling tool for analyzing long-range (beyond 50 kilometers) transport of pollutants and their impacts on Federal Class I areas.

Page 8-3, add the following acronyms and definitions:

> **FLAG –** Federal Land Managers AQRV Work Group. An interagency workgroup whose objective is to achieve greater consistency in the procedures Federal Land Managers use in identifying and evaluating AQRVs (air quality related values).
>
> **FLM** – Federal Land Managers.

Page 8-5, add the following acronym and definition:

> **IMPROVE** - Interagency Monitoring of Protected Visual Environments Program. Includes representatives from the NPS, FS, BLM, FWS, EPA and regional-state organizations. Activities include research on all aspects of the visibility issue.

Page B-7, Appendix B, replace the paragraph preceding Table B-6 with the following paragraph:

> Impacts determined in the Scenario #2 cumulative visibility modeling conducted by the FLM are given in Table B-6 and Table B-6.1 using 1990 and 1992 meteorological data, respectively. Also included in these two tables are visibility impacts from the Project only. The FLM modeling included the facilities listed in Table B-1 (seven other PSD sources and the Project) in the CALPUFF modeling analysis.

Page B-7, Appendix B, replace Table B-6 with the following updated modeling results table:

Table B-6 Visibility Impacts from the FLM 1990 Modeling Analysis

The Project Visibility Impacts (without other PSD sources)

Class I Area	Change in Light Extinction (Days >5%)	Change in Light Extinction (Days >10%)	Maximum Change in Light Extinction (%)
Yellowstone NP	7	1	12.72%
UL Bend WA	4	0	8.41%
North Absaroka WA	3	0	9.11%
Northern Cheyenne	36	11	38.27%

Cumulative Visibility Impacts (the Project with 7 other PSD Sources)

Class I Area	Change in Light Extinction (Days >5%)	Change in Light Extinction (Days >10%)	Maximum Change in Light Extinction (%)
Yellowstone NP	39	26	119.28%
UL Bend WA	50	29	156.50%
North Absaroka WA	35	22	126.83%
Northern Cheyenne	259	224	637.43%

Source: National Park Service and US Fish and Wildlife Service, Dec. 18, 2002.
Note: CALPUFF modeling with 1990 meteorological data and maximum RH of 98%.

Page B-7, Appendix B, add the following table of new modeling results conducted by the FLM after the revised Table B-6:

Table B-6.1 Visibility Impacts from the FLM 1992 Modeling Analysis

The Project Visibility Impacts (without other PSD sources)

Class I Area	Change in Light Extinction (Days >5%)	Change in Light Extinction (Days >10%)	Maximum Change in Light Extinction (%)
Yellowstone NP	13	2	15.41%
UL Bend WA	16	4	28.06%
North Absaroka WA	10	1	14.53%
Northern Cheyenne	32	11	46.87%

Cumulative Visibility Impacts (the Project with 7 other PSD Sources)

Class I Area	Change in Light Extinction (Days >5%)	Change in Light Extinction (Days >10%)	Maximum Change in Light Extinction (%)
Yellowstone NP	32	20	83.67%
UL Bend WA	64	41	150.30%
North Absaroka WA	31	21	85.61%
Northern Cheyenne	286	255	971.98 %

Source: National Park Service and US Fish and Wildlife Service, Dec. 18, 2002.
Note: CALPUFF modeling with 1992 meteorological data and maximum RH of 98%.

Page B-12, Appendix B, insert at the end of the last paragraph the following two sections (Modeling Summary and Case by Case Analysis) including tables B-11 and B-12:

Modeling Summary

After the DEIS was published on November 18, 2002, the Proponent submitted CALPUFF modeling results to the DEQ and NPS for visibility impacts from the Project. (Lorenzen, November 21, 2002) The NPS had requested that the Proponent submit additional years of visibility modeling results. The Proponent had originally submitted 1992 visibility impact results to DEQ, but the Proponent had used seasonal relative humidity (RH) factors [F(RH)]. The NPS disagreed with using seasonal F(RH) data and requested that the Proponent use hourly RH data collected in Yellowstone National Park.

The NPS used the data supplied to them by the Proponent to run 1992 visibility impacts. The NPS submitted CALPUFF 1992 modeling results in an attachment to a letter from the Department of Interior (DOI). (Manson, December 18, 2002)

Table B-11 summarizes both the Proponent and NPS CALPUFF visibility modeling results that have been submitted covering the Project individually, or in a cumulative analysis. This table includes predicted visibility results previously provided in the DEIS and the 1992 visibility impacts submitted to DEQ after the DEIS was published.

The modeling results from the NPS and the Proponent showed similar impacts from the Project, by itself. The cumulative results from the NPS and the Proponent are very different as their modeling protocols for a cumulative analysis differ significantly.

Table B-11 Comparison of Modeling Results from the Proponent and NPS for Class I Area Visibility Impacts

Modeling Scenario	Parameters	Scenario #1		Scenario #2		Scenario #3
Modeling Analysis		**Proponent [a]**	**Proponent [c]**	**NPS**	**NPS**	**Proponent [b]**
Met Data Year		**1990**	**1992**	**1990**	**1992**	**1990**
Emissions						
Main Power Boiler (lbs/hr)	NO_X	281	281	281	281	281
	SO_2	471	471	471	471	471
	SO_4	25	25	25	25	25
	PM_{10}	60	60	60	60	60
Fugitives and Baghouses (lbs/hr)	PM_{10}	3.7	3.7	3.7	3.7	3.7
Class I Increment						
All Class I Areas	NO_X	< Increment	--	< Increment	--	--
	SO_2	< Increment	--	< Increment	--	--
	PM_{10}	< Increment	--	< Increment	--	--
Class I Visibility (Proponent Only Analysis)						
Yellowstone	>5%	9	15	7	13	--
	>10%	1	2	1	2	--
	Max	13.0	16.5	12.7	15.4	--
UL Bend	>5%	4	12	4	16	--
	>10%	0	3	0	4	--
	Max	7.9	20.6	8.4	28.1	--
NAWA	>5%	6	13	3	10	--
	>10%	1	2	0	1	--
	Max	11.1	14.9	9.1	14.5	--
NCIR	>5%	38	--	36	32	--
	>10%	15	--	11	11	--
	Max	41.0	--	38.3	46.9	--
Class I Visibility (Cumulative Analysis)						
Yellowstone	>5%	15	--	39	32	5
	>10%	3 [d]	--	26	20	4 [f, g]

Modeling Scenario	Parameters	Scenario #1		Scenario #2		Scenario #3
Modeling Analysis		Proponent [a]	Proponent [c]	NPS	NPS	Proponent [b]
Met Data Year		1990	1992	1990	1992	1990
	Max	14.7	--	119.3	83.6	15.7
UL Bend	>5%	5	--	50	64	6
	>10%	0	--	29	41	5 [g]
	Max	9.9	--	149.5	150.3	117.7
NAWA	>5%	12	--	35	31	3
	>10%	2 [e]	--	22	21	3 [d]
	Max	13.7	--	125.8	85.6	18.51
NCIR	>5%	--	--	259	286	--
	>10%	--	--	224	255	--
	Max	--	--	618.4	972.0	--

Notes:

[a] The Proponent used a 1996 Baseline Date for including sources in the cumulative analysis.

[b] The Proponent used a 1975 Baseline Date for including sources and included negative emissions in the cumulative analysis.

[c] Calculated with hourly RH data but excluded faulty Yellowstone RH values.

[d] Significant on at least two of the three days at the same receptors that have impacts above 10% change in light extinction.

[e] Significant on both days and at the same receptors that have impacts above 10% change in light extinction.

[f] Significant on at least two of the four days but not at the same receptors that have impacts above 10% change in light extinction.

[g] Based on modeling results provided by the Proponent, Project significance levels could not be determined.

Case-by-Case Analysis

Due to the predicted high visibility impacts (>10%) from the Project, the Project Proponent felt that the NPS should perform a case-by-case analysis for each of the impacted days to provide further information about specific adverse impacts to any of the Class I areas. The Project Proponent felt that the NPS representing the DOI did not follow its own guidelines in the FLAG Phase I Report (12/2000) by performing a case-by-case analysis before reaching a decision of adverse impact on the Class I areas.

The Assistant Secretary of the US Fish and Wildlife Service, on behalf of the DOI and the NPS, submitted a letter finding the Project would cause an adverse impact on Yellowstone National Park and UL Bend WA (Manson, December 18, 2002). A case-by-case analysis was not submitted as part of this letter.

In response to the finding that the Project had an adverse impact, the Project Proponent prepared and submitted to the DEQ a case-by-case analysis on the daily impacts of the Project to Yellowstone National Park that were greater than 5% change in light extinction (Dickey, December 30, 2002).

The Proponent has claimed that the high impacts that have occurred in the Class I areas have occurred on days with high humidity. Therefore, natural conditions (i.e., precipitation, fog, etc.) resulting from high humidity interfered with the natural background visibility and caused greater changes in light extinction than the impacts from the Project.

A day-to-day analysis has been carried out for the specific days in 1990 and 1992 on which CALPUFF modeling indicated visibility impacts to Yellowstone National Park, due to the Project alone, in excess of 5% change in light extinction. Relevant data for these days are shown in Table B-12.

The analysis utilized the most recent CALPUFF model results as submitted to DEQ and the NPS (Lorenzen, November, 21, 2002) for the Project. These modeling results are nearly similar to those obtained by the NPS. Since details of the NPS modeling were unavailable to the Proponent, all analysis was based on the Project modeling. Time periods analyzed are consistent with those used for the CALPUFF modeling.

The first column of Table B-11 shows natural background visibility for Yellowstone National Park per FLAG data, taking account of the mean daily relative humidity (RH) factor [F(RH)] as incorporated in CALPUFF meteorological data. The second column lists the modified visual range when model-predicted light extinction due to the Project is added to natural background. The percent change in light extinction (compared to theoretical natural conditions) due to the Project, as predicted by CALPUFF, is given in the third column.

Measured visibility at the Yellowstone National Park IMPROVE (Interagency Monitoring of Protected Visual Environments Program) monitoring station is shown in Column 4. The tabulated values of visual range correspond to the 24-hour average measured light extinction for the day. The following column shows the percentage change in light extinction (compared to actual measured extinction) due to the model-predicted Project impact for each day.

The last three columns of Table B-12 summarize information from the IMPROVE monitoring site as provided in data reports. Light extinction data are noted as “interference” if extinction values are very high or change rapidly from hour-to-hour, or if site-specific RH exceeds 90%. This classification is intended to indicate that the measured light extinction was likely affected by natural visibility impairment (fog, precipitation, clouds). The number of hours of interference is listed in the table, as well as the number of hours each day that the measured light extinction was 100 per 10^{-6} meters (Mm^{-1}) or greater, and the site RH was greater than 90%. A background light extinction (b_{ext}) value of 100 Mm^{-1} is taken as an arbitrary but conservative indicator of significant natural visibility impairment.

Table B-12 Modeled and Measured Yellowstone Visibility Data (Days with Predicted Impacts Greater than 5% Change in Light Extinction)

Date	Natural Background Visual Range (km)	Visual Range with Roundup (km)	% Change in b_{ext}	Measured Back-ground (km)	% Change in b_{ext}	# of Inter-ference Hours	# of Hours with b_{ext} > 100	# of Hours RH > 90
1990 Impacts								
01/15/90	205	189	8.22	12	0.47	24	17	5
01/16/90	202	191	5.66	17	0.48	22	9	4
03/05/90	241	214	12.86	10	0.56	22	18	16
03/23/90	245	231	5.81	15	0.34	18	15	0
04/05/90	253	239	6.03	153	3.65	0	0	0
07/19/90	251	237	5.59	96	2.13	9	1	3
07/20/90	241	220	9.63	75	3.00	11	3	2
09/28/90	249	233	7.14	91	2.61	7	0	7
10/06/90	238	226	5.31	14	0.32	19	10	14
1992 Impacts								
03/05/92	242	228	5.72	92	2.17	14	0	8
03/08/92	228	214	6.83	58	1.74	8	2	5
03/18/92	224	204	9.86	18	0.78	13	8	12
04/11/92	220	204	7.97	54	1.95	15	4	14
05/21/92	207	197	5.11	116	2.86	19	0	7
06/15/92	202	189	7.16	23	0.80	24	17	23
07/20/92	239	222	7.60	43	1.37	16	6	13
07/21/92	215	200	7.45	116	4.04	20	1	13
07/22/92	226	213	5.94	69	1.82	11	2	10
08/23/92	236	214	10.31	86	3.78	13	1	7
08/24/92	238	205	16.45	123	8.47	5	1	4
08/25/92	242	225	7.57	142	4.45	4	0	4
10/15/92	221	206	6.91	23	0.71	15	5	10
12/03/92	243	232	5.01	38	0.77	11	5	0
12/12/92	203	192	5.57	65	1.79	8	1	5

Source: Dickey, LLC, December 30, 2002.

Conclusions and Observations from the Case-by-Case Analysis

The Proponent believes that the U.S. Assistant Secretary for FWS has made an adverse impact decision without sufficient information by not completing a case-by-case analysis. The Proponent provided the following conclusions and observations from a case-by-case analysis supporting their position that no adverse impact occurs at Yellowstone National Park from the Project (Dickey, December 30, 2002):

- On the vast majority of days of predicted Project impact, actual visibility at the Yellowstone National Park IMPROVE site was highly impacted by natural weather conditions, with many hours of the day classified as "interference."
- When the model-predicted light extinction for the Project is compared to actual visibility, the percent change in light extinction was less than 5% on 23 of the 24 days. The single day with >5% impact (8/24/92) had only 5 hours of indicated weather interference, but the daily F(RH) value corresponds to RH of 84%, indicative of extensive low cloudiness on an August day. The occurrence of regional clouds and precipitation on this day was confirmed by reference to synoptic weather maps.
- The overall results strongly support the Proponent's assertion that days of potential Project impact at Yellowstone National Park are highly correlated with the occurrence of precipitation and generally adverse weather conditions that cause natural visibility impairment. This conclusion follows from the association of the Project impacts with northeasterly winds and a synoptic weather situation marked by low pressure to the south of Yellowstone National Park.
- For the 24 days listed in Table B-11, the mean F(RH) was 4.373, implying an RH of 89%. This further supports the indication that predicted Project impacts are highly correlated with natural conditions of fog, precipitation, and clouds.
- There is no indication of Project impacts during days of clear, high visibility conditions when actual impacts would be discernible by park visitors. Therefore, the modeled light extinction changes do not represent a significant impact (adverse effect) on viewing conditions due to Project emissions.
- Similar case-by-case analyses could not be provided for the UL Bend and North Absaroka wilderness areas because no IMPROVE data is available for these Class I areas. However, the Proponent noted that on the highest visibility impact day (11/18/92) for the UL Bend WA, the daily F(RH) corresponded to an RH greater than 94%, based on Glasgow, Montana surface data. The two other days with predicted impacts greater than 10% at the UL Bend WA had nighttime RH values of 80% or higher. Thus, the predicted visibility impacts are again a direct result of high RH when natural visibility impairment in valley locations such as UL Bend WA is likely (Dickey, December 30, 2002).

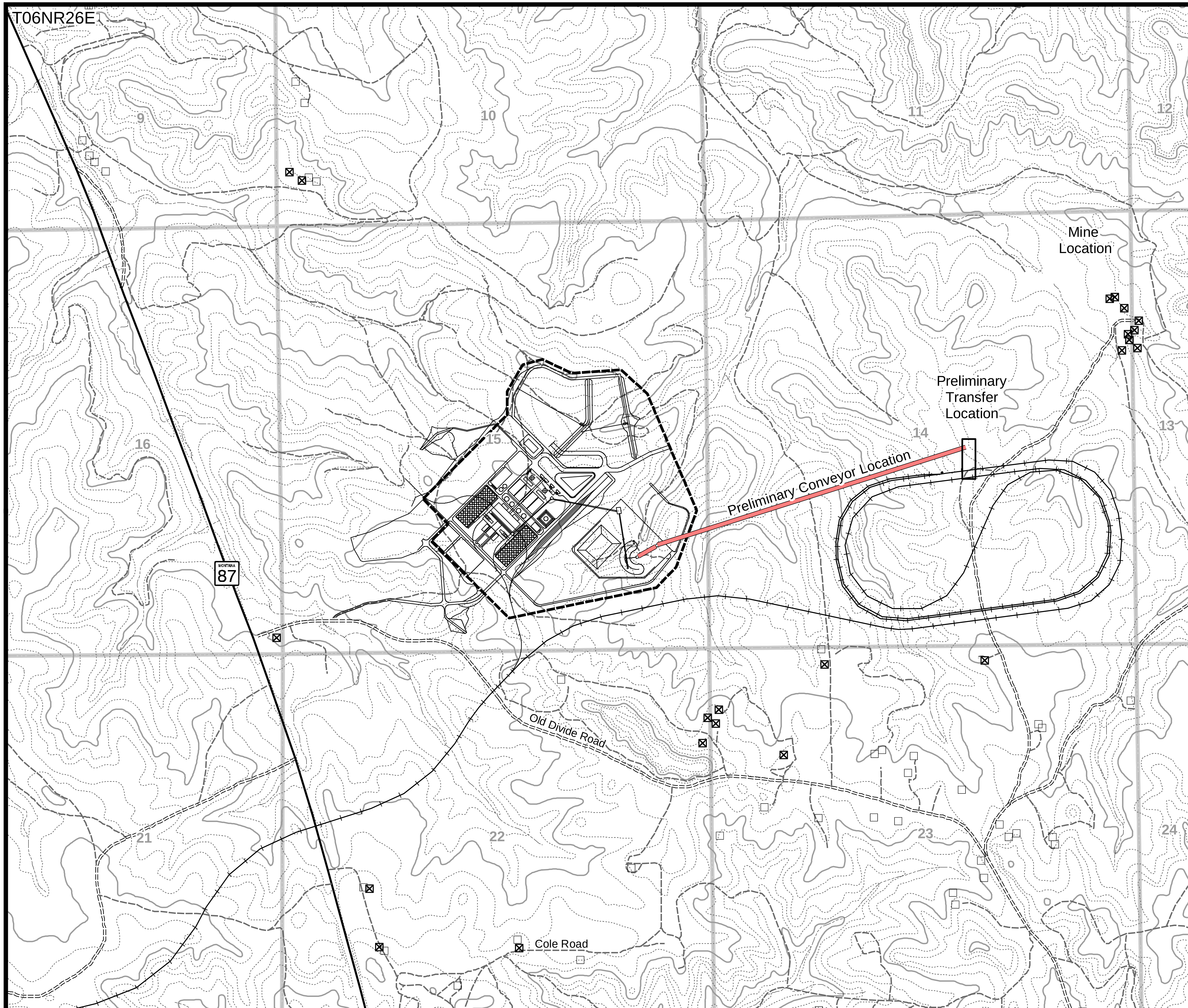

Figure 3-7

Land Use

Roundup Power Project FEIS

Legend

Residence

Non-Residential Structure

Preliminary Transfer Location

Fence Line

Proposed Railroad

State Highway

Local Road

Dirt Road

Section Line

River / Stream

1" : 1,250'

0 625 1,250 2,500 Feet

N W E S

Montana Department of Environmental Quality

Power Engineers

Appendix A
Letters from Local, State and Federal Agencies and Tribes

The Big Sky Country

MONTANA HOUSE OF REPRESENTATIVES

REPRESENTATIVE ALAN OLSON
HOUSE DISTRICT 8

COMMITTEES:
EDUCATION
STATE ADMINISTRATION
FEDERAL, ENERGY, TELECOMMUNICATIONS

HELENA ADDRESS:
PO BOX 200400
HELENA, MONTANA 59620-0400
PHONE: (406) 444-4800

HOME ADDRESS:
18 HALFBREED CREEK ROAD
ROUNDUP, MONTANA 59072
PHONE: (406) 323-3341

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DEC 1 8 2002
DEPT. OF ENVIRONMENTAL QUALITY

December 18, 2002

Mr. Greg Hallsten
P.O. Box 200901
Helena, Montana 59620-0901

Dear Mr. Hallsten,

I am writing to comment on the Draft Environmental Impact Statement for the proposed Roundup Power Project.

First of all I would like to thank you and the others involved in drafting the document for the hours spent in ensuring the public and government agencies have a reasonable document to work with in determining the impacts of the Roundup Power Project.

The first concern I would like to address is the impact on water resources. The draft document is accurate in its description on the aquifers in the area. Potential impacts to residents in the area from withdrawal of water from the Madison formation would be virtually non-existent with a properly constructed well casing program. Casing, cemented back to surface, set through reasonably accessible ground water zones would protect the various aquifers in the Tongue River member of the Fort Union Formation from contamination, either from Madison Formation water due to artesian flow or contamination due to communication from other water sands or coal seams. Additional casing would be run to approximate total well depth and cemented, not necessarily to surface, to protect not only the well bore but also to prevent mixing of other aquifers. Generally, this is standard practice in wells such as these.

On page 3-77 of the document it states there is a "perception" residents of the Bull Mountain Community, mini-farmers, are opposed to coal development. During the scoping meeting and the public hearing on December 5th numerous residents of the Bull Mountains came forward and testified in favor of this project. I do not recall any verbal opposition at either of these public meetings from residents of the Bull Mountains. I too am a part of the Bull Mountain Community. Discussions with my neighbors have generated total support for this project.

As for visibility concerns of the Federal Land Managers addressed on pages 4-103 and Appendix B-4, B-7, I have to question why the FLMs would include air quality data from sources that no longer exist such as the Anaconda smelter. How would operations such as Colstrip, non-existent Anaconda smelter, and the Roundup project, all affect Yellowstone Park at the same time? Is there an air model on the impacts of the annual fires in Yellowstone and surrounding area, and if so how does that compare to the projected loss of visibility from the Roundup project? With Colstrip to the east and Roundup to the northeast of Yellowstone Park, what weather patterns associated with flow in the parks direction lead to a loss in visibility, as east winds are generally associated with inclement weather?

There is no doubt this project will have an impact on the environment. Every day, every one affects the environment. Every new car, subdivision, agriculture operation, cottage business, and tourist has an impact on the environment. The positive economic impacts associated with this project amount to a compelling state interest. The lack of good paying jobs and the inability to raise revenue for local and state government programs due to the decline of tax base and tax payers make this an issue of compelling state interest.

Once again, thank you for your time and efforts on this project.

Sincerely,

Alan Olson

Department of Energy

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

TRANSMISSION BUSINESS LINE

January 3, 2003

In reply refer to: TOP/PPO2-2

Mr. Greg Hallsten
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

Dear Mr. Hallsten:

I am writing in regards to the Roundup Power Project Draft Environmental Impact Statement (DEIS). Although formal comments were due by December 18, 2002, I understand we are still able to submit comments to this report.

The Roundup Power Project developer has requested transmission service from the Bonneville Power Administration Transmission (BPAT) through the Open Access Transmission Tariff process. This secures their position in BPAT's long-term transmission request queue. The general process is as follows:

1. Long-term firm transmission service is requested.
2. If the transmission provider determines a System Impact Study (SIS) is required an SIS agreement is executed. The SIS is a general study to identify any system constraints and the general scope of network upgrades required to provide the requested firm transmission service.
3. When the SIS is completed and if the requestor decides to move forward a System Facility Study (SFS) agreement is executed. The SFS is a more detailed study to determine specific facility additions, upgrades, and/or remedial action schemes required to provide the requested firm transmission service. This includes estimated cost and construction schedule.
4. When the SFS is completed and the requestor decides to move forward, a Construction Agreement is executed, pending completion of any required environmental studies and analyses.
5. Upon completion of the SFS and any required construction and environmental analyses, a transmission service agreement will be offered to the requesting entity.

This process is described in more detail in BPAT's Open Access Transmission Tariff. Since there are several transmission requests ahead of the Roundup Power Project in BPAT's long-term transmission request queue, and requests must be considered in queue order, the SIS is expected to be completed in the fourth quarter of 2003. After the SIS is completed it is estimated the SFS could take an additional 4-6 months depending on the scope of network upgrades identified.

The first comment on the Roundup Power Project DEIS is in Section 2.4.2, 230kV Transmission System Alternative, page 2-53, second paragraph. The last sentence states, "Studies performed by both transmission providers have identified upgrades that are proposed and underway to support this flow." I suggest the following alternative. "Studies will be performed by both transmission providers to identify necessary upgrades to support this flow."

The second comment is in the section titled Infrastructure Development, Transmission, Page 4-98, second paragraph. This paragraph states, "According to BPA, major transmission improvements to the BPA system are planned. These improvements would include substation upgrades and transmission line additions between Montana and the Pacific Northwest." I suggest the following alternative. "BPAT has a current project to increase the West-of-Hatwai cutplane capacity in Washington. However, this does not provide increased capacity from Montana to the Northwest. In order to provide service to the Roundup Power Project major facility additions will be required. This could potentially include substation upgrades and/or transmission line additions. Studies will be done in queue order based on BPAT's long-term transmission request queue to determine the improvements needed."

If you have any questions or comments, please call me at (360) 619-6668.

Sincerely,

Charles E. Matthews
Process Manager, Network Planning

Montana Department of Transportation
David A. Galt, Director
Judy Martz, Governor
2701 Prospect Avenue
PO Box 201001
Helena MT 59620-1001

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MT DEPT. OF ENV. QUALITY
PERMITTING & COMPLIANCE DIV.

November 22, 2002

Greg Hallsten
Montana Department of Environmental Quality
P.O. Box 200901
Helena, Montana 59620-0901

Subject: Roundup Power Project-Draft Environmental Impact Statement

Greg,
We have reviewed primarily transportation issues in the subject document and have the following comments:

- The meaning or intent of the third sentence in the first paragraph on page 3-74 that begins "The Montana Department of Transportation does not attempt to justify…" is not clear. A better explanation of what is intended should be provided or the sentence deleted.

- Additionally, in the second paragraph on page 3-74 US Route 87and US Route 12 are referred to as SR 87 and SR 12. If this SR is identifying the roadways as "State Routes" it is incorrect. They are both US Routes.

If you have any questions please contact me at (406) 444-6303. Thanks

Dan Martin, Planner
Program & Policy Analysis Bureau
Rail, Transit and Planning Division

copies: Patricia Saindon, Administrator, Rail, Transit and Planning Division
Bruce Barrett, Administrator, Billings District
Sandra Straehl, Program and Policy Analysis Bureau Chief

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, D.C. 20240

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DEQ
DIRECTOR'S OFFICE

December 18, 2002

Ms. Jan Sensibaugh
Director, Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

Dear Ms. Sensibaugh:

The National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) have been participating in the Clean Air Act (CAA) "Prevention of Significant Deterioration" (PSD) permit review for the construction and operation of the Roundup Power Project (RPP) since January 2002.

The proposed RPP would be a 780 Megawatt, coal-fired, electric generating station located approximately 180 km northeast of Yellowstone National Park (NP) and 122 km south of UL Bend Wilderness Area (WA). Under the Clean Air Act, both Yellowstone NP (administered by the NPS) and UL Bend WA (administered by the FWS) are designated as "Class I" air quality areas. The CAA gives Federal Land Managers an affirmative responsibility to protect air quality related values (including visibility) of these areas, and to consider whether any major emitting facilities will have an adverse impact on such values 42 USC 7475(d)(2)(B). We have concluded that if constructed and operated under the conditions outlined in your Preliminary Determination and draft permit, RPP's proposed emissions – when analyzed alone and in combination with existing emissions in the area – could cause perceptible visibility impairment at Yellowstone NP and UL Bend WA. Based on our analysis, we believe emissions from RPP will have an adverse impact on park air quality related values, and we ask the MT DEQ, pursuant to 42 USC 7475(d)(2)(C)(ii) to consider our concerns on the record in making a determination. Enclosed are detailed comments that support our adverse impact finding.

RPP is a modern, well-planned facility. It will be cleaner than nearly all of its predecessors. The adverse impact comes from the fact that RPP will contribute to concentrations which cause an adverse effect at Yellowstone NP and UL Bend WA, two Class I areas. We would welcome the opportunity to discuss this and other approaches with you and other environmental regulators in the region, as well as with permit applicants and other interested stakeholders, as you deem appropriate. Perhaps we could first explore a full range of options and discuss possible approaches with you and your staff, before we begin a more formal multi-stakeholder approach. We recently proposed a similar approach regarding a permit action in the State of Wyoming.

In closing, in the spirit of Secretary Norton's "Four C's" process of "consultation, cooperation, communication, all in the service of conservation," we solicit your help in resolving our concerns about the RPP project and fulfilling our mutual obligations under the Clean Air Act to protect the air quality in these special areas for the enjoyment of future generations. By working together we are hopeful that we can protect the visibility at Yellowstone NP and UL Bend WA. If there are any questions regarding this matter, please contact Christine Shaver of the NPS Air Resources Division at (303) 969-2074, or Sandra Silva of the FWS Air Quality Branch at (303) 969-2814.

Sincerely,

Craig Manson
Assistant Secretary for Fish and Wildlife
Fish and Wildlife and Parks

Enclosure

cc:

Richard Long
U.S. Environmental Protection Agency
Mail Code HP-AR
999 18th St., Suite 300
Denver, Colorado 80202-2466

Jay Littlewolf
Air Quality Division
Northern Cheyenne Tribe
P.O. Box 128
Lame Deer, Montana 59043

Ann Acheson
USDA Forest Service, Region 1
P.O. Box 7669
Missoula, Montana 59807

Determination of Adverse Impact to Visibility at Yellowstone National Park and UL Bend Wilderness Area for the Roundup Power Project
by
U.S. Department of the Interior
December 2, 2002

Background

Roundup Power is proposing to construct a new power plant consisting of two, 390 Megawatt, pulverized coal-fired boilers. The proposed facility would be located next to the Bull Mountains Coal Mine in south-central Montana in Musselshell County, near the town of Roundup. This location is approximately 122 km south of UL Bend Wilderness Area (WA) and 180 km northeast of Yellowstone National Park (NP), Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS) and the National Park Service (NPS), respectively. This project would result in Prevention of Significant Deterioration (PSD) significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM_{10}), volatile organic compounds (VOC), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS (TPY)
NO_X	2329
SO_2	3939
PM_{10}	512
VOC	99
CO	4917

The NPS Air Resources Division and the FWS Air Quality Branch received the PSD permit application for the Roundup Power Project (RPP) in January 2002. On February 19, 2002, a Technical Analysis outlining the comments of both NPS and FWS offices was jointly submitted to the Montana Department of Environmental Quality (MT DEQ). This Technical Analysis presented comments and recommendations regarding Best Available Control Technology (BACT) and the air quality modeling analysis submitted with the RPP PSD application. Due to errors discovered with data used in the air quality modeling, a revised air quality analysis was submitted by RPP on April 22, 2002. After reviewing the results, a second comment letter was sent to MT DEQ by NPS and FWS on May 6, 2002. In this letter, we notified MT DEQ that based upon the results in the air quality analysis, the RPP facility had the potential to have an adverse impact to visibility at Yellowstone NP and UL Bend WA.

On August 12, 2002, MT DEQ released the *Preliminary Determination on Permit Application* for the Roundup Power Project. Using the emission rates outlined in this draft permit and the 1990 meteorological data supplied by RPP, we performed additional modeling to assess potential impacts at Yellowstone NP and UL Bend WA, if RPP operated under the conditions outlined in the draft permit. Our results again indicated that potential adverse visibility impacts might occur from RPP's emissions alone, and when RPP's emissions are combined with other PSD sources in the area. On August 27 we sent a third comment letter to MT DEQ that repeated our concern that potential adverse impacts could occur at Yellowstone NP and UL Bend WA. We again requested that RPP conduct additional modeling with an additional year of meteorological data (1992) to better define the impacts at these areas.

On October 28, RPP submitted the SO_2 increment analysis and the cumulative visibility analysis that we requested in our previous letters. The results indicate that the SO_2 increment will not be violated at Yellowstone NP or UL Bend WA, and we agreed with these results. However, in conducting the cumulative visibility analysis with the 1990 data, RPP used a modeling methodology we do not consider valid. This approach is considered invalid because it excludes several large sources, including many that RPP included in the SO_2 increment analysis. We conducted a separate modeling analysis using the correct number of sources. This modeling found an extremely high number of days when there would be perceptible visibility impacts, and shows that RPP would be a significantly contributing source on those days. These modeling results and concerns were again presented in a fourth letter to MT DEQ on November 6, 2002.

On November 18, MT DEQ released the Draft Environmental Impact Statement (DEIS) for this project. The DEIS presents multiple modeling results that have been submitted by both RPP and NPS/FWS. NPS/FWS modeling results submitted in our November 6, 2002, letter to MT DEQ were presented in Scenario 2 (Table B-6) of the DEIS. On December 2, 2002, the NPS/FWS discovered a small modeling error associated with these results. The NPS/FWS modeling results calculated visibility impacts from hour 1 to hour 0 in the modeling post-processor instead of from hour 0 to hour 23. This results in small changes in predicted impacts. The new results are presented below in Tables 1 and 2. The results also confirm our concern that RPP in combination with other PSD sources in the area would adversely impact visibility at both Yellowstone NP and UL Bend WA. Please note that the North Absaroka and Northern Cheyenne Class I areas are not administered by the Department of the Interior. However, we have included these areas in our modeling analyses for completeness.

Table 1 – RPP only

Results of December 2, 2002, NPS/FWS modeling for the proposed Roundup Power Plant. Should replace those presented in November 6, 2002, letter to MT DEQ and published as Table B-6 in RPP Draft Environmental Impact Statement.

RPP VISIBILITY IMPACT by NPS/FWS with STATE PROPOSED EMISSION LIMITS- **1990** Meteorological Data with f(RH) Max = 98%			
Area	Days > 5% Change in Extinction	Days >10% Change in Extinction	Maximum Change in Extinction
Yellowstone NP	**7**	**1**	**12.72 %**
UL Bend WA	**4**	**0**	**8.41%**
North Absaroka WA	3	0	9.11 %
Northern Cheyenne	36	11	38.27%

Table 2 – Cumulative Sources

Results of December 2, 2002, NPS/FWS cumulative visibility modeling for the proposed Roundup Power Plant and 7 PSD sources. Should replace those presented in November 6, 2002, letter to MT DEQ and published as Table B-6 in RPP Draft Environmental Impact Statement.

RPP with STATE PROPOSED EMISSION LIMITS + 7 PSD SOURCES VISIBILITY IMPACT by NPS/FWS – **1990** Meteorological Data with f(RH) Max = 98%			
Area	Days > 5% Change in Extinction	Days >10% Change in Extinction	Maximum Change in Extinction
Yellowstone NP	**39**	**26**	**119.28 %**
UL Bend WA	**50**	**29**	**149.50%**
North Absaroka WA	35	22	125.83 %
Northern Cheyenne	259	224	618.43%

As noted in Tables 1 and 2, these analyses were based on 1990 meteorological data. Following publication of the DEIS, additional modeling of RPP-only impacts using 1992 meteorological data was submitted by RPP (November 21, 2002, letter to D. Walsh, MT DEQ, from D. Lorenzen). The NPS and FWS were unable to replicate the RPP results exactly, but the results are very similar. RPP did not submit a cumulative visibility analysis using 1992 data, so the NPS/FWS performed this analysis using the source inventory supplied by RPP for the 1990 analysis. The NPS/FWS results using the 1992 data are presented below in Tables 3 and 4.

Table 3 – RPP only

Results of NPS/FWS modeling for the proposed Roundup Power Plant using 1992 data.

RPP VISIBILITY IMPACT by NPS/FWS with STATE PROPOSED EMISSION LIMITS- **1992** Meteorological Data with f(RH) Max = 98%			
AREA	Days > 5% Change in Extinction	Days >10% Change in Extinction	Maximum Change in Extinction
Yellowstone NP	**13**	**2**	**15.41%**
UL Bend WA	**16**	**4**	**28.06%**
North Absaroka WA	10	1	14.53%
Northern Cheyenne	32	11	46.87%

Table 4 – Cumulative Sources

Results of NPS/FWS cumulative visibility modeling for the proposed Roundup Power Plant and 7 PSD sources using 1992 data.

RPP with STATE PROPOSED EMISSION LIMITS + 7 PSD SOURCES VISIBILITY IMPACT by NPS/FWS - **1992** Meteorological Data with f(RH) Max = 98%			
AREA	Days > 5% Change in Extinction	Days >10% Change in Extinction	Maximum Change in Extinction
Yellowstone NP	**32**	**20**	**83.67%**
UL Bend WA	**64**	**41**	**150.30%**
North Absaroka WA	31	21	85.61%
Northern Cheyenne	286	255	971.98%

Discussion of Modeling Results and Air Quality Impacts

A 10% change in extinction is the generally accepted level that would be perceptible to the casual observer. A 5% change could be perceptible for a particular scene under special visibility conditions.

During this review process, both RPP and NPS/FWS have submitted numerous modeling results. While the magnitude of visibility impacts vary slightly, the general trend is that RPP alone would cause perceptible visibility impacts at Yellowstone NP and UL Bend WA. This is shown in Tables 1 and 3. In the November 6, 2002, letter to MT DEQ, the NPS and FWS stated that based on the results of the 1990 RPP-only analysis, the FWS would not consider the impacts caused by RPP alone to be adverse, but that additional modeling may produce different results. Based upon the results now available for the 1992 analysis (Table 3), the impacts from RPP alone would also have an adverse impact on visibility at UL Bend WA.

These RPP-only modeling results also trigger a cumulative visibility analysis for both Class I areas. These cumulative impacts (Tables 2 and 4) are severe in both frequency and magnitude, and constitute an adverse impact at both areas. Moreover, RPP would be a significant contributor to these impacts. These results indicate that RPP has not met the demonstration required under the Administrative Rules of Montana, which require the owner or operator to demonstrate that the RPP "…will not **cause or contribute to** adverse impact on visibility within any federal Class I area or the department will not issue a permit." (17.8.1106(1)) (emphasis added).

The 1992 results presented in Tables 3 and 4 demonstrate that the 1990 impacts (Tables 1 and 2) are not isolated events, and the RPP would continue to cause and contribute to adverse visibility impacts over time. These results further confirm the NPS/FWS finding that the RPP project would cause and significantly contribute to adverse visibility impacts and cumulative visibility impacts at Yellowstone NP and UL Bend WA.

RPP and the MT DEQ have raised the issue as to whether RPP's contribution to the adverse cumulative visibility impacts are "significant." A review of the modeling outputs for the 1990 RPP-only and for the 1990 cumulative visibility impacts was done by the NPS/FWS to examine this issue. The results demonstrate that RPP's contributions on days in which the cumulative visibility impacts exceed 10% at Yellowstone NP and UL Bend WA are indeed significant. For instance, on Day #15 at receptor #33, the cumulative change in extinction is 12.24%. On that same day and at the same receptor, the change in extinction caused by RPP alone is 6.77%, or 55% of the total cumulative visibility impact. On Day #16 at receptor #33, the cumulative change in extinction is 14.32%. The extinction caused by RPP alone on this date and receptor is 6.33%, representing 44% of the cumulative visibility impact. Similarly, for UL Bend WA, on day #46 at receptor #351, RPP's contribution was 8.41% of the total 29.18% change in extinction (29%). Our review of both the 1990 and 1992 results shows many additional instances when RPP represents a significant percentage of a cumulative change in extinction that is greater than 10% change in extinction at Yellowstone NP and UL Bend WA.

Adverse Impact Demonstration

Under the regulations promulgated for visibility protection (40 CFR §51.301) visibility impairment is defined as "...any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." The threshold for perceptibility, where a just noticeable change occurs in the scene, has been found to correspond to a change in extinction as low as 2% under ideal conditions. A change in extinction will evoke a just noticeable change in most landscape, and FLMs consider a change in extinction greater than 10% to be unacceptable, unless there is mitigation.

In 1872, the enabling legislation that established Yellowstone NP as the world's first national park states that the Yellowstone NP

> "...is hereby reserved and withdrawn from settlement, occupancy or sale under the laws of the United States, and dedicated and set apart as a public park or pleasuring-ground for the benefit and enjoyment of the people." (17 Stat. 32)

Scenery and visibility play a critical role in the quality of visitor experience, and visitors to national parks and wildernesses list the ability to view unobscured views as a significant part of a satisfying experience. The enjoyment and appreciation of Yellowstone NP and UL Bend WA are linked to the ability of visitors to view the scenery clearly. A significant reduction in visibility would hinder the benefits and enjoyment of visitors to Yellowstone NP and UL Bend WA, as well as diminish the national significance of these majestic landscapes. Air pollution currently impairs visibility to some degree in every national park and refuge, increasing the importance of preventing additional impairment. Visibility impacts from the RPP alone would cause a significant change in extinction that would hinder the benefits and enjoyment of visitors to Yellowstone NP and UL Bend WA on the days those impacts occur. The emissions from RPP would also significantly contribute to the more frequent and severe cumulative visibility impacts that occur at both Yellowstone NP and UL Bend WA.

The Federal Land Manager considers impacts to air quality related values such as visibility to be adverse if such impacts would impair the quality of the visitor experience or diminish the area's national significance. This is consistent with the Code of Federal Regulations (CFR) which defines an adverse impact on visibility as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's visual experience of a Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Class I area, and (2) the frequency and timing of natural conditions that reduce visibility." (40 CFR §51.300, et seq. §52.57)

The Administrative Rules of Montana also give a similar definition, stating that "adverse impact on visibility means visibility impairment which the department determines does or is likely to interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within a federal Class I area. The determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility" (17.8.1101(2)). These definitions support our position that perceptible visibility impacts of the frequency and magnitude of those predicted for RPP are indeed adverse.

With respect to the relationship of visibility impacts and times of visitor use of the Class I areas, Yellowstone NP and UL Bend WA are both open to visitor use 24 hours a day, year-round. Thus visitation can and does occur at any time. There were nearly three million recreational visits to Yellowstone NP during 2001. For many visitors this is a once-in-a-lifetime experience, and the NPS and FWS are greatly concerned that the experience of each and every visitor not be interfered with by adverse visibility impairment on any day(s) in which visitation occurs. Regarding natural conditions that reduce visibility, RPP has stated that the 1990 impact that is greater than 10% occurs during a snowstorm and that a park visitor 1) would not be out in the elements to view the scenery with any expectation of seeing vast distances and 2) the natural background impairment of the snowstorm would far outweigh the impact of RPP (October 21, 2002, letter to D. Walsh, MT DEQ, from J.W. Dickey). This argument is flawed because it assumes that the snowstorm would be occurring throughout the entire 1.1 million hectare area of Yellowstone NP, and would affect all visitors present in the park at that time. Further, it is unlikely that this weather condition would persist throughout the entire period that is modeled.

Congress recognized the importance of visibility in national parks and wilderness areas when it amended the Clean Air Act (CAA) in 1977 and established a national goal of preventing any future visibility impairment, and remedying any existing visibility impairment due to human-caused air pollution in areas such as Yellowstone NP and UL Bend WA. The CAA directs that the FLMs identify and protect air quality related values, including visibility. In the case of the CAA, the FLM gleans additional insight from a passage in Senate Report No. 95-127, 95th Congress, 1st Session, 1977 which states,

> "The Federal Land Manager holds a powerful tool. He is required to protect Federal lands from deterioration of an established values, even when Class I [increments] are not

exceeded. ...While the general scope of the Federal Government's activities in preventing significant deterioration has been carefully limited, the FLM should assume an aggressive role in protecting the air quality values of land areas under their jurisdiction. In cases of doubt the land manager should err on the side of protecting the air quality-related values for future generations."

Conclusions

We have stated our concern about potential impacts resulting from the RPP facility in four comment letters to MT DEQ. Three of these letters clearly identify the potential for adverse impacts at Yellowstone NP and UL Bend WA. Attempts have been made in two conference calls and in numerous informal communications to resolve issues with RPP and MT DEQ. Modeling analyses submitted by both RPP and the NPS/FWS have repeatedly indicated that RPP will have an adverse impact on visibility at Yellowstone NP and UL Bend WA. The RPP would also significantly contribute to adverse cumulative visibility impacts at both Yellowstone NP and UL Bend WA. These adverse impacts from RPP have been repeatedly demonstrated in the many modeling analyses presented as part of the ongoing PSD and EIS process.

The FLM finding of an adverse impact is based upon a demonstration that the current or predicted deterioration of air quality will diminish the area's national significance, impair the structure and functioning of the area's ecosystem, or impair the quality of the visitor experience in the area. Modeling results presented in the RPP PSD application and in the DEIS (based on 1990 data) show one day exceeding a 10% change in extinction and seven days greater than 5% change in visibility extinction at Yellowstone NP. Four days exceed a 5% change in extinction at UL Bend WA. Further modeling by RPP and NPS/FWS using 1992 data shows two days at Yellowstone NP and four days at UL Bend WA exceeding a 10% change in extinction. Thirteen and 16 days exceed 5% change in extinction at Yellowstone NP and UL Bend WA, respectively. The results of the cumulative visibility analysis (both 1990 and 1992 data) indicate that the RPP would be a significant contributing source to adverse visibility impacts at Yellowstone NP and UL Bend WA. The values represented in all analyses (whether RPP-only or cumulative) predict impacts that would be perceptible to visitors at Yellowstone NP and UL Bend WA, and would violate two of the three adverse impact criteria cited above (i.e., impair the visitor's experience and diminish the area's national significance).

The NPS and FWS have concluded that RPP alone would cause an adverse impact to visibility at Yellowstone NP and UL Bend WA, and contribute significantly to a cumulative adverse impact on visibility at Yellowstone NP and UL Bend WA. This finding is clearly supported by language found in the Clean Air Act, Code of Federal Regulations, the Administrative Rules of Montana, and in the enabling legislation that established Yellowstone National Park. Therefore, we ask that the MT DEQ not grant a final PSD permit to RPP until our adverse impact concerns are adequately addressed.

-WOHEHIV-
The Morning Star

NORTHERN CHEYENNE TRIBE ADMINISTRATION

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-WOHEHIV-
The Morning Star

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DEC 1 9 2002

DEQ
DIRECTOR'S OFFICE

Montana Department of Environmental Quality
P.O. Box 200901
Helena, Montana 59620-0901

Re: Comments on the Draft Environmental Impact Statement for the proposed Roundup Power Project

Dear Mr. Greg Hallstein

Thank you for the opportunity to make comments on the Draft EIS:

1. Page 3-4, 3.2.3: Add, "The town of Lame Deer, MT, PM10 non-attainment area, is located (down wind) southeast of the RPP."

2. Pages 4-4 to 4-5, 4.2.1: The Northern Cheyenne Tribe is alarmed at the potential visibility impacts from RPP, especially the cumulative effects from the combined sources of Colstrip 1,2,3 and 4 and the potential developments of coalbed methane on the Crow reservation. The tribe has been in contact with the NPS and FWS, Chris Shaver and Sandra Silva, about these visibility issues. The tribe believes, too, that up to date modeling with current sources be done to show the cumulative effects that impact the Northern Cheyenne Reservation.

3. Page 4-5, 4.2.1: Paragraph number 4 and 5: Acid rain has been known to form miles downwind of a coal fired power plant. We have over twenty years of met data on the Northern Cheyenne Reservation. The prevailing winds are from the west, northwest and north, therefore the reservation would be impacted from RPP.

4. Page 4-16, 4.2.1: Paragraph number 2: Change the last sentence to read: "The closest **federal non-mandatory** Class I area is the Northern Cheyenne Reservation (NCR), located 130 (81) km southeast of the site."

5. The Northern Cheyenne Air Quality Division received this EIS on December 12, 2002. The comments were due within one week(Dec. 18). Due to the limited time line to review this EIS other environmental professionals did not have sufficient time to make comments. The environmental staff will need to be involved in the formal determination regarding adverse impacts.

For any question on these comments please contact Jay Littlewolf at 406-477-6506.

Sincerely,

Geri Small

Geri Small, President
Northern Cheyenne Tribe

cc: Northern Cheyenne Tribal Council
Dick Long, EPA, Region VIII
Monica Morales, EPA, Region VIII
Jay Littlewolf, Air Quality, NCT

Yellowstone County

COMMISSIONERS
(406) 256-2701
(406) 256-2777 (FAX)

P.O. Box 35000
Billings, MT 59107-5000
commission@co.yellowstone.mt.us

December 9, 2002

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DEC 1 0 2002

MT DEPT. OF ENV. QUALITY
PERMITTING & COMPLIANCE DIV.

Mr. Greg Hallsten
Montana Department of Environmental Quality
P.O. Box 200901
Helena, Montana 59620-0901

Dear Mr. Hallsten:

The purpose of this letter is to **support** the construction and operation of the proposed 700-megawatt coal-fired power plant south of Roundup in Musselshell County. A review of the draft EIS would indicate two deficiencies in the study: 1. Lack of full consideration for the **positive economic impact** the project would have to this region. 2. The predominate **wind direction** for this region is from the **Southwest.** The possible decrease in visibility to Yellowstone National Park is misrepresented.

As a Yellowstone County Commissioner, I ask that you issue the necessary permits required for the construction and operation of this much-needed project.

Sincerely,

James E. Reno, Commissioner

Cc: Musselshell County Commissioners
Joe Gerbase, Attorney

17 December 2002

From: Subdivisions and Planning

Subject: Comments on Roundup Power Project Draft EIS

To: Montana Department of Environmental Quality
Attn: Greg Hallsten
PO Box 200901
Helena, MT 59620-0901

Dear Mr Hallsten,

Overall the draft EIS for the proposed Roundup power plant is good and reaches the proper conclusion that the project should go forward and be granted the air quality permit. However, the draft understates the county government's ability to provide increased emergency services during the construction phase and also understates short-term road impacts.

It is not my intention to provide bullets for those who oppose this project, but to have the document properly recognize that there will be short-term impacts. The following issues should be more fully addressed in the EIS and are referenced by paragraph and page numbers:

1. Page 3-66, section on taxes: This section should put into perspective the overall financial health of the county in relation to the reduction of taxable valuation since 1986. The county has been forced to reduce or eliminate many services during this period and this significantly affects our ability to provide increased services to these projects during the construction phase. Once tax revenues increase, we can deal with these issues appropriately. When you couple the impact of the mine construction and power plant construction, we will have some significant impacts quickly, and these will be before new revenues begin. Since paragraph 4.12.1 rightfully acknowledges the perspective of both projects, the rest of the document should do so also.

2. Page 3-75, section on health and safety: The sections on law enforcement and fire were not coordinated with the proper department officials, and this affects the conclusions in

section 4.12.8 because of incomplete information. The County Sheriff, and County Fire Chief who chairs the County Fire Council, were not consulted.

3. Paragraph 4.1.1, page 4-1 discusses mitigation that may be required and mitigation that may be recommended as a condition for permitting. The draft EIS does not make any recommendations for any matter related to emergency services, nor does it discuss who or how these services are to be provided. The assumption seems to be that the county can absorb these impacts. They are not negligible during the construction phase due to lack of funding, and they will be significant to law, fire, ambulance, and roads. If mitigation of these cannot be required, they must be stridently sought by us. Understating the short-term impacts does not assist this process.

4. Paragraph 4.12.6, page 4-91. There is no mention of impacts to county and local roads during the construction phases of the mine or power plants.

5. Paragraph 4.12.8, page 4-93. Musselshell County has had and continues to have a high crime rate associated with our poor economic conditions. The data used to suggest a low crime rate for 1999 was a known aberration due to faulty reporting. A short time prior to 1999 we had the highest crime rate in the state, and using 1999 data misrepresents our current crime statistics. Our current law enforcement department is underfunded and understaffed. Any increase in crime will have serious impacts to the department's capabilities and this was acknowledged on page 3-75 but not here or the following impact tables on page 4-96. Although the County fire department is properly trained and staffed and has significant capabilities, they are located a long way from the proposed site. Other area fire agencies are not properly staffed, trained, nor equipped to handle any increase in demands for services from new development or from the power plant or mine requirements. (There is no discussion in the EIS of how these services would be provided at the sites.) The County is in the process of developing a strategic fire plan to address the current and future deficiencies and has taken steps to improve services, but we recognize our present limitations. On page 3-75, it is recognized that our ambulance service is already at the limits of providing services. Section 4.12.8 fails to follow up and make any statement about this issue.

6. Table 4-37: The section on traffic fails to recognize impact to county and local roads during construction, before revenues increase. The section on law fails to recognize that any increase, particularly during the construction phase, would be a significant adverse impact. The section on ambulance is also understated during the construction phase. The impacts would be severe for the ambulance service during construction with 800 workers in a high-risk environment. The impact to fire services would be moderate to severe permanently. The ability of the county fire department to provide structural protection is already limited and any additional development will further stress this system. Although the mine operators have stated they will handle fire, every major event at either site will involve local government services for law, fire, and EMS and we expect this to be so for the power plants.

7. Paragraph 4.12.11, second section, draws the wrong conclusions as discussed above.

8. Page 4-106 section on socioeconomic cumulative impacts is again understated as discussed above. Providing adequate emergency services to the community and to these projects is essential for the success of the projects, and our emergency services community has impacts that need more discussion in the EIS.

9. The consultation section does not list any consultation with local officials. No where in the document was Disaster and Emergency Services referenced or consulted.

10. In the reference section, land use portion, county subdivisions and planning is the source for the facts at-a glance document.

Sincerely,

Kirby Danielson
Subdivisions and Planning

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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MT DEPT. OF ENV. QUALITY
PERMITTING & COMPLIANCE DIV.

Ref: 8P-AR

DEC 18 2002

Steve Welch, Director
Permitting and Compliance Division
Montana Department of Environmental Quality
P.O. Box 200901
Helena, Montana 59620-0901

Dear Mr. Welch:

I am writing to provide comments on the Preliminary Determination on the Roundup Power Project (Permit #3182-00) (draft permit). I understand that you are accepting comments on the draft permit through December 18, 2002. We believe there are several issues that should be addressed and provisions of the draft permit that should be revised before the permit is issued in final form. The enclosure to this letter specifically discusses concerns we have with the draft permit.

With respect to the draft permit our major concerns are with Best Available Control Technology (BACT) and Case-By-Case Maximum Available Control Technology (MACT). Specifically, we believe that lower BACT levels should be established for SO2, NOx and particulates and that the Case-By-Case MACT requirements have not been met. The BACT and MACT concerns, as well as other concerns with the draft permit, are addressed in the enclosure to this letter. We believe the draft permit should be revised to address the enclosed concerns before it is issued in final form.

Please contact me at (303) 312-6005 if you have any questions regarding this letter.

Sincerely,

Richard R. Long, Director
Air and Radiation Program

Enclosures
cc: John Wardell, 8MO
Geri Small, President, Northern Cheyenne Tribe
Jay Little Wolf, Air Program Manager, Northern Cheyenne Tribe

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EPA COMMENTS ON DRAFT MONTANA PSD PERMIT
FOR ROUNDUP POWER PROJECT

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The comments below pertain to each of the two 390-MW pulverized coal (PC) fired boilers.

1. Particulate:

The draft permit specifies 0.015 lb/MMBtu as BACT, based on use of a baghouse. We believe 0.012 lb/MMBtu or lower should be specified as BACT. A BACT determination of 0.012 was recently made by the Wyoming DEQ for the WYGEN2 project, a 500-MW PC-fired boiler to be constructed by Black Hills Corporation. Wyoming's determination was based on use of a baghouse with membrane-type bags (e.g, Goretex).

2. Sulfur dioxide:

a. BACT in terms of lb/MMBtu. The draft permit specifies 0.12 lb/MMBtu (on a 30-day rolling average) as BACT, based on use of a dry SO_2 scrubber and assuming 94% control efficiency and worst-case coal sulfur content (equivalent to 1.90 lb/MMBtu at the scrubber inlet). We believe a much tighter lb/MMBtu limit should be specified as BACT, for the following reasons:

(i) Typical coal sulfur content is much less than worst-case. In its BACT analysis, the Montana DEQ apparently accepted the permit applicant's use of worst-case coal sulfur content as the basis for the proposed SO_2 emission limit of 0.12 lb/MMBtu, without any comparative analysis with available coal at lower sulfur content. (Reference: revised permit application to Montana DEQ dated April 11, 2002, page 1.). While use of the worst-case coal scenario might be appropriate for establishing a short-term (3-hour or 24-hour) SO2 emission limit, we consider it inappropriate for establishing a 30-day average emission limit, especially considering that coal blending can be used at minimal additional cost (and is routinely used in the power plant industry) to eliminate or reduce the effect of coal sulfur 'spikes.'

Since the Montana DEQ's BACT analysis does not indicate what the typical coal sulfur content would be for the Roundup project, we have independently examined coal sulfur content data available from various organizations, such as the Wyoming Geologic Survey and the Energy Information Administration website (http://www.eia.doe.gov/cneaf/electricity/cq/cq.pdf). From these data, it appears to us that typical coal sulfur content in Montana is probably less than half of the worst-case coal sulfur content used by the permit applicant. Based on typical coal sulfur content, 94% to 96% scrubber efficiency (see further discussion below) and coal blending, we believe an SO_2 emission rate in the range of 0.04 to 0.06 lb/MMBtu could routinely be achieved on a 30-day average.

(ii) Actual SO2 emission rates at other power plants. Emissions data on EPA's acid rain program website (www.epa.gov/airmarkets) for years 2000 through 2001 reveal that several PSD-permitted power plant boilers in this region (for example, Bonanza 1, Intermountain Power 1 and 2, Rawhide 1, Hunter 3 and Colstrip 3 and 4) routinely achieve below 0.10 lb/MMBtu for SO_2, on a 30-day average. In fact, Bonanza, Intermountain Power and Hunter 3 routinely achieve below 0.080 lb/MMBtu on a 30-day average, despite the fact that the SO_2 scrubbers at these boilers were constructed many years ago.

(iii) BACT determinations for similar projects. BACT determinations by other states in this region are further evidence that an emission rate much lower than the 0.12 lb/MMBtu proposed by Montana DEQ can be achieved. For example, a BACT determination of 0.10 lb/MMBtu (on a 30-day rolling average) and 96% control efficiency was made by the Wyoming DEQ for the WYGEN2 project (based on use of a semi-dry SO_2 scrubber). Also, a BACT determination of 0.10 lb/MMBtu (on a 30-day rolling average) was made by the Utah DEQ for Hunter Unit #3, a 495-MW PC-fired boiler operated by Pacificorp (based on use of a wet SO_2 scrubber). Also, a BACT determination of 96% control efficiency was made by the State of New Mexico for the Mustang power project.

(iv) Visibility impacts Severe visibility impacts identified by the Federal Land Managers may necessitate a tighter emission limit in lb/MMBtu than would otherwise be necessary.

b. BACT in terms of control efficiency. A minimum required SO_2 scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO_2 emissions are minimized at all times, regardless of the sulfur content in the coal. Because of the severe visibility impacts identified by the Federal Land Managers, we believe the permit should specify scrubber efficiency in the range of 94% to 96% (on a 30-day rolling average), with compliance to be demonstrated via SO_2 CEMS at the scrubber inlet and outlet. We note that 40 CFR 60.47a(b)(1) already requires inlet and outlet CEMS. We consider 96% efficiency achievable based in part on BACT determinations by other states (mentioned above), and on vendor literature from Babcock and Wilcox (a manufacturer of large PC-fired boilers and control equipment; see www.babcock.com), which indicates that even higher SO_2 control efficiencies of 96% to 98% can be achieved with dry scrubbers, even where low-sulfur western coal is used.

3. Nitrogen oxides.

The draft permit specifies 0.07 lb/MMBtu (on a 30-day rolling average) as BACT, based on combined use of low-NO_x burners (LNB), selective catalytic reduction (SCR) at 80% control efficiency, and overfire air (OFA). The Montana DEQ's discussion of available control technologies for NO_x fails to mention ultra-low-NO_x-burners (ULNB). Vendor literature from Babcock and Wilcox (see www.babcock.com) indicates that ULNB, in conjunction with 90% efficient SCR, could achieve NO_x emission rates in the range of 0.015 to 0.025 lb/MMBtu.

ULNB combined with SCR is currently available. For example, it has been installed at the Hawthorn plant in Kansas City. ULNB is important to consider because we believe there are potential NO_x-related visibility issues with the draft permit for Roundup project (as discussed elsewhere in this letter). These issues may necessitate a more stringent NO_x emission limitation than would otherwise be necessary. Also, we believe SCR can achieve better than 80% control. We note that the State of New Mexico made a BACT determination for the Mustang power project with a 93% efficient SCR.

CASE BY-CASE MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT)

The project is subject to case-by-case MACT pursuant to section 112(g) of the Clean Air Act. However, Montana DEQ did not establish case-by-case MACT limits or follow the procedures specified in the Administrative Rules of Montana (ARM) 17.8.342 or 40 CFR §63.43(c) *Review options*, (f) *Administrative procedures for review of the Notice of MACT Approval*, (g) *Notice of MACT Approval* and (h) *Opportunity for public comment on the Notice of MACT Approval.*[1]

1. The draft permit does not contain a case-by-case MACT determination for the Project.

2. Montana DEQ must issue a Notice of MACT Approval with the initial case-by-case MACT determination as described in §63.43(g). The permit may serve as the Notice of MACT Approval or a separate and independent Notice of MACT Approval may be issued according to §63.43(c)(2).

3. The minimum public comment period for a Notice of MACT Approval as required by §63.43(h)(1)(ii) is 30 days.

4. The case-by-case MACT determination must contain information specified in §63.43(g) *Notice of MACT Approval* such as, but not limited to:
   a. MACT emission limitations,
   b. notification, operation and maintenance, performance testing, monitoring, reporting and record keeping,
   c. compliance certifications, and
   d. other terms and conditions necessary to ensure Federal enforceability of the MACT emission limitation.

5. The Permit must include all applicable requirements from Part 63 subpart A, as required by §63.43(c)(4).

6. Construction on the Project is prohibited until Montana DEQ has issued a final and effective case-by-case MACT determination as required by §63.42(c).

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[1]Although the permit analysis at page 6 indicates that case-by-case MACT applies to the main boilers, nowhere does the draft permit specify MACT limits.

7. The Permit must be revised to include a case-by-case MACT determination in accordance with ARM 17.8.342 and 40 CFR part 63, subpart B, §63.40 through 63.44.

INCREMENT IMPACT AT NORTHERN CHEYENNE INDIAN RESERVATION (NCIR) CLASS I AREA

In the draft EIS, cumulative modeled impacts predict that the 3-hr and 24-hr SO2 Class I increments are exceeded in the NCIR Class I area (see Table B-2 of the draft EIS). Under our stated policies, if the Project's modeled contribution is significant, then it would appear that the permit should not be issued without further control or offsets. See 40 CFR 51.166(k); pages C.52 and C.53 of EPA's October 1990 New Source Review Workshop Manual; EPA's July 5, 1988 Memorandum from Gerald A. Emison, Director, OAQPS, to Thomas J. Maslany, entitled "Air Quality Analysis for Prevention of Significant Deterioration (PSD)."

Presently, our regulations establish no set values for significance for impacts on Class I increment, and to our knowledge, the Montana SIP does not establish values for significance for such impacts either. In concluding in the draft EIS that the Roundup Project would not be a significant contributor to increment exceedances in the NCIR Class I area, it appears that the State has assumed that Class I significance levels EPA proposed in 1996 as part of the NSR reforms proposal (published in the Federal Register on July 23, 1996 - 61 FR 38250) are appropriate. It would be helpful if you could confirm that this is the approach you are using and your basis for concluding that these values represent an appropriate significance threshold for evaluating impacts on Class I increment.

In addition, we note that the modeled values for the Project are just under the significance levels for Class I increment used in the draft EIS. Under the circumstances, we believe it is important to carefully verify these modeled values and to correct any deficiencies in the modeling. For example, it appears that the predicted increment exceedances were based on the CALPUFF model being used for all sources near and far to the Class I area. This is not the correct regulatory approach for sources near the Class I area. Rather, the correct regulatory modeling approach would be to use CALPUFF for sources greater than 50 kilometers from the Class I area and ISC for sources less than 50 kilometers from the Class I area. Also, as we describe in greater detail elsewhere in this letter, it appears you may have underestimated emissions from the auxiliary boilers and other sources in your modeling, and we are unable to determine whether modeled values for the main boilers represent worst-case emissions on a 3-hour and 24-hour basis.

Even if issuance of the permit is appropriate without further conditions, the apparent Class I increment violation would need to be addressed through reduction of emissions from other sources that contribute to the problem. In this regard, 40 CFR 51.166(a)(3) requires a SIP to be revised if the State or EPA determines that an applicable increment is being violated. Under this regulatory provision, the plan must be revised within 60 days of such a finding by the

State or notification by EPA, or by such later date as prescribed by the Administrator after consultation with the State.

VISIBILITY

EPA Region 8 supports the letter of August 27, 2002 from Christine Shaver of the National Park Service and Sandra Silva of the US Fish and Wildlife Service to the Montana Department of Environmental Quality. This letter outlines the concerns these Federal Land Managers (FLMs) have regarding the incremental visibility impacts resulting from the air emissions from the Roundup Power Project. The analysis performed by the FLMs demonstrates significant impacts from sulfur dioxide and nitrogen oxides on many PSD Class I areas surrounding the plant, including Yellowstone National Park, UL Bend Wilderness Area, North Absaroka Wilderness, and Northern Cheyenne Indian Reservation (NCIR).

SHORT-TERM EMISSION LIMITS

Generally, the PSD regulations require short-term emission limits to ensure protection of the applicable national ambient air quality standard (NAAQS) and PSD increments. Specifically, the PSD regulations clearly require that the application of BACT be at least as stringent as any applicable standard of performance under 40 CFR Part 60. However, this should not be taken to supercede any additional limitations as needed to enable the source to demonstate compliance with the NAAQS and PSD increments. See enclosed November 24, 1986 memorandum from Gerald A. Emison, Director, Office of Air Quality Planning and Standards, to David Kee, Director, Air Management Division, Region V, regarding "Need for Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant.

Currently the draft permit only contains SO2 emission limitations on a 30-day rolling average. This approach may be acceptable <u>only</u> if modeling for protection of the short-term NAAQS and PSD increments was based on worst-case hourly SO_2 emissions, rather than on the 30-day emission limitations in the draft permit. Based on the information we've reviewed, we cannot tell whether worst case hourly conditions were modeled. Table 4-8 (page 4-13) of the draft EIS indicates that hourly lb/hr limits and annual lb/hr limits were modeled. The document does not clearly explain what the hourly lb/hr limits are based on; there are no such limits in the draft permit. For example, are these levels based on the source's maximum potential to emit?

At a minimum, we believe that the permit action should either establish short-term emission limits in the permit itself, or justify that worst-case hourly SO2 emission limits have been modeled for protection of short-term NAAQS and PSD increments. Our preference would be that the permit itself include the worst-case modeled hourly SO2 emission limits, in addition to the 30-day BACT limits.

Our concern about short-term emission limits does not apply to the particulate matter or carbon monoxide emission limits because for these pollutants the draft permit levels are in terms of lbs/hr averaged over the period of a stack test (typically about 3 hours), rather than on a 30-day rolling average.

The NOx emission limits in the draft permit are expressed on a rolling 30-day average, but we do not see this as an issue for protection of NAAQS and PSD increment, because the NOx NAAQS and increment are annual averages. However, we do support the comment that the National Park Service made in its August 27, 2002 letter to Dan Walsh, that an equivalent 24-hr limit be set for NOx to control short-term impacts upon visibility.

AUXILIARY BOILERS

1. The draft permit only requires a stack test once every five years for NO_x and SO_2 emissions from the auxiliary boilers. We do not believe this is adequate to demonstrate continuous compliance with the emission limitations in lbs/hr. For SO2, the permit should also require recordkeeping for sulfur content in the fuel oil burned, the quantity of fuel oil burned per hour, and the resulting SO2 emission rate in lb/hr. For NOx, the permit should require annual stack tests, unless test results are sufficiently below the emission limitation that test frequency can be reduced to once every five years.

2. We have several questions with respect to the PM10, SOx and NOx emission calculations on pages 23 and 24 of the draft permit and the provisions in sections II.A.13 through 17 and 19.

First, section II.A.16 limits diesel consumption of the two auxiliary boilers to 5,438,400 gallons per rolling 12-month period and section II.A.17 limits the combined hours of operation of the two auxiliary boilers to 3,300 hours per rolling 12-month period. If you divide total oil consumed by total hours of operation (5,438,400/3,300) you would consume 1,648 gal/hr. Yet the calculations on pages 23 and 24 assume that 823 gals/hr of oil are used. The calculations on pages 23 and 24 of the draft permit and the emission calculations for the auxiliary boilers in Appendix B[2] of the permit application seem to imply that the fuel oil consumption for all auxiliary boilers will be around 2,766,000 or 2,716,000 gallons year, respectively. We question whether the limit in section II.A.16 was developed in error. If not, we question why 823 gal/hr was used in calculations on pages 23 and 24.

Second, the limit in section II.A.13 is not consistent with the calculations on pages 23 and 24 of the draft permit. The calculations in the draft permit indicate that emissions will be 64.61 lbs of SO2/hr, yet section II.A.13 has a limit of 6.46 lbs of SO2/hr. It appears that the limit in section II.A.13 is incorrect. This potential error impacts the modeling. Table 4-8 on page 4-14 of the draft EIS indicates that a limit of 6.47 lbs of SO2/hr was used in the modeling for each of the auxiliary boilers. The permit application also appears to indicate that 6.47 lbs of SO2/hr was used in the permit modeling.

---

[2]We were looking at the revised table dated 3/5/02 that was in Tab 2 of the March 8, 2002 letter from Nicole Wentz to Dan Walsh.

Third, the limit in section II.A.19 is not consistent with the calculations on pages 23 and 24 of the permit. Section II.A.19 indicates that the sulfur content of the No. 2 fuel oil used in the auxiliary boilers shall not exceed 0.05%, yet the calculations on pages 23 and 24 indicate that the sulfur content of the fuel oil is 0.5%. Perry's Chemical Engineer's Handbook indicates that No. 2 fuel oil contains 0.5% sulfur (see 1984 edition, pages 9-10 to 9-11). We question whether the limit in section II.A.19 is correct. We also believe that section II.A.19 should be rewritten to make it clear that only No. 2 fuel oil or better can be burned in the auxiliary boilers. Finally, we note that the permit limit for sulfur content in fuel oil needs to be at least as stringent as the 1 lb of sulfur per mmBTU fired limit required by ARM 17.8.322(4).

MISCELLANEOUS CONCERNS

1. The permit should make it clear whether compliance with lb/hr limits for SO2 and NOx at the PC fired boilers is to be determined via: (a) periodic stack tests, or (b) a combination of CEMS for flow and for pollutant concentration in the stack. EPA recommends (b), especially since the CEMS's are required for other purposes anyway.

2. There is no emission limit for sulfuric acid mist. We believe there should be an emission limit for sulfuric acid mist and a compliance monitoring method (EPA Method 8).

3. Section III.H of the permit indicates that construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit revoked. We believe this is an unreasonably long period of time before construction must begin. BACT could change considerably in three years; accordingly, our PSD regulations (40 CFR 52.21(r)(2)) provide:

> Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

Although the Montana SIP does not appear to contain an equivalent provision, it does contain ARM 17.8.819, "Control Technology Review," which corresponds to our 40 CFR 51.166(j). Subsection (4) of ARM 17.8.819 provides that for phased construction projects, the determination of BACT must be reviewed and modified as appropriate "at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of BACT for the source." This makes clear that the maximum length of time a BACT determination should be considered valid is 18 months, and although the Roundup Project has not been labeled a phased construction project, we believe the permit must include a term, consistent with ARM 17.8.819(4), requiring review of and potential revision to BACT if construction does not begin within 18 months. In the alternative, the permit should be revised to require that construction begin within 18 months.

4. In Table 5-7 (page 50 of the permit application) and Table 4-38 (page 4-99 of the draft EIS), it does not appear that the flare emission limits from the Billings/Laurel sources were considered in the NAAQS/MAAQS modeling; the limits shown appear to be only the limits from the Billings/Laurel SO2 State Implementation Plan (SIP). The flare limits must be considered in the NAAQS/MAAQS modeling.

5. The draft permit does not provide a method for monitoring compliance with the VOC emission limit in section II.A.10.

6. The draft permit does not indicate how the DEQ determined that the 10 to 12-year-old PM-10 ambient data represent the year preceding the receipt of the application. We believe the DEQ should provide an explanation as to why the data represent the year preceding the receipt of the application, or require that ambient PM-10 data be collected that represents such timeframe.

7. EPA has not approved into the SIP the de minimis permitting provisions mentioned in section II.C.2. We believe section II.C.2 should be removed from the permit.

MONTANA HISTORICAL SOCIETY

225 North Roberts ◆ P.O. Box 201201 ◆ Helena, MT 59620-1201
◆ (406) 444-2694 ◆ FAX (406) 444-2696 ◆ www.montanahistoricalsociety.org ◆

Thursday, December 12, 2002

ATTN: Greg Hallsten
DEQ
POB 200901
Helena MT 59620

RECEIVED

DEC 1 3 2002

MT DEPT. OF ENV. QUALITY
PERMITTING & COMPLIANCE DIV.

RE: DEIS Roundup Power Project

Dear Mr. Hallsten:

Thank you for providing us a copy of the above referenced document for our review. We are able to provide only brief generic comment since we have not received copies of the relevant cultural resource reports referenced on page 7-6.

p.1-7 It is at this point incorrect to state that the SHPO is reviewing the project under section 106 of the NHPA as no responsible federal agency is identified. SHPO normally consults with DEQ or other state agencies under the Montana Antiquities Act and/or MEPA.

p.2-40 Again reference to section 106 of the NHPA is misleading unless this becomes a federal undertaking. We agree with generic mitigation of impacts to cultural resources as proposed under CR-1, -2, -3 and 4 (however we find the reference to section 106 technically misleading).

p.3-36 We have not seen the current cultural resource inventories so we cannot comment on the inventory section of this document, or possible effects to particular resources whose location and nature is unknown to us.

p.4-52 Again, since we have not seen the cultural resource reports we are unable to comment other that to agree that areas not inventoried (i.e. groundwater well/pipeline, disposal haul road and conveyor routes) may contain important unknown cultural resources.

p.5-3 The correct relationship among the NHPA , MEPA and SHPO is stated here.

Whether or not we are requested to provide comment on specific site significance, effects or mitigation we believe it would be appropriate that the cultural resource reports prepared for this project be submitted to our office for inclusion in the statewide inventory; see M.C.A.22-3-423.

We would be more than happy to provide more detailed comment or opinion regarding site eligibility, effects or mitigation to DEQ, or the proponent, as desired, once we have the referenced reports.

Sincerely,

Stan Wilmoth

Stan Wilmoth, Ph.D.
State Archaeologist/Deputy, SHPO

NEW FILE DEQ Roundup Power

Exhibit G

Montana Environmental Information Center's Affidavit and Petition for Hearing and Stay of Permit Issuance challenging Continental Energy Services, Inc's Silver Bow Generation Plant (March 29, 2002)

MTN 2002-02 AQ

ORIGINAL

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MAR 29 2002

BOARD OF ENVIRONMENTAL REVIEW

PETER MICHAEL MELOY
MELOY LAW FIRM
80 S. WARREN
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TELEPHONE: (406) 442-8670
FAX: (406) 442-4953

Before the Board of Environmental Review,
Department of Environmental Quality,
State of Montana.

In Re: Permit Applicant Continental Energy Services, Inc. Silver Bow Generation Plant (Permit No. 3165-00) Montana Environmental Information Center	**AFFIDAVIT AND PETITION FOR HEARING AND FOR STAY OF PERMIT ISSUANCE**

STATE OF MONTANA)
):ss
COUNTY OF LEWIS AND CLARK)

This matter arises from the proposed issuance by the Montana Department of Environmental Quality ("DEQ") of Air Quality Permit #3165-00 to Continental Energy Service, Inc. Silver Bow Generation Plant to construct a natural gas fired power plant outside Butte, Montana. The permit will become effective March 30, 2002, unless a party requests a hearing and challenges the permit. The undersigned individual on behalf of Montana Environmental Information Center ("MEIC"), having first been duly sworn, deposes and says the following, in support of his challenge to the Permit and request for hearing pursuant to § 75-2-211, M.C.A.:

MEIC'S STANDING

1) Petitioner MEIC is a Montana non-profit public benefit corporation pursuant to 35-2-101, *et. seq.*, MCA, with over 4,000 members state - and nation-wide, and at all times pertinent hereto has had its principal office in Helena, Lewis and Clark County, Montana. MEIC has been in existence for over twenty eight years, and strives to protect the air, water and lands of Montana from pollution and to preserve Montana's quality of life. MEIC has been active in lobbying the legislature and executive branch agencies and educating the citizens of Montana about protection of Montana's air quality.

This action is brought on MEIC's own behalf and on behalf of its members. Members reside and work in Silver Bow and Deer Lodge Counties in the vicinity of Continental Energy's proposed Silver Bow Generation Plant. MEIC members use and enjoy the area because of its aesthetic qualities, lifestyle opportunities, and environmental amenities and have an interest in preserving them. MEIC and its members are actively involved in environmental issues in the Butte area and throughout the state, including issues relating to energy development, power generation and air quality. MEIC and its members are thus directly and adversely affected by the issuance of Air Quality Permit # 3165-00 by the DEQ and will sustain actual injury if the proposed action is carried forth without adequate environmental review, testing and disclosure and compliance with all existing laws. MEIC and its members have a further interest in participating in governmental decisions, in disseminating relevant information about those decisions to the general public and in insuring that all laws and procedures are complied with. **Those interests are directly and adversely affected by the failures of the Department as alleged herein.** MEIC and individual members of MEIC commented in, or otherwise participated in, the environmental review and permitting process for the Silver Bow Generation Project.

REQUEST FOR A HEARING

2) MEIC requests a hearing pursuant to 75-2-211 (10) M.C.A., in that MEIC represents individuals who are adversely affected by the Department's decision. Said persons, as well as MEIC, participated in the public comment process.

ALLEGATIONS AND BASIS FOR REQUESTED RELIEF

3) As set forth in the following paragraphs, MEIC alleges that the Permit was approved in violation of the Clean Air Act of Montana and regulations promulgated thereunder, the federal Clean Air Act and regulations promulgated thereunder, and the Montana Environmental Policy Act ("MEPA") and regulations promulgated thereunder. The decision to issue the permit was not in accordance with the procedures required by law, was arbitrary, capricious and an abuse of discretion.

4) Continental proposes to construct, and has sought an air quality permit for, a 500 megawatt (MW) electrical power generation facility to be located approximately 6 miles west of Butte, Montana. The facility will consist of two nominal 175 MW combined cycle natural gas combustion turbines (with two associated heat recovery steam generators including duct burners) and a 150 MW matched steam turbine (and associated power generator). In addition to the turbines and generators, the plant will have two emissions stacks, nine cooling towers, an electrical interconnection with transformers, and other equipment.

5) On July 20, 2001, DEQ received Continental's application for an air quality permit. In December, 2001, DEQ issued a draft air quality permit, along with a

draft environmental impact statement ("EIS"). The final EIS was issued in February, 2002. On March 12, 2002, DEQ issued its record of decision ("ROD") stating its intent to issue the permit.

6) Both the EIS and the ROD disclose that the plant will result in an increase in air pollution in the area, with adverse impacts to environmental quality. Importantly, on page 9 of the ROD, DEQ states:

> "**The No Action alternative,** which would be the denial of the air quality and MPDES permits and narrative standard authorizations, **is the environmentally preferred alternative.** Without the permits, the Silver Bow Generation Plant could not operate and likely would not be built. The environmental impacts associated with the Silver Bow Generation Plant and with the pipeline expansion would not occur."

The pollutants to be released into the Montana atmosphere include, but are not limited to, the following:

a) **Particulate matter: 235 tons per year; 227 tons per year at PM-10 (ten microns or less in diameter).** These fine particulates are of special concern because of their ability to penetrate deep into the lungs. Such "inhalable" particles can lodge deep in the lungs for months or years. Particulates can lead to cancer, cause and aggravate cardiopulmonary problems, and have been linked to increases in Sudden Infant Death Syndrome. In addition to their health effects, particulates have aesthetic effects such as impaired visibility and coating of surfaces. Natural visual ranges of 80 to 100 miles have been reduced by pollution to averages of less than 20 miles in the eastern United States and 50 to 70 miles in the west.

Table 4-31 of the EIS shows that the regional background concentration of particulate matter is currently 30 micrograms per cubic meter. Modeling results indicate that the Silver Bow Generation Plant could increase this level to 100 micrograms per cubic meter bringing the area substantially closer to the 150 microgram standards. This is especially disturbing given the plant's proximity to the Class I airsheds of Yellowstone National Park and the Anaconda-Pintler Wilderness Area (just 25 miles to the west), as well as to the Butte PM Non-Attainment Area just six miles away. In its comments on the draft EIS, MEIC stated its concern that the EIS had failed to incorporate Butte PM monitoring data in its analysis. In responding to that concern, DEQ stated in the final EIS "The CES facility is proposed to be located approximately 6 miles west of Butte, Montana. The predominant winds in this area are from the Northwest. Thus, the majority of the time CES would have little influence on the PM10 nonattainment area." It is common meteorological knowledge that prevailing Northwesterly winds could easily impact an area located just 6 miles to the east. By failing to consider and account for the available monitoring data, neither the EIS nor Continental's air quality permit properly reviews and assesses the air quality impacts of the facility and fails to meet the requirements of state and federal law.

b) **Sulfur oxides (SOx): 10.7 tons per year.** SO2 contributes to particulate levels through the formation of sulfate particles and acid aerosols and is the primary cause of acid precipitation. Acid rain is harmful to both terrestrial and aquatic environments (particularly forests, lakes, and streams) and can damage buildings, monuments, and other structures as well. In addition to tree and fish mortality, human health, livestock, crops, and wildlife can all suffer adverse effects from acid rain.

c) **Nitrogen oxides (NOx): 168 tons per year.** Nitrogen oxides (NOx) include both nitric oxide (NO) and nitrogen dioxide (NO2). NO2 is a brownish gas that reacts with volatile organic compounds (VOC) in the presence of sunlight to create photochemical smog (of which the main component is ground-level ozone). While ozone is critically important in the upper atmosphere as a shield against the sun's high-energy ultraviolet radiation, it is itself a very reactive and harmful gas, both for humans and vegetation (including crops). Like SO_2, NO_x leads to higher particulate levels (nitrate particles) and contributes to acid rain.

d) **Volatile organic compounds (VOCs): 94.2 tons per year.** Volatile organic compounds are carbon containing compounds that can contribute to the formation of smog.

e) **Carbon monoxide (CO): 732 tons per year.** CO is an odorless and colorless gas which is released into the atmosphere when carbon in fuels doesn't burn completely. The gas can become dangerous if it is inhaled excessively.

f) **Ammonia (NH_4): 272 tons per year.** Ammonia is a toxic gas that can be carried many miles before being deposited in lakes or streams. As a form of nitrogen, ammonia can act as a nutrient precursor that can lead to algal blooms, eutrophication, and fish kills.

DEQ failed to adequately disclose and evaluate the health and environmental effects of the discharge of the foregoing pollutants in both the permit and the EIS. DEQ has provided no site-specific monitoring data to justify its contention that existing ambient air quality is below NAAQS and MAAQS. Instead, the department states merely "It is ... believed that typical Montana background data is representative of the site with the possible exception of particulate and VOC." The basis for the department's belief is an unsubstantiated statement as to the levels of industrialization and population in the area. If the baseline is incorrectly estimated, then the conclusions as to the compatibility with state and federal standards may be incorrect.

7) In addition, the EIS discloses that the plant will discharge approximately **2,375,720 tons of carbon dioxide (CO2)** into the air each year. The Permit and EIS provide no analysis of the health, environmental, and economic impacts of global climate change and provide no analysis to justify the statement that an additional release of 2,375,720 tons per year of CO2 is insignificant. CO2 is the most significant greenhouse gas emission caused by humans, and power plants are the leading source of CO2 emissions globally, nationally, and in Montana. DEQ's own "Montana Greenhouse Gas Emissions Inventory" report (issued January 1997) states there is "virtual certainty" (defined as "nearly unanimous agreement among scientists, with no credible alternative views existing") that "Greenhouse gas concentrations in the atmosphere are increasing due to human activities" and that "Added greenhouse gases cause added heating." According to the same document, Montana's 1990 estimated total emission of CO2 was 21,982,000 tons. Projected emissions from the Silver Bow Generation Plant represent an increase of 11% over that figure.

In addition to potentially severe economic, social, and political dislocations, global warming caused by greenhouse gases poses numerous environmental and public health concerns including increases in insect populations and the spread of infectious tropical diseases, a greater frequency of El Niño and extreme weather events (such as floods, droughts, and fires), the melting of glaciers and polar ice caps, rising sea levels, desertification, and general ecosystem disruption and extinctions caused by the rapid rate of change. Some of these effects, such as the disappearance of glaciers in Glacier National

Park in northwestern Montana, (which may be left "glacier-less" in as few as 33 years), are already dramatically evident.

In its comments on the draft EIS, MEIC noted that the amount of pollution issued from the Silver Bow Generation Plant would be not only absolutely but proportionately greater than the amounts released by NorthWestern's permitted "Montana First Megawatts" power plant in Great Falls. DEQ responded in the final EIS that the two plants were of different design and that the NorthWestern facility should be considered a 160 MW, not 240 MW plant. DEQ's response ignores NorthWestern's stated plans to convert the facility from simple cycle to combined cycle and to increase its final capacity to 240 MW (see page 4 of the Application of NorthWestern Generation I, LLC for Comment and Findings on a Power Purchase and Sales Agreement with the Montana Power Company on file with the Montana Public Service Commission). Given that capacity, the release of pollutants by Silver Bow Generation Plant will significantly exceed the release of pollutants from the NorthWestern plant both in absolute terms and also relative to the amount of electrical energy produced. DEQ failed in its analysis of Best Available Control Technology by stating, for example, that carbon monoxide catalysts or other controls were cost-prohibitive / economically unfeasible despite NorthWestern's commitment to incorporate such technology in its Great Falls plant. The Silver Bow Generation Plant should not be given a competitive advantage because of less stringent pollution controls.

8) MEPA, § 75-1-101, *et seq*, MCA, and DEQ's implementing regulations require that the final EIS be based on complete and accurate information and to fully inform the public and the decision maker of the potential effects, including cumulative effects, of the proposed action. In this case, DEQ's failure to conduct

such a review and its failure to follow procedures as required by law was arbitrary, capricious, an abuse of discretion and a violation of MEPA and its implementing regulations. In particular, the shortcomings of the EIS include, but are not limited to the following:

a. As mentioned above, the EIS failed to discuss or evaluate the impact of increased greenhouse gase emissions caused by the proposal, and may have incorrectly modeled the impacts of other air pollutants.

b. The EIS failed to adequately analyze reasonable alternatives to the proposed action, in violation of MEPA and A.R.M. 17.4.617 (5). According to the final EIS, "The purpose of the Proposed Action is to permit activities that provide additional electricity to meet increased demand for power within the western United States." DEQ dismissed "alternative sources of energy" as an alternative to the proposal, despite the enormous potential for renewable energy development in Montana at prices competitive with gas turbine technology. The draft EIS listed "alternative sources of energy" as one of six alternatives to the generation plant that were considered but eliminated from detailed study. It was the only alternative that was dismissed without explanation. MEIC noted in its comments to DEQ that given the selection criteria listed in the draft EIS, renewable energy should have qualified as a legitimate alternative for analysis. In the final EIS, DEQ responded that an alternative energy source does not bear a logical relationship to a gas-fired power plant. In fact, alternative energy sources can be employed to fulfill the same purpose as the proposed action and have been shown to be feasible, cost-effective, and environmentally-preferred. By "alternative energy sources," MEIC means not only supply-side renewable resources such as wind power, but also demand-side resources such as energy conservation and energy efficiency. Since the EIS was deficient in its analysis of alternatives, the decision maker had no means of making a reasoned and fully informed decision about the proposed project and the issuance of the air quality permit.

C. The final EIS also failed to conduct any analysis of the "upstream" environmental impacts associated with the plant's fuel requirements. The plant's **natural gas demand of 85 million cubic feet per day represents an increase of 55% over the total current consumption in the state of Montana.** Such a massive demand for natural gas cannot be met without impacts to the environment. As stated by MEIC in its comments, some of North America's most prized wild areas such as Montana's Rocky Mountain Front are continually threatened by the prospect of oil and gas exploration and drilling. The final EIS argues that an analysis of potential impacts to these sensitive areas would be speculative, because the source of gas for the plant has yet to be definitively determined. DEQ is itself speculating by considering impacts about which it currently has no information to be non-existent. DEQ cannot legally abdicate its responsibility to study the full range of impacts associated with the project. **To the contrary, until the source of gas has been selected and the impacts analyzed, the EIS remains incomplete.** MEPA requires DEQ to fully analyze the environmental impacts associated with its decision to grant an air quality permit to Continental. As acknowledged in the Record of Decision, without the granting of such permits, the Silver Bow Generation Plant would not become operational and the environmental impacts associated with the plant would be avoided. Therefore, the decision to grant the air quality permit is directly responsible (a necessary condition) for the power plant's need to acquire 31 billion cubic feet of natural gas per year.

The final EIS also erroneously dismisses the likelihood of development along the Rocky Mountain Front because of a current, temporary moratorium. But recent statements and proposals made at the federal level by President George W. Bush, Senator Conrad Burns, USDA Secretary Ann M. Veneman, and others indicate that the Rocky Mountain Front is a high priority for additional exploration and development (see, for example, "Veneman says Rocky Mountain Front not off limits to oil and gas exploration," Great Falls Tribune, March 29, 2002).

9) MEIC incorporates by reference the public comments submitted by MEIC as well as all written comments and issues raised by the public and other materials in the agency file. MEIC reserves the right to add additional grounds for appeal during the contested case hearing requested herein, if additional issues or information become available during that process.

RELIEF REQUESTED BY MEIC

MEIC requests the following relief:

a) That the Board order an in-person contested case hearing before the Board of Environmental Review in Helena, Montana, or a duly appointed hearing examiner, for purposes of challenging the validity of the Permit.

b) That the Board stay the Department's decision pending the hearing and adoption of a final decision by the Board of Environmental Review as required by law.

c) That the Board provide any and all other relief that the it determines to be appropriate in this case.

Dated this 29th day of March, 2002.

Peter Michael Meloy
Attorney for MEIC

James D. Jensen
on behalf of Montana Environmental Information Center

STATE OF MONTANA)
):ss
COUNTY OF LEWIS AND CLARK)

On this 29 day of March, 2002, before me the undersigned Notary Public, personally appeared James D. Jensen, known to me to be the person whose name is subscribed to the within instrument, and acknowledged to me that he executed the same.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year first above written.

Notary Public for the State of Montana
Residing at: Helena, MT
My Commission Expires: AP 21, 2002

Exhibit H

Montana Environmental Information Center’s Comments on DEQ Environmental Assessment for Laurel Generating Station (MAQP: #5261-00) (Jun. 30, 2023)

June 30, 2023

Department of Environmental Quality
c/o Air Quality Bureau
P.O. Box 200901
Helena, MT 59620-0901
DEQ-ARMB-Admin@mt.gov

Submitted via email to DEQ-ARMB-Admin@mt.gov

RE: Comments on DEQ Environmental Assessment for Laurel Generating Station (MAQP: #5261-00)

To Whom It May Concern:

On behalf of the Thiel Road Coalition, Montana Environmental Information Center (MEIC), and Northern Plains Resource Council (NPRC), we submit these comments on the Montana Department of Environmental Quality's (DEQ) revised environmental assessment for NorthWestern Energy's (NWE) proposed 175-megawatt (MW) gas-fired power plant, which is being constructed on the banks of the Yellowstone River in Laurel, Montana. The Laurel Generating Station, or LGS, is of significant concern to the Thiel Road Coalition, MEIC, and NPRC, as well as their members, because it would, among other things, increase air pollution in an already impacted community; threaten to pollute the waters of the Yellowstone River; generate climate-harming greenhouse-gas emissions, even while clean and affordable alternatives to fossil-fuel generation exist; and produce significant noise and aesthetic impacts that would disturb the tranquility of nearby residents and visitors to the area.

DEQ previously analyzed the proposed plant's environmental impacts under the Montana Environmental Policy Act (MEPA). A Montana District Court judge subsequently determined that DEQ's environmental assessment (EA) was insufficient, particularly its failure to analyze climate-change impacts from the plant's greenhouse-gas emissions and its analysis of the plant's lighting impacts.[1] The Court further directed DEQ to reconsider its determination that the gas plant's impacts would not be significant.[2] The Court vacated and remanded the EA to the

[1] Order, *MEIC v. DEQ*, Cause No. DV 21-1307, 31–32 (Apr. 6, 2023) ("Order") (attached as Ex. 1 to MEIC Comments submitted May 11, 2023 (*see* note 5)).

[2] *Id.* at 29–30.

agency to redo its analysis consistent with the Court's order.[3] Upon request from the agency and NorthWestern, the Court subsequently stayed its order pending appeal.[4]

Prior to the release of the revised EA, MEIC submitted comments to DEQ regarding its anticipated analysis. The Thiel Road Coalition, MEIC, and NPRC incorporate and adopt those prior comments here.[5]

DEQ issued a draft of its revised analysis under MEPA on June 1, 2023, inviting public comment on the draft.[6] The Draft EA is deficient in several regards, including that it fails to adequately disclose or evaluate the plant's climate impacts, including its greenhouse-gas emissions;[7] impacts to the human population;[8] and the cumulative and secondary effects of these potential impacts.[9]

I. Under MEPA, DEQ is required to take a "hard look" at all of the Laurel Generating Station's environmental impacts in an EIS.

MEPA requires Montana agencies to "take a 'hard look' at the environmental impacts of a given project or proposal."[10] A full environmental impact statement, or EIS, is required if a proposed action will "significantly affect[] the quality of the human environment."[11] However, DEQ may first prepare an EA if the agency cannot determine without further evaluation whether the project will require an EIS, or where the otherwise significant impacts of the action can be mitigated "below the level of significance."[12]

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[3] *Id.* at 34.

[4] Order, *MEIC v. DEQ*, Cause No. DV 21-1307 (Jun. 8, 2023).

[5] MEIC Comments on DEQ Environmental Assessment for Laurel Generating Station (MAQP: #5261-00) (May 11, 2023) ("MEIC Comments"). Attached as Exhibit 1. Exhibits submitted with the comments will be transmitted to DEQ by Sharefile.

[6] DEQ Supp. Draft EA for the Prelim. Det. on Mont. Air Quality Permit #5261-00 (Jun. 1, 2023) ("Draft EA").

[7] ARM 17.4.609(3)(d).

[8] *Id.* at (3)(e).

[9] *Id.* at (3)(d)-(e).

[10] *Mont. Wildlife Fed'n v. Mont. Bd. of Oil & Gas Conservation*, 2012 MT 128, ¶ 43, 365 Mont. 232, 280 P.3d 877 (citation omitted).

[11] ARM 17.4.607(1).

[12] ARM 17.4.607(3)(b), 607(4).

When an agency prepares an EA, the EA must evaluate the direct, secondary, and cumulative environmental impacts of the proposed action;[13] reasonable alternatives to the proposed action;[14] and mitigation measures.[15] "The agency must examine the relevant data and articulate a satisfactory explanation for its action, including a rational connection between the facts found and the choice made."[16] "[G]eneral statements about 'possible' effects and the existence of 'some risk' do not constitute a 'hard look' absent a justification regarding why more definitive information could not be provided."[17]

Once again, DEQ's revised Draft EA for the Laurel Generating Station fails to satisfy MEPA's fundamental mandate, as it does not disclose fully or evaluate rationally the project's environmental impacts.[18] Without appropriate disclosure and analysis of the project's impacts, DEQ cannot make a rational determination as to whether those impacts will be significant and the public is deprived of a full understanding of, and ability to comment on, the potential impacts.

A full analysis of the Laurel plant's environmental impacts will confirm that they are significant, requiring preparation of an EIS. And in that EIS, DEQ must consider and address all of the new information that is submitted by members of the public during this comment process.[19] Once the agency does so, it will be clear that NorthWestern's proposal to build and operate a massive new gas plant would result in substantial, irreversible, and entirely avoidable harm to Montana's environment and the public's health.

II. DEQ's EIS must evaluate the Laurel Generating Station's climate impacts.

[13] *Mont. Wildlife Fed'n*, ¶ 45; ARM 17.4.609(3)(e).

[14] ARM 17.4.609(3)(f).

[15] ARM 17.4.609(3)(g).

[16] *Montana Wildlife Fed'n*, ¶ 43 (quoting *Clark Fork Coal. v. Mont. DEQ*, 2008 MT 407, ¶ 47, 347 Mont. 197, 211, 197 P.3d 482, 492).

[17] *Id.* (quoting *Neighbors of Cuddy Mtn. v. U.S. Forest Serv.*, 137 F.3d 1372, 1380 (9th Cir. 1998)).

[18] *See* MCA § 75-1-102 (MEPA's purposes); ARM 17.4.607 (purpose of EA).

[19] ARM 17.4.621(1)(c) (requiring DEQ to "prepare supplements to either draft or final environmental impact statements whenever … prior to completion of a final EIS, the agency determines that there is a need for substantial, additional information to evaluate the impacts of a proposed action or reasonable alternatives").

In its analysis of the impacts of the LGS, DEQ's Draft EA fails to consider the climate-change impacts of the plant's greenhouse-gas emissions,[20] which NWE states would be 769,706 tons per year of carbon dioxide equivalent (CO2e) emissions from the RICE units alone.[21] MEIC previously submitted comments documenting the significant threats posed by climate change, which would be accelerated and exacerbated by the plant's greenhouse-gas emissions.[22] Limitations on these potential emissions could be achieved through more efficient generators, heat rate limits, or operational restrictions, among other alternatives.[23] And they could be avoided altogether by abandoning the plant in favor of renewable energy sources.

Citing the Montana Legislature's recent amendments to MEPA, DEQ's Draft EA "analyze[d] *only* the aesthetic impacts from the proposed action's lighting," explicitly excluding any analysis of greenhouse-gas emissions or climate change.[24] To the extent DEQ asserts that such impacts are now beyond the scope of MEPA, this does not absolve the agency of its environmental obligations because the Legislature's attempt to bar such analysis violates the protections of Montana's Constitution, which guarantees "a clean and healthful environment in Montana for present and future generations."[25]

Even if the Legislature's recent MEPA amendments were constitutional, moreover, DEQ's analysis failed to comply with them. As discussed below, because the statutory triggers described in MCA § 75-1-201(2)(b)(ii) have occurred, DEQ's review of greenhouse-gas emissions—and the corresponding climate-change impacts of those emissions—is required.

A. DEQ's evaluation of the Laurel plant's greenhouse-gas emissions is required under the newly enacted MEPA amendments.

Under the Legislature's newly enacted (and unconstitutional) MEPA amendments, "an environmental review … may include an evaluation [of greenhouse-gas emissions or corresponding impacts to the climate in the state or

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[20] *Id.* at 2–3 (emphasis added).

[21] LGS Permit Application at 131 (attached as Ex. 2 to MEIC Comments submitted May 11, 2023 (*see* note 5)).

[22] *See* note 5.

[23] *See, e.g.*, U.S. EPA, Region 7, Comments on PSD Permit for Mid-Kansas Electric Company's Rubart Station (Jan. 17, 2013), *available at* https://www.epa.gov/sites/default/files/2015-08/documents/20130117_rubart_psd_comments.pdf (attached as Ex. 3 to MEIC Comments submitted May 11, 2023 (*see* note 5)).

[24] EA at 3.

[25] Mont. Const. Art. II, § 3; Art. IX, § 1.

beyond its borders] if the United States congress amends the federal Clean Air Act to include carbon dioxide emissions as a regulated pollutant."[26] DEQ makes no attempt in its Draft EA to explain why this condition has not yet been satisfied. And, as detailed below, it is clear that this condition *has* been met. Accordingly, DEQ must evaluate the plant's climate impacts before granting NorthWestern an air permit.

1. <u>The U.S. Supreme Court has already affirmed that greenhouse gases, including carbon dioxide, are considered "air pollutants" under the Clean Air Act.</u>

Over fifteen years ago, in *Massachusetts v. EPA*, the United States Supreme Court settled the question of whether greenhouse gases—including carbon dioxide—are regulated "air pollutants" under the Clean Air Act (CAA).[27] The Court concluded, in no uncertain terms, that "[b]ecause greenhouse gases fit well within the Clean Air Act's capacious definition of 'air pollutant,'" the EPA "has the statutory authority to regulate the emission of such gases."[28]

The Court's analysis and decision rested on its interpretation of the statutory language of the CAA. The Court explained that "[t]he Act defines 'air pollutant' to include 'any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive ... substance or matter which is emitted into or otherwise enters the ambient air.'"[29] Based on this definition, the Court held that "[o]n its face, the [Clean Air Act's definition of air pollutant] embraces all airborne compounds of whatever stripe, and underscores that intent through the repeated use of the word 'any.'"[30] "Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons" are, the Court concluded, "without a doubt 'physical [and] chemical ... substance [s] which [are] emitted into ... the ambient air."[31] Accordingly, the Court held that "[t]he statute is unambiguous" that greenhouse gases, including carbon dioxide, are covered as "air pollutants" under the CAA.[32]

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[26] MCA § 75-1-201(2)(b)(ii).

[27] 549 U.S. 497 (2007).

[28] *Id.* at 532.

[29] *Id.* at 528–529 (citing 42 U.S. § 7602(g), (h)).

[30] *Id.* at 29.

[31] *Id.* (alterations in original).

[32] *Id.*; *accord Am. Lung Ass'n v. EPA*, 985 F.3d 914, 934 (D.C. Cir. 2021), *cert. granted sub nom. N. Am. Coal Corp. v. EPA*, 142 S. Ct. 417 (2021), and *cert. granted sub nom. North Dakota v. EPA*, 142 S. Ct. 418 (2021), and *cert. granted in part sub nom. Westmoreland Mining Holdings LLC v. EPA*, 142 S. Ct. 418 (2021), and *cert.*

In reaching this conclusion, the Court rejected the EPA's argument that Congress had indicated an intent for the agency to refrain from regulating greenhouse-gas emissions. The Court explained that "[w]hile the Congresses that drafted § 202(a)(1) might not have appreciated the possibility that burning fossil fuels could lead to global warming, they did understand that without regulatory flexibility, changing circumstances and scientific developments would soon render the Clean Air Act obsolete."[33]

The Supreme Court's holding in *Massachusetts v. EPA* definitively settled the issue of whether greenhouse gases, including carbon dioxide, qualify as "air pollutants" under the Clean Air Act. They do. Because the statute already "include[s] carbon dioxide emissions as a regulated pollutant[,]" the requirements of the Montana Legislature's new MEPA amendment have already been satisfied.[34] The Legislature's apparently mistaken belief that the Clean Air Act would have to be amended to regulate greenhouse gases does nothing to change this fact. DEQ must accordingly evaluate the climate impacts of NorthWestern's proposed gas plant before determining whether the company's requested air permit should be granted.

2. <u>Congress recently amended the Clean Air Act to explicitly regulate carbon dioxide.</u>

If there were any lingering doubt about the reach of the CAA, Congress recently eliminated it with the enactment of the Inflation Reduction Act (IRA).[35] The IRA affirmed the Supreme Court's holding in *Massachusetts v. EPA* by codifying the fact that carbon dioxide and other greenhouse gases are regulated "air pollutants" under the Act.

Congress was unequivocal in the IRA that its intention in enacting the included CAA amendments was "[t]o ensure that reductions *in greenhouse gas*

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granted sub nom. W. Virginia v. EPA, 142 S. Ct. 420 (2021), and *rev'd and remanded on other grounds sub nom. W. Virginia v. EPA*, 213 L. Ed. 2d 896 (2022) (noting that "the [Supreme] Court confirmed that carbon dioxide and other greenhouse gases constituted 'air pollutants' covered by the Clean Air Act" in *Massachusetts v. EPA*).

[33] *Id.* at 532.

[34] MCA § 75-1-201(2).

[35] *See also* G. Dotson and D. J. Maghamfar, "The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act," Environmental Law Reporter, 53 ELR 1007 (2023) (analyzing IRA amendments to the Clean Air Act) (attached as Exhibit 2).

emissions are achieved through use of the existing authorities of this Act."[36] Comments made by legislators subsequent to the passage of the IRA confirm this understanding: the IRA amendments to the CAA were designed to ensure that the Act regulates greenhouse gases, including carbon dioxide, as pollutants.[37] To accomplish this clear legislative goal, Congress amended the CAA to explicitly define greenhouse gases as "air pollutants," principally by defining the term "greenhouse gas" as "the *air pollutants* carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons, and sulfur hexafluoride."[38] Because the IRA added this language to Title I of the CAA, and because the CAA's definition of "air pollutant" applies to that title, the IRA confirms that these six enumerated gases are "air pollutants" under the Act.[39] Congress also used wording elsewhere in the IRA to make apparent its understanding and intent that greenhouse gases are air pollutants, including by allocating funding in various contexts to reduce "*greenhouse gas emissions and other air pollutants*."[40] These amendments leave no room for uncertainty: the CAA's definition of "air pollutants" includes greenhouse gases, including carbon dioxide.

In addition to amending the CAA to explicitly define "greenhouse gases" as regulated air pollutants, the IRA further demonstrates congressional support for the regulation of greenhouse-gas emissions under the CAA by including directives for regulation of emissions from mobile sources; the application of § 111 of the Act to greenhouse-gas emissions from the oil-and-gas sector; and EPA's authority and duty to address greenhouse emissions from the power sector.[41] These provisions necessarily assume—and affirm—that Congress intended for greenhouse gases, including carbon dioxide, to be defined as, and regulated as, "air pollutants" under the CAA.

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[36] Inflation Reduction Act of 2022, PL 117-169, Aug. 16, 2022, 136 Stat. 1818 (emphasis added) ("IRA").

[37] L. Friedman, "Democrats Designed the Climate Law to Be a Game Changer. Here's How," N.Y. Times (Aug. 22, 2022), *available at* https://www.nytimes.com/2022/08/22/climate/epa-supreme-court-pollution.html (noting that "[t]he chair of the Senate Environment and Public Works Committee stated after the IRA passed, 'The language, we think, makes pretty clear that greenhouse gases are pollutants under the Clean Air Act'").

[38] IRA, 136 Stat. 1818 at 2,064, 2,065, 2,067, 2,069, 2,070, 2,072-73, 2,076, 2,077, 2,078, 2,079, 2,083, 2,086 (emphasis added).

[39] 42 U.S. § 7602.

[40] IRA § 60201, 136 Stat. 1818 (emphasis added); *id.* § 60106 (emphasis in original).

[41] IRA, 136 Stat. at 2,068–69.

3. Congressional amendments to the CAA comport with all existing case law interpreting the statute.

The recent CAA amendments also lay to rest any lingering questions about the Supreme Court's 2022 decision in *West Virginia v. EPA*, which held that Congress did not grant the EPA—in Section 111(d) of the Clean Air Act—the authority to devise emissions caps for greenhouse gases based on the generation-shifting approach the agency took in its "Clean Power Plan."[42] As the recent CAA amendments make clear, *West Virginia* did not, as some critics have suggested, review or revise the Court's position in *Massachusetts v. EPA*, or any other Supreme Court case, that greenhouse gases are "air pollutants" subject to regulation under the CAA.[43]

At the outset, the Supreme Court's decision in *West Virginia v. EPA* simply did not address the question of whether greenhouse gases are covered as "air pollutants" under the CAA. Indeed, the Court explicitly noted that "the only question before the Court [wa]s … narrow: whether the 'best system of emission reduction' identified by EPA in the Clean Power Plan was within the authority granted to the Agency in Section 111(d) of the Clean Air Act."[44] In other words, the Supreme Court was considering a highly specific regulation that deployed a highly specific mechanism for curbing greenhouse-gas emissions, not determining whether greenhouse gases are covered as "air pollutants" under the Act, which was already well-settled law at the time the Court rendered its decision.

But to the extent that any question remained over the effect of *West Virginia v. EPA*, the IRA's CAA amendments make clear that Congress intended to include greenhouse-gas emissions as regulated air pollutants under the Act by defining greenhouse gases as "air pollutants" in the amendments and appropriating significant funds to ensure reductions of these harmful pollutants.

4. The EPA's newly proposed standards for power plants further confirm that greenhouse gases are regulated "air pollutants" under the CAA.

The EPA's recently proposed carbon-pollution standards for fossil-fuel-burning power plants—which also post-date the Supreme Court's decision in *West*

[42] *W. Virginia v. EPA*, 142 S. Ct. 2587, 2596 (2022).

[43] *Id.*

[44] *Id.* at 2,596.

Virginia v. EPA and Congress's enactment of the IRA—offer an example of the agency's regulation of greenhouse gases, including carbon dioxide, under the CAA.[45]

As the preamble to the proposed rule explains, the EPA derives its rulemaking authority for the rule, at least in part, from the IRA's CAA amendments. Despite some reductions in carbon-dioxide emissions in the past two decades, the proposed rule notes that "progress in emission reductions is not uniform across all states and so Federal policies play an essential role."[46] Noting the power sector's role as a "leading emitter of CO2 in the U.S.," the proposed rule explains that "current CO2 levels continue to endanger human health and welfare."[47] Because of this threat, the proposed rule explains, "CAA section 135, added by IRA section 60107[,]" provides "the EPA $18 million 'to ensure that reductions in [greenhouse gas] emissions are achieved through use of the existing authorities of [the Clean Air Act].'"[48] The preamble to the proposed rule further explains that the legislative history of the IRA "makes clear that Congress anticipated that the EPA could promulgate rules … to ensure [greenhouse-gas] emissions reductions from fossil fuel-fired electricity generation."[49] While not the exclusive basis for its rulemaking authority, the preamble to the proposed rule notes that "[t]hese overarching incentives and policies [embodied in the IRA] are important context for this rulemaking."[50]

In addition to undertaking rulemaking related to the regulation of greenhouse gases, including carbon dioxide, under the CAA amendments, the proposed rule also demonstrates the EPA's understanding of the narrow holding in *West Virginia v. EPA*. While the preamble to the proposed rule acknowledges the Supreme Court's ruling in *West Virginia v. EPA*, it construes the holding as doing nothing beyond "invalidat[ing] the [Clean Power Plan's] generation-shifting [best system of emissions reductions] under the major questions doctrine."[51] In other words, as discussed above, the EPA's description in the preamble to the proposed

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[45] EPA, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (May 23, 2023) (attached as Exhibit 3).

[46] *Id.* at 33,260.

[47] *Id.*

[48] *Id.* (citing CAA section 135(a)(6)) (alteration in original).

[49] *Id.* at 33,316 (citing 168 Cong. Rec. E879 (Aug. 26, 2022) (statement of Rep. Frank Pallone, Jr.)).

[50] *Id.* at 33,262.

[51] *Id.* at 33,629.

rule makes clear that the agency views the holding in *West Virginia v. EPA* as narrow, with no impact on greenhouse gases qualifying as "air pollutants" under the Act. Indeed, the proposed rule is an example of the EPA exercising its authority to regulate greenhouse-gas emissions under the authority of the CAA.

B. DEQ's refusal to consider the Laurel plant's climate-change impacts violates Montana's Constitution.

Even if carbon dioxide was not a regulated pollutant under the federal Clean Air Act, DEQ's express refusal to evaluate LGS's contribution to climate change and its impacts in Montana violates Montana's constitution. First, the Legislature's 2023 amendment to MEPA that purports to prohibit climate analyses, HB 971, unconstitutionally limits legislative remedies designed to protect Montanans' fundamental environmental rights.[52] And second, setting aside MEPA, DEQ is independently obligated to ensure its actions do not impede Montanans' environmental rights.[53] For both reasons, DEQ must evaluate the climate impacts of the LGS's 769,706 tons of annual greenhouse-gas emissions.

First, the legislature's adoption of MCA § 75-1-201(2)(a), which prohibits "an evaluation of greenhouse gas emissions and corresponding impacts to the climate in the state or beyond the state's borders" unless certain conditions are met, violates the State constitution's environmental protections.[54] "MEPA's procedural mechanisms help bring the Montana Constitution's lofty goals into reality by enabling fully informed and considered decision making, thereby minimizing the risk of irreversible mistakes depriving Montanans of a clean and healthful environment."[55] MEPA is expressly part of the Legislature's scheme to "provide adequate remedies" to prevent unreasonable environmental degradation as required under Article IX, Section 1 of Montana's Constitution.[56]

The Constitution, as implemented by MEPA, prohibits the state from authorizing unexamined environmental harm.[57] However, if DEQ's interpretation of MCA § 75-1-201(2)(a) is correct, NorthWestern could build and operate the LGS without accounting for actual or potential climate-change impacts of greenhouse-gas emissions, despite the environmental harm these emissions ultimately cause in Montana. Because MCA § 75-1-201(2)(a) permits unexamined environmental harm,

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[52] Mont. Const. art II, § 3, art. IX, § 1.

[53] *Id.*

[54] Mont. Const. art. II, § 3; art. IX, § 1.

[55] *Park Cnty. Env't Council v. Montana Dep't of Env't Quality*, 2020 MT 303, ¶ 70, 402 Mont. 168, 477 P.3d 288.

[56] Mont. Const. art. IX, § 1(3); *see* MCA § 75-1-102 (MEPA's purposes).

[57] *Park Cnty. Env't Council*, ¶ 71.

it impairs Montanans' fundamental constitutional rights, Mont. Const. art. II, § 3, art. IX, § 1, and the Legislature's obligation to provide environmental remedies to address the climate-change impacts of greenhouse-gas emissions.[58]

While MEPA, as amended by HB 971, purports to prohibit DEQ from considering the harmful impacts of climate change and its contributors under that statute, the agency is nonetheless obligated to "maintain and improve a clean and healthful environment in Montana for present and future generations."[59] Doing so necessarily requires the agency to, at a minimum, consider the climate-related impacts of projects it authorizes.

For these reasons, too, DEQ must evaluate harm from LGS's greenhouse-gas emissions on Montana's climate.

III. DEQ must sufficiently analyze the impacts of lighting on human health.

In addition to the plant's climate impacts, the Draft EA overlooked other potential impacts from the construction and operation of the LGS. Under MEPA, an EA must consider impacts on the "human population in the area" including "human health" and any other "appropriate social … circumstances," including the cumulative impacts in light of other industrial uses in the area.[60] The Draft EA insufficiently analyzes the impacts of the Laurel plant's proposed lighting on those living in surrounding communities.

While DEQ purports to consider lighting impacts in its analysis, it fails entirely to describe—much less evaluate—the impacts of lighting on human health.[61,62] The Draft EA does little more than offer an imprecise quantification of

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[58] Mont. Const. art. IX, § 1(3); *Park Cnty. Env't Council*, ¶¶ 60, 61, 62, 84.

[59] Mont. Const. art. IX, § 1(1).

[60] ARM 17.4.609 (3)(e).

[61] EA at 6–30.

[62] In its lighting analysis, DEQ characterizes the Laurel Generating Station as "infrastructure necessary for grid reliability." EA at 26. DEQ's analysis, however, does not purport to analyze Montana's "grid reliability" and offers no support whatsoever for this statement. It should accordingly be removed from the agency's final EA. Insofar as DEQ considers "grid reliability" an impact of the project, it must offer analysis to substantiate that assertion. *See Klamath-Siskiyou Wildlands Ctr. v. Bureau of Land Mgmt.*, 387 F.3d 989, 995 (9th Cir. 2004) (noting that a "conclusory presentation does not offer any more than the kind of 'general

the anticipated type of lighting that will be used at the site, with some rough estimations of what types of lighting will be included and how often that lighting will be used.[63] But the Draft EA makes no attempt to convert that description into analysis on the tangible effects on human health.[64] This omission is particularly problematic in light of the well-documented adverse health effects of nighttime lighting on people. These impacts include altering hormone production and impacting metabolism, immune function, and endocrine balances in the reproductive, adrenal, and thyroid hormone axes, all of which can lead to the growth of some cancers.[65]

DEQ must also analyze the cumulative impacts of lighting in an area the agency acknowledges as having additional industrial uses with external lighting.[66] Under MEPA, DEQ must consider a project's "cumulative and secondary impacts,"[67] which include any "further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action."[68] To satisfy MEPA's mandate in this case, DEQ must consider the cumulative impacts of adding more constant industrial lighting to the Laurel area. Instead, DEQ concludes, without disclosing any quantifiable baselines to which to compare the additional impacts or any analysis of the actual effect on the human population, that the project's cumulative and secondary impacts will be insignificant.[69] DEQ's failure to take a hard look at the lighting impacts of the proposal on top of the

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statements about possible effects and some risk' which … [is] insufficient to constitute a 'hard look'").

[63] EA at 6–26.

[64] *See, e.g., Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008) (holding an EA insufficient where it quantified an impact but failed to discuss the actual environmental effects); *compare Protect Our Communities Found. v. Jewell*, 825 F.3d 571, 584 (9th Cir. 2016) (holding an EA sufficient where the agency "properly canvassed the available literature" regarding impacts to human health and evaluated that information in light of the project).

[65] K. Navara, R. Nelson, "The dark side of light at night: psychological, epidemiological, and ecological consequences," Journal of Pineal Research, 217 (May 29, 2007) (attached as Exhibit 4); *see also* Y.M. Cho, *et al*. "Effects of artificial light at night on human health: A literature review of observational and experimental studies applied to exposure assessment," Chronobiology International (Sep. 16, 2015) (attached as Exhibit 5).

[66] Draft EA at 29.

[67] ARM 17.4.609(3)(d)-(e).

[68] ARM 17.4.603(18).

[69] Draft EA at 29.

impacts of industry already in the surrounding area of the proposed generating station violates the agency's duty to consider cumulative impacts.[70]

The Draft EA's failure to adequately evaluate the direct, indirect, and cumulative impacts related to increased lighting violates MEPA.[71]

IV. DEQ must examine the impacts of noise from the LGS.

In addition to evaluating the impacts of the Laurel plant's lighting and greenhouse-gas emissions, DEQ must also consider the project's noise impacts under MEPA. This analysis must extend beyond direct effects to "cumulative and secondary impacts,"[72] which include any "further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action."[73] MEIC previously submitted comments regarding DEQ's noise evaluation, which are incorporated and adopted by reference here.[74] In addition to the information presented by MEIC in its prior comments, DEQ can look to other environmental analyses examining noise—including the attached Draft Environmental Impact Statement for the Plymouth Generating Facility—as an example of a more thorough analysis of noise impacts from a gas-fired power plant.[75]

Sincerely,

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[70] ARM 17.4.609(3)(d)-(e), (g).

[71] *Id*.

[72] ARM 17.4.609(3)(d)-(e).

[73] ARM 17.4.603(18).

[74] *See* note 5.

[75] Draft Env't Impact. Statement for Plymouth Generating Project (Sep. 11, 2002) (excerpts attached as Exhibit 6).

Exhibit I

Energy + Environmental Economics, *Resource Adequacy in the Pacific Northwest*
(March 2019)

Resource Adequacy in the Pacific Northwest

March 2019

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

March 2019

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Study Sponsors

This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy, and the Public Generating Pool (PGP). PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington: Chelan County PUD, Clark Public Utilities, Cowlitz County PUD, Eugene Water and Electric Board, Klickitat PUD, Grant County PUD, Lewis County PUD, Tacoma Power, Snohomish County PUD, and Benton PUD.

Acknowledgements

E3 thanks the staff of the Northwest Power and Conservation Council (NWPCC) for providing data and technical review.

Conventions

The following conventions are used throughout this report:

+ All costs are reported in **2016 dollars.**
+ All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).

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Acronyms

CONE	Cost of New Entry
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GENESYS	NWPCC's Generation Evaluation System Model
GHG	Greenhouse Gas
ISO	Independent System Operator
LOLE	Loss-of-Load Expectation
LOLF	Loss-of-Load Frequency
LOLP	Loss-of-Load Probability
MISO	Midwest Independent System Operator
MMT	Million Metric Ton
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
RA	Resource Adequacy
RECAP	E3's Renewable Energy Capacity Planning Model
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

Executive Summary

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized

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grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

Background and Approach

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

+ How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
+ How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?
+ How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
+ How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;

- Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
- Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
- Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.

2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;
    - Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.
3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.
4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;
    - Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
    - Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;

- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy.

1 Introduction

1.1 Study Background & Context

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

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1.2 Prior Studies

In 2017-2018, E3 completed a series of studies[1] for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon. These studies were conducted using E3's RESOLVE model, which is a dispatch and investment model that identifies optimal long-term generation and transmission investments in the electric system to meet various decarbonization and renewable energy targets. The studies found that the least-cost pathway to reduce greenhouse gases from electricity generation is to replace coal generation with a mix of energy efficiency, renewables, and natural gas generation. While these studies examined in great detail the economics of new resources needed to achieve decarbonization, including the type, quantity, and location of these resources, they did not look in-depth at reliability and Resource Adequacy.

1.3 Purpose of Study

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

+ How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
+ How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?

[1] https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

1.4 Report Contents

The remainder of this report is organized as follows:

- Section 2 introduces Resource Adequacy and current practices in the Northwest
- Section 3 describes the study's modeling approach
- Section 4 highlights key inputs and assumptions used in the modeling
- Section 5 presents results across a variety of time horizons and resource portfolios
- Section 6 discusses implications of the results
- Section 7 summarizes the study's conclusions and lessons learned

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2 Resource Adequacy in the Northwest

2.1 What is Resource Adequacy?

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run standard on the maximum frequency of reliability events where generation is insufficient to serve all load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Council (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy but have no formal governing role.

While a variety of approaches are used, the industry best practice is to establish a standard for resource adequacy using a two-step process:

+ **Loss-of-load-probability (LOLP) modeling:** LOLP modeling uses statistical techniques and/or Monte Carlo approaches to simulate the capability of a generation portfolio to produce sufficient generation to meet loads across a wide range of different conditions. Utilities plan the system to meet a specific reliability standard that is measured through LOLP modeling such as the expected frequency and/or size of reliability events; a relatively common standard used in LOLP modeling is "one day in ten years," which is often translated to an expectation of 24 hours of lost load every ten years, or 2.4 hours per year.[2]

+ **Planning reserve margin (PRM) requirements:** Utilities then determine the required PRM necessary to ensure that the system will meet the specific the reliability standard from the LOLP modeling. A PRM establishes a total requirement for capacity based on the peak demand of an electric system plus some reserve margin to account for unexpected outages and extreme conditions; reserve margin requirements typically vary among utilities between 12-19% above peak demand. To meet this need, capacity from resources that can produce their full power on demand (e.g., nuclear, gas, coal) are typically counted at or near 100%, whereas resources that are constrained in their availability or ability to dispatch (e.g., hydro, storage, wind, solar) are typically de-rated below full capacity.

While LOLP modeling is more technically rigorous, most utilities perform LOLP modeling relatively infrequently and use a PRM requirement to heuristically ensure compliance with a specific reliability standard due to its relative simplicity and ease of implementation. The concept and application of a PRM to measure resource adequacy has historically worked well in a paradigm in which most generation capacity is "firm"; that is, the resource will be available to dispatch to full capacity, except in the event of unexpected forced outages. Under this paradigm, as long as the system has sufficient capacity to meet its peak demand (plus some reserve margin for extreme weather and unexpected forced outages), it will be capable of serving load throughout the rest of the year as well.

However, growing penetrations of variable (e.g., wind and solar) and energy-limited (e.g., hydro, electric energy storage, and demand response) resources require the application of increasingly sophisticated modeling tools to determine the appropriate PRM and to measure the contribution of each resource towards resource adequacy. Because wind and solar do not always generate during the system peak and because storage may run out of charge while it is serving the system peak, these resources are often de-

[2] Other common interpretations of the "one day in ten year" standard include 1 "event" (of unspecified duration) in ten years or "one hour in ten years" i.e., 0.1 hrs/yr

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rated below the capability of a fully dispatchable thermal generator when counted toward meeting the PRM.

2.2 Planning Practices in the Northwest

A number of entities within the Northwest conduct analysis and planning for resource adequacy within the region. Under its charter to ensure prudent management of the region's federal hydro system while balancing environmental and energy needs, the Northwest Power and Conservation Council (NWPCC) conducts regular assessments of the resource adequacy position for the portion of the Northwest region served by the Bonneville Power Administration. The NWPCC has established an informal reliability target for the region of 5% annual loss of load probability[3]—a metric that ensures that the region will experience reliability events in fewer than one in twenty years—and uses GENESYS, a stochastic LOLP model with a robust treatment of the resource's variable hydroelectric conditions and capabilities, to examine whether regional resources are sufficient to meet this target on a five-year ahead basis.[4] These studies provide valuable information referenced by regulators and utilities throughout the region.

While the work of the Council is widely regarded as the most complete regional assessment of resource adequacy for the smaller region, the Council itself holds no formal decision-making authority to prescribe new capacity procurement or to enforce its reliability standards. Instead, the ultimate administration of resource adequacy lies in the hands of individual utilities, often subject to the oversight of state commissions. Most resource adequacy planning occurs within the planning and procurement processes

[3] This Council's standard, which focuses only on whether a reliability event occurred within a year, is unique to the Northwest and is not widely used throughout the rest of the North America

[4] The most recent of these reports, the Pacific Northwest Power Supply Adequacy Assessment for 2023, is available at: https://www.nwcouncil.org/sites/default/files/2018-7.pdf (accessed January 18, 2019).

of utilities: individual utilities submit integrated resource plans (IRPs) that consider long-term resource adequacy needs and conduct resource solicitations to satisfy those needs.

Utilities rely on a combination of self-owned generation, bilateral contracts, and front-office transactions (FOTs) to satisfy their resource adequacy requirements. FOTs represent short-term firm market purchases for physical power delivery. FOTs are contracted on both a month-ahead, day-ahead and hour-ahead basis. A survey of the utility IRPs in the Northwest reveals that most of the utilities expect to meet a significant portion of their peak capacity requirements in using FOTs.

FOTs may be available to utilities for several potential reasons including 1) the region as a whole has a capacity surplus and some generators are uncontracted to a specific utility or 2) natural load diversity between utilities such that one utility may have excess generation during another's peak load conditions and vice versa. The use of FOTs in place of designated firm resources can result in lower costs of providing electric service, as the cost of contracting with existing resources is generally lower than the cost of constructing new resources.

However, as loads grow in the region and coal generation retires, the region's capacity surplus is shrinking, and questions are emerging about whether sufficient resources will be available for utilities to contract with for month-ahead and day-ahead capacity products. In a market with tight load-resource balance, extensive reliance on FOTs risks under-investment in the firm capacity resources needed for reliable load service.

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Table 1: Contribution of FOTs Toward Peak Capacity Requirements in 2018 in the Northwest

Utility	Capacity Requirement (MW)	Front Office Transactions (MW)	% of Capacity Requirement from FOTs
Puget Sound[5]	6,100	1,800	30%
Avista[6]	2,150	-	0%
Idaho Power[7]	3,078	313	10%
PacifiCorp[8]	11,645	462	4%
BPA[9]	11,506	-	0%
PGE[10]	4,209	106	3%
NorthWestern[11]	1,205	503	42%

[5] Figure 6-7: Available Mid C Tx plus Additional Mid-C Tx w/ renewals in PSE 2017 IRP: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf?la=en&revision=bb9e004c-9da0-4f75-a594-6c30dd6223f4&hash=75800198E4E8517954C63B3D01E498F2C5AC10C2
[6] Figure 6.1 (for peak load), Chapter 4 Tables for resources in Avista 2017 IRP: https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2017-electric-irp-final.pdf?la=en
[7] Table 9.11 in Idaho Power 2017 IRP: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf
[8] Table 5.2 in PacifiCorp 2017 IRP (Interruptible Contracts + Purchases): https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf
[9] Bottom of the page in BPA fact sheet: https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf
[10] PGE 2016 IRP Table P-1 Spot Market Purchases (rounded from 106), Capacity Need : https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp
[11] Table 2-2 for peak load and netted out existing resources (Ch. 8) @ 12%PRM from NorthWestern Energy 2015 IRP: https://www.northwesternenergy.com/our-company/regulatory-environment/2015-electricity-supply-resource-procurement-plan

3 Modeling Approach

3.1 Renewable Energy Capacity Planning (RECAP) Model

3.1.1 MODEL OVERVIEW

This study assesses the resource adequacy of electric generating resource portfolios for different decarbonization scenarios in the Northwest region using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida.

RECAP calculates a number of reliability metrics which are used to assess the resource adequacy for an electricity system with a given set of loads and generating resources.

- **Loss of Load Expectation (hrs/yr) – LOLE**
  - The total number of hours in a year where load + reserves exceeds generation
- **Expected Unserved Energy (MWh/yr) – EUE**
  - The total quantity of unserved energy in a year when load + reserves exceeds generation
- **Loss of Load Probability (%/yr) – LOLP**
  - The probability in a year that load + reserves exceeds generation at any time
- **Effective Load Carrying Capability (%) – ELCC**
  - The additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage, hydro, and demand response). Equivalently, this is the quantity of perfectly dispatchable

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generation that could be removed from the system by an incremental dispatch-limited generator

- **Planning Reserve Margin (%) – PRM**
  - The resource margin above a 1-in-2 peak load, in %, that is required in order to meet a specific reliability standard (such as 2.4 hrs./yr. LOLE)

This study uses 2.4 hrs./yr. LOLE reliability standard which is based on a commonly accepted 1-day-in-10-year standard. All portfolios that are developed by RECAP in this analysis for resource adequacy are designed to meet a 2.4 hrs./yr. LOLE standard.

RECAP calculates reliability statistics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE and other reliability statistics.

RECAP was specifically designed to calculate the reliability of electric systems operating under high penetrations of renewable energy and storage. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response.

3.1.2 MODEL METHODOLOGY

The steps of the RECAP modeling process are shown below in Figure 1. RECAP calculates long-run resource availability through Monte Carlo simulation of electricity system resource availability using weather conditions from 1948-2017. Each simulation begins on January 1, 1948 and runs hourly through December 31, 2017. Hourly electric loads for 1948-2017 are synthesized using statistical analysis of actual load shapes and weather conditions for 2014-2017 combined with recorded historical weather conditions.

Then, hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory (NREL) and paired with historical weather days through an E3-created day-matching algorithm. Next, nameplate capacity and forced outage rates (FOR) for thermal generation are drawn from various sources including the GENESYS database and the Western Electric Coordinating Council's Anchor Data Set. Hydro is dispatched based on the load net of renewable and thermal generation. Annual hydro generation values are drawn randomly from 1929-2008 water years and shaped to calendar months and weeks based on the Northwest Power and Conservation Council's GENESYS model. For each hydro year, we identify all the hydro dispatch constraints including maximum and minimum power capacity, 2-hour to 10-hour sustained peaking limits, and hydro budget, specific to the randomly-drawn hydro condition. For each x-hour sustained peaking limit (where x = 2, 4, and 10), RECAP dispatches hydro so that the average capacity over consecutive x hours does not exceed the sustained peaking capability. Overall, hydro is dispatched to minimize the post-hydro net load subject to the above constraints. In other words, hydro is used within assumed constraints to meet peak load needs while minimizing loss-of-load. Finally, RECAP uses storage and demand response to tackle the loss-of-load hours and storage is only discharged during loss-of-load hours. A more detailed description of the RECAP model is in Appendix B.2.

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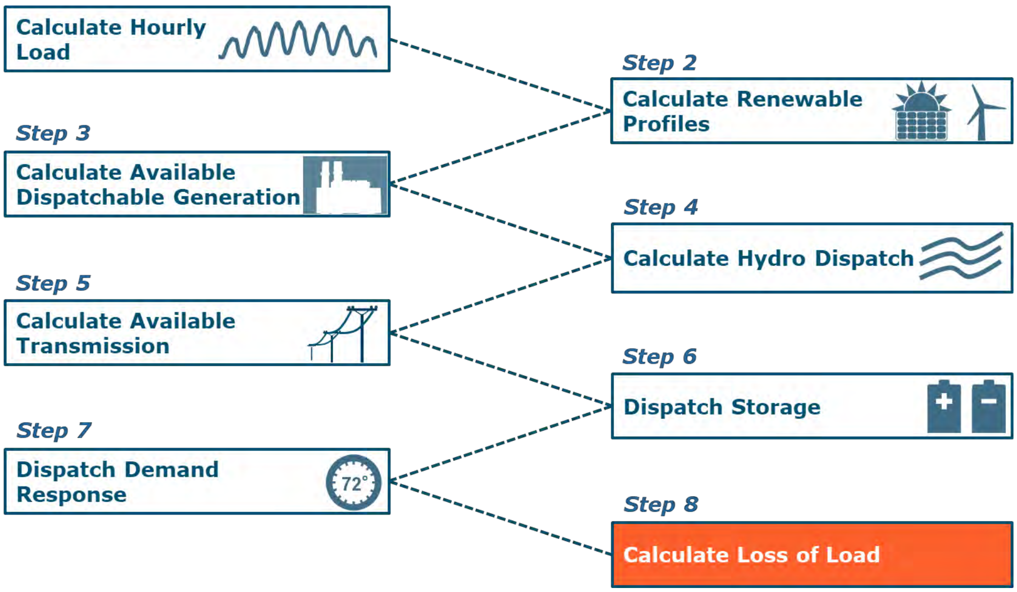
Figure 1: Overview of RECAP Model



3.1.3 PORTFOLIO DEVELOPMENT

RECAP is used in this study to both test the reliability of the existing 2018 Greater Northwest electricity system as well as to determine a total capacity need in 2030 and to develop portfolios in 2050 under various levels of decarbonization that meet a 1-day-in-10-year reliability standard of 2.4 hrs./yr.

To develop each 2050 decarbonization portfolio, RECAP calculates the reliability of the system in 2050 after forecasted load growth and the removal of all fossil generation but the maintenance of all existing carbon-free resources. Unsurprisingly, these portfolios are significantly less reliable than the required 2.4 hrs./yr. nor do they deliver enough carbon-free generation to meet the various decarbonization targets. To improve the reliability and increase GHG-free generation of these portfolios, RECAP tests the contribution of small, equal-cost increments of candidate GHG-free resources. The seven candidate resources in this study are:

+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ Solar (based on an assumed diverse mix of resources from each state)
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

The resource that improves reliability the most (as measured in loss-of-load-expectation) is then added to the system. This process is repeated until the delivered GHG-free generation is sufficient to meet the GHG target (e.g., 80% reduction) for each particular scenario. Once a portfolio has achieved the objective GHG target, RECAP calculates the residual quantity of perfect firm capacity that is needed to bring the portfolio in compliance with a reliability standard of 2.4 hrs./yr. This perfect firm MW capacity is converted to MW of natural gas capacity by grossing up by 5% to account for forced outages. Natural gas capacity is used because it is the most economic source of firm capacity. To the extent that other carbon-free resources can substitute for natural gas capacity, this is reflected in deeper decarbonization portfolios that have higher quantities of wind, solar, and storage along with a smaller residual requirement for firm natural gas capacity.

Figure 2 illustrates a simple example of this portfolio development process where RECAP has 3 candidate resources: wind, solar, and storage. The model evaluates the contribution to reliability of equal-cost increments of the three candidate resources and selects the resource that improves reliability the most. From that new portfolio, the process is repeated until either the system reaches a reliability standard of 2.4 or a particular GHG target is achieved.

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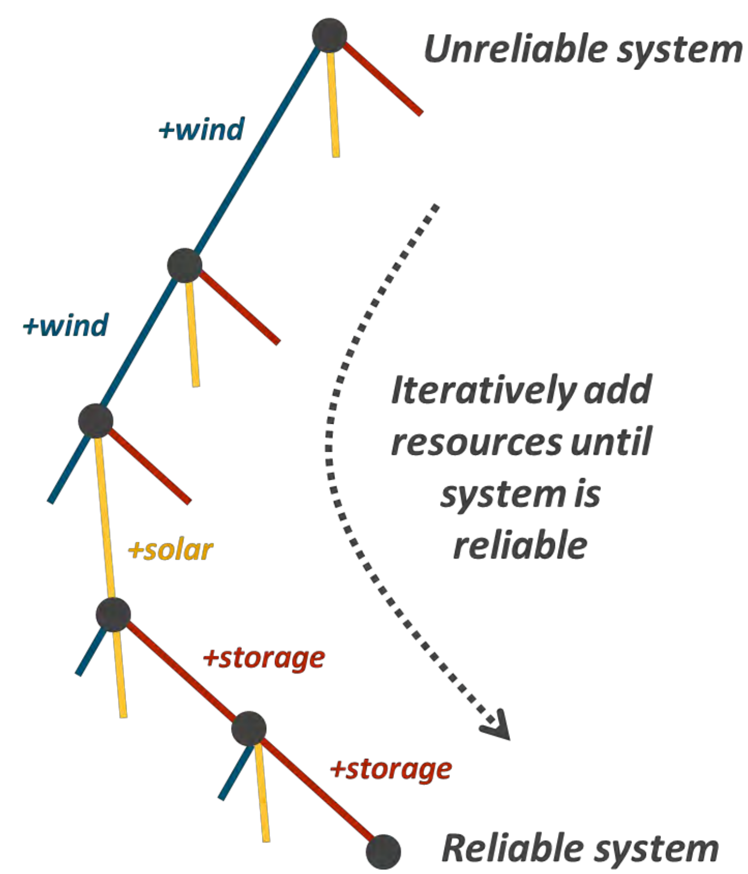
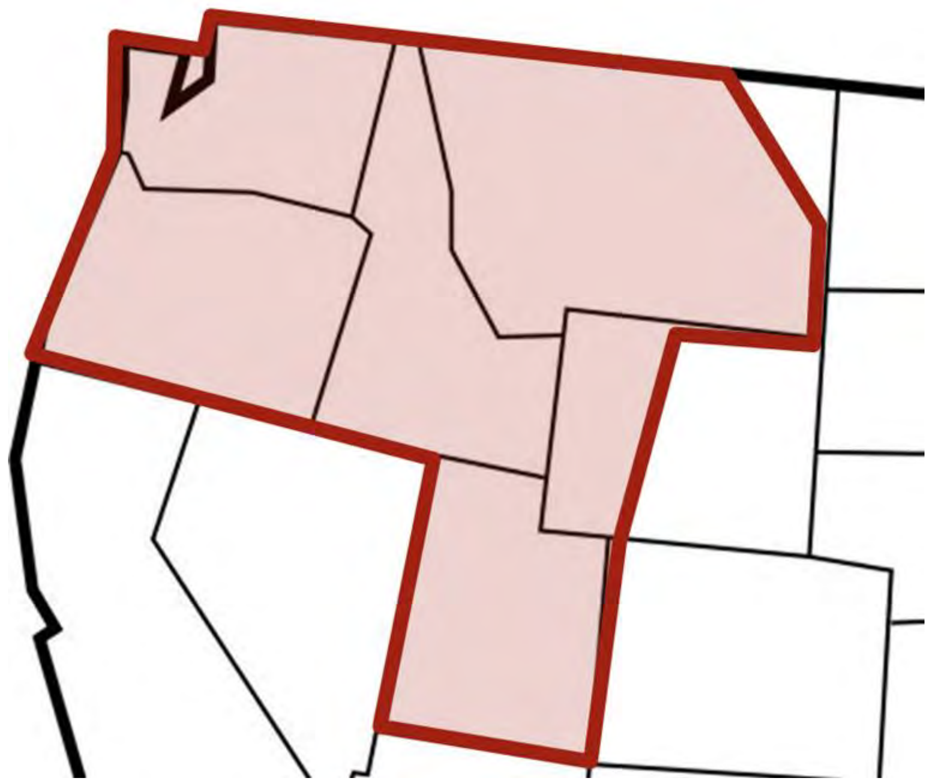
Figure 2: RECAP Portfolio Development Process



3.2 Study Region

The geographic region for this study consists of the U.S. portion of the Northwest Power Pool (NWPP), excluding Nevada, which this study refers to as the "Greater Northwest". This region includes the states of Washington, Oregon, Idaho, Utah, and parts of Montana and Wyoming.

Figure 3: The study region - The Greater Northwest



It is important to note that this is a larger region than was analyzed in the prior E3 decarbonization work in the Northwest which only analyzed a "Core Northwest" region consisting of Oregon, Washington, northern Idaho and Western Montana. The larger footprint encompasses the utilities that have traditionally coordinated operational efficiencies through programs under the Northwest Power Pool and includes utilities that typically transact with each other to maintain resource adequacy and optimize resource portfolios. The larger region also incorporates a footprint that allows for diversity of both load and resources which minimizes the need for firm capacity. The Balancing Authority Areas (BAAs) that were included in this Greater Northwest study region are listed in Table 2.

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Table 2: List of Balancing Authorities Included in Study

Balancing Authority Areas Included in Greater Northwest Study Region		
Avista	Bonneville Power Administration	Chelan County PUD
Douglas County PUD	Grant County PUD	Idaho Power
NorthWestern	PacifiCorp East	PacifiCorp West
Portland General Electric	Puget Sound Energy	Seattle City Light
Tacoma Power	Western Area Power Administration Upper Great Plains	

3.3 Scenarios & Sensitivities

This study examines the resource adequacy requirements of the Greater Northwest region across multiple timeframes and decarbonization scenarios.

+ **Near-term (2018)** reliability statistics are calculated for today's system based on 2018 existing loads and resources. These results are presented to give the reader a sense of existing challenges and as a reference for other scenario results.
+ **Medium-term (2030)** reliability statistics are calculated in 2030 for two scenarios: a *Reference* scenario and a *No Coal* scenario. The *Reference* scenario includes the impact of expected load growth and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants. The *No Coal* scenario assumes that all coal is retired.
+ **Long-term (2050)** reliability statistics are calculated in 2050 for multiple scenarios including a *Reference* scenario and for a range of decarbonization targets. The *Reference* scenario includes the impact of load growth, growth in renewable capacity to meet current RPS policy goals, and the retirement of all coal. Decarbonization scenarios assume GHG emissions are reduced to 60%, 80%, 90%, 98% and 100% below 1990 GHG levels through the addition of wind, solar, and electric energy storage.

These scenarios are summarized in Table 3.

Table 3: List of Scenarios and Descriptions

Analysis Period	Scenario	Description
Near-term (2018)	Reference	2018 Existing Loads and Resources
Medium-Term (2030)	Reference	Includes load growth through 2030 and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants
	No Coal	Same as 2030 reference but all coal generation in the region is retired (11 GW)
Long-Term (2050)	Reference	Includes load growth through 2050, renewable capacity additions to meet RPS targets, and ***retirement of all coal generation*** (11 GW)
	60% GHG Reduction	Scenarios achieve specified greenhouse gas reduction (relative to 1990 levels) through addition of solar, wind, and energy storage; sufficient gas generating capacity is maintained to ensure reliability (except in 100% GHG Reduction)
	80% GHG Reduction	
	90% GHG Reduction	
	98% GHG Reduction	
	100% GHG Reduction	

This study further explores the potential resource adequacy needs of a 100% carbon free electricity system in 2050 recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. To better understand how those technologies might impact the viability of achieving this ambitious goal, the study includes several sensitivity analyses of the 100% GHG Reduction scenario that assume the wide-scale availability of several such emerging technology options. These sensitivities are described in Table 4.

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Table 4: 100% GHG Reduction in 2050 Sensitivities

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

3.4 Key Portfolio Metrics

Each of the scenarios is evaluated using several different metrics which are defined below:

3.4.1 CLEAN ENERGY METRICS

A number of metrics are used to characterize the greenhouse gas content of generation within the region in each of the scenarios. These are:

+ **Greenhouse Gas Emissions (MMT CO2):** the annual quantity of greenhouse gas emissions attributed to ratepayers of the Greater Northwest region, measured in million metric tons.
+ **Greenhouse Gas Reduction (%):** the reduction below 1990 emission levels (approximately 60 million metric tons) for the Greater Northwest region.
+ **Clean Portfolio Standard (%):** the total quantity of GHG-free generation (including renewable, hydro, and nuclear) divided by retail electricity sales. Because this metric allows the region to retain the clean attribute for exported electricity and offset in-region or imported natural gas

generation, this metric can achieve or exceed 100% without reducing GHGs to zero. This metric is presented because it is a common policy target metric across many jurisdictions to measure clean energy progress and is the near-universal metric used for state-level Renewables Portfolio Standards. This metric is consistent with California's SB 100 which mandates 100% clean energy by 2045.

+ **GHG-Free Generation (%):** the total quantity of GHG-free generation, minus exported GHG-free generation, divided by total wholesale load. For this metric, exported clean energy cannot be netted against in-region or imported natural gas generation. When this metric reaches 100%, GHG emissions have been reduced to zero.

3.4.2 COST METRICS

+ **Renewable Curtailment (%):** the total quantity of wind and solar generation that cannot be delivered to loads in the region or exported, expressed as a share of total available potential generation from wind and solar resources.
+ **Annual Cost Delta ($B)** is the annual cost in 2050 of decarbonization scenarios relative to the 2050 Reference scenario. While the 2050 Reference scenario will require significant costs to meet load growth, this metric only evaluates the *change* in costs for each decarbonization scenario relative to the Reference scenario. By definition, the 2050 Reference scenario has an annual cost delta of zero. The annual cost delta is calculated by comparing the incremental cost of new wind, solar, and storage resources to the avoided cost of natural gas capital and operational costs.
+ **Additional Cost ($/MWh)** is the total annual cost delta ($B) divided by total wholesale load, which provides an average measure of the incremental rate impact borne by ratepayers within the region. While this metric helps to contextualize the annual cost delta, it is important to note that the incremental cost will not be borne equally by all load within the Greater Northwest region and some utilities may experience higher additional costs.

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3.5 Study Caveats

3.5.1 COST RESULTS

The study reports the incremental costs of achieving various GHG targets relative to the cost of the reference scenario. While the method used to estimate capital and dispatch costs is robust, it does not entail optimization and the results should be regarded as high-level estimates. For this reason, a range of potential incremental costs are reported rather than a point estimate. The range is determined by varying the cost of wind, solar, energy storage and natural gas.

3.5.2 HYDRO DISPATCH

For this study, RECAP utilizes a range of hydro conditions based on NWPCC data covering the time period 1929 – 2008. Within each hydro year, hydroelectric energy "budgets" for each month are allocated to individual weeks and then dispatched to minimize net load, subject to sustained peaking limit constraints that are appropriate for the water conditions. Hydro resources are dispatched optimally within each week with perfect foresight. There are many real-life issues such as biological conditions, flood control, coordination between different project operators, and others that may constrain hydro operations further than what is assumed for this study.

3.5.3 TRANSMISSION CONSTRAINTS

This analysis treats the Greater Northwest region as one zone with no internal transmission constraints or transactional friction. In reality, there are constraints in the region that may prevent a resource in one corner of the region from being able to serve load in another corner. To the extent that constraints exist, the Greater Northwest region may be less resource adequate than is calculated in this study and additional effective capacity would be required to achieve the calculated level of resource adequacy. It is assumed that new transmission can be developed to deliver energy from new renewable resources to wherever it is needed, for a cost that is represented by the generic transmission cost adder applied to resources in different locations.

3.5.4 INDIVIDUAL UTILITY RESULTS

Cost and resource results in this study are presented from the system perspective and represent an aggregation of the entire Greater Northwest region. These societal costs include all capital investment costs (i.e., “steel in the ground”) and operational costs (i.e., fuel and operation and maintenance) that are incurred in the region. The question of how these societal costs are allocated between individual utilities is not addressed in this study, but costs for individual utilities may be higher or lower compared to the region as a whole. Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources.

Resource adequacy needs will also be different for each utility as individual systems will need a higher planning reserve margin than the Greater Northwest region as a whole due to smaller size and less diversity. The capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production.

3.5.5 RENEWABLE RESOURCE AVALIBILITY AND LAND USE

The renewable resource availability assumed for this study is based on technical potential as assessed by NREL. It is assumed wind and solar generation can be developed in each location modeled in this study up to the technical potential. However, the land consumption is significant for some scenarios and it is not clear whether enough suitable sites can be found to develop the large quantities of resources needed for some scenarios. Land use is also a significant concern for the new transmission corridors that would be required.

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4 Key Inputs & Assumptions

4.1 Load Forecast

The Greater Northwest region had an annual load of 247 TWh and peak load of 43 GW in 2017. This data was obtained by aggregating hourly load data from the Western Electric Coordinating Council (WECC) for each of the selected balancing authority areas in the Greater Northwest region.

This study assumes annual load growth of **1.3% pre-energy efficiency** and **0.7% post-energy efficiency**. This assumption is consistent with the previous E3 decarbonization work for Oregon and Washington and is benchmarked to multiple long-term publicly available projections listed in Table 5. The post-energy efficiency growth rate includes the impact of all cost-effective energy efficiency identified by the NWPCC, scaled up to the full Greater Northwest region and assumed to continue beyond the end of the Council's time horizon. Electrification of vehicles and buildings is only included to the extent that it is reflected in these load growth forecasts. For example, the NWPCC forecast includes the impact of 1.1 million electric vehicles by 2030.

In general, E3 believes these load growth forecasts are conservatively low because they exclude the effect of vehicle and building electrification that would be expected in a deeply decarbonized economy. To the extent that electrification is higher than forecasted in this study, resource adequacy requirements would also increase. In this study, total loads increase 25% by 2050, whereas other studies[12] that have comprehensively examined cost-effective strategies for economy-wide decarbonization include

[12] https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

significant quantities of building, vehicle, and industry electrification that cause electricity-sector loads to grow by upwards of 60% by 2050 even with significant investments in energy efficiency.

Table 5. Annual load growth forecasts for the Northwest

Source	Pre EE	Post EE
PNUCC Load Forecast	1.7%	0.9%
BPA White Book	1.1%	-
NWPCC 7th Plan	0.9%	0.0%
WECC TEPPC 2026 Common Case	-	1.3%
E3 Assumption	**1.3%**	**0.7%**

Hourly load profiles are assumed to be constant through the analysis period and do not account for any potential impact due to electrification of loads or climate change. The Greater Northwest system is a winter peaking system with loads that are highest during cold snaps on December and January mornings and evenings. An illustration of the average month/hour load profile for the Greater Northwest is shown in Figure 4.

Figure 4: Month/Hour Average Hourly Load in the Greater Northwest (GW)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
Mar	24	23	23	23	24	25	28	30	30	30	30	29	29	28	28	27	27	28	28	29	29	28	27	25
Apr	22	22	21	22	22	24	27	28	28	28	28	27	27	27	26	26	26	26	27	27	28	27	25	23
May	22	21	21	21	21	22	24	26	26	27	27	27	27	27	27	27	27	27	27	27	27	27	25	23
Jun	23	22	21	21	22	22	24	26	27	27	28	28	29	29	29	29	29	29	29	29	28	28	26	24
Jul	24	23	22	22	22	23	24	26	27	28	29	30	31	31	32	32	32	32	32	31	30	30	28	26
Aug	23	22	21	21	21	22	24	25	26	27	28	29	29	30	30	31	31	31	30	30	30	28	26	24
Sep	21	20	20	20	20	22	24	25	26	26	26	27	27	27	27	27	27	28	27	28	27	26	24	22
Oct	21	21	20	20	21	23	25	26	27	27	27	27	27	26	26	26	26	27	27	28	27	26	24	22
Nov	24	23	23	23	23	24	26	28	30	30	30	29	29	28	28	28	28	29	31	30	30	29	28	26
Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

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Projecting these hourly loads using the post-energy efficiency load growth forecasts yields the following load projections in 2030 and 2050.

Table 6. Load projections in 2030 and 2050 for the Greater NW Region

Load	2018	2030	2050
Median Peak Load (GW)	43	47	54
Annual Energy Load (TWh)	247	269	309

To evaluate the reliability of the Greater Northwest system under a range of weather conditions, hourly load forecasts for 2030 and 2050 are developed over seventy years of weather conditions (1948-2017). Historical weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA) for the following sites in the Greater Northwest region.

Table 7: List of NOAA Sites for Historical Temperature Data

City	Site ID
Billings, MT	USW00024033
Boise, ID	USW00024131
Portland, OR	USW00024229
Salt Lake City, UT	USW00024127
Seattle, WA	USW00024233
Spokane, WA	USW00024157

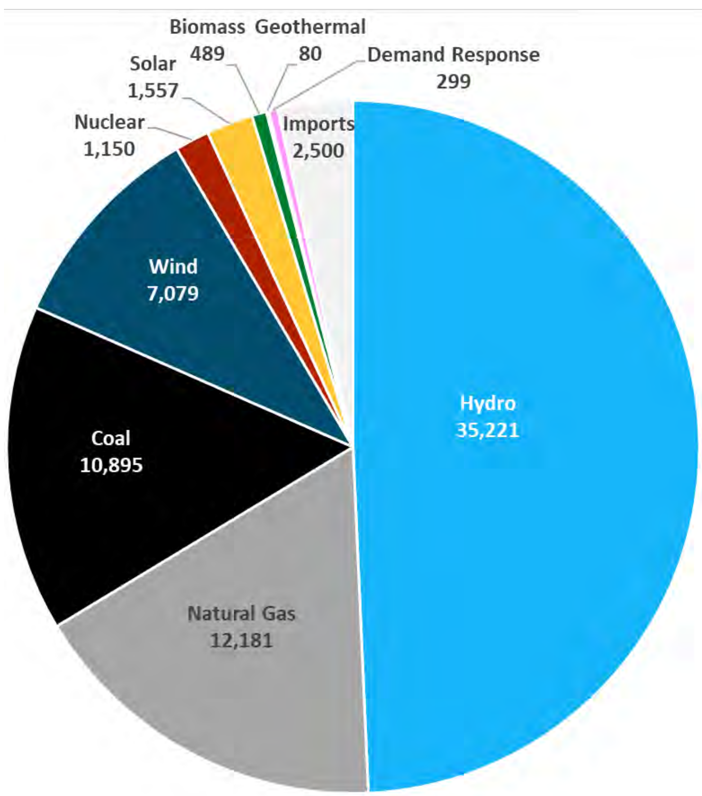
4.2 Existing Resources

A dataset of existing generating resources in the Greater Northwest was derived from two sources: 1) the NWPCC's GENESYS model, used to characterize all plants within the Council's planning footprint; and 2) the WECC's Anchor Data Set, used to gather input data for all existing plants in areas outside of the NWPCC's footprint. For each resource, the dataset contains:

- Dependable capacity (MW)
- Location
- Commission and announced retirement date
- Forced outage rate (FOR) and mean time to repair (MTTR)

A breakdown of existing resources by type is shown in Figure 5.

Figure 5: Existing 2018 Installed Capacity (MW) by Resource Type



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Several power plants have announced plans to retire one or more units. The table below lists the notable coal and natural gas planned retirements through 2030.

Table 8: Planned Coal and Natural Gas Retirements

Power Plant	Resource Type	Capacity (MW)
Boardman	Coal	522
Centralia	Coal	1,340
Colstrip 1 & 2	Coal	614
North Valmy	Coal	261
Naughton	Natural Gas	330

4.2.1 WIND AND SOLAR PROFILES

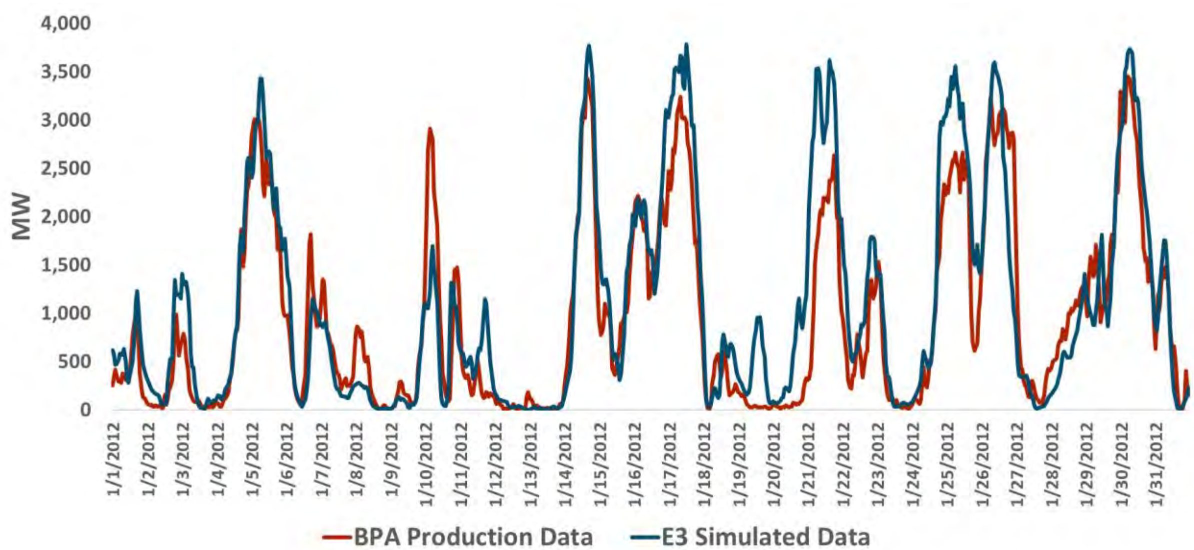
Hourly wind and solar data were collected for each existing resource in the combined dataset at the location of the resource. For wind, NREL's Wind Integration National Dataset Toolkit was used which includes historical hourly wind speed data from 2007-2012. For solar, NREL's Solar Prospector Database was used which includes historical hourly solar insolation data from 1998-2012. These hourly wind speeds and solar insolation values were then converted into power generation values using the NREL System Advisor Model (SAM) under assumptions for wind turbine characteristics (turbine power curve and hub height) and solar panel characteristics (solar inverter ratio). RECAP simulates future electricity generation from existing wind and solar resources using the historical wind speed data and solar insolation data respectively.

Simulated wind generation from existing wind plants within BPA territory was benchmarked to historical wind production data[13]. To simulate wind generation from existing plants accurately, wind turbine

[13] BPA publishes production from wind plants within its Balancing Authority Area in 5-min increments: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

technology (power curve and hub height) varies for each existing wind farm, based on the year of installation. Figure 6 shows how the simulated wind production compares to historical wind production in BPA territory in January 2012.

Figure 6: Comparison of historical wind generation to simulated wind production for January 2012



A detailed description of the renewable profile simulation process is described in Appendix C.

4.2.2 HYDRO

Hydro availability is based on a random distribution of the historical hydro record using the water years from 1929-2008. This data was obtained from the NWPCC's GENESYS model. Future electricity generation from existing hydro resources is simulated using the historical hydro availability. Available hydro energy is dispatched in RECAP subject to sustained peaking limits (1-hr, 2-hr, 4-hr, 10-hr) and minimum output levels. The sustained peaking limits are based on detailed hydrological models developed by NWPCC. Available hydro budgets, sustained peaking limits, and minimum output levels are shown for three hydro

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years – 1937 (critical hydro year), 1996 (high hydro year), and 2007 (typical hydro year). The 10-hour sustained peaking limits for each month represent the maximum average generation for any continuous 10-hour period within the month.

Figure 7: Monthly budgets, sustained peaking limits and minimum outputs levels for 1937 (critical hydro)

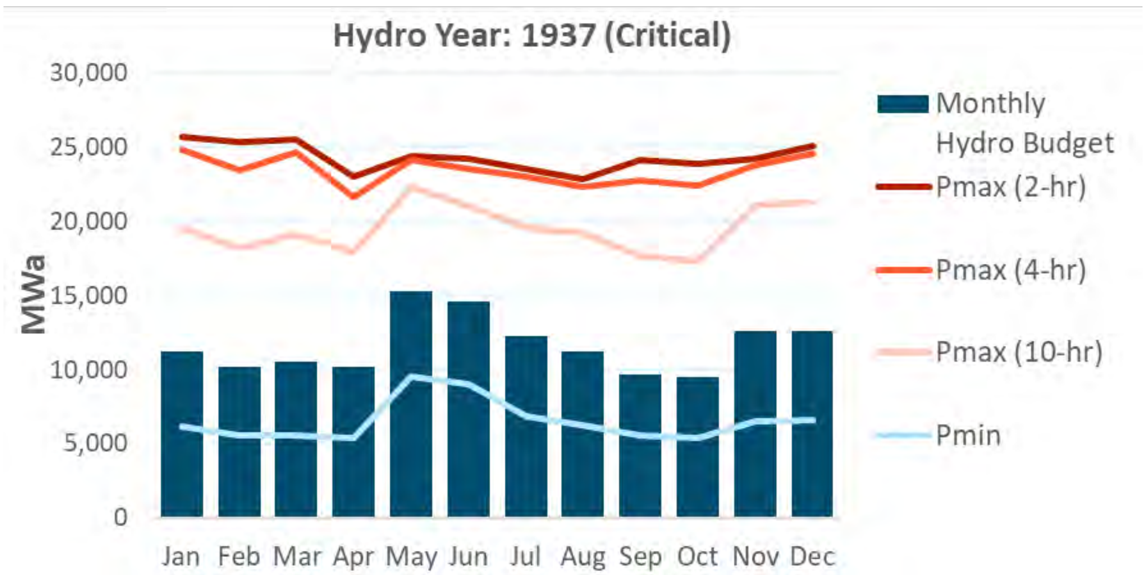


Figure 8: Monthly budgets, sustained peaking limits and minimum outputs levels for 1996 (high hydro)

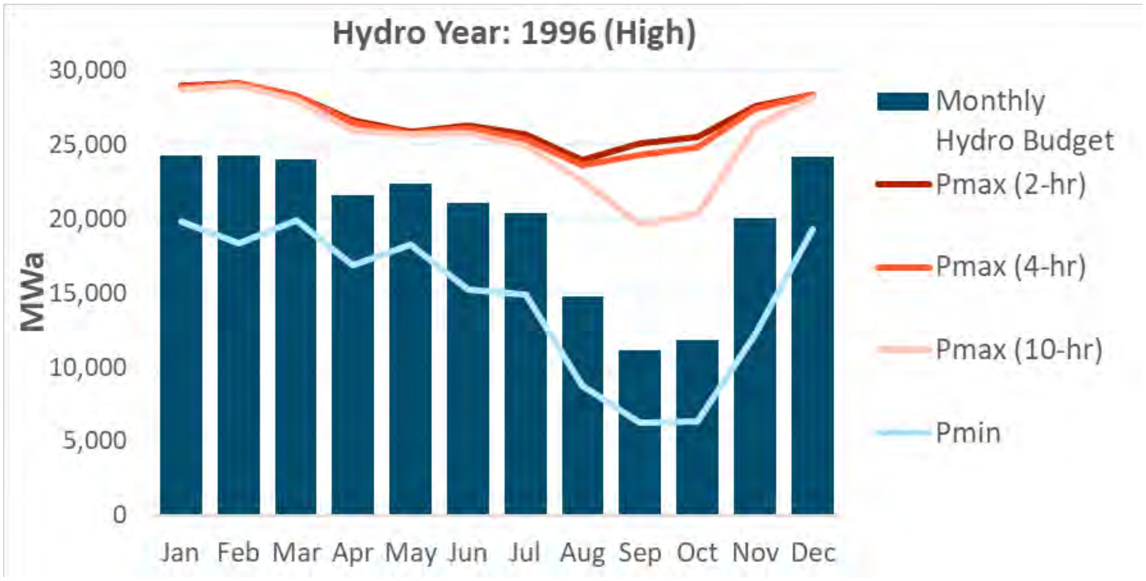
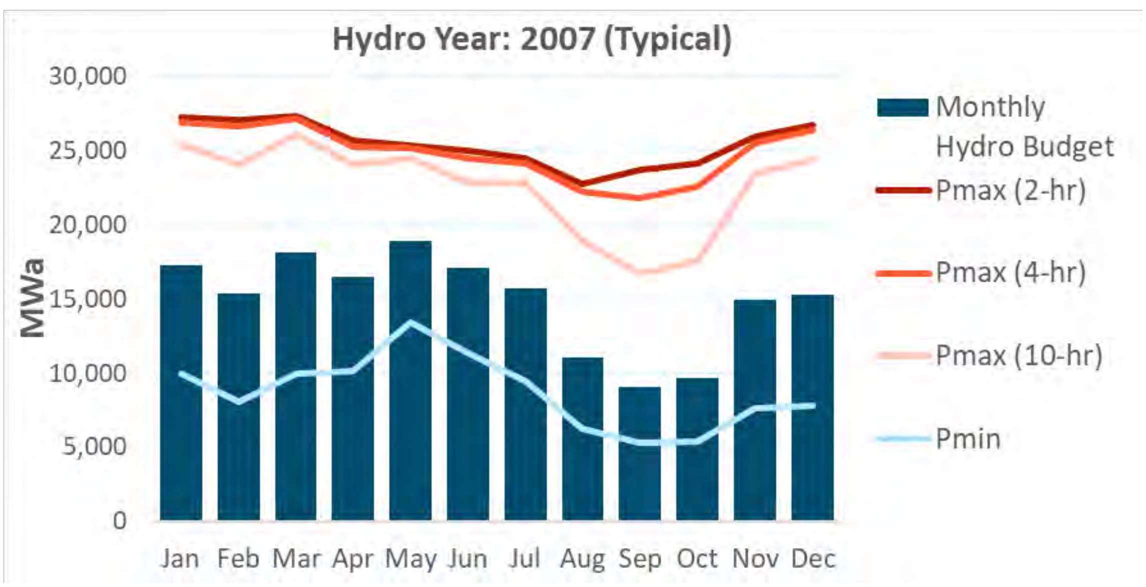


Figure 9: Monthly budgets, sustained peaking limits and minimum outputs levels for 2007 (typical hydro)



4.2.3 IMPORTS/EXPORTS

The Greater Northwest region is treated as one zone within the model, but it does have the ability to import and export energy with neighboring regions, notably California, Canada, Rocky Mountains, and the Southwest. Import and export assumptions used in this model are consistent with the NWPCC's GENESYS model and are listed in Table 9. Monthly and hourly import availabilities are additive but in no hour can exceed the simultaneous import limit of 3,400 MW. In the 100% GHG Reduction scenarios, import availability is set to zero to prevent the region from relying on fossil fuel imports.

Table 9: Import Limits

Import Type	Availability	MW
Monthly Imports	Nov – Mar	2,500
	Oct	1,250
	Apr – Sep	-
Hourly Imports	HE 22 – HE 5	3,000
	HE 5 – HE 22	-
Simultaneous Import Limit	**All Hours**	**3,400**

For the purposes of calculating the CPS % metric i.e., "clean portfolio standard", the model assumes an instantaneous exports limit of 7,200 MW in all hours.

Table 10: Export Limit

Export Type	Availability	MW
Simultaneous Export Limit	**All Hours**	**7,200**

4.3 Candidate Resources

Candidate resources are used to develop portfolios of resources in 2050 to both achieve GHG reduction targets or ensure acceptable reliability of 2.4 hrs./yr. LOLE. For a more detailed description of the portfolio development process, see Section 3.1.3. The 7 candidate resources are:

+ Solar (geographically diverse across Greater Northwest)
+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

Natural gas generation is also added as needed to meet any remaining reliability gaps after the GHG reduction target is met. The new renewable candidate resources (solar, NW wind, MT wind, WY wind) are assumed to be added proportionally across a geographically diverse footprint which has a strong impact on the ability of variable renewable resources to provide reliable power that can substitute for firm generation. Figure 10 illustrates the location of new candidate renewable resources. When a resource is added, it is added proportionally at each of the locations shown in the figure below.

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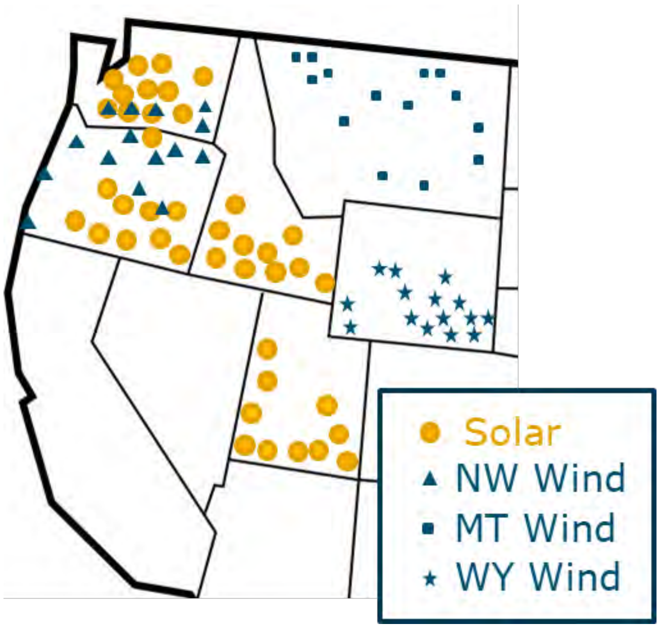
Figure 10: New Renewable Candidate Resources



The generation output profile for each location was simulated by gathering hourly wind speed and solar insolation data from NREL's Wind Integration National Dataset Toolkit and Solar Prospector Database and converting to power output using NREL's System Advisor Model. The wind profiles used in this study are based on 135 GW of underlying wind production data from hundreds of sites. The solar profiles used in this study are based on 80 GW of underlying solar production data across four states. This process is described in more detail in Appendix C.

New storage resources are available to the model in different increments of duration at different costs which provide different value in terms of both reliability and renewable integration for GHG reduction. Note that the model can choose different quantities of each storage duration which results in a fleet-wide storage duration that is different than any individual storage candidate resource. Because storage is modeled in terms of capacity charge/discharge and duration, many different storage technologies could provide this capability. The cost forecast trajectory for Li-Ion battery storage was used to estimate costs, but any storage technology that could provide equivalent capacity and duration, such as pumped hydro or flow batteries, could substitute for the storage included in the portfolio results of this study.

New renewable portfolios are within the bounds of current technical potential estimates published in NREL.

Table 11. NREL Technical Potential (GW)

State	Wind Technical Potential (GW)
Washington	18
Oregon	27
Idaho	18
Montana	944
Wyoming	552
Utah	13
Total	**1,588**

4.3.1.1 Resource Costs

All costs in this study are presented in 2016 dollars. The average cost of each resource over the 2018-2050 timeframe is shown in Table 12 while the annual cost trajectories from 2018-2050 are shown in Figure 11.

Table 12. Resource Cost Assumptions (2016 $)

Technology	Unit	High[14]	Low[15]	Transmission	Notes
Solar PV	$/MWh	$59	$32	$8	Capacity factor = 27%
NW Wind	$/MWh	$55	$43	$6	Capacity factor = 37%
MT/WY Wind	$/MWh	$48	$37	$19	Capacity factor = 43%
4-hr Battery	$/kW-yr	$194	$97		

[14] Source for high prices: 2017 E3 PGP Decarbonization Study
[15] Source for low prices: NREL 2018 ATB Mid case for wind and solar; Lazard LCOS Mid case 4.0 for batteries

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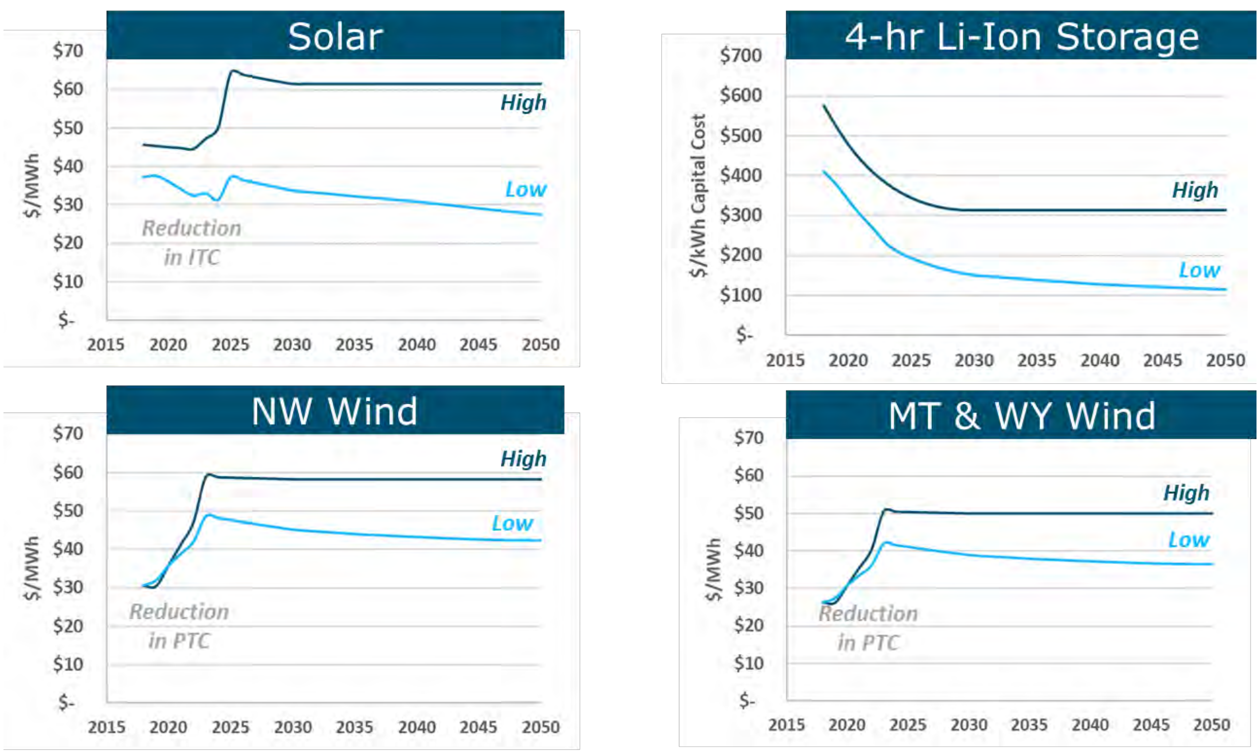
Technology	Unit	High[14]	Low[15]	Transmission	Notes
8-hr Battery	$/kW-yr	$358	$189		
16-hr Battery	$/kW-yr	$686	$373		
Natural Gas Capacity	$/kW-yr	$150	$150		7,000 Btu/kWh heat rate; $5/MWh variable O&M
Gas Price	$/MMBtu	$4	$2		
Biogas Price	$/MMBtu	$39	$39		

Figure 11: Cost trajectories over the 2018-2050 timeframe (2016 $)



4.4 Estimating Cost and GHG Metrics

The cost of the future electricity portfolios consists of (1) fixed capital costs for building new resources, and (2) operating costs for running both existing and new resources. For new wind and new solar resources, the cost of generation is calculated using their respective levelized costs (see Table 12). Cost of electricity generation from natural gas plants includes both the capital cost for new natural gas plants and the operating costs (fuel costs and variable operating costs). All the natural gas plants are assumed to operate at a heat rate of 7,000 Btu/kWh, with the price of natural gas varying from $2 to $4 per MMBtu (see Table 12). Storage resources are assumed to have only fixed cost, but no operating cost. All exports are assumed to yield revenues of $30 per MWh.

In this study, annual GHG emissions are compared against 1990 emission levels, when the emissions for the Greater Northwest region was 60 million metric tons. GHG emissions are calculated for each thermal resource depending on the fuel type. For natural gas plants, an emission rate of 117 lb. of CO_2 per MMBtu of natural gas is assumed, yielding 0.371 metric tons of CO_2 per MWh of electricity generated from natural gas (assumed 7,000 Btu/kWh heat rate). For coal plants, an emission rate of 1.0 ton of CO_2 per MWh of electricity generated from coal is assumed.

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5 Results

5.1 Short-Term Outlook (2018)

The 2018 system (today's system) in the study region is supplied by a mix of various resources, as described in Section 4.2. The annual electricity load for the study region is 247 TWh with a winter peak demand of 43 GW. Hydro energy provides the plurality of generation capacity with significant contributions from natural gas, coal and wind generation.

Resource adequacy conclusions vary depending on what metric is used for evaluation. The region has sufficient capacity to meet the current standard used by the NWPCC of 5% annual loss of load probability (LOLP). The region does not have sufficient capacity to meet the 2.4 hrs./yr. LOLE standard used in this study. In other words, most loss of load is concentrated in a few number of years which matches intuition for a system that is dependent upon the annual hydro cycle and susceptible to drought conditions. Full reliability statistics for the Greater Northwest region are shown in Table 13.

Table 13. 2018 Reliability Statistics

Metric	Units	Value
Annual LOLP (%)	%	3.7%
Loss of Load Expectation (LOLE)	hrs/yr	**6.5**
Expected Unserved Energy (EUE)	MWh/yr	5,777
Normalized EUE	%	0.003%
1-in-2 Peak Load	GW	43
PRM Requirement	% of peak	12%
Total Effective Capacity Requirement	GW	48

Table 14. 2018 Load and Resource Balance

Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

In order to meet an LOLE target of 2.4 hrs./yr., a planning reserve margin (PRM) of 12% is required. The PRM is calculated by dividing the quantity of effective capacity needed to meet the LOLE target by the median peak load, then subtracting one. This result is lower than many individual utilities currently hold within the region (typical PRM ~15%) due to the load and resource diversity across the geographically large Greater Northwest region. As shown in Table 14, the total effective capacity (47 GW) available is slightly lower than the total capacity requirement (48 GW) which is consistent with the finding that the

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system is not sufficiently reliable to meet a 2.4 hrs./yr. LOLE target. The effective capacity percent contributions from wind and solar are shown to be 7% and 12%, respectively. These relatively low values stem primarily from the non-coincidence of wind and solar production during high load events in the Greater Northwest region, notably very cold winter mornings and evenings.

It should be noted that the effectiveness of firm capacity is set to 100% by convention in calculating a PRM. The contribution of variable resources is then measured relative to firm capacity, incorporating the effect of forced outage rates for firm resources.

5.2 Medium-Term Outlook (2030)

The Greater Northwest system in 2030 is examined under two scenarios:

+ **Reference**
    - Planned coal retirements; new gas gen for reliability
+ **No Coal**
    - All coal retired; new gas gen for reliability

The resulting generation portfolios in both scenarios (both of which meet the 2.4 hrs./yr. LOLE reliability standard) are shown in Figure 12 alongside the 2018 system for context. To account for the load growth by 2030, 5 GW of net new capacity is required to maintain reliability. In the *Reference* Scenario where 3 GW of coal is retired, 8 GW of new firm capacity is needed by 2030 for reliability. Similarly, the *No Coal* Scenario (where all 11 GW of coal is retired) results in 16 GW of new firm capacity need by 2030. The study assumes all the new capacity in the 2030 timeframe need is met through additional natural gas build. It should be noted that regardless of what resource mix is built to replace the retirement of coal, the siting, permitting, and construction of these new resources will take significant time so planning for these resources needs to begin well before actual need. The portfolio tables for each scenario are summarized in Appendix A.2.

Figure 12: Generation Portfolios in 2030

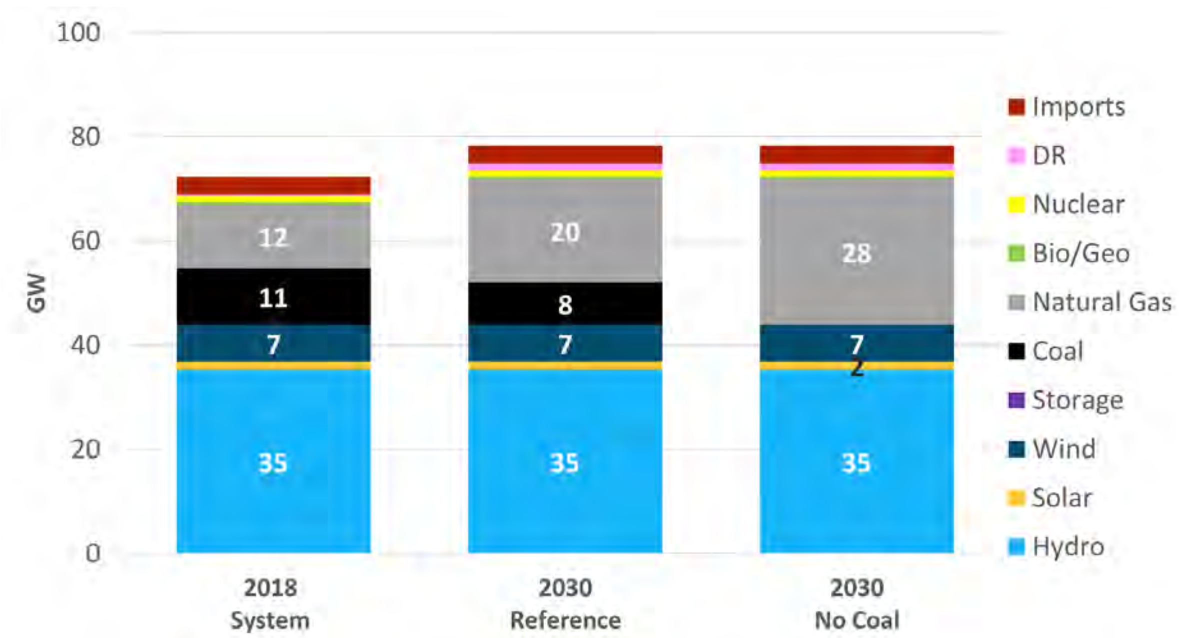

Table 15. 2030 Generation Portfolio: Key Metrics

Metric	2030 Reference	2030 No Coal
GHG-Free Generation (%)	61%	61%
GHG Emissions (MMT CO_2 / year)	67	42
% GHG Reduction from 1990 Level	-12%[16]	31%

[16] Negative value for %GHG reduction from 1990 level indicates that emissions are above 1990 level

As these metrics show, without either natural gas replacement of coal capacity or significant increase in renewable energy, GHG emissions are forecasted to rise in the 2030 timeframe. However, repowering coal with natural gas has the potential to reduce GHG emissions by 31% below 1990 levels.

In order to meet an LOLE target of 2.4 hrs/yr, the region requires a planning reserve margin (PRM) in 2030 of 12%.

Table 16. 2030 Load and Resource Balance, Reference Scenario

Load			**Load MW**
Peak Load			45.9
Firm Exports			1.1
PRM (12%)			5.8
Total Requirement			**52.9**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	8.2	100%	8.2
Gas	19.9	100%	19.9
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	2.2	45%	1.0
Hydro	35.2	53%	18.7
Wind	7.1	9%	0.6
Solar	1.6	14%	0.2
Storage	0	—	0
Total Internal Generation	**76.1**		**50.5**
Firm Imports	3.4	74%	2.5
Total Supply	**79.5**		**52.9**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3 Long-Term Outlook (2050)

The Greater Northwest system in 2050 is examined under a range of decarbonization scenarios, relative to 1990 emissions.

+ 60% GHG Reduction
+ 80% GHG Reduction
+ 90% GHG Reduction
+ 98% GHG Reduction
+ 100% GHG Reduction

The portfolio for each decarbonization scenario was developed using the methodology described in Section 3.1.3. To summarize this process, RECAP iteratively adds carbon-free resources (wind, solar storage) to reduce GHG in a manner that maximizes the effective capacity of these carbon-free resources, thus minimizing the residual need for firm natural gas capacity. Once a cost-effective portfolio of carbon-free resources has been added to ensure requisite GHG reductions, the residual need for natural gas generation capacity is calculated to ensure the entire portfolio meets a 2.4 hrs./yr. LOLE standard.

5.3.1 ELECTRICITY GENERATION PORTFOLIOS

All the 2050 decarbonization portfolios are shown together in Figure 13. Higher quantities of renewable and energy storage are required to achieve deeper levels of decarbonization, which in turn provide effective capacity to the system and allow for a reduction in residual firm natural gas capacity need, relative to the reference case. Detailed portfolio results tables for each scenario are provided in Appendix A.2.

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Figure 13: Generation Portfolios for 2050 Scenarios

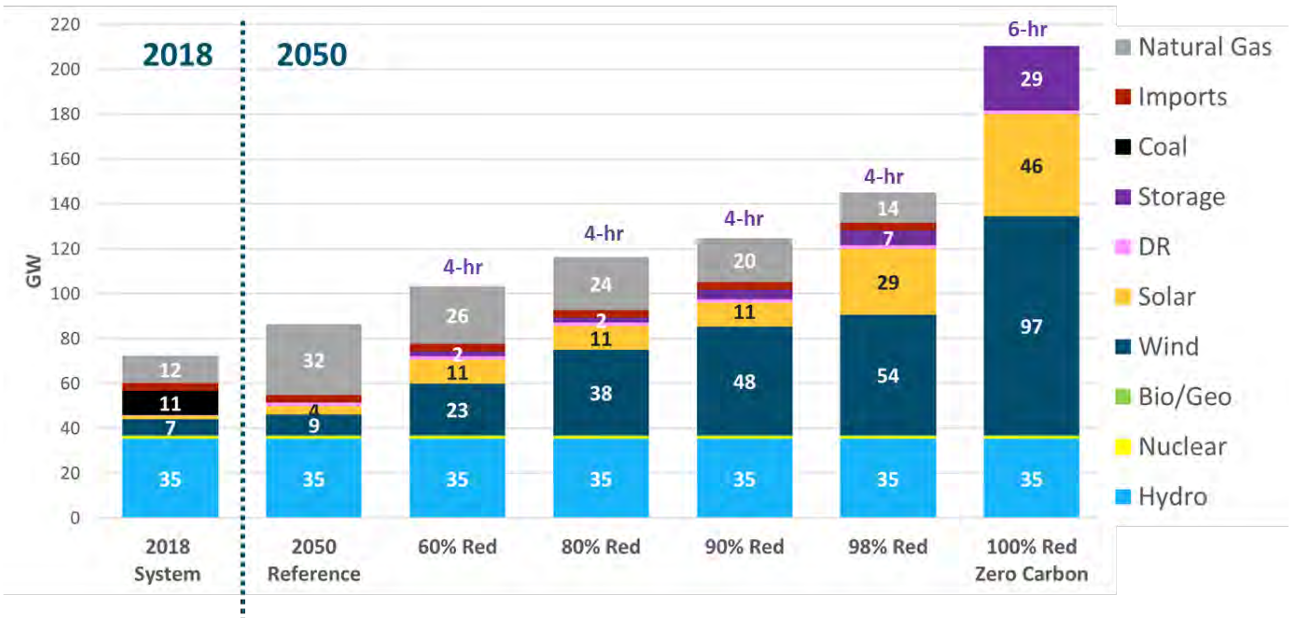

Table 17. 2050 Decarbonization Scenarios: Key Generation Metrics

			GHG Reduction Scenarios				
Metric	Units	Reference Scenario	60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
GHG Emissions	MMT/yr	50	25	12	6	1	0
GHG Reductions	% below 1990	16%	60%	80%	90%	98%	100%
GHG-Free Generation	% of load	60%	80%	90%	95%	99%	100%
Clean Portfolio Standard	% of sales	63%	86%	100%	108%	117%	123%
Annual Renewable Curtailment	% of potential	Low	Low	4%	10%	21%	47%

Table 17 evaluates the performance of each decarbonization portfolio along several key generation metrics that were described in detail in Section 3.4.

Analyzing the portfolio of each decarbonization scenario and resulting performance metrics yields several interesting observations.

+ On retiring all 11 GW of coal by 2050 in the *Reference* scenario, the Greater Northwest system requires 20 GW of new capacity in order to meet the 2.4 hrs./yr. LOLE standard used in the study. This suggests that 9 GW of net new firm capacity is needed to account for load growth through 2050.
+ The integration of more renewables and conservation policies provides the energy needed to serve loads in a deeply decarbonized future, but new gas-fired generation capacity is needed for relatively short, multi-day events with low renewable generation, high loads, and low hydro availability.
+ To reduce GHG emissions to 80% below 1990 levels, RECAP chooses to build 38 GW of wind, 11 GW of solar, and 2 GW of 4-hour storage. In addition to this renewable build, 12 GW of new firm capacity is required for reliability (after retaining all the existing natural gas plants) which is assumed to be met through natural gas build. The generation portfolio under 80% Reduction Scenario results in a 100% clean portfolio standard and 90% GHG-free generation.
+ RECAP achieves deeper levels of decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) by overbuilding renewables with 54 GW of wind, 29 GW of solar, and 7 GW of 4-hour storage. Annual renewable oversupply becomes significant (at 21%). Nevertheless, the system still requires an additional gas build of 2 GW after retaining all existing natural gas plants, to ensure reliability during periods of low renewable generation. The capacity factor for these gas plants is extremely low (3%), underlining their importance for reliability.
+ The 100% GHG Reduction Scenario (Zero Carbon Scenario) results in no GHG emissions from the electricity sector. The generation portfolio consists only of renewables (97 GW of wind and 46 GW of solar) and energy storage (29 GW of 6-hour storage). Ensuring a reliable system using only renewables and energy storage requires a significant amount of renewable overbuild – resulting

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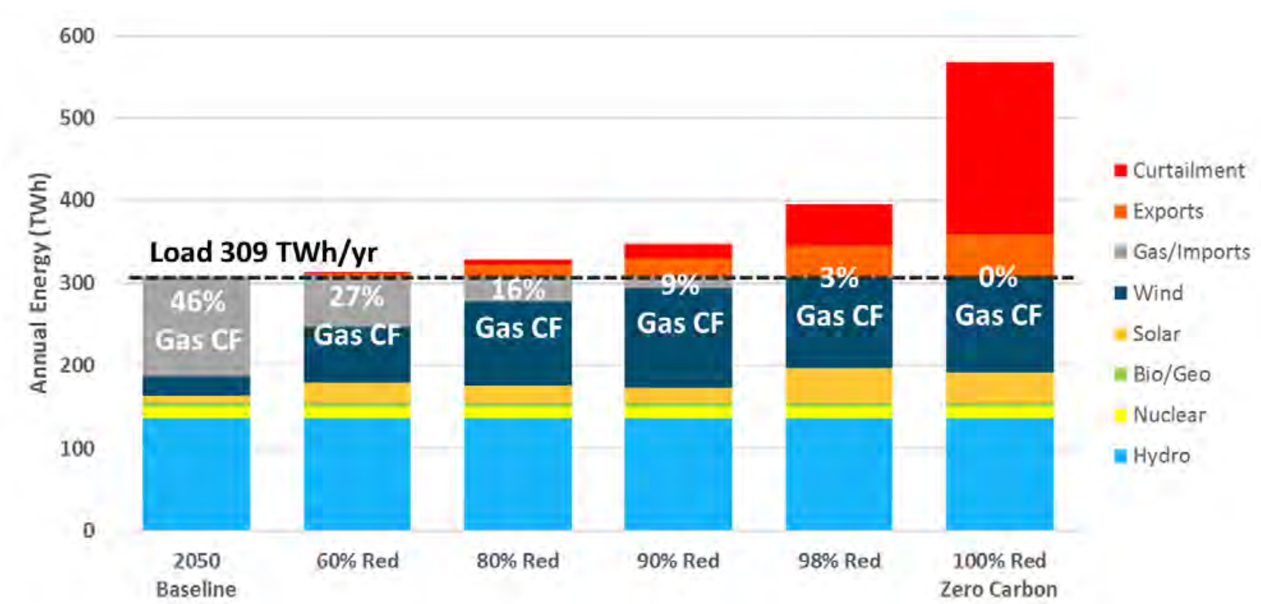
in nearly half of all the generated renewable energy to be curtailed. Compared to the 98% GHG Reduction Scenario (which results in 99% GHG-free generation), the Zero Carbon Scenario requires almost double the quantity of renewables and even greater quantity of energy storage.

With increases in renewable generation, generation from natural gas plants decreases. Due to negligible operating costs associated with renewable production, it is cost optimal to use as much renewable generation as the system can. During periods of prolonged low renewable generation when energy storage is depleted, natural gas plants can ramp up to provide the required firm capacity to avoid loss-of-load events. In the deep decarbonization scenarios, gas is utilized sparingly and even results in very low capacity factors (such as 9% and 3%). However, RECAP chooses to retain (and even build) natural gas as the most cost-effective resource to provide reliable firm capacity. Renewable overbuild also results in significant amounts of curtailment.

Figure 14: Annual generation mix across the scenarios



A planning reserve margin of 7% to 9% is required to meet the 1-in-10 reliability standard in 2050 depending on the scenario. Accounting for a planning reserve margin, the total capacity requirement (load plus planning reserve margin) in 2050 is 57-59 GW. As shown in Table 18, this capacity requirement is met through a diverse mix of resources. Variable or energy-limited resources such as hydro, wind, solar and storage contribute only a portion of their entire nameplate capacity (ELCC) towards resource adequacy. Load and resource tables for the 80% and 100% Reduction scenarios are shown below.

Table 18. 2050 Load and Resource Balance, 80% Reduction scenario

Load			**Load MW**
Peak Load			52.8
Firm Exports			1.1
PRM (9%)			4.9
Total Requirement			**58.8**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	23.5	100%	23.5
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	53%	18.7
Wind	38.0	19%	7.2
Solar	10.6	19%	2.0
Storage	2.2	73%	1.6
Total Internal Generation	**116.8**		**56.3**
Firm Imports	3.4	74%	2.5
Total Supply	**120.2**		**58.8**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

Table 19. 2050 Load and Resource Balance, 100% Reduction scenario

Load			Load MW
Peak Load			52.8
Firm Exports			1.1
PRM (7%)			4.0
Total Requirement			**58.0**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	0	—	0
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	57%	20.1
Wind	97.4	22%	21.5
Solar	45.6	16%	7.3
Storage	28.7	20%	5.7
Total Internal Generation	**214.2**		**58.0**
Firm Imports	0	—	0
Total Supply	**214.2**		**58.0**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3.2 ELECTRIC SYSTEM COSTS

System costs are estimated using the methodology and cost assumptions described in Section 4.3.1.1 and Section 4.4. Electric system costs represent the cost of decarbonization relative to the 2050 *Reference* scenario, and so by definition all annual and unit cost increases in this scenario are zero. The 2050 *Reference* scenario does require significant investment in new resources in order to reliably meet load growth and existing RPS policy targets, so the zero incremental cost is not meant to make any assessment on the absolute change (or lack thereof) in total electric system costs or rates by 2050.

Table 20 evaluates the performance of 2050 decarbonization scenarios along two cost metrics for both a low and high set of cost assumptions.

Table 20: 2050 Decarbonization Scenarios: Key Cost Metrics

Metric		Units	Reference Scenario	GHG Reduction Scenarios				
				60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
Annual Cost Increase	Lo	$BB/yr *(vs. Ref)*	—	$0	$1	$2	$3	$16
	Hi			$2	$4	$5	$9	$28
Unit Cost Increase	Lo	$/MWh *(vs. Ref)*	—	$0	$3	$5	$10	$52
	Hi			$7	$14	$18	$28	$89

Analyzing the cost results for each decarbonization scenario yields several interesting observations

+ To reduce GHG emissions to 80% below 1990 levels, a portfolio of wind/solar/storage can be obtained at an additional annual cost of $1 to $4 billion ($3 to $14/MWh) after accounting for the avoided costs of new gas build and utilization. Assuming an existing average retail rate of $0.10/kWh, this implies an increase of 3%-14% in real terms relative to the *Reference* Scenario. Because the 80% reduction scenario achieves a 100% clean portfolio standard (as shown in Section 5.3.1), this scenario is compelling from both a policy perspective and a cost perspective in balancing multiple objectives across the Greater Northwest region.

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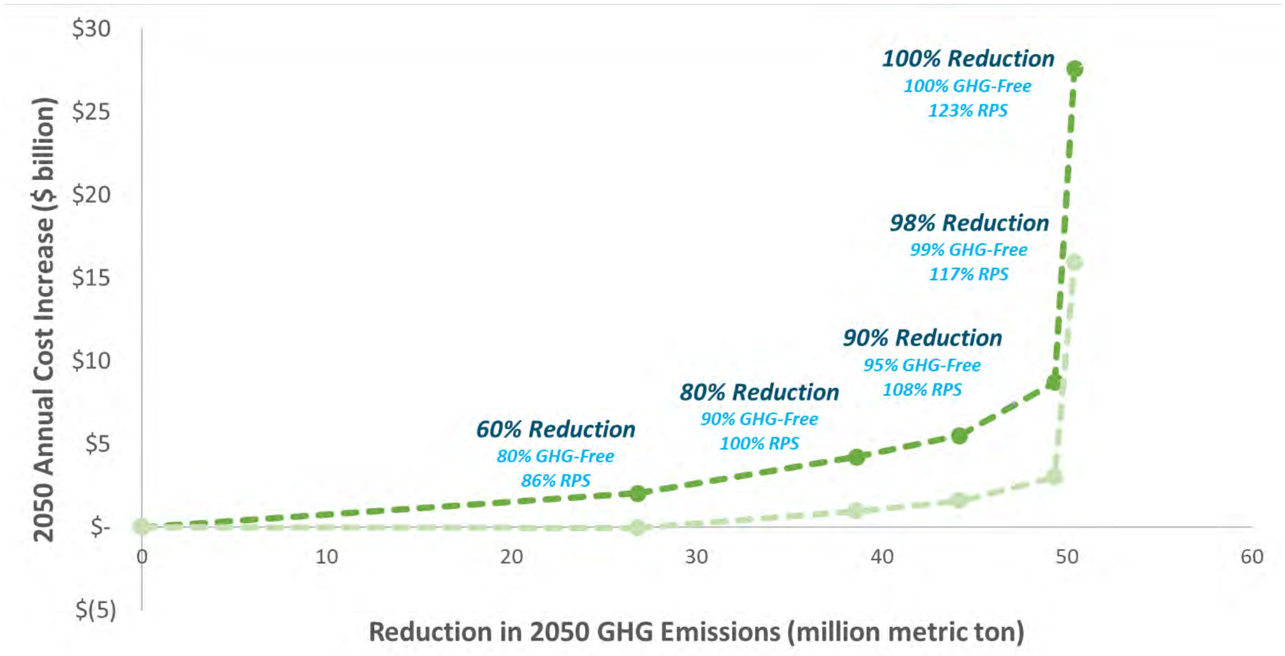
+ Deep decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) of the Greater Northwest system can be obtained at an additional annual cost of $3 to $9 billion ($10 to $28/MWh), i.e., the average retail rates increase 10%-28% in real terms relative to the *Reference* Scenario. This suggests that deep decarbonization of the Greater Northwest system can be achieved at moderate additional costs, assuming that natural gas capacity is available as a resource option to maintain reliability during prolonged periods of low renewable production.
+ The 100% GHG Reduction Scenario requires a significant increase in wind, solar and storage to eliminate the final 1% of GHG-emitting generation. An additional upfront investment of $100 billion to $170 billion is required, relative to the 98% GHG Reduction scenario. Compared to the *Reference* Scenario, the Zero Carbon Scenario requires an additional annual cost of $16 to $28 billion ($52 to $89/MWh), i.e., the average retail rates nearly double.

Costs for individual utilities will vary and may be higher or lower than the region as a whole. This report does not address allocation of cost between utilities.

As shown in Figure 15, the cost increases of achieving deeper levels of decarbonization become increasingly large as GHG emissions approach zero. This is primarily due to the level of renewable overbuild that is required to ensure reliability and the increasing quantities of energy storage required to integrate the renewable energy.

Figure 15: Cost of GHG reduction

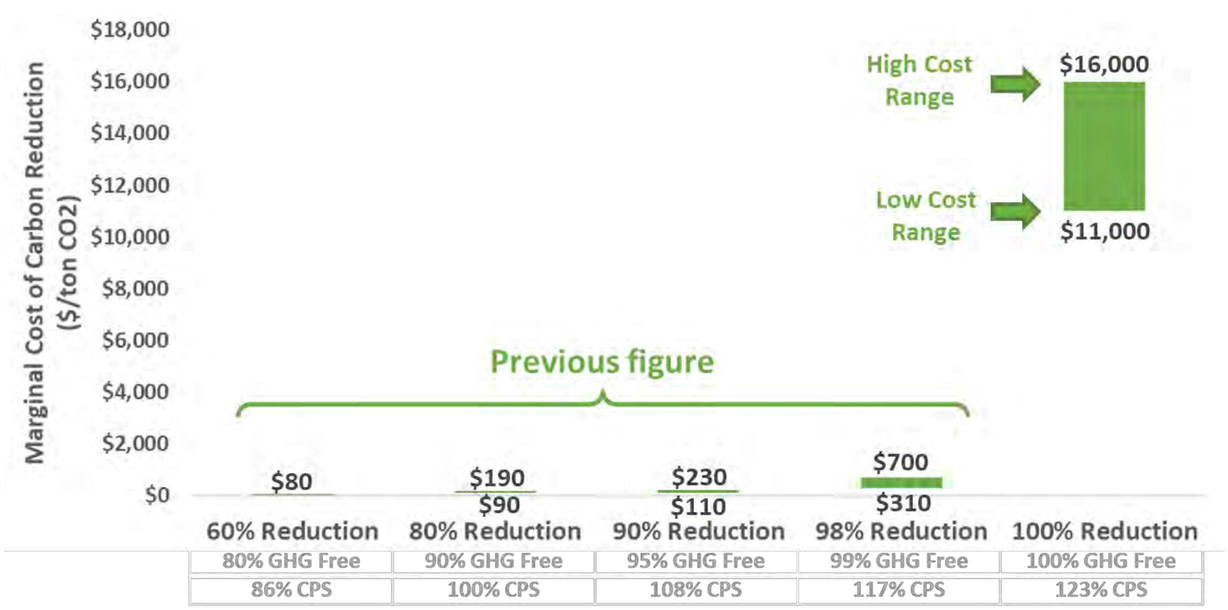


The marginal cost of GHG reduction represents the incremental cost of additional GHG reductions at various levels of decarbonization. Figure 16 and Figure 17 both show the increasing marginal cost of GHG abatement at each level of decarbonization. At very deep levels of GHG reductions, the marginal cost of carbon abatement greatly exceeds the societal cost of carbon emissions, which generally ranges from $50/ton to $250/ton[17], although some academic estimates range up to $800/ton[18].

[17] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[18] https://www.nature.com/articles/s41558-018-0282-y

Figure 16: Marginal Cost of GHG Reduction: 60% Reduction To 98% Reduction

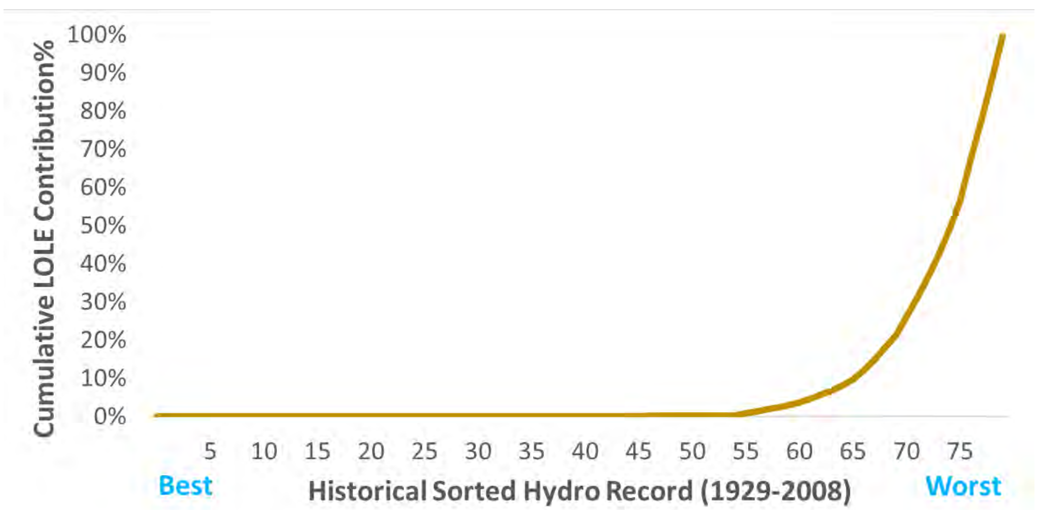
Figure 17: Marginal Cost of GHG Reduction: 60% Reduction to 100% Reduction



5.3.3 DRIVERS OF RELIABILITY CHALLENGES

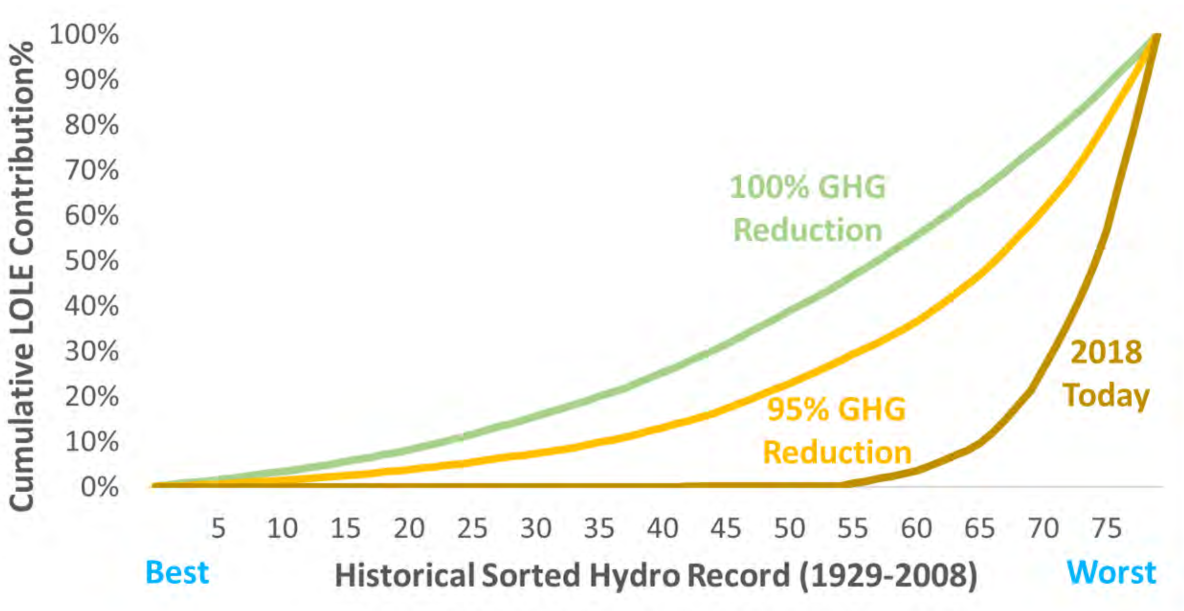
The major drivers of loss of load in the Greater Northwest system include high load events, prolonged low renewable generation events, and drought hydro conditions. In today's system where most generation is dispatchable, prolonged low renewable generation events do not constitute a large cause of loss-of-load events. Rather, the largest cause of loss-of-load events stem from the combination of high load events and drought hydro conditions. This relationship between contribution to LOLE and hydro conditions is highlighted in Figure 18 which shows nearly all loss of load events concentrated in the worst 25% of hydro years.

Figure 18. 2018 System Loss-of-Load Under Various Hydro Conditions



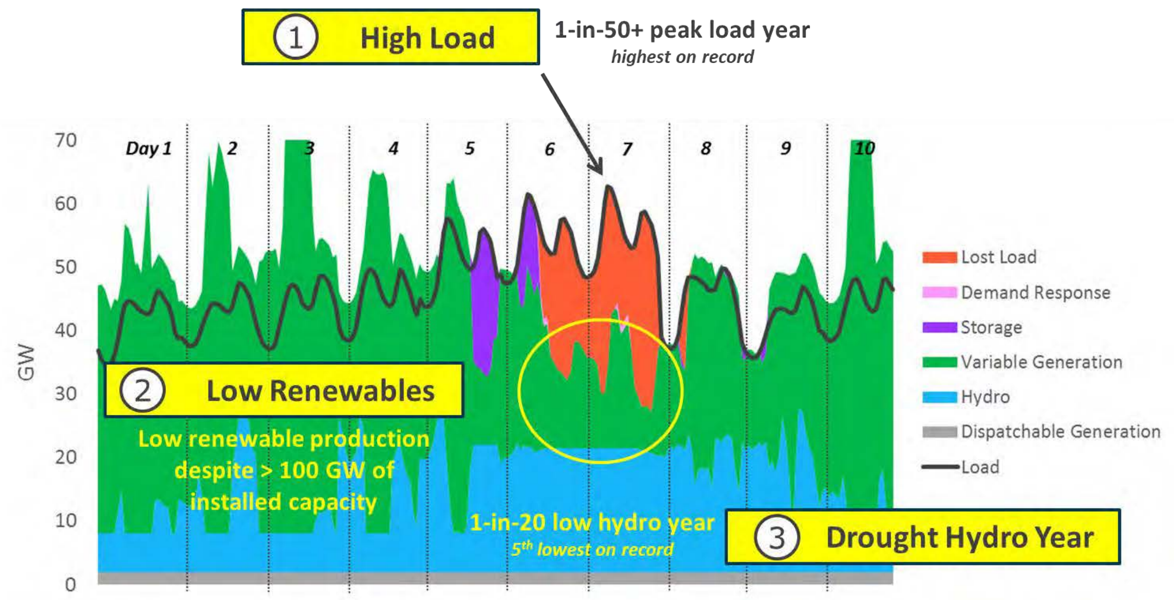
At very high renewable penetrations, in contrast, prolonged low renewable generation events usurp drought hydro conditions as the primary driver of reliability challenges. Figure 19 shows that at high levels of GHG reductions, loss-of-load is much less concentrated in the worst hydro years as prolonged low renewable generation events can create loss-of-load conditions in any year.

Figure 19. 2018 System GHG Reduction Scenarios Loss-of-Load Under Various Hydro Conditions



In practice, these prolonged periods of low renewable output manifest via multi-day winter storms that inhibit solar production over very wide geographic areas or large-scale high-pressure systems associated with low wind output. Figure 20 presents an example of multiday loss-of-load in a sample week in 2050 in the 100% GHG Reduction scenario. In a system without available dispatchable resources to call during such events, low solar radiation and wind speed can often give rise to severe loss-of-load events, especially when renewable generation may be insufficient to serve all load and storage quickly depletes. As shown in the example, over 100 GW of total installed renewables can only produce less than 10 GW of output in some hours. It is the confluence of events like these that drive the need for renewable overbuild to mitigate these events, which in turn leads to the very high costs associated with ultra-deep decarbonization.

Figure 20: Loss-of-load Example in a Sample Week



5.3.4 ROLE OF NATURAL GAS GENERATION CAPACITY

The significant buildout of renewables and storage to meet decarbonization targets contributes to the resource adequacy needs of the system and reduces the need for thermal generation. However, despite the very large quantities of storage and renewables in all the high GHG reduction scenarios, a significant amount of natural gas capacity is still needed for reliability (except for the 100% GHG Reduction scenario where natural gas combustion is prohibited). Even though the system retains significant quantities of gas generation capacity for reliability, the capacity factor utilization of the gas fleet decreases substantially at higher levels of GHG reductions as illustrated in Figure 21. It is noteworthy that all scenarios except 100% GHG reductions require more gas capacity than exists in 2018, assuming all coal (11 GW) is retired.

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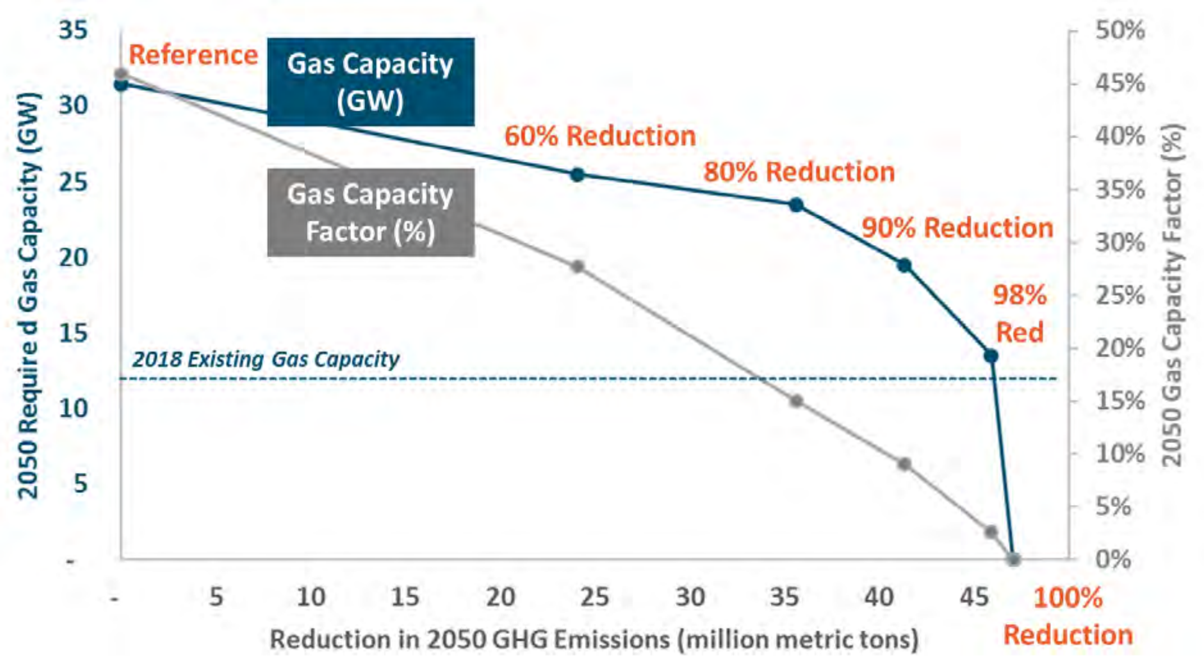
Figure 21: Natural Gas Required Capacity in Different 2050 Scenarios



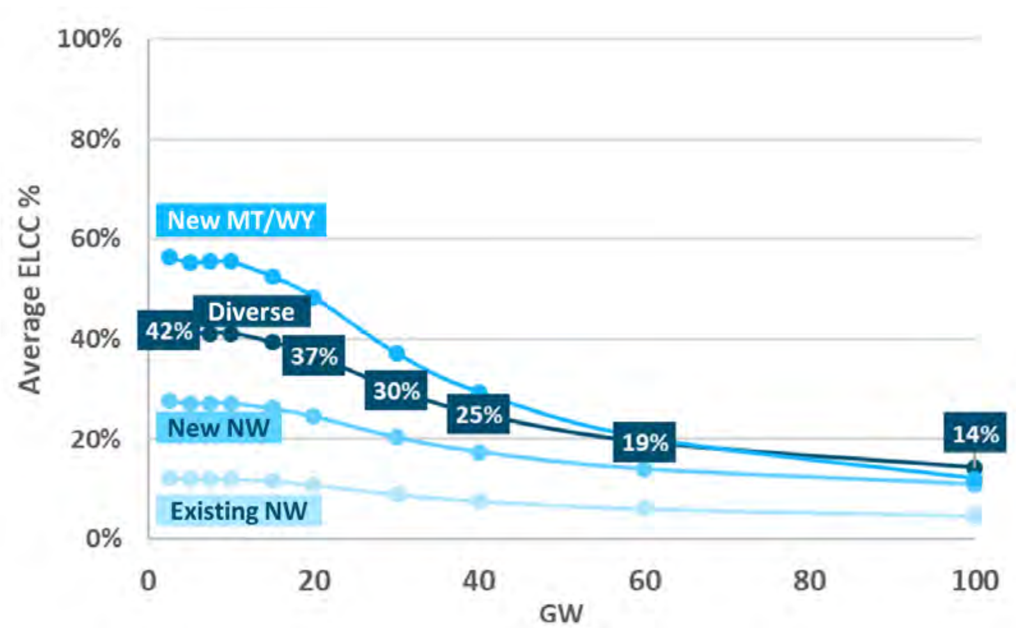
5.3.5 EFFECTIVE LOAD CARRYING CAPABILITY

Effective Load Carrying Capability (ELCC) is a metric used in the electricity industry to quantify the additional load that can be met by an incremental generator while maintaining the same level of system reliability. Equivalently, ELCC is a measure of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, storage, or demand response.

5.3.5.1 Wind ELCC

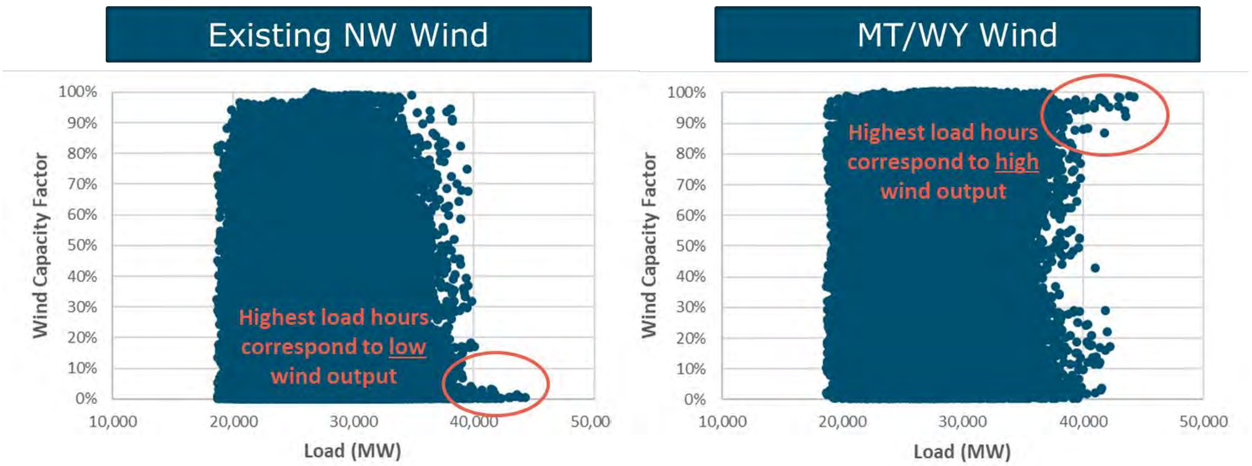
Wind resources in this study are grouped and represented as existing Northwest (Oregon and Washington) wind, new Northwest wind, and new Wyoming and Montana wind. The ELCC curves of each representative wind resource and as well as the combination of all three resources (i.e., “Diverse”) are shown in Figure 22.

Figure 22: Wind ELCC at Various Penetrations



These results are primarily driven by the coincidence of wind production and high load events. Existing wind in the Northwest today, primarily in the Columbia River Gorge, has a strong negative correlation with peak load events that are driven by low pressures and cold temperatures. Conversely, Montana and Wyoming wind does not exhibit this same correlation and many of the highest load hours are positively correlated with high wind output as illustrated in Figure 23.

Figure 23: Load and Wind Correlation (Existing NW Wind and New MT/WY Wind)



Comparing and contrasting the ELCC of different wind resources yields several interesting findings:

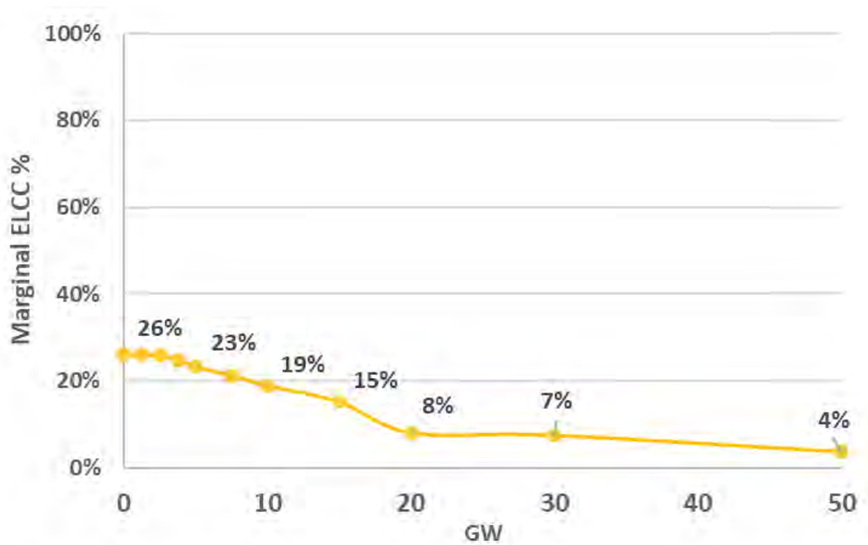
+ The wide discrepancy between the "worst" wind resource (existing NW) and the "best" wind resource (new MT/WY) is primarily driven by the correlation of the wind production and peak load events in Washington and Oregon. Existing NW wind is almost entirely located within the Columbia River Gorge which tends to have very low wind output during the high-pressure weather systems associated with the Greater Northwest cold snaps that drive peak load events. Conversely, MY/WY wind is much less affected by this phenomenon due largely to geographic distance, and wind output tends to be highest during the winter months when the Northwest is most likely to experience peak load events.
+ All wind resources experience significant diminishing returns at high levels of penetration. While wind may generate significant energy during the system peak, ultimately the net load peak that drives ELCC will shift to an hour with low wind production and reduce the effectiveness with which wind can provide ELCC. Diversity mitigates the rate of decline of ELCC.
+ New NW wind has notably higher ELCC values than existing NW wind due to both improvements in turbine technology but also through larger geographic diversity of wind development within the Northwest region but outside of the Columbia River Gorge.

+ Diverse wind (combination of all three wind groups) yields the highest ELCC values at high penetrations. This is because even the best wind resources experience periods of low production and additional geographic diversity can help to mitigate these events and improve ELCC.

5.3.5.2 Solar ELCC

Solar resources in this study are grouped and represented as existing solar and new solar which is built across the geographically diverse area of Idaho, Washington, Oregon, and Utah. In general, solar provides lower capacity value than wind due to the negative correlation between winter peak load events and solar generation which tends to be highest in the summer. Like wind, solar ELCC also diminishes as more capacity is added. Figure 24 shows this information for the ELCC of new solar in the Greater Northwest region.

Figure 24: Solar ELCC at Various Penetrations



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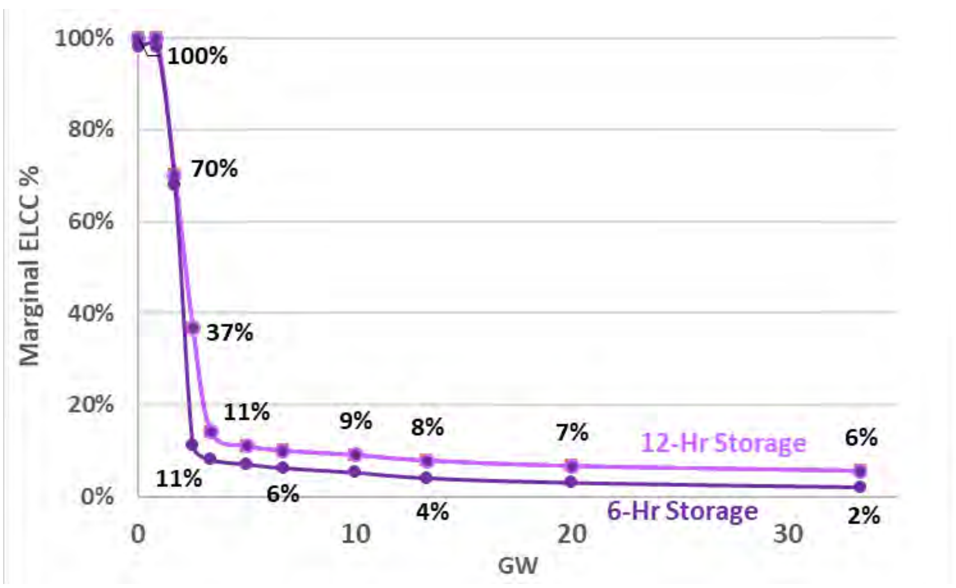
5.3.5.3 Storage ELCC

At small initial penetrations, energy storage can provide nearly 100% ELCC as a substitute for peaking generation that only needs to discharge for a small number of hours. However, at higher penetrations, the required duration for storage to continue to provide ELCC to the system diminishes significantly. This is primarily due to the fact that storage does not generate energy and ELCC is a measure of perfect capacity which can reliably generate energy. This result holds true for both shorter duration (6-hr) and longer duration (12-hr) storage which represents the upper end of duration for commercially available storage technologies. Figure 25 highlights the steep diminishing returns of storage toward ELCC.

Figure 25: Storage ELCC at Various Penetrations



This steeply-declining ELCC value for diurnal energy storage is particularly acute in the Pacific Northwest. This has to do with the fact that there is a significant quantity of energy storage implicit with the 35-GW hydro system in the region. The Federal Columbia River Power System is already optimized over multiple days, weeks and months within the bounds of non-power constraints such as flood control, navigation and fish & wildlife protections. Significant quantities of energy are stored in hydroelectric reservoirs today and dispatched when needed to meet peak loads. Thus, additional energy storage has less value for providing resource adequacy in the Northwest than it does in regions that have little or no energy storage today.

5.3.5.4 Demand Response ELCC

Demand response (DR) represents a resource where the system operator can call on certain customers during times of system stress to reduce their load and prevent system-wide loss-of-load events. However, DR programs have limitations on how often they can be called and how long participants respond when they are called. DR in this study is represented as having a maximum of 10 calls per year with each call lasting a maximum of 4 hours. This is a relatively standard format for DR programs, although practice varies widely across the country. This study also assumes perfect foresight of the system operator such that a DR call is never "wasted" when it wasn't actually needed for system reliability.

Figure 26: Cumulative and Marginal ELCC of DR

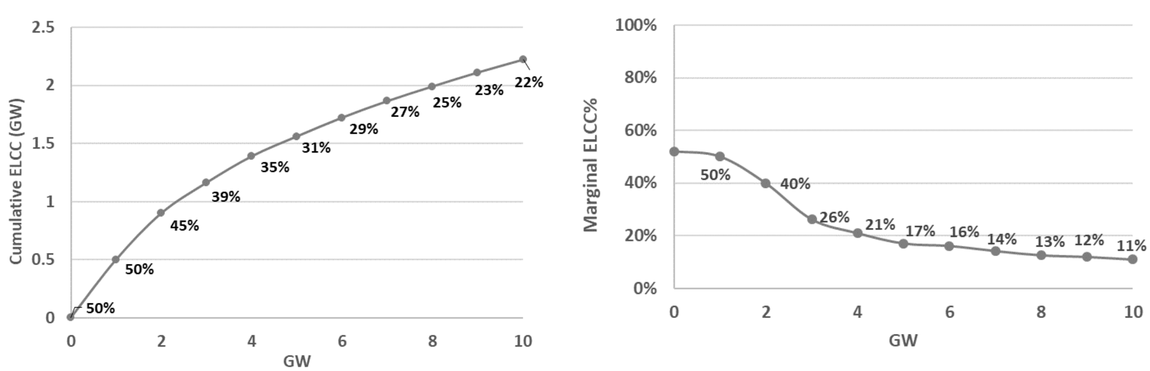


Figure 26 shows the cumulative and marginal ELCC of DR at increasing levels of penetration. Due to the limitations on the number of calls and duration of each call, DR has an initial ELCC of approximately 50%. Similar to energy storage, conventional 4-hour DR has less value in the Pacific Northwest than in other regions due to the flexibility inherent in the hydro system. Also, the capacity value of DR declines as the need for duration becomes longer and longer.

5.3.5.5 ELCC Portfolio Effects

Grouping different types of renewable resources, energy storage, and DR together often creates synergies between the different resources such that the combined ELCC of the entire portfolio is more than the sum of any resource's individual contribution. For example, solar generation can provide the energy that storage needs to be effective and storage can provide the on-demand dispatchability that solar needs to be effective. This resulting increase in ELCC is referred to as the diversity benefit.

Figure 27 shows the average ELCC for each resource type both on a stand-alone basis and also with a diversity allocation that accrues to each resource when they are added to a portfolio together.

Figure 27: ELCC of Solar, Wind, and Storage with Diversity Benefits

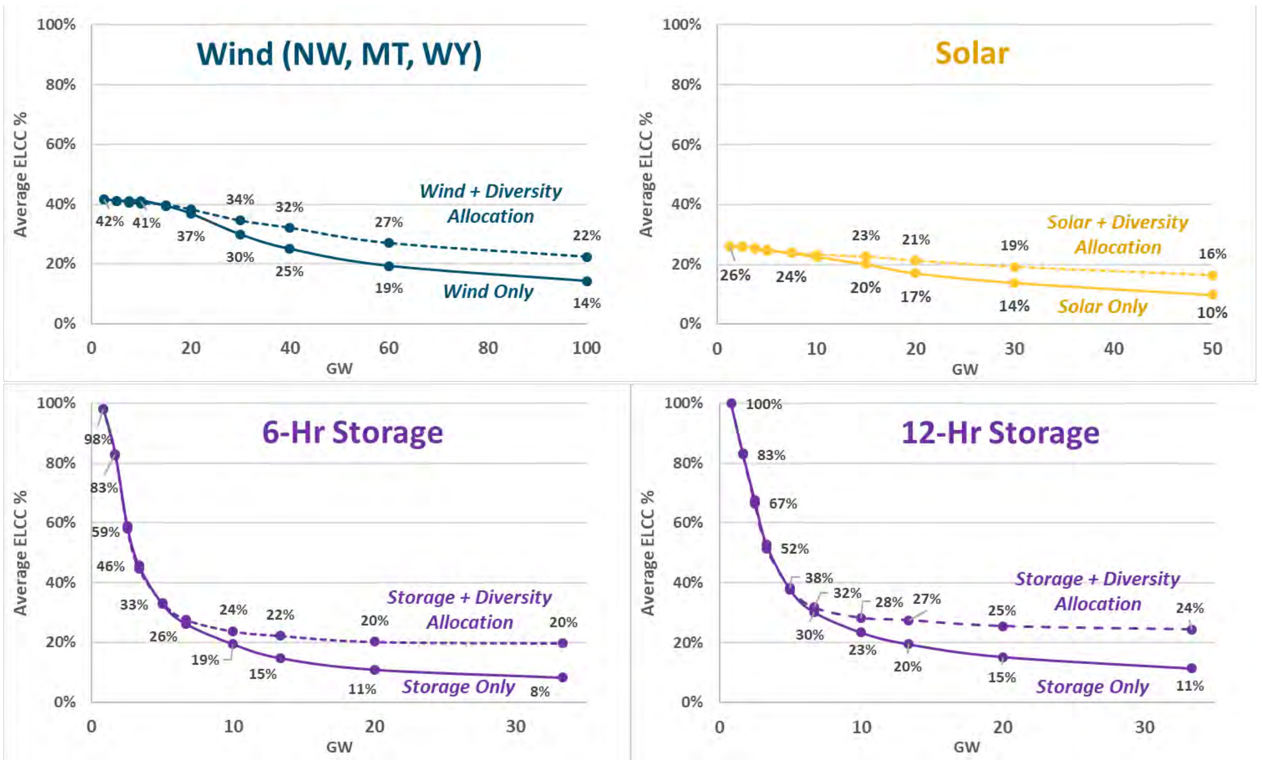


Figure 28 presents the cumulative portfolio ELCC of wind, solar, and storage up to the penetrations required to reliably serve load in a 100% GHG Reduction scenario. At high penetrations of renewables and storage, most of the ELCC is realized through diversity, although it still requires approximately 170 GW of nameplate renewable and storage resources to provide an equivalent of 37 GW of firm ELCC capacity that is required to retire all fossil generation. However, unlike adding these resources on a standalone basis, a combined portfolio continues to provide incremental ELCC value of approximately 20% of nameplate even at very high levels of penetration.

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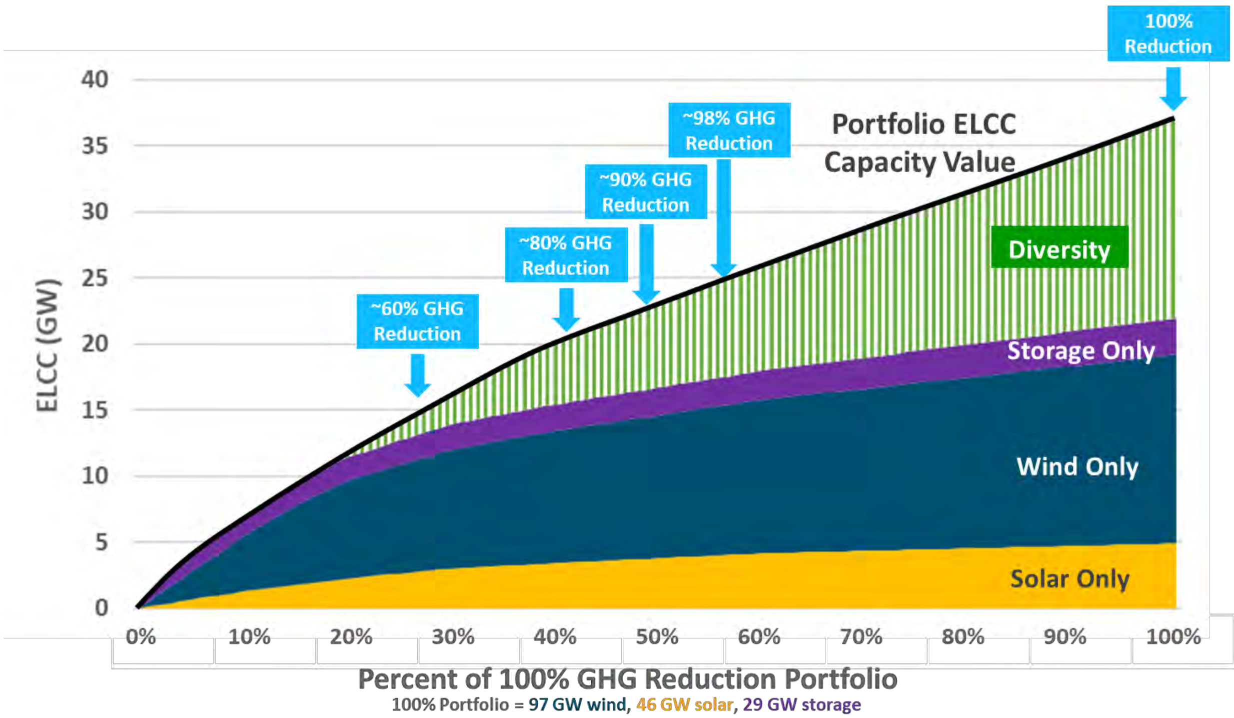
Figure 28: ELCC of Different Portfolios in 2050



5.3.6 SENSITIVITY ANALYSIS

This study also explores the potential resource adequacy needs of a 100% GHG free electricity system recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. Specifically, the alternative resources analyzed are: clean baseload, ultra-long duration storage, and biogas which are further described in Table 21.

Table 21: Sensitivity Descriptions

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

All three of these alternative technology options have the potential to greatly reduce the required renewable overbuild of the system as shown in Figure 29. This is achieved because each of these technologies is dispatchable and can generate energy during prolonged periods of low wind and solar production when short-duration energy storage would become depleted.

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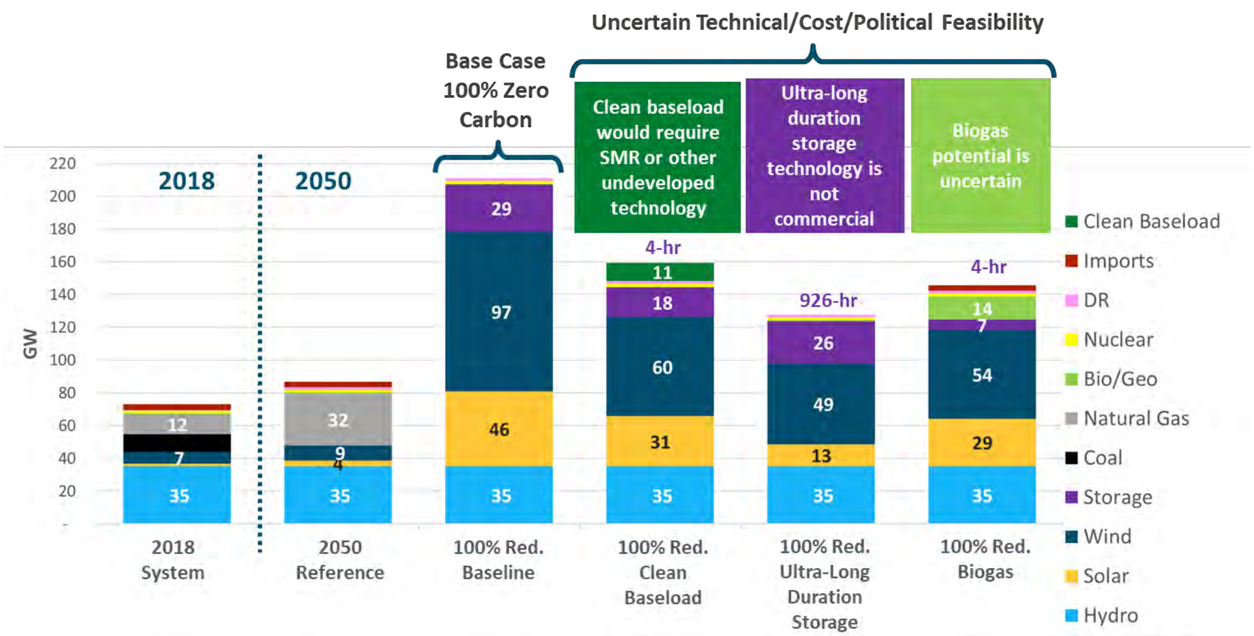
Figure 29: 2050 100% GHG Reduction Sensitivity Portfolio Results



While these alternative technologies clearly highlight the benefits, there are significant technical feasibility, economic, and political feasibility hurdles that stand in the way of large-scale adoption of these alternatives at the present time. In particular, clean baseload would require some technology such as small modular nuclear reactors which is not yet commercially available. Geothermal could provide a clean baseload resources but is limited in technical potential across the region. Fossil generation with carbon capture and sequestration (CCS) is another potential candidate, but the technology is not widely deployed, the cost at scale is uncertain, and current CCS technologies do not achieve a 100% capture rate. Ultra-long duration storage (926 hours) is not commercially available at reasonable cost assuming the technology is limited to battery storage or other commercially proven technologies. Biogas potential is also uncertain and there will be competition from other sectors in the economy to utilize what may be available. A detailed table of installed nameplate capacity for each portfolio is summarized in Appendix A.2.

Table 22 shows key cost metrics for the 100% GHG Reduction sensitivity scenarios. For consistency with the base case scenarios, all costs are relative to the 2050 *Reference* scenario.

Table 22. 100% GHG Reduction Sensitivity Key Cost Metrics

Metric	100% GHG Reduction Baseline	100% GHG Reduction Clean Baseload	100% GHG Reduction Ultra-Long Duration Storage	100% GHG Reduction Biogas
Carbon Emissions (MMT CO_2 / year)	0	0	0	0
Annual Incremental Cost ($B)	$12- $28	$11-$22	$370-$920	$2 - $10
Annual Incremental Cost ($/MWh)	$39-$91	$36-$70	$1,200-$3,000	$5 - $32

Analyzing the portfolio and key cost metrics for each of the 100% GHG Reduction sensitivity cases yields several notable observations.

+ In the Clean Baseload sensitivity, the availability of a carbon-free source of baseload generation dramatically reduces the amount of investment in variable renewables and storage needed to maintain reliability: adding 11 GW of clean baseload resource displaces a portfolio of 15 GW solar, 37 GW wind, and 11 GW of storage. In the context of a highly renewable grid, baseload resources that produce energy round-the-clock—including during periods when variable resources are not available—provide significant reliability value to the system. However, at an assumed price of $91/MWh, the scenario still results in considerable additional costs to ratepayers of between $11-22 billion per year relative to the Reference Scenario.
+ The Ultra-Long Duration Storage sensitivity illustrates a stark direct relationship between the magnitude of renewable overbuild and the storage capability of the system: limiting renewable curtailment while simultaneously serving load with zero carbon generation reliability requires energy storage capability of a duration far beyond today's commercial applications (this relationship is further explored in Figure 30 below). Without significant breakthrough in storage technologies, such a portfolio is beyond both technical and economic limits of feasibility.

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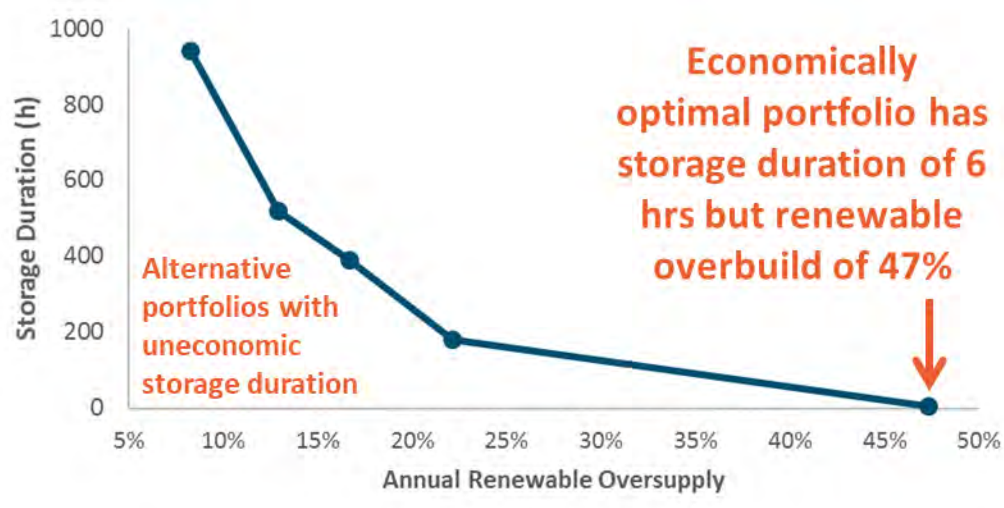
Figure 30: Tradeoff between Renewable Curtailment and Storage Duration



+ The Biogas sensitivity demonstrates the relatively high value of the potential option to combust renewable natural gas in existing gas infrastructure. In this scenario, 14 GW of existing and new gas generation capacity is retained by 2050, serving as a reliability backstop for the system during periods of prolonged low renewable output by burning renewable gas. This sensitivity offers the lowest apparent cost pathway to a zero-carbon electric system because biogas generation does not require significant additional capital investments. While the biogas fuel is assumed to be quite expensive on a unit cost basis, the system doesn't require very much fuel, so the total cost remains reasonable. Moreover, biogas generation uses the same natural gas delivery and generation infrastructure as the Reference Case, significantly reducing the capital investments required. However, the availability of sufficient biomass feedstock to meet the full needs of the electric sector remains an uncertainty. Moreover, there may be competing uses for biogas in the building and industrial sectors that inhibit the viability of this approach.

6 Discussion & Implications

6.1 Land Use Implications of High Renewable Scenarios

Renewables such as wind and solar generation require much greater land area to generate equivalent energy compared to generation sources such as natural gas and nuclear. In the deep decarbonization scenarios, significant amount of land area is required for renewable development. In the 100% GHG Reduction Scenario, estimates of total land use vary from 3 million acres to 14 million acres which is equivalent to 20 to 100 times the land area of Portland and Seattle combined. This is almost three times the land use required under the 80% GHG Reduction scenario.

Table 23. Renewable Land Use in 2050

2050 Scenario	Units	Solar Total Land Use	Wind – Direct Land[19] Use	Wind – Total Land[20] Use
80% GHG Reduction	Thousand acres	84	94	1,135 – 5,337
100% GHG Reduction	Thousand acres	361	241	2,913 – 13,701

Even though such vast expanses of land are available, achieving very high levels of decarbonization would require extensive land usage for such large renewable development. Additionally, significant quantities of land would be required to site the necessary transmission to deliver the renewable energy.

[19] Direct land use is defined as disturbed land due to physical infrastructure development and includes wind turbine pads, access roads, substations and other infrastructure

[20] Total land use is defined as the project footprint as a whole and is the more commonly cited land-use metric associated with wind plants. They vary with project and hence as presented as a range

Both direct and total land use for wind is sourced from NREL's technical report: https://www.nrel.gov/docs/fy09osti/45834.pdf

Land use for solar is sourced from NREL's technical report: https://www.nrel.gov/docs/fy13osti/56290.pdf

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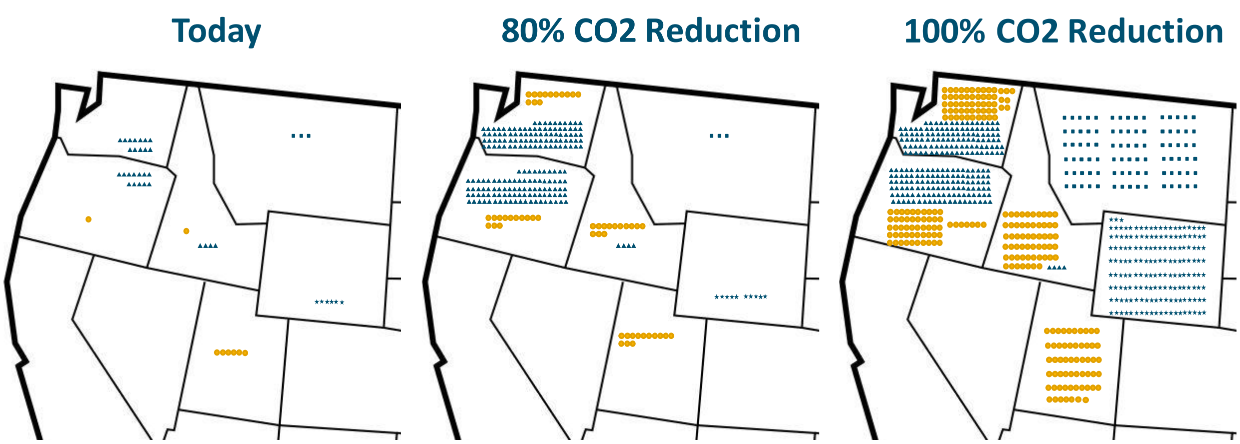
Figure 31 highlights the scale of renewable development that would be required to achieve 100% GHG reductions via only wind, solar, and storage. Each dot in the map represents a 200 MW wind or solar farm. Note that sites are not to scale or indicative of site location.

Figure 31: Map of Renewable Land Use Today and in 80% and 100% GHG Reduction Scenario. Each dot represents one 200 MW power plant (blue = wind, yellow = solar)



6.2 Reliability Standards

Determining the reliability standard to which each electricity system plans its resource adequacy is the task of each individual Balancing Authority as there is no mandatory or voluntary national standard. There are several generally accepted standards used in resource adequacy across North America, with the most common being the "1-in-10" standard. There is, however, a range of significant interpretations for this metric. Some interpret it as one loss-of-load ***day*** every ten years. Some interpret it as one loss-of-load ***event*** every ten years. And some interpret it as one loss-of-load ***hour*** every ten years. The translation of these interpretations into measurable reliability metrics further compounds inconsistency across jurisdictions. However, the ultimate interpretation of most jurisdictions ultimately boils down to the use of one of four reliability metrics:

+ **Annual Loss of Load Probability (aLOLP)**
    - The probability in a year that load + reserves exceed generation at any time
+ **Loss of Load Frequency (LOLF)**
    - The total number of events in a year where load + reserves exceed generation
+ **Loss of Load Expectation (LOLE)**
    - The total number of hours in a year where load + reserves exceed generation
+ **Expected Unserved Energy (EUE)**
    - The total quantity of unserved energy in a year when load + reserves exceed generation

Each of these metrics provides unique insight into the reliability of the electric system and provides information that cannot be ascertained by simply using the other metrics. At the same time, each of the metrics is blind to many of the factors that are ascertained through the other metrics.

The NWPCC sets reliability standards for the Pacific Northwest to have an annual loss of load probability (aLOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, this metric does not provide any information on the number of events, duration of events, or magnitude of events that occur during years that experience loss of load. While this metric has generally served the region well when considering that the biggest reliability drive (hydro) was on an annual cycle, this metric becomes increasingly precarious when measuring a system that is more and more dependent upon renewables.

This study uses loss of load expectation (LOLE), because it is a more common metric that is used by utilities and jurisdictions across the country. Unlike aLOLP, LOLE does yield insight on the duration of events which can help to provide greater detail whether or not a system is adequately reliable.

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However, LOLE does not capture the magnitude of events when they occur and thus misses a potentially large measure of reliability as compared to a metric such as EUE. EUE captures the total quantity of energy that is expected to go unserved each year. While this metric is not perfect, it is likely the most robust metric in terms of measuring the true reliability of an electric system, particularly in a system that is energy-constrained. Despite these attributes, EUE is not commonly used as a reliability metric in the industry today.

RECAP calculates all the aforementioned reliability metrics and can be used to compare and contrast their performance across different portfolios. Table 24 shows the four reliability metrics across different 2050 decarbonization scenarios.

Table 24: Reliability Statistics Across 2050 Decarbonization Portfolios

Reliability Metric	Units	2050 Reference	80% GHG Red.	100% GHG Red.
aLOLP	%/yr	**3.6%**	**8.1%**	**10.5%**
LOLF	#/yr	**0.16**	**0.29**	**0.13**
LOLE	hrs/yr	**2.4**	**2.4**	**2.4**
EUE	GWh/yr	**1.0**	**2.0**	**19.0**

Because the portfolios were calibrated to meet a 2.4 hrs./yr. LOLE standard, all portfolios yield exactly this result. However, this does not mean that all portfolios are equally reliable. Notably, the 100% GHG Reduction scenario has nearly 20 times the quantity of expected unserved energy (EUE) as compared to the reference scenario. The value of unserved energy varies widely depending on the customer type and outage duration; studies typically put the value between $5,000 and $50,000/MWh. This means that the economic cost of unserved energy in the 2050 Reference Scenario is between $5 million and $50 million per year. However, in the 100% GHG Reduction Scenario, which meets the same target for LOLE, the value of unserved energy could be nearly $1 billion annually.

This gives an important insight to some of the qualities of a system that is highly dependent upon dispatch-limited resources. For a traditional system that is composed mainly of dispatchable generation (coal, natural gas, nuclear, etc.), the primary reliability challenge is whether there is enough capacity to serve peak load. Even if the peak is slightly higher than expected or power plants experience forced outages and are unavailable to serve load, the difference between available generation and total load should be relatively small. Conversely, for a system that is highly dependent upon variable generation and other dispatch limited generation, there is a much greater chance that the sum of total generation could be *significantly* lower than total load. This phenomenon was highlighted in Section 5.3.3. The reliability statistics above confirm this intuition by highlighting how aLOLP, LOLF, and LOLE are each uniquely inadequate to fully capture the reliability of a system that is highly dependent upon variable renewable energy. For a system that is heavily dependent on variable generation, EUE may be a more useful reliability metric than the conventional LOLE metrics.

6.3 Benefits of Reserve Sharing

One of the simplifying assumptions made in this study to examine reliability across the Greater Northwest is the existence of a fully coordinated planning and operating regime within the region. In reality, however, responsibility for maintaining reliability within the system is distributed among individual utilities and balancing authorities with oversight from state utility commissions. The current distributed approach to reliability planning has two interrelated shortcomings:

1) Because the region's utilities each plan to meet their own needs, they may not rigorously account for the natural load and resource diversity that exists across the footprint. If each utility built physical resources to meet its own need, the quantity of resources in the region would greatly exceed what would be needed to meet industry standards for loss-of-load.

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2) As an informal mechanism for taking advantage of the load and resource diversity that exists in the region, many utilities rely on front-office transactions (FOTs) or market purchases instead of physical resources, as was discussed in Section 2. This helps to reduce costs to ratepayers of maintaining reliability by avoiding the construction of capacity resources. However, as the region transitions from a period of capacity surplus to one of capacity deficit, and because there is no uniform standard for capacity accreditation, there is a risk that overreliance on FOTs could lead to underinvestment in resources needed to meet reliability standards.

Formal regional planning reserve sharing could offer multiple benefits in the Greater Northwest by taking advantage of load and resource diversity that exists across the region. A system in which each utility builds physical assets to meet its own needs could result in overcapacity, because not every system peaks at the same time. Planning to meet regional coincident peak loads requires less capacity than meeting each individual utility's peak loads. Further, surplus resources in one area could be utilized to meet a deficit in a neighboring area. Larger systems require lower reserve margins because they are less vulnerable to individual, large contingencies. A regional entity could adopt more sophisticated practices and computer models than individual utilities and manage capacity obligation requirements independent from the utilities.

Table 25 provides a high-level estimate of the benefits that could accrue if the Northwest employed a formal planning reserve sharing system. The benefits are divided into (1) benefits due to switching from individual utility peak to regional peak and (2) benefits due to lower target PRM.

A regional planning reserve sharing system could be established in the Greater Northwest. A regional entity could be created as a voluntary organization of utilities and states/provinces. The regional entity would perform loss-of-load studies for the region and calculate the regional PRM and develop accurate methods for estimating capacity credit of hydro and renewables. The entity would create a forward capacity procurement obligation based on studies and allocate responsibility based on their share of the regional requirement.

Table 25. Possible Benefits from a Regional Planning Reserve Sharing System in the Northwest[21]

Capacity Requirement	BPA + Area	NWPP (US)
Individual Utility Peak + 15% PRM (MW)	33,574	46,398
Regional Peak + 15% PRM (MW)	32,833	42,896
Reduction (MW)	741	3,502
Savings ($MM/year)	***$89***	***$420***
	BPA + Area	**NWPP (US)**
Regional Peak + 12% PRM (MW)	31,977	41,777
Reduction (MW)	1,597	4,621
Savings ($MM/year)	***$192***	***$555***

Rules similar to other markets could be made for standardized capacity accreditation of individual resources such as dispatchable generation, hydro generation, variable generation, demand response and energy storage. Tradable capacity products could be defined based on the accredited capacity.

A regional entity could be formed by voluntary association in the Greater Northwest. It could be governed by independent or stakeholder board. Alternatively, new functionality could be added to the existing reserve sharing groups such as Northwest Power Pool (NWPP) and Southwest Reserve Sharing Group, which expand their operating reserve sharing to include planning reserve sharing. It would not require setting up a regional system operator immediately and PRM sharing could be folded into a regional system operator if and when it forms.

[21] Calculated regional and non-coincident peaks using WECC hourly load data averaged over 2006-2012. Savings value estimated using capacity cost of $120/kW-yr. Assumes no transmission constraints within the region. Ignores savings already being achieved through bilateral contracts

7 Conclusions

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

7.1 Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;
    - Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
    - Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
    - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.
2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;
    - Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.
3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.
4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

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- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;
- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

Appendix A. Assumption Development Documentation

A.1 Baseline Resources

Table 26. NW Baseline Resources Installed Nameplate Capacity (MW) by Year.

Category	Resource Class	2018	2030	2050
Thermal	Natural Gas	12,181	19,850	31,500
	Coal	10,895	8,158	0
	Nuclear	1,150	1,150	1,150
	Total	**24,813**	**29,745**	**33,237**
Firm Renewable	Geothermal	79.6	79.6	79.6
	Biomass	489.2	489.2	489.2
Variable Renewables	Wind	7,079	7,079	9,205
	Solar	1,557	1,557	3,593
Hydro	Hydro	35,221	35,221	35,221
Storage	Storage	0	0	0
DR	Shed Demand Response	600	2,200	5,500
Imports	Imports*	3,400	3,400	3,400

*Imports consist of market purchases and non-summer firm imports. For more details, please refer to Imports section.

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A.2 Portfolios of Different Scenarios

Table 27. Portfolios for 2030 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	No Coal
Solar	1.6	1.6
Wind	7.1	7.1
DR	2.2	2.2
Hydro	35.2	35.2
Coal	8.2	-
Natural Gas	19.9	28.0
Nuclear	1.2	1.2
Bio/Geo	0.6	0.6
Storage	-	-
Imports	3.4	3.4

Table 28. Portfolios for 2050 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	60% GHG Reduction	80% GHG Reduction	90% GHG Reduction	98% GHG Reduction	100% GHG Reduction
Solar	3.6	10.6	10.6	10.6	29.2	45.6
Wind	9.2	22.9	38.0	48.2	53.8	97.4
DR	5.5	5.5	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2	35.2	35.2
Coal	-	-	-	-	-	-
Natural Gas	31.5	25.5	23.5	19.5	13.5	-
Nuclear	1.2	1.2	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6	0.6	0.6
Storage	-	2.2 (4-hr)	2.2 (4-hr)	4.4 (4-hr)	6.7 (4-hr)	28.7 (6-hr)
Imports	3.4	3.4	3.4	3.4	3.4	-

Table 29. Zero Carbon Sensitivity Portfolios in 2050– Installed Nameplate Capacity (GW) by Scenario

Resource Class	100% GHG Reduction Renewables	100% GHG Reduction Baseload Tech	100% GHG Reduction Long Duration Storage	100% GHG Reduction Biogas
Solar	45.6	30.7	13.5	29.2
Wind	97.4	60.5	49.2	53.8
DR	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2
Coal	-	-	-	-
Natural Gas	-	-	-	13.5
Nuclear	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6
Storage	28.7 (6-hr)	18.0 (4-hr)	25.9 (926-hr)	6.7 (4-hr)
Clean Baseload	-	11.3	-	-
Imports	-	-	-	-

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Appendix B. RECAP Model Documentation

B.1 Background

RECAP is a loss-of-load-probability model developed by E3 to examine the reliability of electricity systems under high penetrations of renewable energy and storage. In this study, RECAP is used to assess reliability using the *loss-of-load expectation* (LOLE) metric. LOLE measures the expected number of hours/yr when load exceeds generation, leading to a loss-of-load event.

LOLE is one of the most commonly used metrics within the industry across North America to measure the resource adequacy of the electricity system. LOLE represents the reliability over many years and does not necessarily imply that a system will experience loss-of-load every single year. For example, if an electricity system is expected to have two 5-hour loss-of-load events over a ten-year period, the system LOLE would be 1.0 hr./yr LOLE (10 hours of lost load over 10 years).

There is no formalized standard for LOLE sufficiency promulgated by the North American Electric Reliability Coordinating Council (NERC), and the issue is state-jurisdictional in most places expect in organized capacity markets. In order to ensure reliability in the electricity system, the Northwest Power and Conservation Council (NWPCC) set reliability standards for the Pacific Northwest. The current reliability standard requires the electricity system to have an annual loss of load probability (annual LOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, in a system with high renewables, LOLE is a more robust reliability metric.

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B.2 Model Overview

RECAP calculates LOLE by simulating the electric system with a specific set of generating resources and economic conditions under a wide variety of weather years, renewable generation years, hydro years, and stochastics forced outages of generation and transmission resources, while accounting for the correlation and relationships between these. By simulating the system thousands of times under different combinations of these conditions, RECAP is able to provide a statistically significant estimation of LOLE.

B.2.1 LOAD

E3 modeled hourly load for the northwest under current economic conditions using the weather years 1948-2017 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

+ Max and min daily temperature (including one and two-day lag)
+ Month (+/- 15 calendar days)
+ Day-type (weekday/weekend/holiday)
+ Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1948-2017) under current economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (10 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1948-2017 under today's economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This 'base' load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource in Section 0.

Operating reserves of 1,250 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 1,250 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

B.2.2 DISPATCHABLE GENERATION

Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states developed using NWPCC data. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).

B.2.3 TRANSMISSION

RECAP is a zonal model that models the northwest system as one zone without any internal transmission constraints. Imports are assumed to be available as mentioned in Imports Section 4.2.3.

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B.2.4 WIND AND SOLAR PROFILES

Hourly wind and solar profiles were simulated at all wind and solar sites across the northwest. Wind speed and solar insolation data was obtained from the NREL Western Wind Toolkit[22] and the NREL Solar Prospector Database[23], respectively and transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2014.

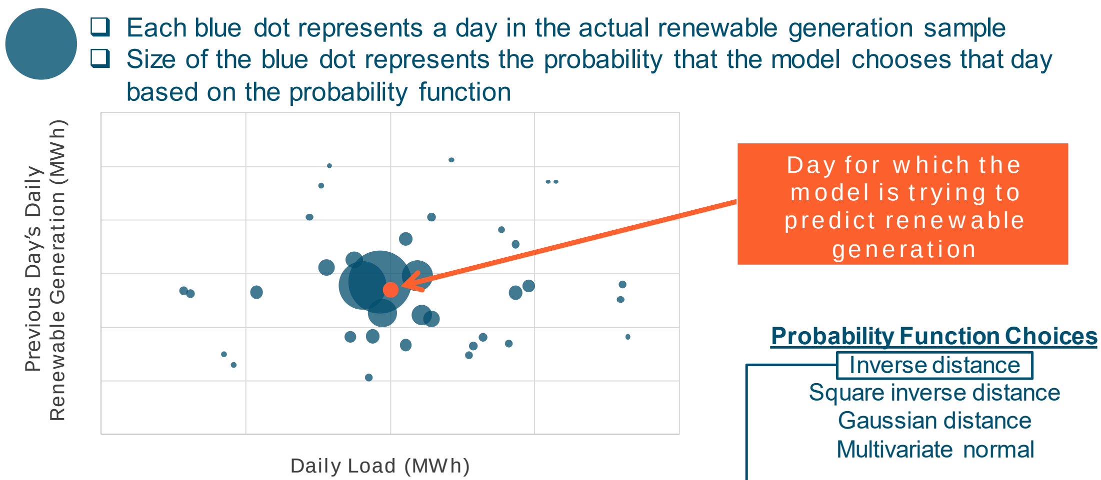
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data i.e., years with available renewable data. For each day in the historical load profile (1948-2017), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

- Season (+/- 15 days)
  - Probability is 1 inside this range and 0 outside of this range
- Load
  - For winter peaking systems like the northwest, high load days tend to have low solar output
- Previous Day's Renewable Generation
  - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 32

[22] https://www.nrel.gov/grid/wind-toolkit.html
[23] https://nsrdb.nrel.gov/

Figure 32: Renewable Profile Selection Process



$$\text{Probability of sample i being selected} = \frac{\frac{1}{Distance_i}}{\sum_{j=1}^{n} \frac{1}{Distance_j}}$$

$$\text{Where distance}_i = \text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$$

B.2.5 HYDRO DISPATCH

Dispatchable hydro generation is a hybrid resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. It is important to differentiate this resource from non-dispatchable hydro such as many run-of-river systems that produce energy when there is hydro available, similar to variable wind and solar facilities, especially in a system like northwest which has an abundance of hydro generation.

To determine hydro availability, the model uses a monthly historical record of hydro production data from NWPCC's records from 1929 – 2008. The same data is used to model hydro generation in NWPCC's GENESYS model. For every simulated load year, a hydro year is chosen stochastically from the historical database. The study assumes no significant hydro build in the future and no correlation with temperature,

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load or renewable generation. Once the hydro year is selected, the monthly hydro budgets denote the amount of energy generated from hydro resources in that month. Since RECAP optimizes the hydro dispatch to minimize loss-of-load, providing only monthly budgets can dispatch hydro extremely flexibly. For example, some of the hydro can be held back to be dispatched during generator outages. Such high flexibility in hydro dispatch is not representative of the current northwest hydro system. Therefore, the monthly budget is further divided into weekly budgets to ensure hydro dispatch is in line with operating practices in the northwest.

In addition to hydro budgets, hydro dispatch has other upstream and downstream hydrological and physical constraints that are modeled in a hydrological model by NWPCC. RECAP does not model the complete hydrological flow but incorporates all the major constraints such as sustained peaking (maximum generation and minimum generation) limits. Sustained peaking maximum generation constraint results in the average hydro dispatch over a fixed duration to be under the limit. Similarly, minimum generation constraints ensure average dispatch over a fixed duration is above the minimum generation sustainable limits. Sustainable limits are provided over 1-hour, 2-hour, 4-hour and 10-hour durations.

The weekly budgets and sustained peaking limits together make the hydro generation within RECAP representative of the actual practices associated with hydro generation in the northwest. Output from RECAP are benchmarked against hydro outputs from NWPCC's GENESYS model.

B.2.6 STORAGE

The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.)

B.2.7 DEMAND RESPONSE

The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

B.2.8 LOSS-OF-LOAD

The final step in the model calculates loss-of-load if there is insufficient available dispatchable generation, renewables, hydro, storage, and demand response to serve load + operating reserves.

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Appendix C. Renewable Profile Development

The electricity grid in the Greater Northwest consists of significant quantities of existing wind and solar generation. Significant new renewable build is expected to be built in the future, as explored in this study. Representing the electricity generation from both existing and future renewable (solar and wind) resources is fundamental to the analysis in this study. In this appendix section, the process of developing these renewable profiles for both existing and new renewable resources is elaborated.

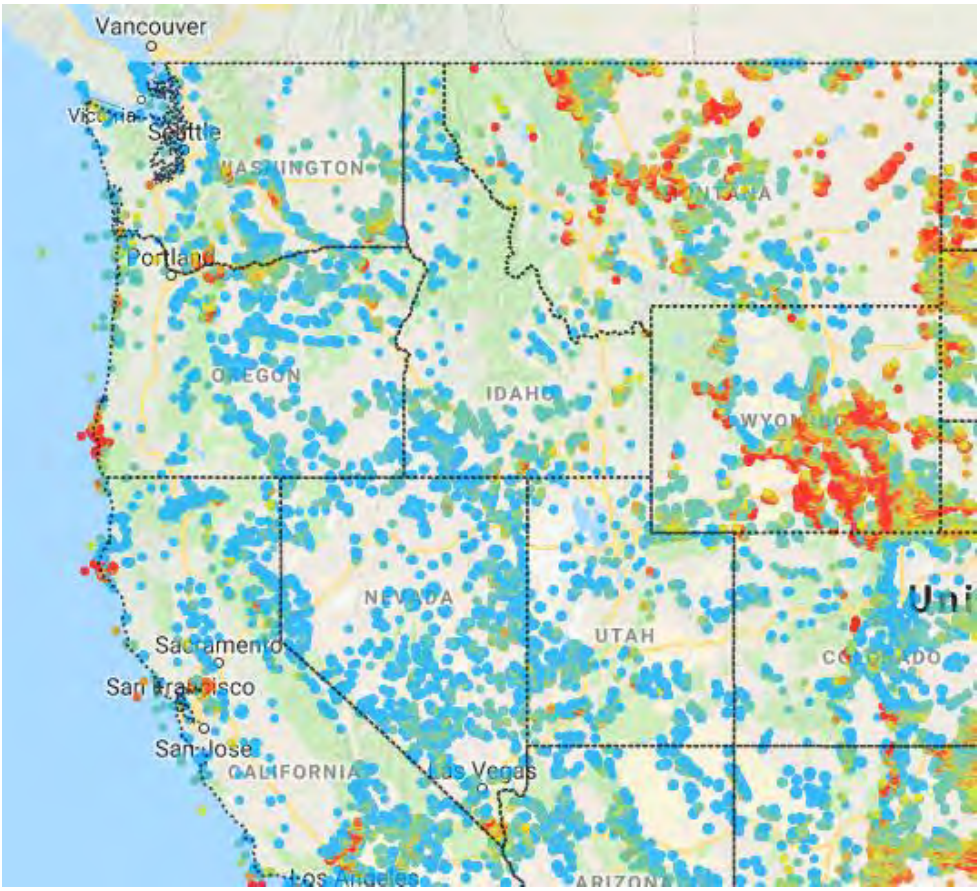
C.1 Wind Profiles

C.1.1 SITE SELECTION

Existing wind site locations (latitude and longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. New candidate wind sites are identified based on the highest average wind speed locations across the Greater Northwest region using data published by NREL[24] (see Figure 33).

[24] https://maps.nrel.gov/wind-prospector/

Figure 33: Wind speed data in the northwest (Source: NREL)



While striving to place new candidate wind sites in the windiest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in wind generation (e.g. the likelihood that the wind will be blowing in one location even when it is not in another). The new candidate sites used in this study are shown in Figure 34. New sites were aggregated geographically into three single resources that were used in the study modeling: Northwest, Montana, and Wyoming. For example, Montana wind in the study is represented as a single profile with new wind turbines installed proportionally across the various “blue squares” shown in Figure 34.

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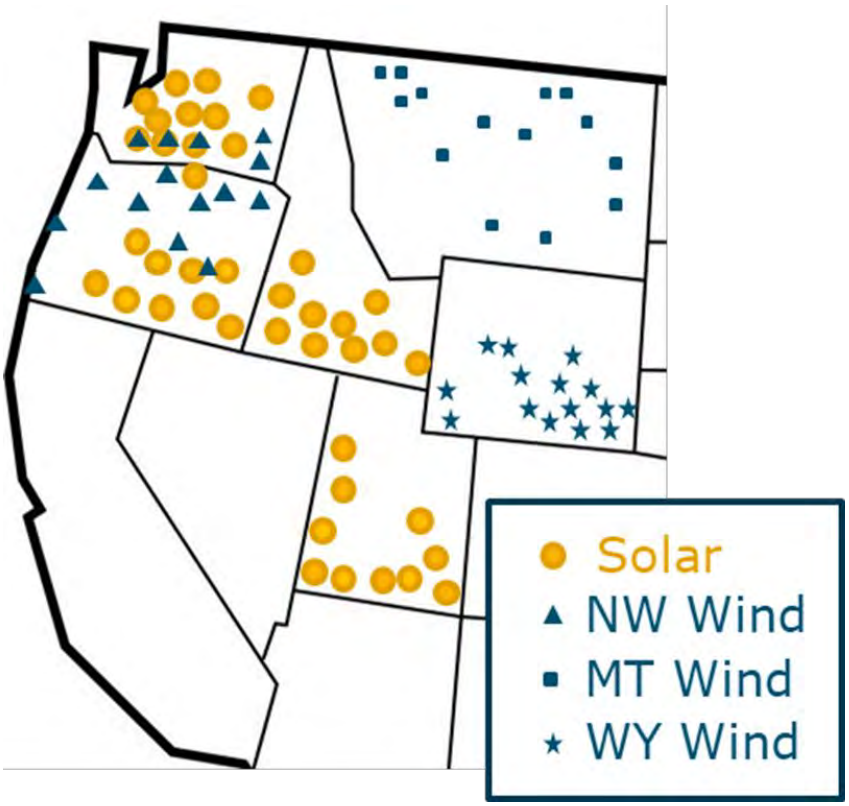
Figure 34: New Candidate Solar and Wind Sites



C.1.2 PROFILE SIMULATION

NREL's Wind Integration National Dataset (WIND) Toolkit[25] contains historical hourly wind speed data from 2007-2012 for every 2-km x 2-km grid cell in the continental United States. This data is downloaded for each selected site location (both existing and new sites).

[25] https://www.nrel.gov/grid/wind-toolkit.html

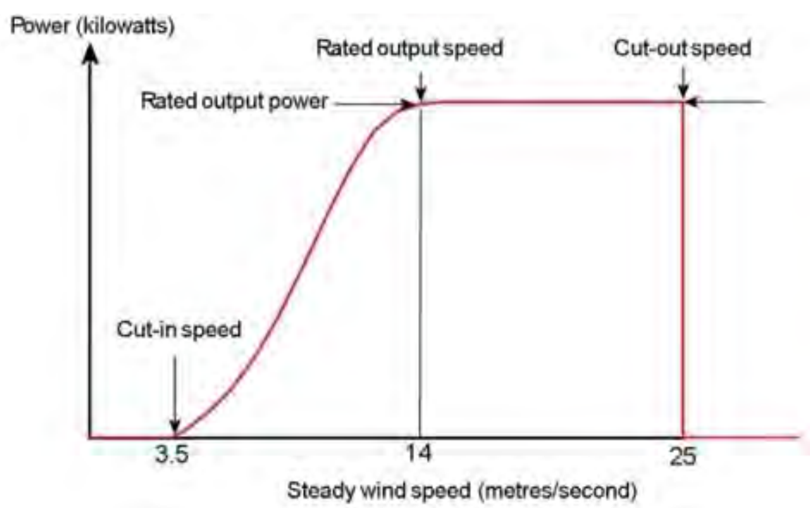
The amount of electricity generated from a wind turbine is a function of wind speed and turbine characteristics, such as the turbine hub height (height above the ground), and the turbine power curve (the mapping of the windspeed to the corresponding power output). Wind speeds increase with height above the ground. Since all NREL WIND data is reported at 100-meters, the wind profile power law is used to scale wind speeds to different heights, depending on the height of the turbine being modeled. This relationship is modeled as:

$$\frac{wind\ speed\ at\ height\ x}{wind\ speed\ at\ heigh\ y} = \left(\frac{height\ x}{height\ y}\right)^{wind\ shear\ coefficient}$$

A wind shear coefficient of 0.143 is used in this study.

A typical power curve is shown in Figure 35. Turbine power curves define the cut-in speed (minimum windspeed for power generation), rated speed (minimum wind speed to achieve maximum turbine output), cut-out speed (maximum wind speed for power generation) and power generation between the cut-in speed and rated speed.

Figure 35: Typical Wind Turbine Power Curve



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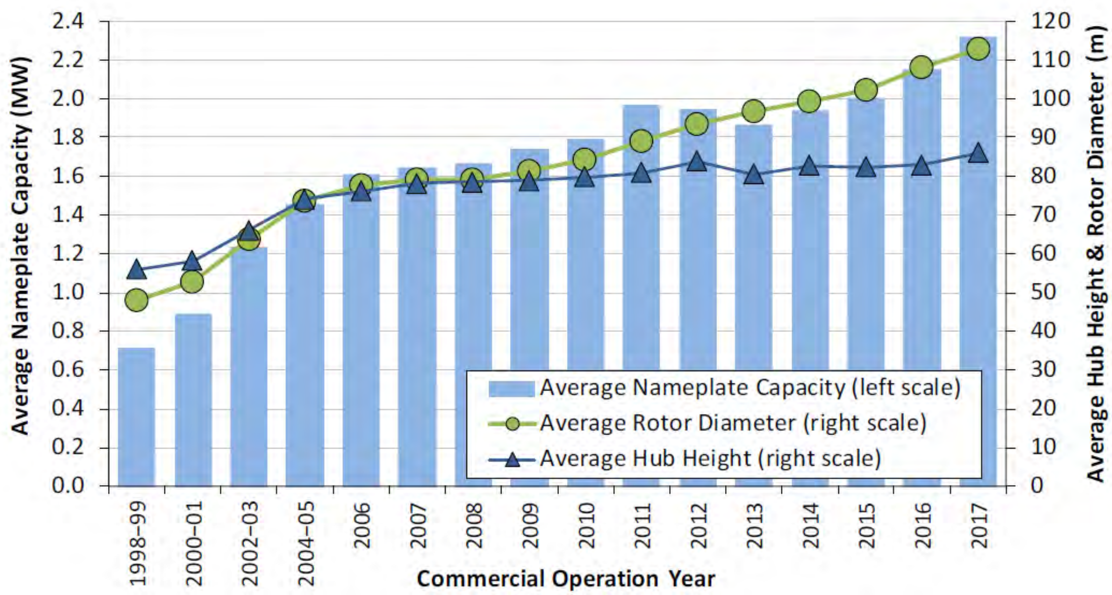
With the advancement of wind turbine technology, hub heights have increased over the years (see Figure 36). For existing wind resources, the hub heights are assumed to be the annual average hub height based on the install year. For new turbines, hub height is assumed to be 100 meters.

Figure 36: Average turbine nameplate capacity, rotor diameter and hub height for land-based wind project in the US



For existing turbines, *Nordic 1000 54m 1 MW (MT)* turbine power curve generates wind profiles that benchmark well to the historical generation profiles. The validation process of turbine power curve selection is described in greater detail in Section C.1.3. For new turbines, NREL standard power turbine curves are used to produce future wind profiles.

The wind generation profiles simulation process can be performed for each 2 km X 2 km grid cell and are usually limited to maximum power of 8 - 16 MW due to land constraints and the number of turbines that can fit within that area. However, each wind site that is selected as described in Section C.1.1 (shown in Figure 34), was modeled as 3 GW of nameplate installed wind capacity and encompasses hundreds of adjacent grid cells from the NREL WIND Toolkit database. Note that the actual installed wind capacity varies by scenario in the study and so these 3 GW profiles were scaled up and down to match the installed capacity of each specific scenario. The adjacent grid cells are chosen such that they are the closest in geographical distance from the first wind site location (first grid cell). Representing a single wind site using hundreds of grid cells represents wind production more accurately and irons out any local production spikes that are limited to only a few grid cells in the NREL WIND Toolkit database.

C.1.3 VALIDATION

BPA publishes historical wind production data[26] in its service territory. This data is used to identify a turbine power curve that best benchmarks wind energy production from existing projects as simulated using historical wind speed data. Three turbine power curves were tested – *GE 1.5SLE 77m 1.5mW (MG)*, *Nordic 1000 54m 1Mw (MT)*, and *NREL standard.* Based on annual capacity factors and hourly generation matching, *Nordic 1000 54m 1Mw (MT)* turbine was selected to represent existing wind turbines in the study. These benchmarking results are illustrated in Figure 37 and Figure 38.

[26] https://transmission.bpa.gov/business/operations/wind/

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Figure 37: Comparison of Annual Wind Capacity Factors for Benchmarking

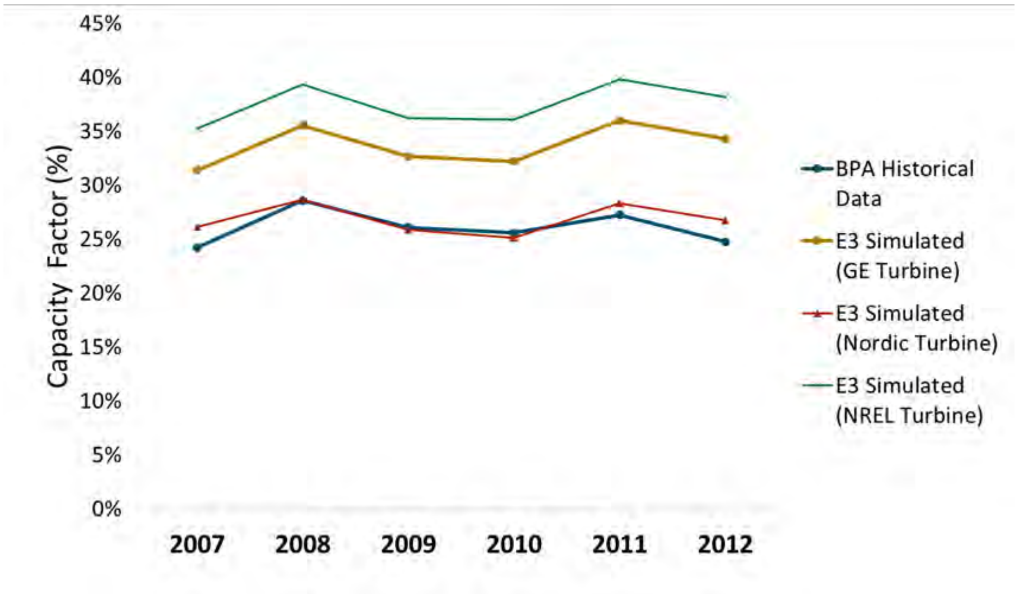
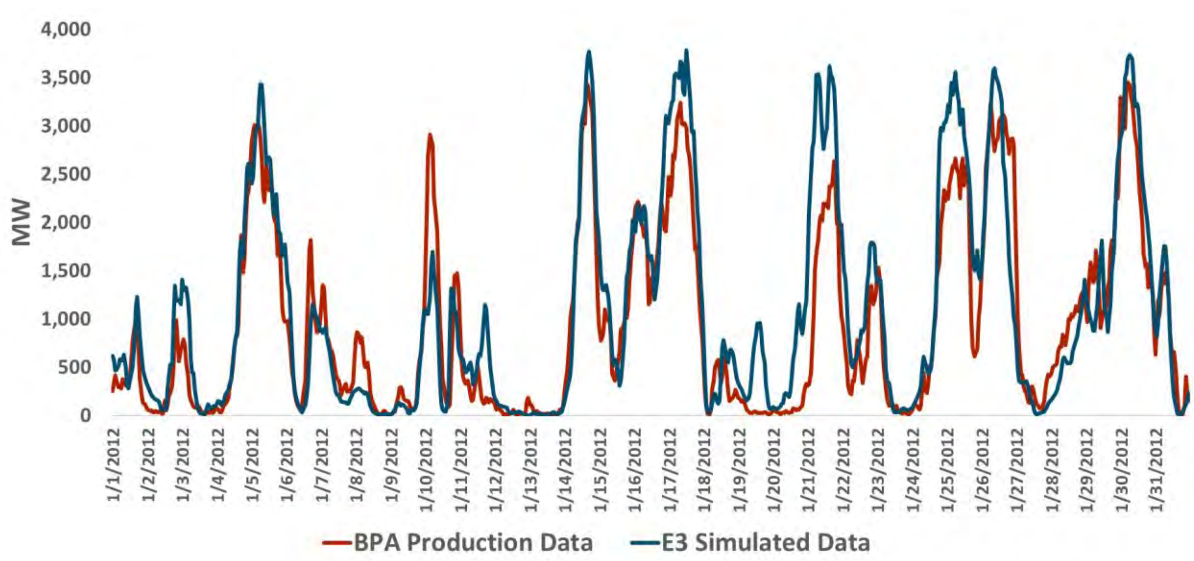


Figure 38: Comparison of Hourly Historical Wind Generation to Simulated Wind Generation for January 2012



C.2 Solar Profiles

C.2.1 SITE SELECTION

Existing solar site locations (latitude, longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. To build new candidate solar resources in the future, the best solar sites in the region are identified based on the highest insolation from the solar maps published by NREL[27] (see Figure 39). While striving to place new candidate wind sites in the sunniest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in solar generation (e.g. the likelihood that the sun will be shining in one location even when it is not in another). The future solar sites used in this study are shown in Figure 34.

[27] https://maps.nrel.gov/nsrdb-viewer/

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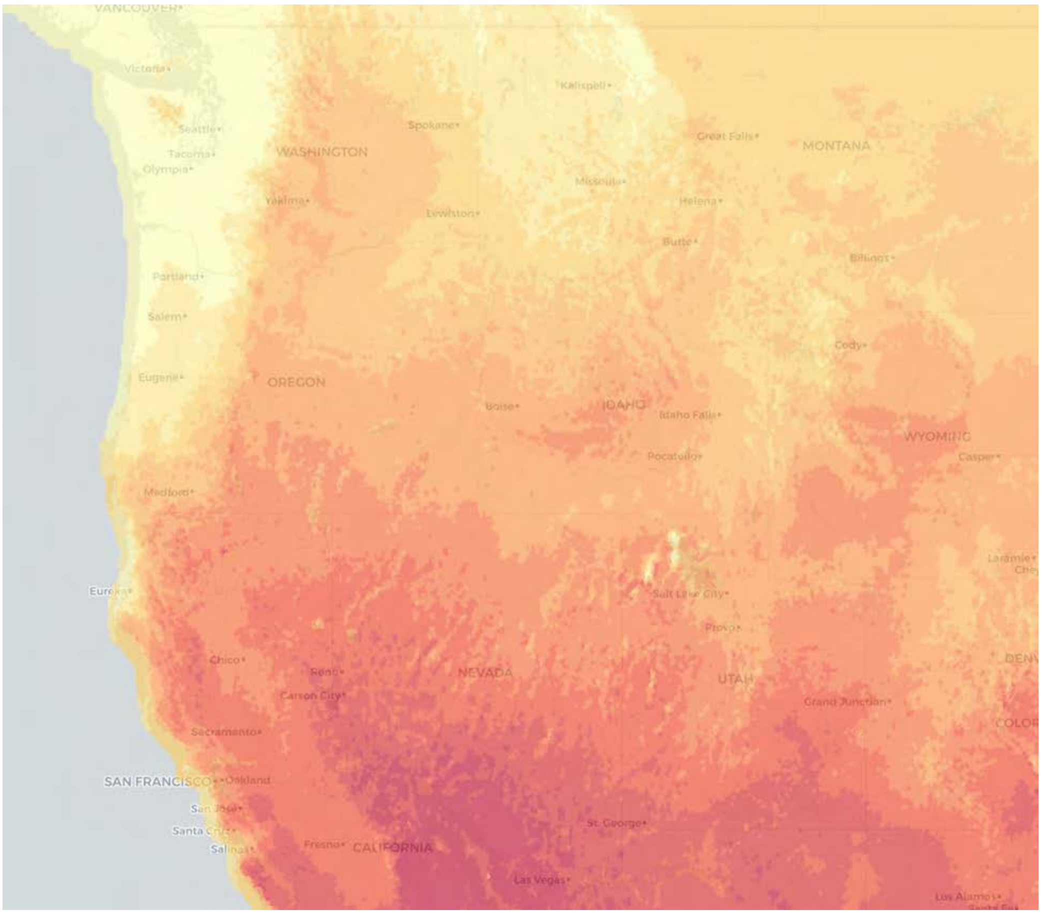
Figure 39: Solar insolation data in the northwest (Source: NREL)



C.2.2 PROFILE SIMULATION

NREL Solar Prospector Database [28] includes historical hourly solar insolation data: global horizontal irradiance (GHI), direct normal irradiance (DNI), diffuse horizontal irradiance (DHI), and solar zenith angle from 1998-2014. This data is downloaded for all each selected site location (both existing and new).

[28] https://nsrdb.nrel.gov/

The hourly insolation data is then converted to hourly production profiles using the NREL System Advisor Model (SAM) simulator. Additional inputs used are tilt, inverter loading ratio and tracking type. All panels are assumed to have a tilt equal to the latitude of their location. The study assumes an inverter loading ratio of 1.3 and that all solar systems are assumed to be single-axis tracking. The NREL SAM simulator produces an hourly time series of generation data that is used to represent the electricity generation from the solar sites in this study.

Forty sites are aggregated to represent the solar candidate resource used in this study. These sites are evenly distributed in the four states of Oregon, Washington, Idaho, and Utah as shown in Figure 34.

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